PUBLIC SERVICE COMMISSION OF WISCONSIN

FINAL

STRATEGIC ENERGY

ASSESSMENT

2020-2026

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Strategic Energy Assessment 2026 – Final

Public Service Commission of Wisconsin
North Tower, 6th Floor
Hill Farms State Office Building
4822 Madison Yards Way
Madison, Wisconsin 53705

Phone: (608) 266-5481 – General toll-free: (888) 816-3831 – Fax: (608) 266-3957
Website: http://psc.wi.gov
Email: PSCSEA@wisconsin.gov
Home Page: http://psc.wi.gov

Questions from the Legislature and the media may be directed to Matthew Sweeney at (608) 266-9600.

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EXECUTIVE SUMMARY

Under Wis. Stat. 196.491(2), the Public Service Commission of Wisconsin (Commission) prepares a biennial Strategic Energy Assessment (SEA) to evaluate Wisconsin's current and future electricity supply. To address all aspects of the Commission's mission to ensure the provision of quality utility services in Wisconsin, this document addresses:

- The **adequacy** of available supplies to support the generation of electricity, as well as the adequacy of the transmission system to carry electricity supplies from generation sources to customers;
- The **reliability** of electric system operations to provide consistent service and avoid outages, including through resilience against extreme events that challenge system operations;
- The **affordability** of customers' electric rates and bills, as regulated by the Commission's authority to approve rates set by regulated electric providers; and
- The **environmentally responsible** provision of electric services, through programs and policies related to energy efficiency, demand response, renewable energy, and electric vehicles; as well as efforts among electric providers to reduce carbon dioxide emissions.

Under the SEA's statutory and administrative code requirements, electric providers and transmission owners operating in Wisconsin[1] file specified historical and forecasted information on electric system operations. All electric providers submitted required data in November 2019, providing forecasted information through 2026.[2] Commission staff analyzed the data submitted along with other information sources to develop the SEA as a comprehensive resource for readers regarding Wisconsin's electric system. The Commission approved a draft SEA for comment in May 2020, and received feedback through a public hearing and written comments submitted by 77 provider representatives, parties, and members of the public. This final SEA report updates the draft to address questions, and suggestions raised through comments. The final SEA also includes additional information on developments occurring since publication of the draft, including the announcement of plans to retire the Edgewater Generating Station Unit 5 coal plant.

The data used for SEA analysis was collected in advance of the global COVID-19 pandemic, which began affecting Wisconsin on a broad scale in March 2020. Moreover, the effects of the pandemic on Wisconsin's electric system are rapidly evolving, and future conditions remain difficult to predict. This draft report provides the information available as of September 2020, and identifies topics where ongoing pandemic-related developments may have significant effects on the published findings.

[1] For purposes of the SEA, electric providers required to submit data include any entity who owns, operates, manages or controls, or who expects to own, operate, manage or control, electric generation capacity in Wisconsin greater than 5 megawatts (MW).

[2] In addition, Dairyland Power Cooperative (DPC) updated its filing in January 2020 to incorporate its announced plans to close the Genoa coal plant.

ELECTRIC SUPPLY IN WISCONSIN

As of November 2019, Wisconsin electric providers projected limited future growth in electric demand from customers. Statewide peak megawatt (MW) demand is projected to increase by less than 0.4 percent annually between 2021 and 2026. While providers projected higher growth of 1.8 percent in 2020, the COVID-19 pandemic is likely to reduce actual peak demand below those levels in 2020.

Wisconsin electric providers plan to procure electric generation capacity sufficient to meet projected customer demand, plus an additional "reserve margin" to ensure supplies are adequate if actual demand exceeds projections. Based on currently known information, Wisconsin's projected capacity slightly exceeds the 8.9 percent reserve margin established for 2020, but may fall below the increased reserve margin of 9.4 percent in each year between 2021 and 2026. The Commission will continue to monitor changing assumptions and utility plans to ensure reserve margin targets are met in future years.

While coal remains the most common source of electricity generation in Wisconsin, the share of energy produced from coal declined from 63 percent to 48 percent between 2010 and 2018. The share of energy produced from natural gas increased from 9 percent to 24 percent, driven by decreases in natural gas prices. Solar and wind generation have also increased since 2010 in connection with declining generation costs.

Electric providers report as of May 2020 that they anticipate adding approximately 2,700 MW of new owned or leased generation capacity through 2026, all from new natural gas combined-cycle plants and new solar projects. Providers also report plans to retire 1,478 MW of generation capacity, primarily coal resources and natural gas combustion turbines that operate less efficiently than new combined-cycle plants.

If all additions and retirements are implemented as reported by electric providers, coal would decline from 48 percent of Wisconsin's generation in 2018 to 38 percent in 2026, natural gas would increase from 27 percent to 34 percent, and solar resources would increase from less than 0.1 percent to 4.5 percent. The share of solar resources may increase further through future procurements from independently developed projects underway in Wisconsin.

ELECTRIC TRANSMISSION IN WISCONSIN

Wisconsin participates in the regional transmission system of the Midcontinent Independent System Operator, Inc. (MISO), which operates an integrated electric grid across 15 states that supports long-distance transmission of electricity supplies. Participating in MISO allows Wisconsin to access low-cost energy resources located in nearby states, and offers access to a wholesale market with clear and predictable energy prices that providers may use to maintain adequate electric supply.

MISO maintains primary responsibility for planning large transmission projects that cross state lines. Commission staff participate as stakeholders within MISO's planning process to ensure Wisconsin's needs and priorities are represented in final decisions.

MISO's most recently completed planning cycle has identified 28 future transmission projects located completely or partially in Wisconsin, with costs totaling $217.8 million. The largest share of costs would be allocated to projects updating aging infrastructure and addressing condition issues.

Commission staff have successfully advocated for improvements to MISO's transmission planning processes. With Wisconsin's support, MISO has recently implemented data enhancements to more accurately assess the benefits of proposed projects, and will be implementing a framework to more precisely allocate transmission costs to the customers receiving benefits.

RELIABILITY AND RESILIENCE

Wisconsin's largest electric providers compare favorably to most states nationwide in minimizing the number of outages that interrupt service to customers. The average duration of outages experienced by Wisconsin customers falls closer to national averages.

Efforts to maintain the electric system's resilience against extreme events such as severe weather and cyberattacks has increased in recent years. The Commission's Office of Energy Innovation has partnered with state emergency management staff to develop energy-related emergency plans and conduct exercises to identify improvements to emergency management practices. In response to the public health emergency declared for COVID-19, the Commission is collecting information regarding the effects of the pandemic on critical energy infrastructure, and collaborating with other agencies to define appropriate responses.

CUSTOMER RATES AND BILLS

The Commission regulates the customer rates charged by investor-owned and municipal utilities to allow utilities to recover their costs while maintaining the lowest feasible cost to customers. Total costs for Wisconsin's largest electric providers increased 1.8 percent between 2009 and 2018, with increasing costs for electric generation and transmission accounting for the largest growth.

Continued increases in generation costs may occur in future years as providers continue to incur construction and procurement costs from investing in new generation resources. These investments may also be accompanied by fuel cost decreases due to the increased deployment of zero-carbon energy resources that require no fuel. Ongoing application of savings from 2017's federal tax reform legislation will also support continued cost reductions.

Based on national data, Wisconsin residential customers are charged higher average rates than Midwest or national averages, but also pay significantly less on their average monthly bills, due to lower average levels of energy use. Comparisons between states should be made cautiously due to differences between states in energy market conditions and regulatory frameworks.

Many Wisconsin electric providers offer innovative rate options designed to help customers exercise control over their costs and reduce their energy bills. 1.5 percent of Wisconsin residential, commercial, and industrial customers are enrolled in time-of-use and real-time pricing rates that can reduce costs for both providers and customers by encouraging customers to shift their usage to hours of the day where energy supply costs are lower. While many customers can benefit from these rates, benefits may be limited for customers that are not able to reduce their energy consumption during high-cost periods of the day.

Low-income customers face a higher energy burden than other customers: they must pay a larger percentage of their total income for the same amount of electric service as other customers. Wisconsin electric providers and the Commission can seek to help low-income customers manage their energy burden in multiple ways, including by referring customers to programs that offer energy efficiency and bill payment assistance.

In March 2020, the Commission directed electric providers to take several steps to address increased affordability concerns related to the COVID-19 pandemic, including prohibiting providers from disconnecting service or charging late fees for any customer unable to pay their bill for the duration of the public health emergency. The Commission also opened an investigation under docket 5-UI-120 to conduct ongoing review of safety, reliability, and affordability issues related to the pandemic.

CLEAN ENERGY PROGRAMS AND POLICIES

Focus on Energy, Wisconsin's statewide energy efficiency and renewable resource program, provides a portfolio of programs to help customers throughout the state reduce their energy use. From 2015 through 2018, Focus achieved lifetime savings sufficient to power more than two million average Wisconsin homes for a year, and reduce carbon dioxide emissions by more than 28.5 million tons. A recent national study found that Wisconsin ran the most cost-effective energy efficiency program of any state in the country.

Beginning in 2020, Focus on Energy has deployed a restructured program portfolio intended to help the program maintain savings levels and cost-effectiveness in future years. Focus on Energy will also be conducting a potential study in 2020-2021 to review the amount of savings Focus will be able to achieve in future years, and assess the program's future impacts on reducing carbon emissions and energy demand.

Wisconsin electric providers operate demand response programs designed to reduce energy demand during peak periods and create financial savings for providers and customers. While available response capacity reached nearly 10 percent of statewide peak demand in 2018, electric providers have only deployed a small fraction of available resources. While some providers are discontinuing established demand response programs due to low enrollment and technical limitations, smart thermostats and other wi-fi technologies are presenting opportunities to establish new program models.

The primary driver for renewable resource development during the past decade has been compliance with Wisconsin's Renewable Portfolio Standard law. Providers have met the Renewable Portfolio Standard (RPS) requirement to provide at least 10 percent of electricity generation through renewable resources each year since 2013, primarily from wind energy received through the regional transmission system.

Declining costs, environmental benefits, and customer interest in zero-carbon energy are beginning to drive increased renewable deployment above RPS requirements. Recently approved solar energy projects would increase renewable energy to 13 percent of generation by 2023, and further increases would occur if other planned projects are approved and implemented. Electric providers have also increased their total capacity offered through community solar programs by 61 percent between 2017 and 2019.

Wisconsin had more than 7,000 customer-owned renewable generation installations operating in 2019, with capacity equal to 1.66 percent of statewide capacity. Customer-owned solar installations account for more than 90 percent of the total number of customer-owned renewable installations and 0.64 percent of total statewide capacity.

Large-scale use of electric vehicles (EVs) could have significant implications for Wisconsin's electric system, by increasing electric demand, modifying the timing and location of energy use, and presenting new considerations for customer rates and service arrangements. The Commission has opened a collaborative, stakeholder-driven investigation to consider EV-related policies. Informed by findings from the investigation the Commission issued a draft order for comment in August 2020 that, if implemented, would require large providers to submit pilot program proposals for Commission approval and establish a framework setting clear expectations for the information any provider must include in proposing EV programs.

ELECTRIC SYSTEM EMISSIONS

Within the past two years, Wisconsin's five largest electric providers have established goals to reduce carbon dioxide (CO_2) emissions from electric generation 100 percent by 2050. Achievement of those goals would reduce statewide emissions from electricity by approximately 85 percent in 2050. Further reductions may be achieved by other providers who have not set formal goals but are also retiring fossil fuel generation and adding zero-carbon generation resources.

Wisconsin electric providers project that their 2020 emissions will achieve reductions of 37.1 percent, driven substantially by the retirement of nearly 1,800 MW of coal generation between 2018 and 2020. Providers expect to achieve continued emissions reductions in future years through deployment of natural gas in place of coal generation, deployment of additional solar resources, increased zero-carbon generation on MISO's regional grid, and continued increases in energy efficiency.

CHAPTER 1 – ELECTRIC SUPPLY IN WISCONSIN

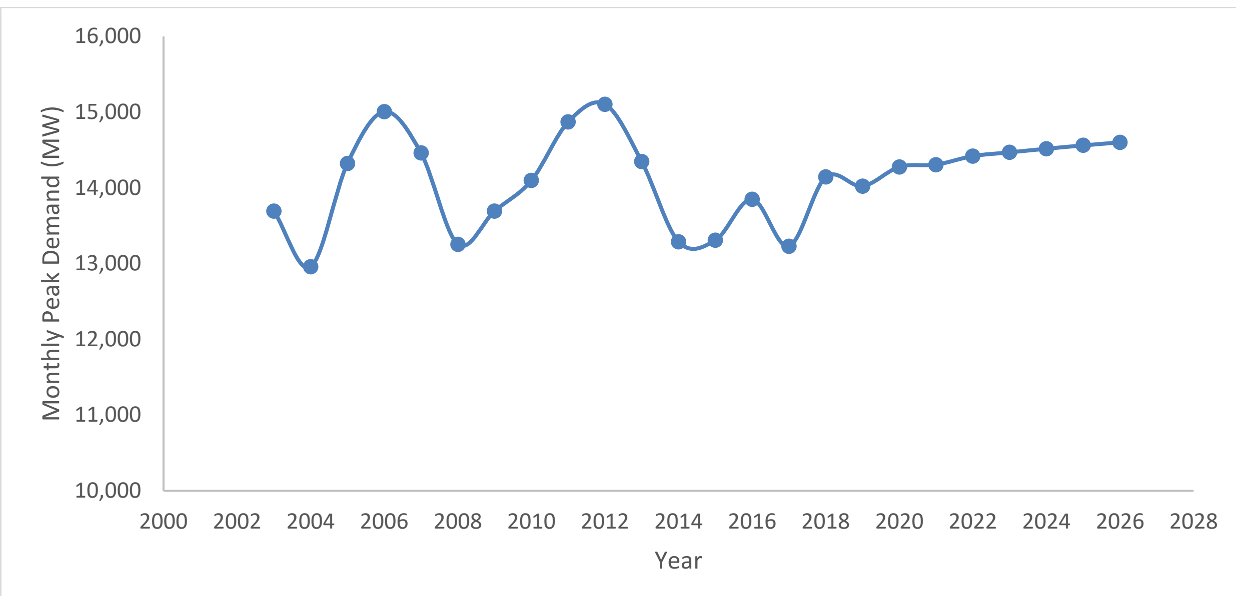
By statute, the Strategic Energy Assessment (SEA) must assess the *adequacy* of Wisconsin's electric supply: whether the state's electric providers have procured enough total power to meet customers' total electric demand. At present, Wisconsin electric providers are assessing supply in the midst of a transition in electric generation sources, as declining costs and environmental considerations begin to increase the share of electricity supplies generated from natural gas and zero-carbon sources such as wind and solar energy.

DEFINING SUPPLY NEEDS

Wisconsin, and electric providers nationwide, define adequate supply as meeting the electricity demand of all customers at all times of the year. In practice, sufficient energy must be available to meet the highest, or peak, usage levels anticipated at any point during the year.

Demand for electricity fluctuates both throughout the day and throughout the year. As shown in Figure 1-1, yearly peak demand levels in Wisconsin have varied between 13,000 and 15,000 MW of electricity demand. Year-by-year differences are influenced by weather conditions as well as other influences such as the addition and subtraction of significant customer loads.

Figure 1-1 Historical and Forecasted Maximum Monthly Peak Demand by Year, MW[3]

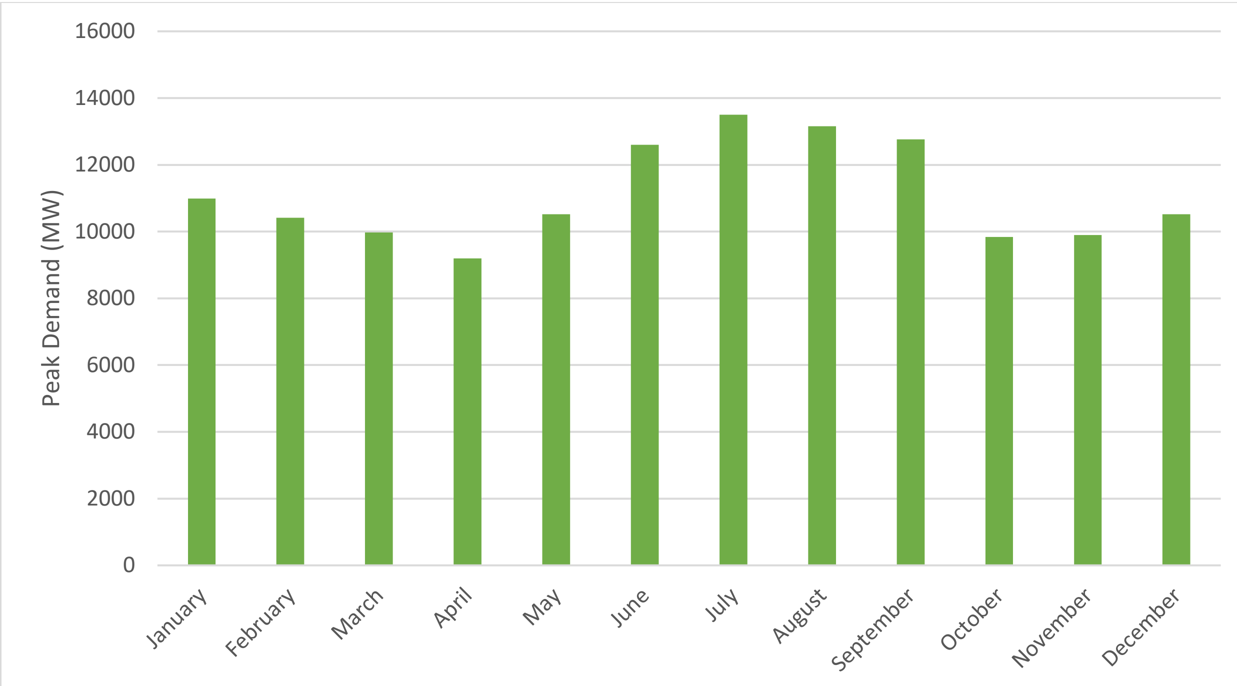


As shown in Figure 1-2, peak energy demand occurs in the summer months of June, July, and August, influenced largely by the increase in air conditioner use. Smaller peaks have historically occurred in the winter, in part due to higher heating loads and the use of holiday lighting. These non-summer peaks have gradually been shifting closer to spring and autumn in recent years due to

[3] Source: Aggregated electricity provider data responses, docket 5-ES-110.

varied changes in weather, technology use, and customer demand. More detailed data on energy use by month can be found in Appendix A, Table A-1.

Figure 1-2 Average Non-Coincidental Peak Demand per Month for the Period 2015-2019[4]



As of November 2019, Wisconsin electric providers expected peak demand to increase each year from 2020 to 2026, but for those increases to be limited in size. Table 1-1 shows that, after a forecasted increase of 1.8 percent between 2019 and 2020, providers collectively project growth levels averaging 0.37 percent annually over the following six years. These forecasts predate the onset of the COVID-19 pandemic, which have driven reductions in actual customer loads during spring and summer 2020. While it appears likely that these effects will reduce actual 2020 peak loads below previously projected levels, the long-term effect of the pandemic on demand in future years remains more uncertain.

Table 1-1 Expected Maximum Monthly Peak Loads, with Percentage Increases from Previous Year[5]

Year	Maximum Monthly Peak Load (MW)	Percentage Increase from Previous Year (%)
2019	14,023	
2020	14,277	1.81%
2021	14,370	0.65%
2022	14,420	0.35%
2023	14,469	0.34%
2024	14,517	0.33%
2025	14,561	0.30%
2026	14,601	0.27%

[4] Source: Aggregated electricity provider data responses, docket 5-ES-110 and previous SEA reports.

[5] Source: Aggregated electricity provider data responses, docket 5-ES-110.

RESERVE MARGINS AND TOTAL REQUIRED ELECTRIC SUPPLY

Projections of peak energy demand serve as the foundation for determining the amount of electricity supply needed to meet customer demand. However, these projections may not match actual future conditions, due to the inherent uncertainties in forecasting customer demand and the variability of peak usage due to weather and other factors. To account for these uncertainties, forecasters define adequate supply to include a "reserve margin" over and above projected peak levels to reduce the risk of inadequate supply if actual demand exceeds projections.

Wisconsin generates and purchases energy supplies within the regional context of the Midcontinent Independent System Operator, Inc. (MISO), which operates an integrated electric grid across Wisconsin and several other states. (See the Sources of Electricity section and Transmission chapter for more detail on MISO.) Wisconsin electric providers therefore assess energy supplies relative to MISO's planning reserve margin, a value determined through statistical modeling designed to identify the amount of excess capacity that minimizes the probability of blackouts resulting from insufficient generation resources.[6] MISO's planning reserve margin was set at 8.9 percent for the 2020-2021 planning cycle, and was increased to 9.4 percent for the 2021-2022 planning cycle.[7] In effect, this reserve margin establishes that electric providers in the MISO market should maintain energy supplies that exceed projected electric demand by 8.9 percent in the current year, and 9.4 percent in future years. MISO defines the value of this margin based on aggregate unforced capacity (UCAP), which takes into account the total energy available from generation sources as well as the likelihood that conditions at any given time may include unit outages and other limitations on actual operating capacity.[8]

Table 1-2 shows total projected capacity for Wisconsin electric providers. The projections submitted by providers incorporate Wisconsin-based energy sources, including planned generation additions and retirements announced as of September 2020, as well as generation outside of the state that is owned or purchased by a Wisconsin provider and delivered through MISO's regional grid. (More detailed calculations of these projections can be found in Appendix A, Table A-2.) Under these projections, Wisconsin's total capacity slightly exceeds MISO's 8.9 percent planning margin in 2020, at

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[6] MISO conducts loss of load expectation studies on an annual basis to set updated reserve margin values, which are designed to identify the value necessary to reduce the probability of large-scale blackouts to less than 1 blackout every 10 years. The value of 8.9 percent represents an increase of one percent from the value set for the 2019-2020 planning cycle. This increase was attributed to changes in the mix of generating resources, aging fossil fuel generating stations, and changes to load profiles and forecasts. See https://cdn.misoenergy.org/20191106%20RASC%20Item%2003a%20PY%202020-21%20LOLE%20study%20results397078.pdf.

[7] MISO's increase in the reserve margin value largely reflects findings from enhanced modeling methods. See https://cdn.misoenergy.org/20200908%20LOLEWG%20Item%2003%202021-22%20PY%20PRM%20LRR%20Results472186.pdf.

[8] The Commission has also historically set planning reserve margin guidelines for Wisconsin electric providers, to serve as a guideline for state-level planning and a reference for annual capacity reports to the Commission under docket 5-EI-141. In its Order of October 10, 2008 (PSC REF#: 102692), the Commission set a state level planning guideline of 14.5 percent when considering generation needs beyond the current year. For the current year planning reserve margin, the Commission requires that Wisconsin electric utilities meet the MISO annual capacity requirement.

10.17 percent. Annual projections fall below the future 9.4 percent planning margin in each year from 2021 through 2026, with values ranging from a low of 7.54 percent in 2022 to a high of 9.34 percent in 2023. Providers' expected demand forecasts were prepared before the COVID-19 pandemic and do not take into account any potential reductions in demand associated with the pandemic, nor does it include unannounced future capacity additions by providers.

Table 1-2 Wisconsin Aggregated Supply and Demand, MW[9]

	2020	2021	2022	2023	2024	2025	2026
Net Capacity[10]	15,640	15,363	15,248	15,552	15,396	15,571	15,613
Expected Demand[11]	14,196	14,131	14,178	14,223	14,270	14,349	14,410
UCAP Planning Reserve Margin[12]	10.17%	8.71%	7.54%	9.34%	7.89%	8.52%	8.35%

MISO's capacity planning auction, conducted in April 2020, confirmed that each Wisconsin electric provider maintains sufficient capacity resources for 2020, supported by established arrangements for providers to import power from out of state when needed to address capacity shortfalls on high-demand days. However, surveys conducted in June 2020 by MISO and the Organization of MISO States (OMS) have identified projected capacity levels that fall below the reserve margin in the years after 2020, consistent with the results in Table 1-2. The Commission will continue to monitor changing assumptions and utility plans to ensure sufficient reserve margin targets are met in future years.

Historically, Wisconsin's energy supply has exceeded required capacity by substantial margins, as shown in Table 1-3. Higher reserve margin values published in previous SEA reports reflected large-scale construction of energy generation sources by Wisconsin electric providers in the 1990s and 2000s and low rates of demand growth.

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[9] Source: Aggregated electricity provider data responses, docket 5-ES-110. Reflects all announced generation additions and retirements as of April 2020.

[10] Net capacity numbers include projected future generation reported by utilities; whether and when those additions are implemented may vary based on multiple factors, including federal and state regulatory approvals and construction timelines. Specifically included in years 2025 and 2026 are the DPC-owned portion of the Nemadji Trail Energy Center (NTEC), which was approved by the Commission in early 2020. DPC had excluded NTEC from its generating assets in those years due to uncertainty surrounding the timing of the plant's deployment, but in light of the Commission's approval of the project Commission staff felt it appropriate to include this generator for the start of its commercial operation in 2025.

[11] Defined by MISO as coincident load serving entity (LSE) peak to MISO peak gross of demand response net full responsibility transaction (FRT).

[12] Equals (net capacity/expected demand) – 1.

Table 1-3 Forecasted Planning Reserve Margins from SEA (%); Forecasted Reserve in ICAP through 2014 and UCAP through 2020[13]

Planning Year	Final SEA 2010	Final SEA 2012	Final SEA 2014	Final SEA 2016	Final SEA 2018	Final SEA 2020
2009	11.7					
2010	24.1					
2011	26.1	6.6				
2012	25.8	7.3				
2013	24.9	21.9				
2014	20.1	15.8	20.5			
2015	18.7	15.8	18.9			
2016	15.1	13.0	17.3	16.9		
2017		11.6	15.3	13.9		
2018		13.3	13.7	13.7	12.0	
2019			14.3	16.4	5.9	
2020			13.8	15.5	8.2	10.2
2021				14.7	9.0	8.7
2022				13.6	9.2	7.5
2023					7.8	9.3
2024					6.4	7.9
2025						8.5
2026						8.4

While relatively low demand growth has continued, sources of supply have also started to decline in scale, in part due to recent and projected future retirements of generation facilities. Electric providers, MISO, the Commission, and other stakeholders will work together to ensure the transition to clean energy generation sources adequately meets affordability, capacity and reliability needs. (See the Projecting Energy Supply section below for further details on currently identified generation retirements and additions.)

SOURCES OF ENERGY SUPPLY

Wisconsin electric providers can procure energy by operating their own generation plants, entering into long-term purchase power agreements (PPAs) with other generation owners, or purchasing electricity from MISO's regional wholesale market, which operates a day-ahead market and a real time market.[14] (See Appendix A, Figure A-1 for data on MISO market prices.)

Providers traditionally also rely on multiple different sources of electric supply.

- **Baseload resources** are designed to meet the minimum level of electric demand over a lengthy duration of time. Baseload power plants use generation sources that can operate on a consistent, ongoing basis, including coal, nuclear, and natural gas combined-cycle plants, and therefore have high "capacity factors" that reflect the percentage of time during the year that they operate. Nuclear plants typically have capacity factors of up to 90 percent, while coal and natural gas plants typically have capacity factors of 60 percent or more.

[13] Source: Table c and previous SEA reports

[14] While the day-ahead and real time markets serve as the primary platforms for providers to meet overall supply needs, MISO also operates transmission rights and ancillary services markets to support grid operations.

- **Intermediate resources** operate during hours of significant demand, but operate less frequently than baseload plants during periods of low demand such as weekends and overnight hours. Common generation sources for intermediate plants include natural gas combined-cycle plants and hydroelectric power. Capacity factors for intermediate plants typically range between 15 and 60 percent.
- **Peaking resources** typically operate only during peak demand times, such as summer afternoons in hot weather. Peaking plants generally have a capacity factor of 15 percent or less. Examples of peaking plants are natural gas combustion turbines and diesel generators. Solar energy may also serve as a peaking resource when it meets demand during daylight peaking hours.

Through its operation of the regional energy market, MISO takes a leading role in determining which plants shall be operated to meet energy supply needs at a given time, directing providers to run those plants whose cost to produce electricity is less than MISO's wholesale market price. For resources such as solar and wind, for which availability varies by weather conditions, these decisions must also take into account whether the resource is available when energy is needed. (See the Reliability and Resilience Chapter for more discussion on reliability considerations for solar and wind resources.)

Figure 1-3 depicts Wisconsin electric providers' in-state operating resources in 2020.

Figure 1-3 Electric Providers' Generation Resources in Wisconsin

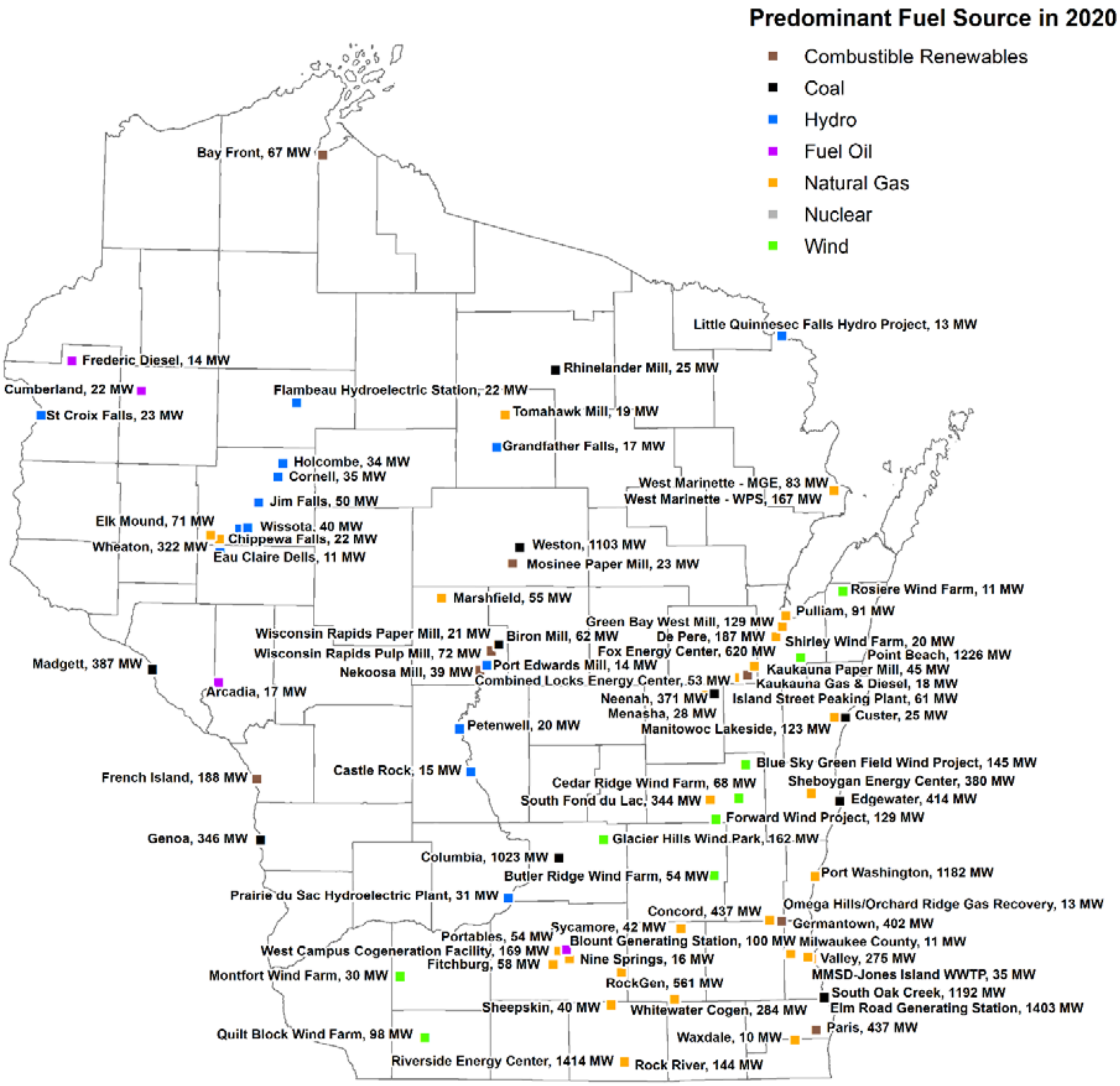
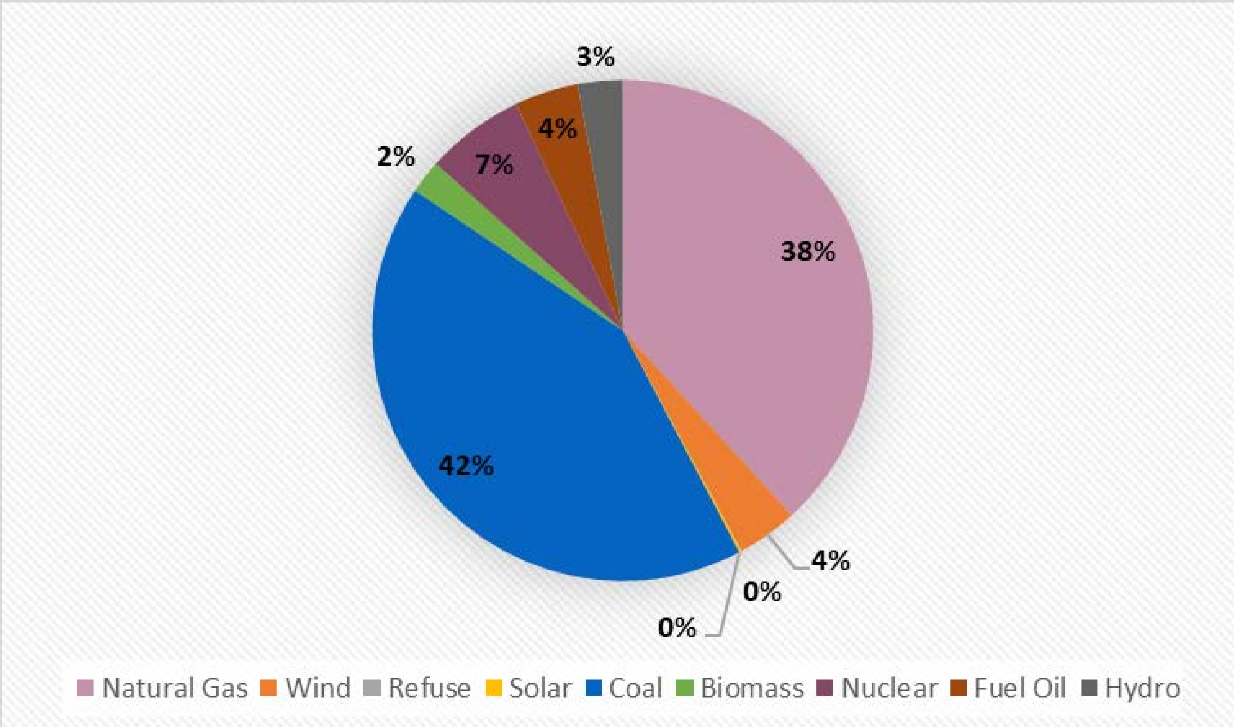


Figure 1-4 breaks down the total capacity of Wisconsin's in-state operating resources by generation source as of January 2020. Coal accounts for approximately 42 percent of total generation capacity in Wisconsin, and natural gas for approximately 38 percent. Zero-carbon energy sources account for approximately 16 percent of capacity, including 7 percent from nuclear energy and 4 percent from wind energy.[15]

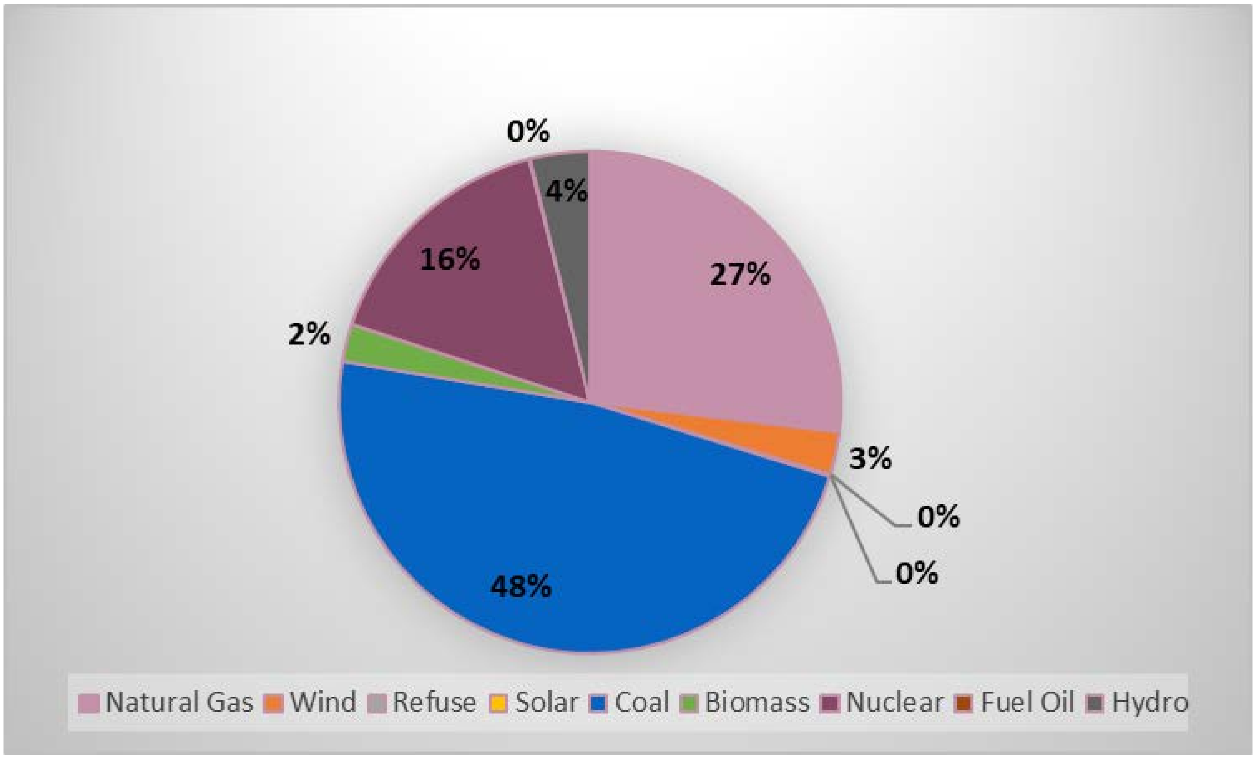
[15] Zero-carbon energy sources include nuclear, wind, solar, biomass, and hydro.

Figure 1-4 Capacity – January 2020



Because different resources operate with different capacity factors, the amount of energy generated from different fuels differs from the amount of capacity. Due to their status as baseload fuels, the share of energy produced from coal and nuclear sources exceeded their share of in-state capacity, accounting in 2018 for 48 percent and 16 percent of energy generation, respectively. Wind and solar energy accounted for a slightly smaller share of energy than capacity due to comparatively low capacity factors.

Figure 1-5 Generation – 2018

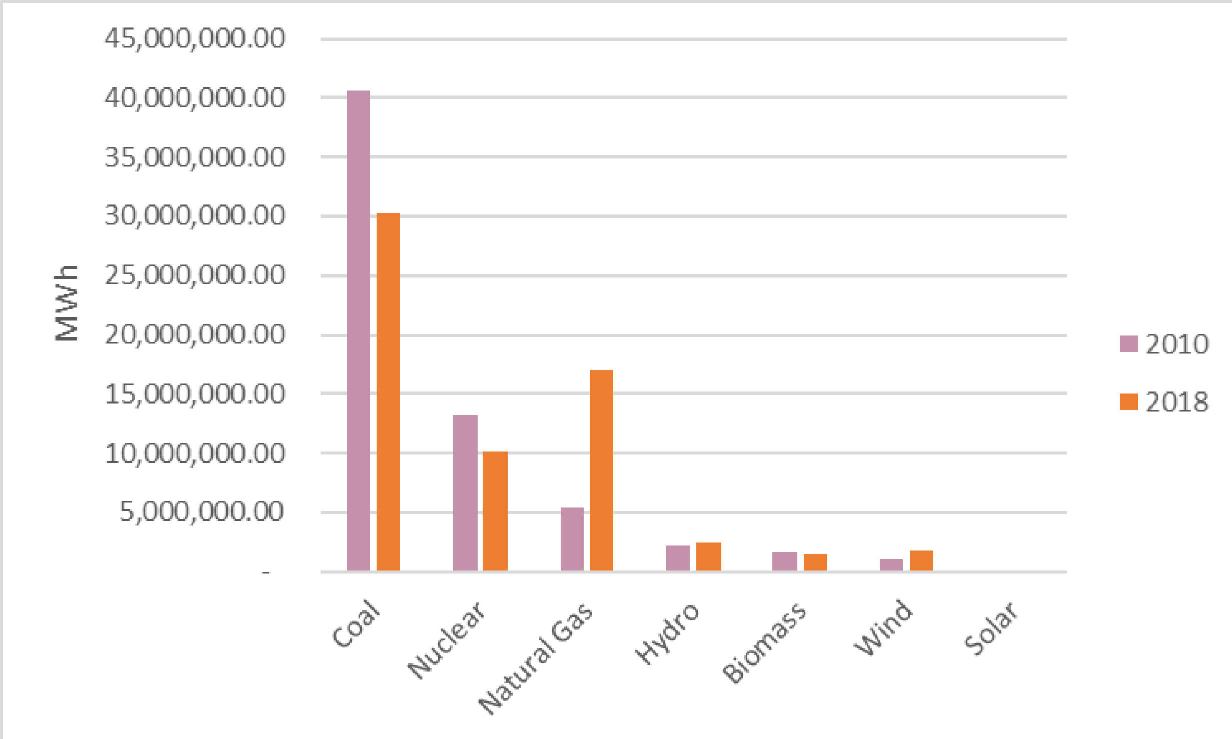


While it is difficult to determine the precise share of generation sources from purchased power, PPA data reported by electric providers suggests that Wisconsin's purchased power may include somewhat higher shares of zero-carbon power sources than in-state generation. In 2020, the market purchases projected by providers are approximately 63 percent coal and natural gas, compared to approximately 75 percent projected from Wisconsin-owned sources. One contributing factor is the greater availability of wind power in MISO region states west of Wisconsin, including Minnesota, Iowa, and North Dakota. Due to windier conditions in those states, wind power sources in those states can produce energy more cost-effectively, at a higher capacity factor. As detailed in Appendix A, Figure A-3, wind resources have steadily increased as a share of MISO's total generation since 2014.

Historical Trends in Sources of Supply

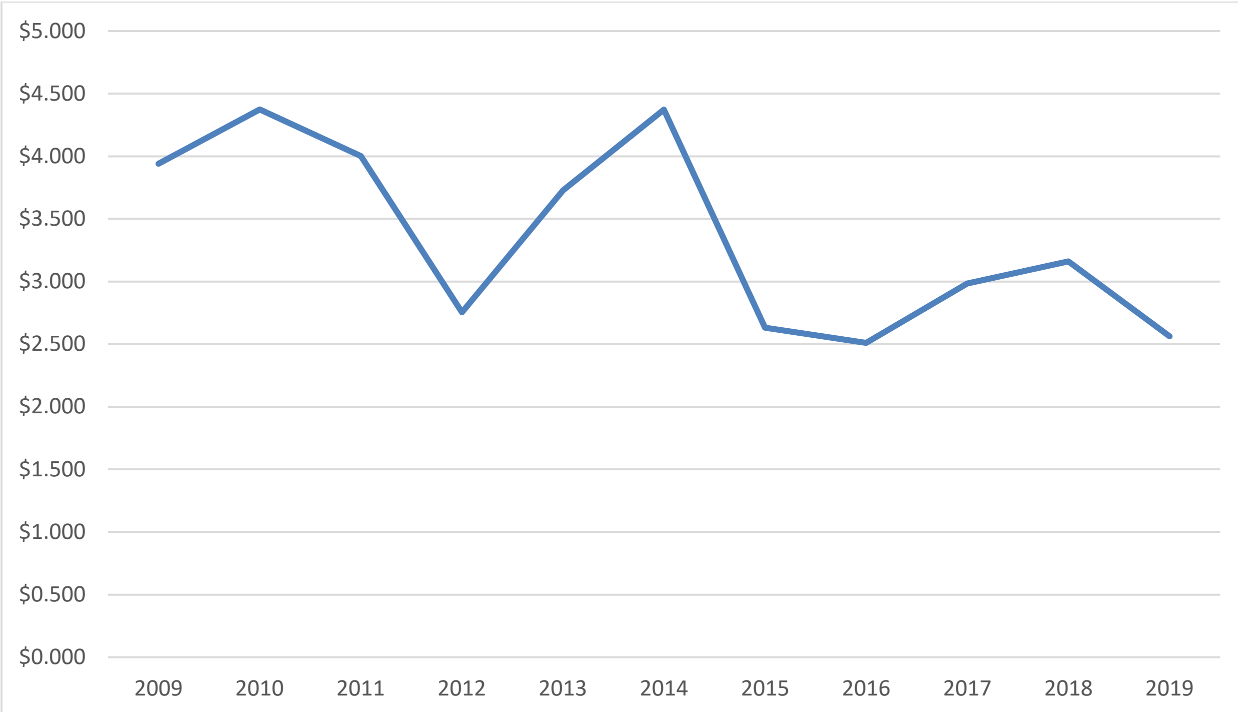
While coal still represents the most common source of electricity generation in Wisconsin, it is accounting for a declining share of total load. As shown in Figure 1-6, the share of energy produced from coal has declined from 63 percent to 48 percent between 2010 and 2018.

Figure 1-6 Comparison of 2010 and 2018 Generation Data



Natural gas resources account for the largest increase in generation share, increasing from 9 percent of generation in 2010 to 24 percent in 2018. This increase has been driven primarily by low natural gas prices. As shown in Figure 1-7, natural gas prices since 2011 have generally remained lower than previous levels, in part due to an expansion in sources of available supply.

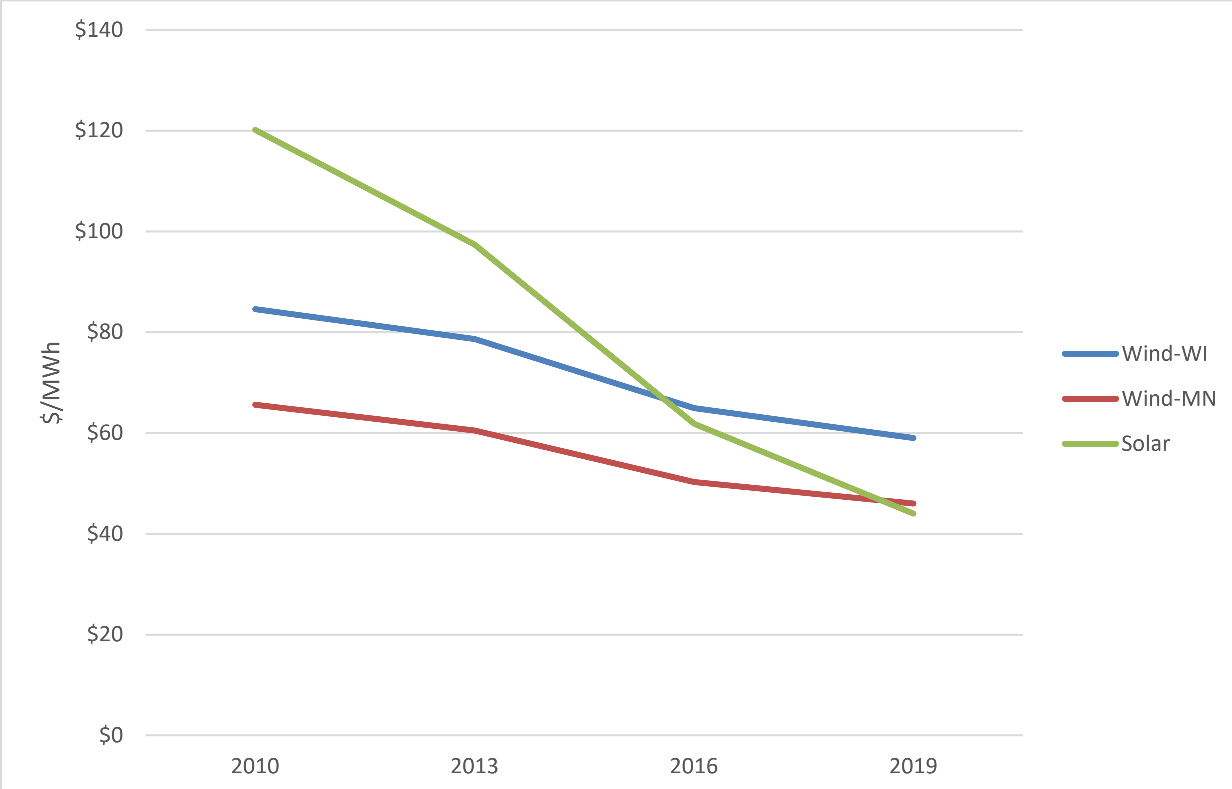
Figure 1-7 Henry Hub Natural Gas Average Annual Cost in $/MMBtu[16]



Multiple zero-carbon energy resources have also experienced significant declines in price during the past decade. As shown in Figure 1-8, since 2010 total generation costs per kilowatt-hour (kWh) have declined 63 percent for solar energy in the Midwest region. Although base costs for wind energy in Wisconsin are higher than in Minnesota, costs in both states have declined at a comparable rate of 30 percent since 2010. After factoring in available tax benefits and other accounting benefits that further reduce prices for many individual projects, these declines have made solar and wind resources more price-competitive with natural gas and coal resources.

[16] Source: Energy Information Administration.

Figure 1-8 Estimated Levelized Unsubsidized Cost of Electricity for Solar and Wind Resources in $/MWh[17]



As a result, solar and wind generation increased between 2010 and 2018. (Total zero-carbon generation decreased from 28 percent to 25 percent due to the closure of the Kewaunee nuclear plant, which offset the gains made by solar and wind.) No utility-scale solar resources were deployed in 2010 and they still accounted for less than 0.1 percent of generation in 2018, but the solar additions reported by electric providers would increase the share of solar resources to slightly more than 4 percent by 2026. If the actual growth in solar resources reflects those reported additions, solar will be the largest source of zero-carbon energy, after nuclear resources, by 2026.

Increased deployment of natural gas and zero-carbon energy resources have been influenced by environmental considerations as well as declining prices. Customer interest in achieving emissions reductions has grown, frequently motivated by a desire to mitigate the impacts of climate change. A number of electric providers in Wisconsin have set goals to reduce carbon dioxide emissions from their generation sources, and report that increased deployment of natural gas and zero-carbon energy resources will be two primary approaches to pursuing those goals. (See the Emissions chapter for greater detail.) The growing emphasis on reducing emissions through shifts in generation has corresponded with a de-emphasis on initiatives to install emissions control equipment on existing generation facilities. While Wisconsin electricity providers have spent more

[17] Source: Energy Information Administration.

than $3 billion on emissions control projects since 2000, no such projects are currently in progress or planned for future years.

PROJECTING ENERGY SUPPLY, 2020-2026

Electric providers' projected additions and retirements indicate that the transition in electric generation sources will continue. As shown in Table 1-4, Wisconsin electric providers have reported as of April 2020 that they will add approximately 2,700 MW of new owned or leased generation capacity between 2020 and 2026. 45 percent of this capacity will come from new natural gas combined-cycle plants, including 1,214 MW from two Commission-approved plants, West Riverside and Nemadji Trail Energy Center.[18] Solar projects comprise the remaining 55 percent of projected generation additions, including Commission-approved projects as well as some proposed future additions not yet submitted for regulatory review. Independent solar developers are also in the process of implementing or planning multiple additional solar projects in Wisconsin that are not included in Table 1-4 but may be leased by electric providers at a future date for additional generation capacity.

Table 1-4 New or Upgraded Utility-Owned or Leased Generation Capacity 2020-2026

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/ Leaser	Fuel	Location	PSC Status and Docket #
2020	50	Badger Hollow (phase 1)	New	MGE	Solar	Iowa County	5-BS-228, approved
2020	100	Badger Hollow (phase 1)	New	WPS	Solar	Iowa County	5-BS-228, approved
2020	50	Two Creeks	New	MGE	Solar	Manitowoc County	5-BS-228, approved
2020	100	Two Creeks	New	WPSC	Solar	Manitowoc County	5-BS-228, approved
2020	9	Dane County Airport	New	MGE	Solar	Dane County	3270-CE-128, approved
2020	5	Morey Field Middleton Airport	New	MGE	Solar	Dane County	
2020	664	West Riverside	New	WP&L	Natural Gas	Beloit	6680-CE-176, approved
2021	50	Badger Hollow (phase 2)	New	MGE	Solar	Iowa County	5-BS-234, approved
2021	100	Badger Hollow (phase 2)	New	WEPCO	Solar	Iowa County	5-BS-234, approved
2022	425	Solar 2022	New	WP&L	Solar	TBD	
2023	50	Riverside Energy Center Expansion	New	MGE	Natural Gas	Rock County	
2023	575	Solar 2023	New	WP&L	Solar	TBD	
2025	550[19]	Nemadji Trail Energy Center	New	DPC, SWL&P	Natural Gas	City of Superior	9698-CE-100

[18] A lawsuit that petitioned for judicial review of the Commission's conditional approval of the Nemadji Trail Energy Center was filed in February of 2020, as Dane County Docket No. 20-CV-585, and remains pending as of the date of this document.

[19] The application in docket 9698-CE-100 for the Nemadji Trail Energy Center (NTEC) stated that the plant would have a nameplate capacity of approximately 550 MW. Based on the record developed in that docket, the Commission's final

As shown in Table 1-5, Wisconsin electricity providers report as of September 2020 that they plan to retire 1,478 MW of generation capacity by 2026. Approximately 40 percent of retired capacity will come from natural gas combustion turbines used as peaking resources, which typically operate less economically than new natural gas combined cycle units. WP&L's retirement of the Edgewater Generating Station Unit 5 coal plant accounts for 26 percent of total retired capacity, and DPC's planned retirement of the Genoa coal plant accounts for another 23 percent of total retired capacity.

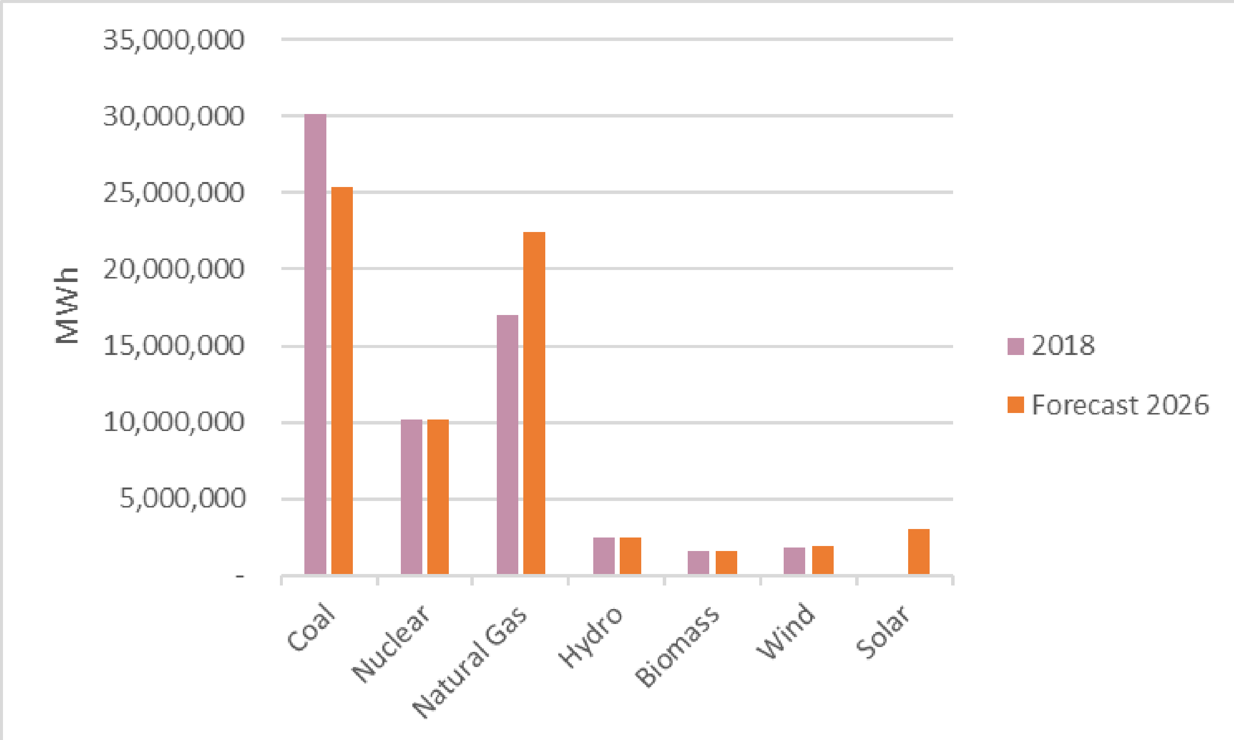
Table 1-5 Retired Utility-Owned or Leased Generation Capacity 2020-2026

Year	Name	Owner/Leaser	Type of Load Served	Capacity (MW)	Fuel	Location
2019	Bay Front 4	NSPW	Peaking	20	Biomass or Biogas	Ashland, WI
2019	Wheaton 5	NSPW	Peaking	53	Fuel Oil	Eau Claire, WI
2020	Fitchburg 1, 2	MGE	Peaking	29, 29	Natural Gas	Madison, WI
2020	Rock River 3, 4, 5, 6	WP&L	Peaking	27, 15, 51, 51	Natural Gas	Beloit, WI
2020	Sheepskin 1	WP&L	Peaking	40	Natural Gas	Edgerton, WI
2021	Nine Springs 1	MGE	Peaking	16	Natural Gas	Madison, WI
2021	Sycamore 1, 2	MGE	Peaking	18, 24	Natural Gas	Madison, WI
2021	Genoa Generating Station	DPC	Base	345	Coal	Genoa, WI
2022	Edgewater 5	WP&L	Base	380	Coal	Beloit, WI
2024	Blount Street 6, 7	MGE	Base	50, 50	Natural Gas	Madison, WI
2024	Rosiere Wind Farm	MGE	Intermittent	11	Wind	Casco, WI
2025	Wheaton 1, 2, 3, 4, 6	NSPW	Peaking	54, 54, 54, 54, 53	Natural Gas and Fuel Oil	Eau Claire, WI

As shown in Figure 1-9, if all additions and retirements are implemented as reported by electric providers, coal would decline from 48 percent of Wisconsin's generation to 38 percent, natural gas would increase from 27 percent to 34 percent, and solar resources would increase from less than 0.1 percent to 4.5 percent. The share of solar resources may increase further through future procurements from independently developed projects.

decision authorizes the construction of the NTEC at a nameplate capacity of approximately 625 MW. As construction of the NTEC is not complete, and the final nameplate capacity is not known, 550 MW has been used in this SEA in order to conservatively estimate generation resources.

Figure 1-9 2018 vs. Forecast 2026 Generation Comparison



As noted above, Wisconsin providers may rely on power purchases in the MISO regional market to maintain supplies, particularly during periods of high demand. These purchases would occur in a MISO regional market also experiencing changes in its resource mix. As shown in Table 1-6, solar resources account for more than 75 percent of capacity proposed to be added to MISO's regional market as of January 2020, while wind resources account for an additional 12.5 percent. Because many individual projects posted to MISO's interconnection queue are not implemented, Table 1-6 should not be considered a precise quantification of the future changes in the regional resource mix. However, the current composition of the queue does still provide an indication that renewable resources will account for a growing share of regional market capacity.

Table 1-6 MISO Interconnection Queue Snapshot in January 2020 for the State of Wisconsin

Type	Amount (MW)	Percentage
Natural gas combined cycle	530	7.5
Wind	900	12.5
Battery storage	320	5
Solar	5400	75
TOTAL	7150	100

Ongoing trends in generation costs could also significantly influence the timing of further changes and the generation sources to be chosen. Some forecasts, including from the National Renewable Energy Laboratory (NREL), suggest that solar and wind costs will continue to decline by an additional 40 percent or more through 2049, which could continue to accelerate the increased deployment of those resources.[20] (See Appendix A, Figure A-2 and Table A-3, for detailed NREL forecast data, including comparisons to costs for other generation sources.) On the other hand, forecasts by the federal U.S. Energy Information Administration (EIA) project solar and wind costs to remain relatively stable in future years, which may result in less rapid deployment.

In addition to generation from solar and wind, the changing costs of battery storage resources could also influence future resource decisions, by providing options to store previously generated electricity for peak periods rather than building additional peaker resources. At current cost levels, Wisconsin electric providers have not formally proposed storage resources to the Commission. However, by one estimate, average costs per kWh of storage resources have declined by nearly 50 percent between 2016 and 2019.[21] Forecasts again differ on the speed by which costs will decline in future years, but multiple forecasts suggest continued cost declines of up to 40 to 60 percent,[22] which could result in more cost-effective storage opportunities in the coming years.[23]

Ongoing changes in generation costs, as well as pursuit of carbon reduction goals, will also influence electric providers' future decisions on whether, and when, to retire additional generation units. In addition to weighing their own internal decision factors, electric providers must also receive MISO approval for unit retirements:

- First, providers considering a retirement may submit an Attachment Y2 form requesting MISO to evaluate the impacts on grid operations of the potential retirement. MISO conducts modeling analysis to assess grid operations in the absence of the unit, and informs the requesting provider of its findings on whether MISO's regional grid would be negatively affected by the retirement. If MISO concludes that retirement of the unit could prevent it from maintaining adequate grid operations, its response indicates that MISO would consider designating the proposed unit a System Support Resource (SSR), which would require it to continue operating until further generation and/or transmission additions can make up for the effects of a retirement.
- Providers who subsequently choose to pursue a unit retirement must submit an Attachment Y form requesting MISO's formal approval. MISO conducts additional, up-to-date modeling analysis on grid operations. If the analysis reveals no concerns, MISO authorizes the provider to proceed with retirement.[24] However, if the analysis concludes retirement

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[20] National Renewable Energy Laboratory (NREL) 2019 Annual Technology Baseline: Electricity. https://atb.nrel.gov/.

[21] Bloomberg New Energy Finance 2019 Battery Price Survey

[22] Ibid. and NREL Annual Technology Baseline Forecasts.

[23] The cost-effectiveness to providers of deploying storage depends on available revenue streams, in addition to the upfront costs of installation projected here. For example, storage is particularly cost-effective in markets with large differences between wholesale electric prices at different hours of the day, which allows for larger arbitrage savings from storing energy for use during high-cost hours. MISO has less hour-by-hour price variability than some other regional markets, which may limit the relative cost-effectiveness of storage compared to other parts of the country.

[24] To allow electric providers flexibility to make their own final determination whether to proceed with retirement, MISO initially notifies a proposer that its Attachment Y study is complete without providing any results. The provider may choose, at this time or any time before, to rescind its Attachment Y request. In this event, MISO will not release the

would prevent MISO from maintaining adequate operations, MISO conducts further review of available resources and proceeds with an SSR designation if no adequate alternatives are identified.

As part of the Commission's data request for this SEA, electric providers submitted all Attachment Y2 and Attachment Y documentation submitted to or received from MISO between 2017 and 2019. Provider responses confirm that announced, upcoming retirements have followed the MISO process, such as the 2020 retirements of the Rock River and Sheepskin natural gas plants.[25] However, retirements under consideration by electric providers could potentially be foregone, or delayed, in response to MISO findings that continued operation is needed.

Provider decisions to proceed with unit retirements must also take into account cost recovery considerations. These considerations can be significant for early retirements, where a proportion of the plant's capital costs remain an unrecovered debt obligation, typically to be collected through customer rates. In a 2019 rate settlement, We Energies agreed to apply to the Commission to reduce the remaining debt obligation of the retired Pleasant Prairie coal plant through securitization, where capital is recovered through a bond issuance that reduces associated financing costs. We Energies submitted its securitization application to the Commission in July 2020, and a Commission decision is planned for late 2020.[26] While financing considerations can vary significantly by provider and by plant, financial tools like securitization can play a role in informing future retirement decisions.

study results to the provider. If the provider does not choose to rescind its request, retirement is approved upon the provider's receipt of study results confirming MISO's approval.

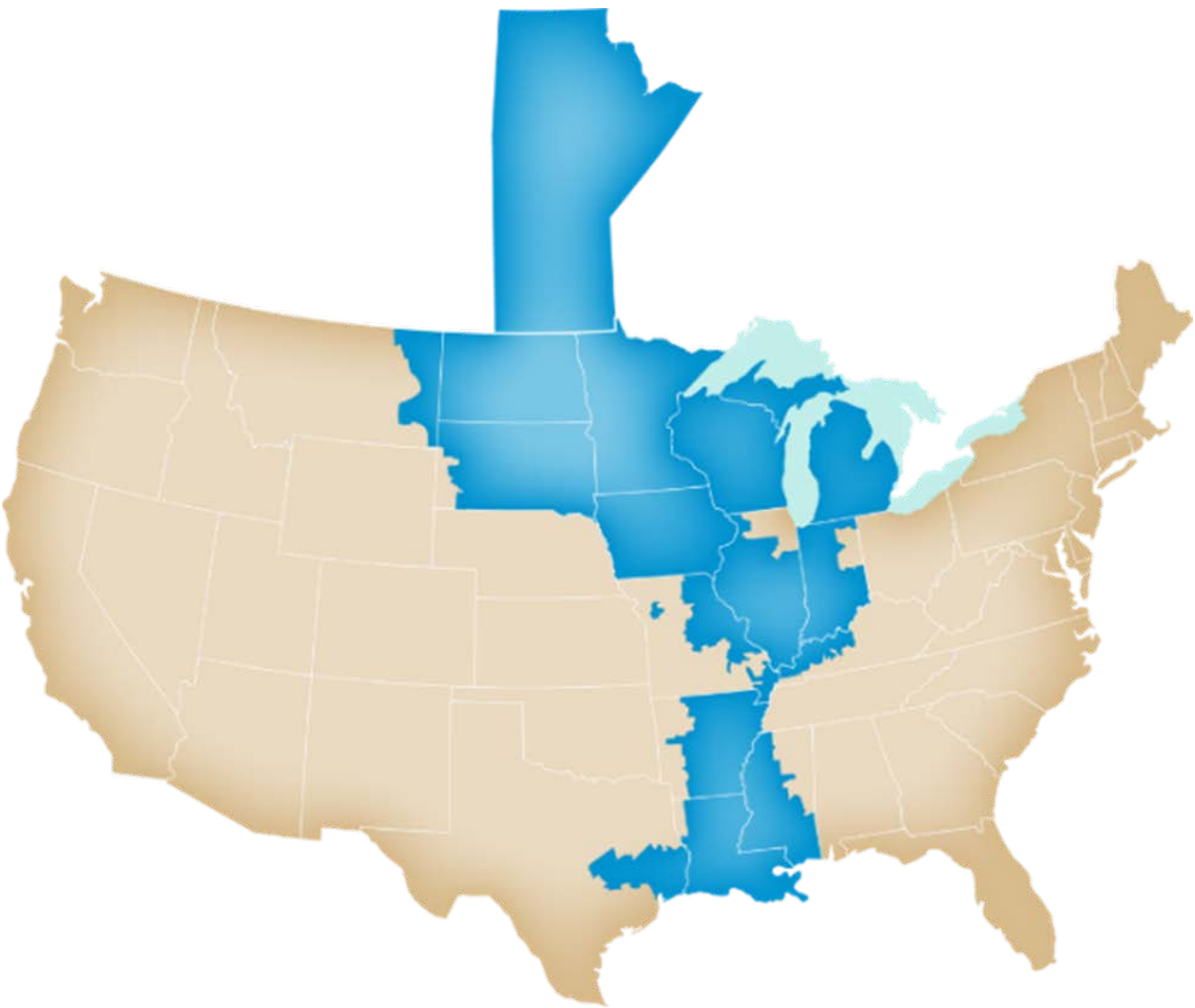
[25] *See* PSC REF#: 381398.

[26] *See* docket 6630-ET-101.

CHAPTER 2 – ELECTRIC TRANSMISSION IN WISCONSIN

Wisconsin electric providers are responsible for delivering adequate and reliable service directly to customers, through their own distribution systems. In addition, high-voltage transmission lines are required to carry energy across long distances and deliver electricity to customers located far from generation resources. Wisconsin participates in the regional transmission system of MISO, which operates an integrated electric grid serving all or part of 15 states and one Canadian province, identified in Figure 2-1.

Figure 2-1 MISO Regional Transmission Map



Participation in MISO is designed to help the state electric system access additional benefits within a larger regional context, including:

- Accessing less expensive wholesale energy and capacity resources available outside of Wisconsin, including low-cost zero-carbon energy resources, such as wind produced west of Wisconsin (see Supply chapter);

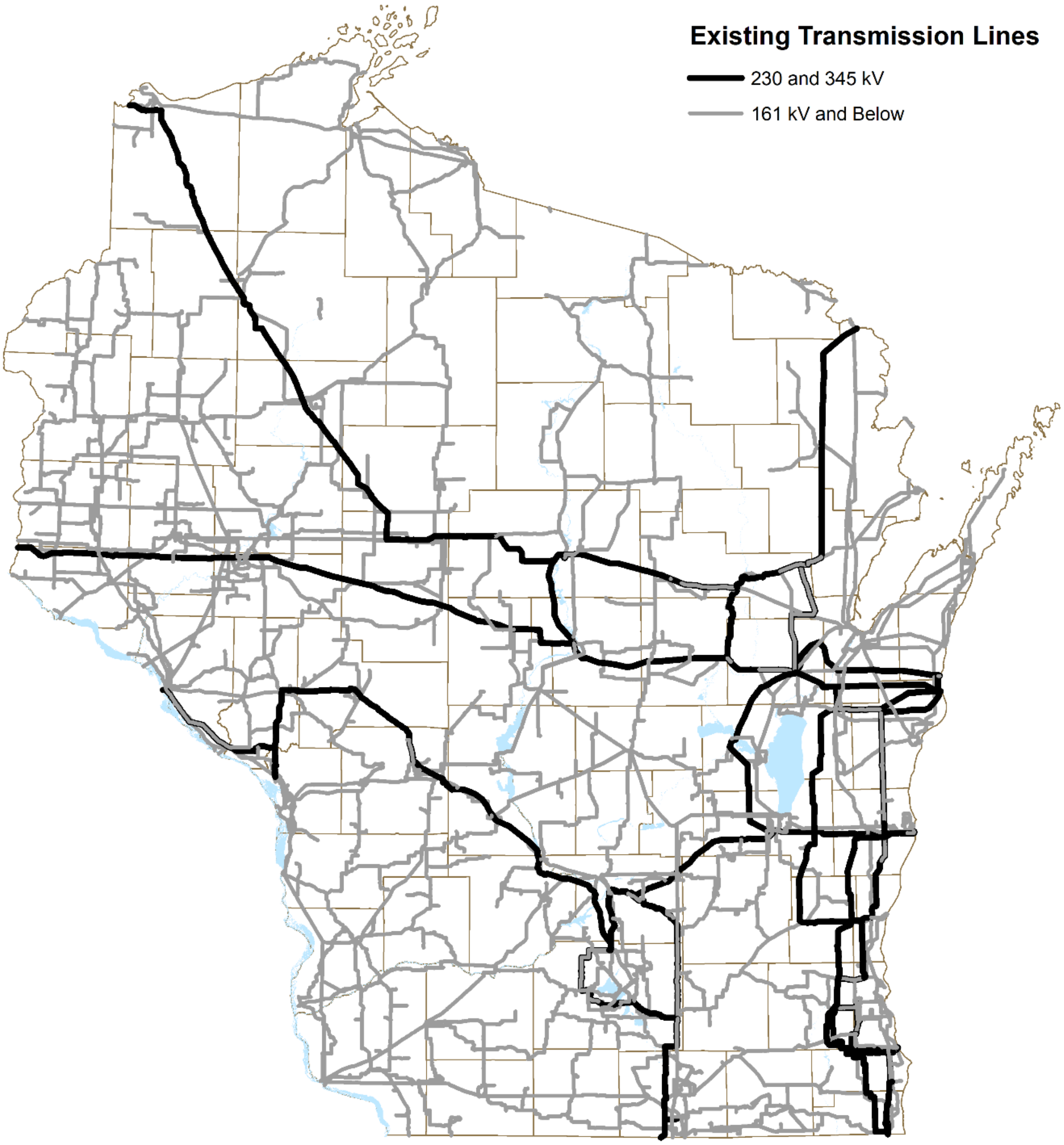
- Reducing the generation capacity reserves any single provider may need to meet peak customer demand by taking advantage of access to more diverse suppliers;
- Offering access to a wholesale market with clear and predictable energy prices, which can allow providers access to energy resources and use price signals to guide their own investment decisions; and
- Managing the transmission grid to enhance region-wide reliability.

Wisconsin has approximately 15,700 miles of high-voltage transmission lines in service, which are mapped in Figure 2-2.[27] Transmission lines with higher voltage ratings are designed to carry the largest volumes of energy efficiently over longer distances. High-voltage lines are located to carry energy from Wisconsin generation facilities to areas of high customer demand within the state, and to connect those high-demand areas with other states in the MISO region. Figure 2-2 does not include the Cardinal-Hickory Creek transmission line approved by the Commission in 2019,[28] which will enhance transmission connections between Madison and Dubuque, Iowa when construction is completed.

[27] Wisconsin defines high-voltage transmission lines as those with rated capacity of 69 kilovolts (kV) or higher.

[28] This transmission project was approved by the Commission in docket number 5-CE-146. That approval is the subject of several lawsuits. The state lawsuits have been consolidated in Dane County Circuit Court as case number 19-cv-3418, and a federal action is also pending in U.S. District Court for the Western District of Wisconsin as case number 19-cv-1007.

Figure 2-2 Existing Transmission Lines



TRANSMISSION PLANNING

Wisconsin electric providers typically initiate planning for local transmission projects, including those that remain within state lines. MISO maintains primary responsibility for planning larger projects, including most projects that cross state lines within its region. Commission staff participate as stakeholders within MISO's process for developing regional plans, in order to ensure Wisconsin's energy needs and policy priorities are accounted for in planning decisions. The

Commission also maintains jurisdiction over final decisions related to the approval and siting of transmission lines constructed within the state.

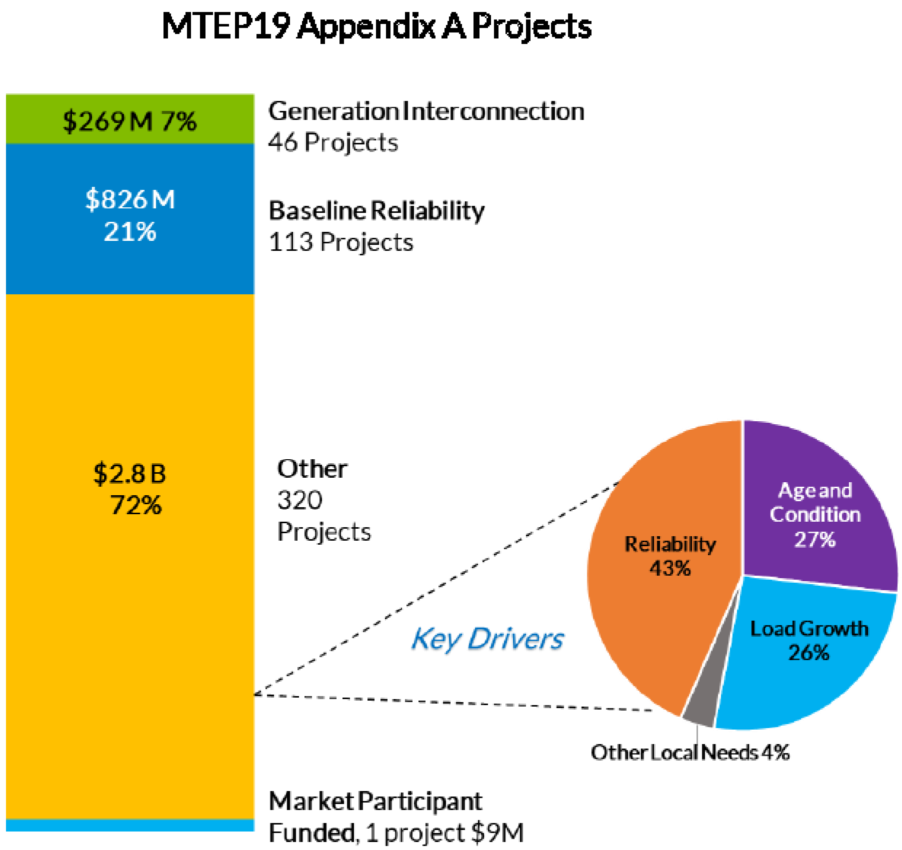
The annual MISO Transmission Expansion Planning (MTEP) process serves as a primary foundation for reviewing transmission needs and identifying and developing transmission projects. MTEP focuses on ensuring infrastructure is sufficient to provide adequate energy delivery throughout the MISO region and to meet national standards for maintaining service reliability. (See the Reliability and Resilience chapter for more detail on reliability measurement.) Issues reviewed and addressed through the MTEP process can include:

- **Baseline reliability** initiatives to ensure adequate transmission is available throughout the regional grid, such as increasing capacity to eliminate localized areas of transmission congestion where available energy exceeds transmission capacity, which can increase energy prices as well as increase the risk of service outages due to overheating or insufficient energy availability;
- **Generation interconnection** updates to support the addition of new generation facilities in specific locations;
- **Reliability** initiatives to address more localized transmission capacity needs within states;
- **Market efficiency projects (MEP)** to reduce transmission costs to customers by reducing congestion on the transmission grid;
- **Age and condition** updates to replace or enhance existing transmission infrastructure; and
- **Load growth** projects to update the transmission system to meet increased energy usage in specific locations.

The most recently completed planning cycle, MTEP 2019 (MTEP19), identified a new set of proposed projects over and above those approved in previous planning cycles. The overall MTEP19 identified 480 transmission projects to meet needs across the full MISO system, at a total cost of $3.9 billion.[29] As shown in Figure 2-3, reliability and baseline reliability projects accounted for slightly more than half of the total project costs. Project allocations by MISO region can be found in Appendix B.

[29] https://cdn.misoenergy.org/MTEP19%20Executive%20Summary%20and%20Report398565.pdf

Figure 2-3 MISO Transmission Projects Identified in MTEP19



MTEP19 includes 28 future projects located completely or partially in Wisconsin, with costs totaling $217.8 million. As shown in Table 2-1, updates to address aging infrastructure and condition issues accounts for the largest number of projects and largest share of costs. Projects for "Other Local Needs" include installing optical cable to enhance communication and security, and improving interconnections between transmission equipment in different regions of the state.

Table 2-1 MTEP19 Projects in Wisconsin

Transmission Project Type	Number	Estimated Cost
Age and Condition	11	$91.4 million
Other Local Needs	5	$46.7 million
Load Growth	2	$30.8 million
Reliability	7	$23.1 million
Baseline Reliability Projects	2	$19.5 million
Generation Interconnection Planning	1	$6.2 million
Totals:	28	$217.8 million

While MTEP19 identified projects that will receive further analysis and development from MISO and participating states, not all identified projects may ultimately be implemented. A number of projects identified in previous MTEP processes were not completed for a variety of reasons, including changing market conditions that reduced or eliminated the reliability needs previously established or that reduced the projected cost-effectiveness of the project.

MISO's upcoming MTEP21 planning process will update the modeling scenarios used to assess transmission needs, to ensure modeling assumptions are consistent with the pace of change related to the decreased use of coal generation and the increased use of zero-carbon energy resources, including renewable energy.[30] Once implemented, these new approaches may result in changes to the mix of transmission projects identified through MTEP. Commission staff participate in MISO stakeholder processes to ensure that project assumptions and analyses are consistent with conditions and requirements in Wisconsin, and that they are likely to result in project proposals that appropriately meet the state's future transmission needs and policy considerations.

In addition to the annual, reliability-focused MTEP process, MISO undertakes additional planning studies to address other issues affecting transmission. The Badger-Coulee and Cardinal-Hickory Creek lines recently approved in Wisconsin were initially identified through MISO's 2011 Multi-Value Project (MVP) study. The MVP study was designed to identify transmission upgrades needed to support the efforts of several participating MISO states to meet public policy goals such as compliance with renewable portfolio standards, as well as to increase reliability and provide economic benefits.

Several ongoing planning studies at MISO may inform project proposals at a future date. For example, MISO's Renewable Integration Impact Assessment (RIIA) is assessing the grid effects of incorporating increasing amounts of renewable energy resources in the MISO region. In addition to assessing effects for maintaining day-to-day operational reliability (see the Reliability and Resilience chapter), RIIA is assessing the impacts on transmission capacity, including the review of the development of additional transmission infrastructure as well as "non-wires alternatives" such as increased use of localized storage resources. Additional specific studies are reviewing the potential future effects of increased electric vehicle usage in the MISO region, specific constraints affecting efficient transmission of information among different zones within the MISO region, and coordination of planning and operations across the "seams" between MISO and other regional transmission operators. Commission staff will continue to monitor and provide input on all studies, to ensure they are conducted effectively and meet Wisconsin's state-specific needs, interests and priorities.

TRANSMISSION COSTS

Transmission costs to Wisconsin electric providers have been increasing in recent years, and account for an increasing share of total costs to utility customers. (See the Customer Rates and Bills chapter for more detail.) Partly for this reason, Commission staff prioritize a close review of costs during their participation in MISO's transmission planning processes. Two specific areas of scrutiny include:

- Ensuring clear identification and rigorous measurement of the benefits provided by each project; and

[30] Due to the time and analysis required to develop these modelling scenarios for MTEP21, the MTEP20 planning process, currently in progress, will use the same scenarios as MTEP19.

- Establishing appropriate methods for allocating the costs of transmission upgrades among electric providers and utility customers.

To achieve MISO approval, proposed market efficiency transmission projects are typically required to achieve a benefit-cost ratio of at least $1.25 in benefits for every $1 in costs. Historically, MISO quantified project benefits solely in terms of reduced production costs, such as those associated with reducing transmission system congestion. However, Commission staff have participated in MISO initiatives to identify and implement additional benefit metrics, with the goal of providing more accurate and detailed evaluation of project impacts, and identifying all positive value to Wisconsin associated with transmission upgrades. In 2019, with support from Commission staff, MISO approved two additional benefits to be added to projects, quantifying avoided costs of transmission investments and reduced costs of importing energy from outside the MISO region.[31] The Federal Energy Regulatory Commission (FERC) approved the use of these benefit metrics in July 2020. Commission staff will monitor implementation of the metrics to ensure they are applied consistently across the review of individual projects, and avoid any double-counting of benefits due to overlap in metric calculations.

MISO and participating stakeholders seek to allocate transmission project costs to electric providers and utility customers in proportion to the share of benefits they receive. Historically, MISO implemented cost allocation methods that included a "postage stamp" approach, according to which benefits are shared by the customers in all of the MISO states in proportion to each state's share of MISO's total load. (Wisconsin's share has historically ranged between 13 and 15 percent.) Commission staff have advocated for modifications to the approach, due to concerns that the postage stamp allocation does not clearly align cost allocations with local benefits, and that other methods are available to determine with greater precision who is actually benefitting from any new transmission investment and assign costs to those customers. With Commission staff support, MISO proposed to modify its approach on large market efficiency transmission projects beginning in 2020 to a direct cost allocation method, which allocates costs according to the beneficiaries on a sub-regional basis. FERC also approved this proposal in July 2020. Commission staff will monitor implementation of the proposal, and advocate to apply the same methods to a wider range of project types.

[31] https://cdn.misoenergy.org/20180814%20PSC%20Item%2006d%20Benefits%20Metrics%20Discussion265122.pdf

CHAPTER 3 – RELIABILITY AND RESILIENCE

In addition to obtaining an adequate total supply of energy to serve customers, Wisconsin electric providers must also carry out their daily operations to ensure *reliability*: providing all customers access to electricity at all times, and avoiding outages whenever possible. As new technologies present opportunities for grid modernization, electric providers and the Commission are reviewing the opportunities available for increased reliability as well as other benefits. In addition, the Commission and electric providers are working with other organizations to increase the Commission's focus on the related concept of *resilience:* protecting system operations against potential extreme events such as severe weather and cyberattacks, and establishing policies and processes to quickly restore service after extreme events occur.

RELIABILITY

All utilities in the United States assess their reliability using three standard metrics defined by the Institute of Electric and Electronic Engineers (IEEE).

- **System Average Interruption Duration Index (SAIDI)** identifies the average number of total minutes a customer experiences electric system outages during a year.[32]
- **Customer Average Interruption Duration Index (CAIDI)** identifies the average number of minutes per customer outage, which reflects the average length of time required for utilities to restore service.[33]
- **System Average Interruption Frequency Index (SAIFI)** identifies the average number of outages a customer experiences during a year.[34]

The use of multiple metrics reflects that electric providers want to limit both the frequency and duration of service outages. A provider that experiences many short outages in a year would have a high SAIFI value, but low SAIDI and CAIDI values. By contrast, a provider with few outages that take a long average time to restore would have high SAIDI and CAIDI values, but a low SAIFI value.

Electric providers with more than 100,000 customers must report annually to the Commission their reliability measures for the preceding year, including customer interruptions due to storms, catastrophic events, or police actions. Figure 3-1 shows statewide SAIFI, SAIDI, and CAIDI for the five major Wisconsin Investor-Owned Utilities (IOU) since 2001. In 2018, the average customer of those utilities experienced less than one outage per year (SAIFI=0.82), with an average duration per outage of approximately three hours (CAIDI=179 minutes). The frequency of outages has consistently declined since reporting began in 2001, while the average duration of outages has increased in recent years compared to average durations in the mid- to late-2000s.

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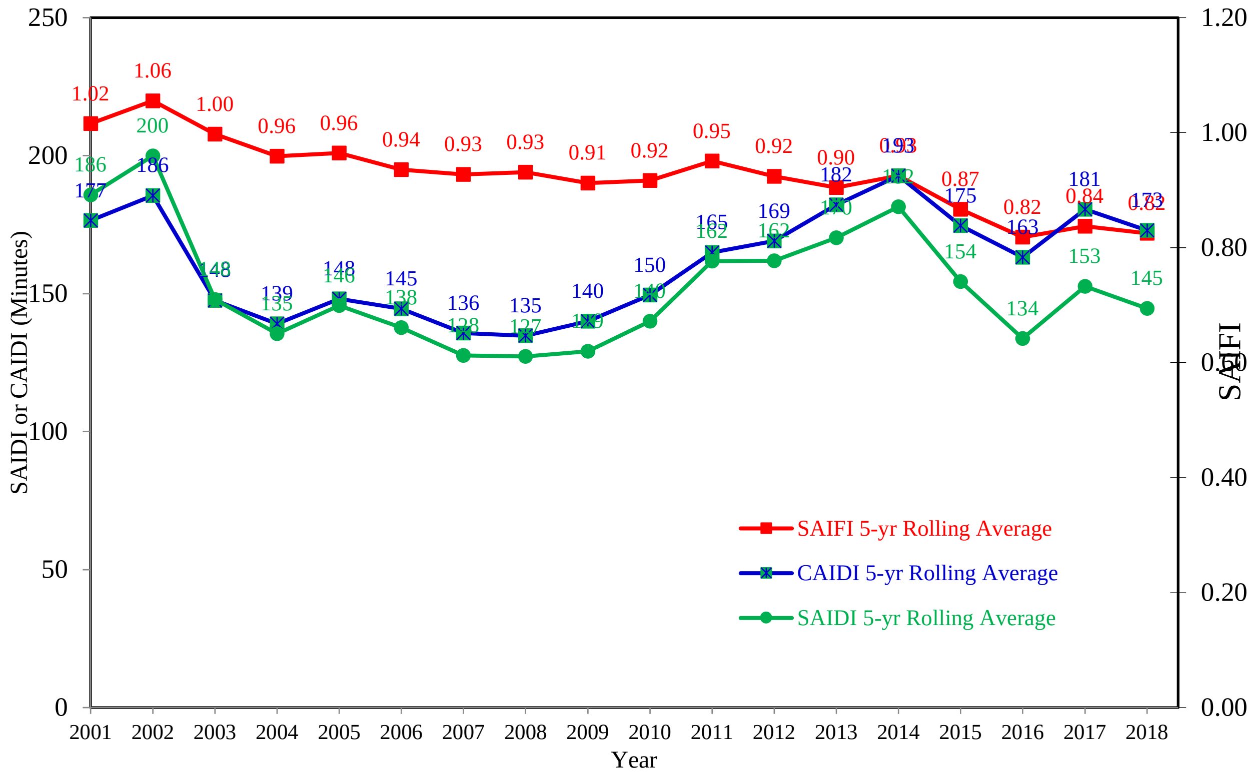
[32] SAIDI = annual sum of customer-minutes of interruption/average number of customers served during the year. Interruptions include any event that results in customer loss of service, including weather events and technical issues.
[33] CAIDI = annual sum of all customer-minutes of interruption durations/annual number of customer interruptions
[34] SAIFI = total annual number of customer interruptions/average number of customers served during the year.

Figure 3-1 Statewide Average SAIFI, SAIDI, and CAIDI Values for Major IOUs[35]



Reports filed with the federal EIA allow a comparison to similar utilities nationwide.[36] As shown in Figure 3-2, Wisconsin electric providers with more than 100,000 customers compared favorably to most states in minimizing the number of outages (SAIFI) during 2018, and fell closer to national averages on outage duration (SAIDI and CAIDI).

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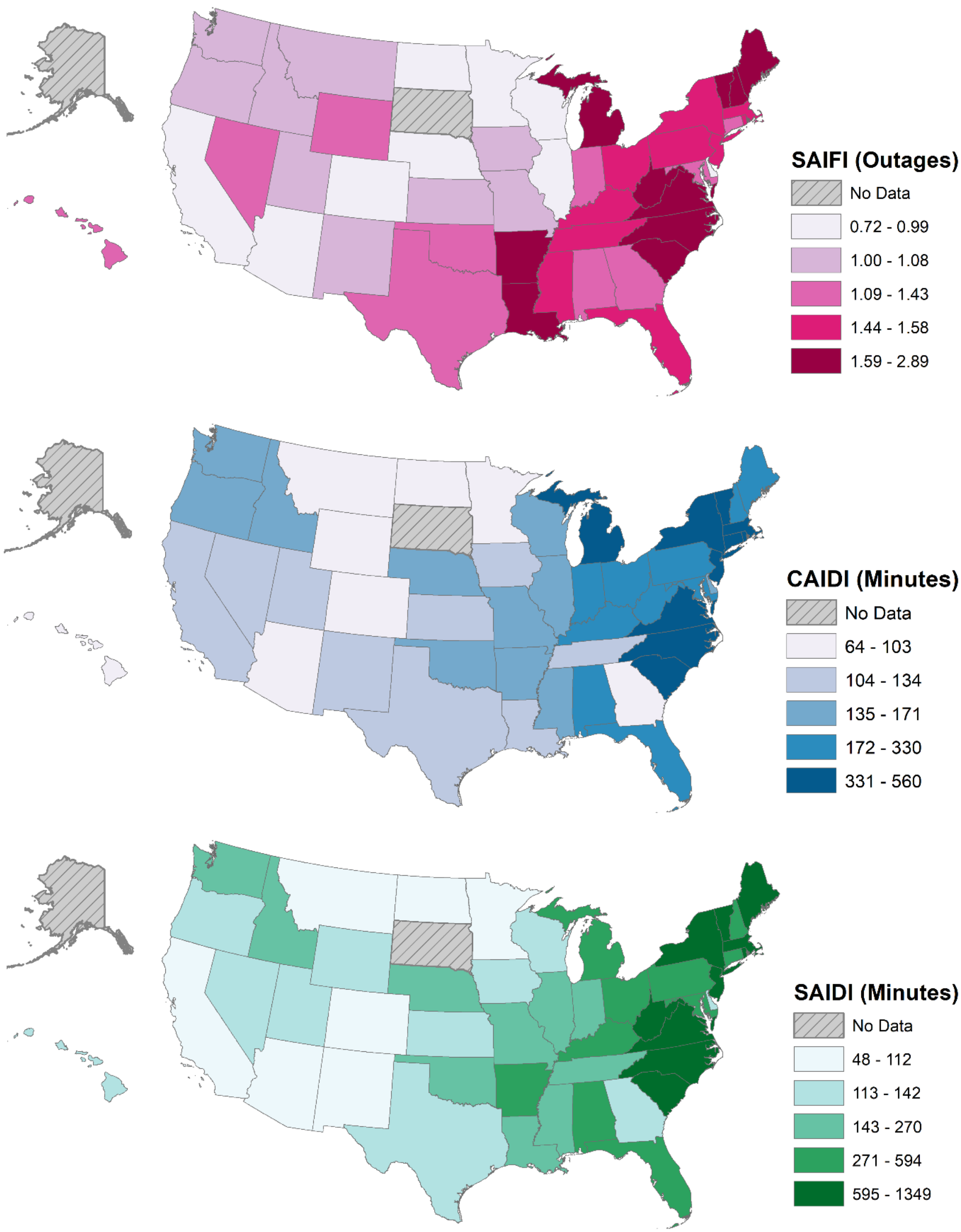
[35] Source: Reports filed with the Commission per Wis. Admin. Code PSC § 113.0604. Five-year rolling averages are used to normalize weather conditions.

[36] Source: Annual Electric Power Industry Report, EIA-861. https://www.eia.gov/electricity/data/eia861/. Although some data is also available for utilities with fewer than 100,000 customers, comparisons are more difficult to make because many smaller utilities in both Wisconsin and other states do not file reliability data through this report.

Figure 3-2 Reliability indices by state for large utilities (>100,000 customers), 2018



NEW GRID TECHNOLOGIES

In recent years, a variety of new electric system technologies have emerged—including the growth of zero-carbon energy generation sources as well as a range of other new technologies supporting daily system operations. Electric providers nationwide are assessing the opportunities for use of these technologies, which are sometimes grouped under the general heading of grid modernization.

To review these emerging opportunities in Wisconsin, the Commission has collaborated with energy providers and stakeholders to inventory the activities already underway in Wisconsin and to clarify long-term priorities for continued exploration. In 2018, the Commission conducted a survey asking utilities and stakeholders to identify the most important grid opportunities. The five leading topics identified by respondents were:

- Interconnection of distributed energy resources;
- Identification of customers' changing expectations, preferences and behaviors;
- Uses and benefits of advanced meters;
- Safety and reliability of the distribution system; and
- Increased electrification.

Respondents' highest modernization priority was studying the integration of renewables and other distributed energy resources (DER). (See the Renewable Policies and Programs section for data on DERs.) Respondents also prioritized reviewing how the full range of emerging technologies can support reliability and more effectively serve customers. Key issues associated with both topics are outlined below.

The Commission also continues to work with providers and stakeholders to consider effective processes for proactively addressing the full range of grid-related opportunities. Recent discussions have highlighted the potential benefits of more extensive provider-stakeholder collaboration to develop specific plans and proposals.[37] While additional dialogue will be appropriate to more extensively explore this idea and define how it might be implemented, such a collaborative approach could improve the quality of grid-related proposals, identify opportunities for innovation, and facilitate broad support for finalized plans.

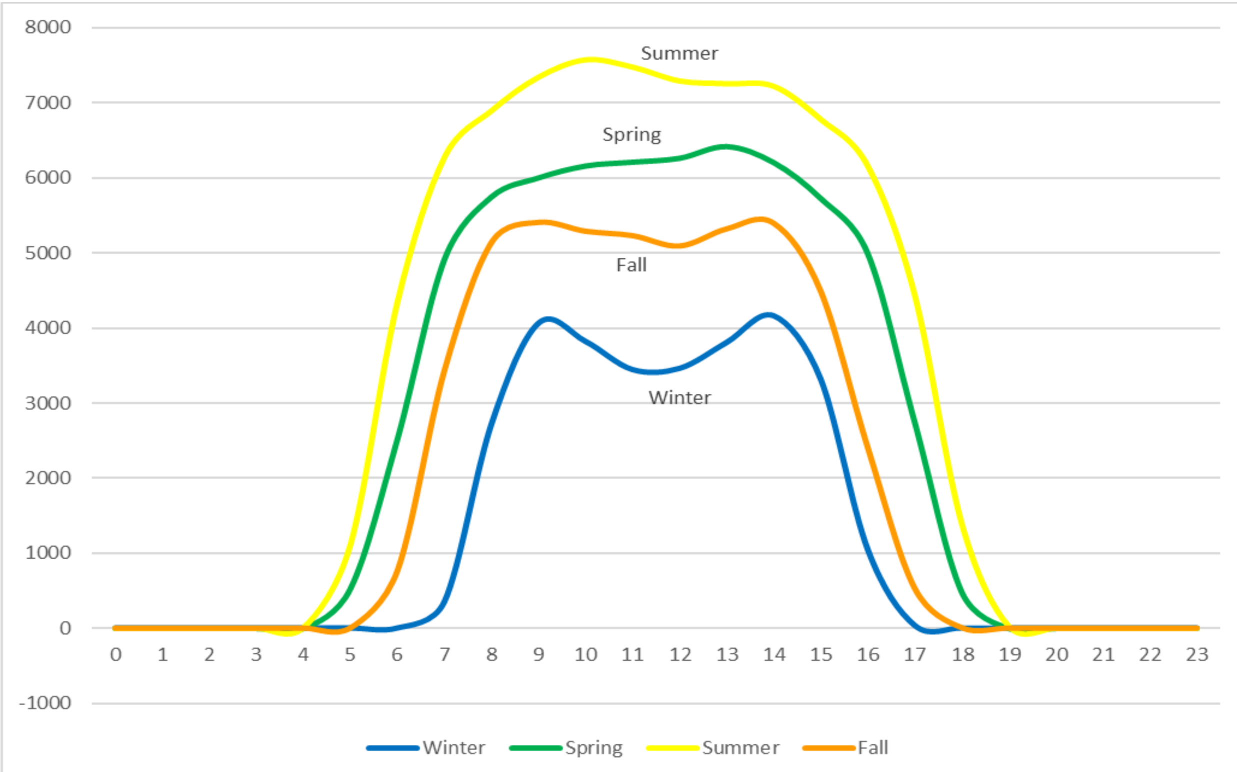
Renewable Resources and Reliability

Renewable energy sources such as solar and wind provide varying amounts of energy at different times of the day and at different times of year. Solar energy is available only during daylight hours and at higher levels in the summer (Figure 3-3); wind resources are highest during the winter and spring and are often greatest during overnight hours (Figure 3-4). Due to the influence of weather

[37] This approach was identified as a recommendation by the Wisconsin Energy Distribution and Technology Initiative (WEDTI), a broad-based stakeholder group who met during 2019-2020 to identify a range of recommendations to address evolving conditions in Wisconsin's electric sector. See: https://www.m-werc.org/wedti-report, Recommendation 4, pp. 23-24.

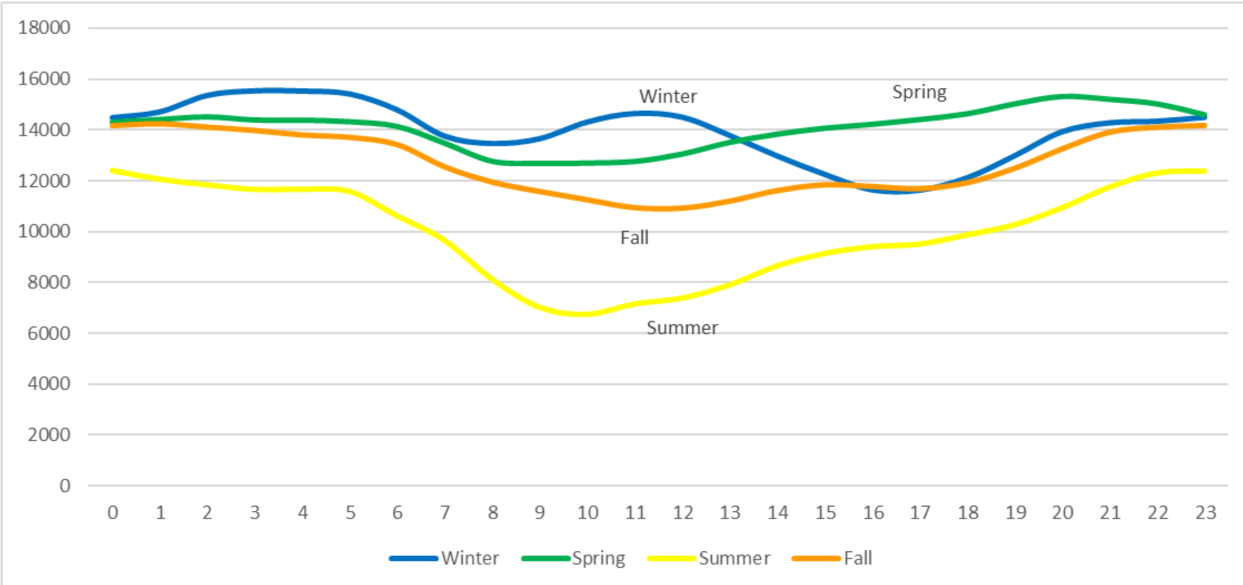
patterns, such as cloud cover for solar resources, the precise amount of available resources is also difficult to predict in advance.

Figure 3-3 Possible Future MISO North Annual Hourly Solar Production, 30-day Averages[38]



[38] PSC REF#: 357406. MISO North refers to MISO's operating regions in Minnesota, Iowa, North Dakota, and parts of South Dakota and Wisconsin. The "possible future" scenario assumes operation of existing wind and solar resources on the MISO system, plus implementation of the wind and solar projects currently listed in MISO's interconnection queue.

Figure 3-4 Possible Future MISO North Annual Hourly Wind Production, 30-day Averages[39]



Reliable electric service requires electric system operators to balance net supply and demand on the electric grid at all times in order to maintain system reliability. Renewable resources can present more complications for maintaining this balance than baseload resources such as coal and nuclear power, which are more consistently available at all times of day; and intermediate resources such as natural gas which can be used on a more intermittent basis but at levels that can be defined in advance. (See the Supply chapter for additional description of baseload, intermediate, and intermittent resources.)

As of 2019, solar and wind resources currently comprise less than 10 percent of generation in Wisconsin's local operations and regional MISO transmission market. (See the Supply chapter.) At these levels, the impacts from balancing those resources with baseload and intermediate resources remain limited. However, challenges may grow as solar and wind penetration continues to increase. One effort to study these effects is MISO's Renewable Integration Impact Assessment (RIIA), which is modeling the impacts of renewable generation thresholds of 10 percent, 20 percent, 30 percent, 40 percent, and 50 percent. In addition to identifying potential transmission needs (see Transmission chapter), study outputs will also identify reliability challenges and potential approaches to address those challenges at each level of penetration.

Commission staff are also monitoring research on additional operational aspects of solar and wind impacts on reliability. Balancing supply and demand for reliability also requires that the system maintain stable electric frequencies and voltage levels, to protect against sudden spikes or drops that could create outages resulting from operating technology failures. Renewable energy can present challenges for frequency control by increasing the amount of variable power on the grid that must be controlled. On the other hand, renewable technologies could help improve both system

[39] Ibid.

frequency and voltage stability. While traditional resources can only provide voltage support while they are generating power, power electronic-based renewable resources, such as solar photovoltaic systems and new generation wind turbines, can provide voltage support at all times while connected to the system.[40] Additionally, these technologies can provide both frequency support and voltage "ride-through" services that limit the impacts when grid instabilities do occur. The National Electric Reliability Corporation's (NERC) Essential Reliability Services (ERS) initiative, currently in progress, is developing informational resources on these operational issues.

Other Grid Technologies

Wisconsin's review identified advanced meters as an additional priority for obtaining further grid benefits. Advanced meters add new technological components to the standard meters traditionally used to quantify energy use for customer billing.

A 2017 Commission survey[41] found that, of the 2.6 million residential meters in Wisconsin at that time, 78 percent included some form of advanced metering infrastructure (AMI). In nearly all cases, advanced components included automated meter reading (AMR) capability that permit the electric provider to remotely collect meter data, eliminating the need for home visits by utility staff and reducing costs for providers and customers. Approximately half of advanced meters included additional components to support two-way communications between the utility and the customer, which can have a variety of benefits, including:

- Enhancing reliability by helping the provider more quickly and efficiently identify outages and initiate more rapid service restoration efforts;
- Providing customers increased information on their energy use, which can meet the growing interests of some customers in taking greater control of their energy use; and
- Supporting the implementation of advanced rates and tariffs, such as rates that depend on market-based pricing. (See the Rates section for more information on advanced rates).

A number of Wisconsin electric providers are also supporting these benefits through upgrades to their customer information systems (CIS). New CIS systems allow utilities to integrate new technologies and meters into system operations, and serve as another platform for providing additional information to customers about their energy usage. Other benefits of system upgrades include improved data security and cost savings through operational efficiencies.

Resilience

Nationwide focus on resilience has grown in recent years, as a result of increasing attention to "high impact, low frequency" (HILF) events—such as severe weather and cyberattacks—that can result in lengthy service interruptions and significant recovery costs. Resilience efforts focus on both taking

[40] Older generation wind turbines may not rely on the applicable power electronics, but could be outfitted with additional equipment to provide those services.
[41] See [PSC REF#: 296929](#).

steps to prevent HILF events from occurring and developing plans and resources to support efficient recovery after an event occurs.

The U.S. Department of Energy (DOE) initiated formal federal policy development on resilience by issuing a Notice of Proposed Rulemaking on the issue in September 2017. National policy effort has since shifted to the Federal Energy Regulatory Commission (FERC), which ended DOE's rulemaking in 2018 and created in its place FERC Docket AD 18-7, under which MISO and other regional transmission organizations have been asked to review the resilience on their systems. While FERC has not taken further action on this docket to date, the Commission has collaborated with other organizations within Wisconsin to enhance state-level planning and policy development on resilience issues.

State law places the primary responsibility for responding to large-scale emergencies that exceed local capacities with the Wisconsin Division of Emergency Management (WEM) within the Department of Military Affairs. The Commission's Office of Energy Innovation (OEI) contains the state's federally designated state energy office, which serves as a lead advisory agency to WEM, and the two agencies work together to carry out OEI's federal requirement to develop energy emergency plans that respond to supply disruptions. Commission personnel also play roles in energy assurance coordination, by sharing information with the federal government and other state governments during emergency situations.

WEM and OEI regularly participate in planning exercises at the state, regional and national level, working with other actors to model planning and responses to HILF events. In May 2018, WEM hosted a three-day "Dark Sky" event which modeled a long-term power outage and incorporated considerations related to cybersecurity and fuel shortages. The exercise included over 1,600 participants from over 240 agencies and departments spanning the local, county, state, federal, and private sector including Commission staff, four investor-owned utilities, municipal electric utilities, water utilities, healthcare, law enforcement, and non-profit partners. The exercise identified several specific recommendations to improve resilience planning, such as increasing the deployment of fueling infrastructure available during outages to support vehicles involved in recovery operations.

OEI is further promoting collaborative resilience planning through its Statewide Assistance for Energy Resilience and Reliability (SAFER2) grant, which focuses on enhancing coordinated statewide planning with local emergency management officials at the regional, tribal, county, and municipal levels. Grant funds have supported meetings and training exercises to gather enhanced information on critical energy infrastructure, clarified specific roles and responsibilities within a collaborative framework, and developed planning templates for specific types of HILF events.

To further expand its collaborative efforts on resilience, OEI has started developing a pilot grant program to provide financial support for innovative pre-disaster resilience measures, including microgrids as well as other resilient building strategies. The program would include a focus on fostering resilience at the local level, by offering participation opportunities to political subdivisions, school districts, tribal governments, and utilities. Preliminary approval of the program was granted in April 2020. Staff are developing program design details and anticipate launching the program in early 2021. The declaration of a public health emergency in response to the COVID-19 pandemic has activated Wisconsin's energy-related emergency response plans. The Commission is collecting information regarding the needs of and effects on critical energy infrastructure and collaborating with WEM and other agency partners to define appropriate responses to operational needs. (Additional actions by the Commission to address the effects of the pandemic on customers are described in the Customer Rates and Bills chapter.)[42]

Cybersecurity

Nationwide attention has also increased regarding the specific resilience threats associated with cybersecurity attacks, which could create outages or diminish service through attacks on the grid control networks used by system operators. In 2018, the U.S. DOE released a Multiyear Plan for Energy Cybersecurity which identifies goals to strengthen cybersecurity preparedness, coordinate event responses, and enhance research and development on cyber-resilience.[43] In the same year, DOE also established an Office of Cybersecurity, Energy Security, and Emergency Restoration to coordinate cybersecurity issues and provide training and support to state and local officials.

In 2015, representatives of Wisconsin electric providers worked with state and local government officials and other owners of critical state infrastructure to add a Cyber Incident component to the Wisconsin Emergency Response Plan. The plan includes provisions to limit the impacts of cyberattacks and maintain critical services. The Dark Sky exercise, mentioned above, served as a test of the Cyber Incident Response Plan by role-playing scenarios involving cyberattacks, in combination with physical attacks, on electric utility infrastructure. Participants exercised the provisions of the plan, including establishment of the state Cyber Response Team, to assess the quality of communication and analysis within the team and identify opportunities for improvement. Areas for cybersecurity improvement identified through the exercise included ongoing collaboration with state electric providers to regularly share information on cybersecurity protections and emerging threats, as well as the development of enhanced operating plans to further clarify roles and responsibilities for responding to future cyberattacks.

[42] These efforts include dockets to investigate the provision of safe, reliable and affordable access to utility services during the pandemic (docket 5-UI-120; see the Affordability for Low-Income Customers section) and to investigate the financial accounting of costs related to the pandemic (docket 5-AF-105; see the Determining Customer Rates section).
[43] U.S. Department of Energy. Multiyear Plan for Energy Sector Cybersecurity. March 2018. https://www.energy.gov/sites/prod/files/2018/05/f51/DOE%20Multiyear%20Plan%20for%20Energy%20Sector%20Cybersecurity%20_0.pdf. Accessed on March 18, 2020.

CHAPTER 4 – CUSTOMER RATES AND BILLS

In addition to ensuring adequate and reliable electric supply, the Commission also seeks to ensure that electric providers offer customers reasonably priced electric service. The Commission regulates the rates charged by investor-owned and municipal electric utilities to identify the prices that minimize costs for customers while still permitting providers to recover from customers the funds needed to offset operating costs and make a reasonable profit to support future investment. Many electric providers also work, under Commission regulation, to develop new and innovative rates and programs to meet customers' evolving needs and cost-effectively serve specific types of customers.

UTILITY COST DRIVERS

As the first step in the rate regulation process, electric providers propose a *revenue requirement,* the total amount of money a utility needs to recover through customer rates to provide adequate and reliable service. Revenue requirements are developed based on historical costs, as well as forecasts of future growth in customer energy use and the future costs of providing service. The revenue requirement also includes a return on equity on the assets used to provide service, such as generation plants, which each provider uses to pay interest on money it borrows and to compensate investors. Commission staff audits each provider's proposed revenue requirement and makes adjustments as appropriate to establish a requirement that will recover costs and provide utilities with a reasonable return, while maintaining the lowest feasible cost to customers. (See the Determining Customer Rates section below for more details on the rate case process.)

Three key trends have influenced revenue requirement levels for providers across Wisconsin in recent years. First, customer sales have grown slowly. Second, electric providers are still considering significant investments to meet electric supply needs, driven by capacity needs within the state and the economic and environmental factors supporting the increased pursuit of new natural gas and zero-carbon generation. Third, application of the cost savings from 2017's federal tax reform have reduced utility costs in recent cases.

Trends in Customer Sales

In 2008, Wisconsin electricity sales fell in response to the recession. While sales have increased every year since 2014, annual growth rates in those years have remained low, and total electricity sales in 2018 remained one percent lower than sales in 2007, as shown in Figure 4-1 and Table 4-1.

Energy efficiency is one key reason electric sales did not return to pre-recession levels by 2018. After incorporating total net energy savings recorded by Focus on Energy's statewide programs since 2007, Figure 4-1 and Table 4-1 show that, in the absence of those reductions in energy use, annual growth rates would have been higher in each of the past 12 years, and total electricity sales would have exceeded pre-recession levels. Using Focus on Energy savings also serves as a conservative estimate of energy efficiency impacts, since many customers may also be taking additional energy-efficient actions outside of the program. Although the effects of the COVID-19 pandemic remain uncertain at this time, response measures and associated slowdowns in economic activity are likely to result in overall sales reductions from 2018 levels.[44]

Figure 4-1 Retail Sales of Electricity, by Sector (MWh)[45]

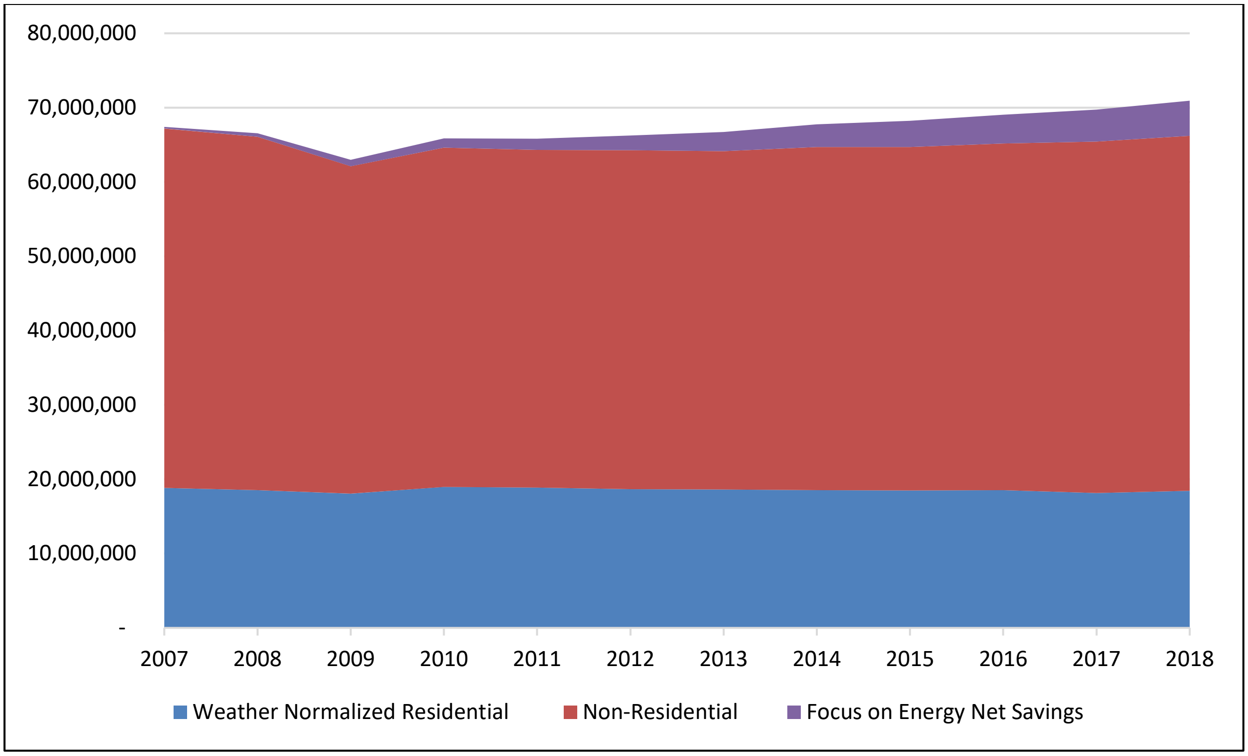


Table 4-1 Annual Growth Rates for Retail Electricity Sales (%)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Average Growth
Residential	-1.6%	-2.6%	5.0%	-0.6%	-1.1%	-0.1%	-0.6%	-0.1%	0.2%	-2.1%	1.7%	-0.2%
Non-Residential	-1.6%	-7.4%	3.6%	-0.5%	0.4%	-0.3%	1.4%	0.0%	1.0%	1.4%	1.0%	-0.1%
Total	-1.6%	-6.0%	4.1%	-0.5%	0.0%	-0.2%	0.9%	0.0%	0.8%	0.4%	1.2%	-0.1%
Total w/o Focus on Energy	-1.2%	-5.4%	4.6%	-0.1%	0.7%	0.7%	1.5%	0.7%	1.3%	1.0%	1.7%	0.5%

Usage by customer provides another measure of the effects of energy efficiency on overall sales. Average electricity use per customer for residential customers declined 5 percent from 2007 through 2018. Average energy intensity per dollar of economic output, the metric commonly used to assess the more widely varying population of non-residential customers, increased nearly 50 percent from 2007 through 2018. (See Appendix C, Figures C-1 and C-2 for illustration of these trends). The

[44] In May 2020, Wisconsin Power and Light and WEC Energy Group (representing Wisconsin Electric Power Company and Wisconsin Public Service) reported that they project sales declines of approximately 5 percent in 2020.

[45] Source: Utility annual reports filed with the Commission; Focus on Energy. For this analysis, weather-normalized sales for residential customers are used to remove data outliers from unusual weather events such as the polar vortex of 2014.

effects of these per-customer trends have been partially offset by the increase in the number of total customers served, but not at sufficient levels for total sales to reach their pre-2008 levels.

Sources of Utility Costs

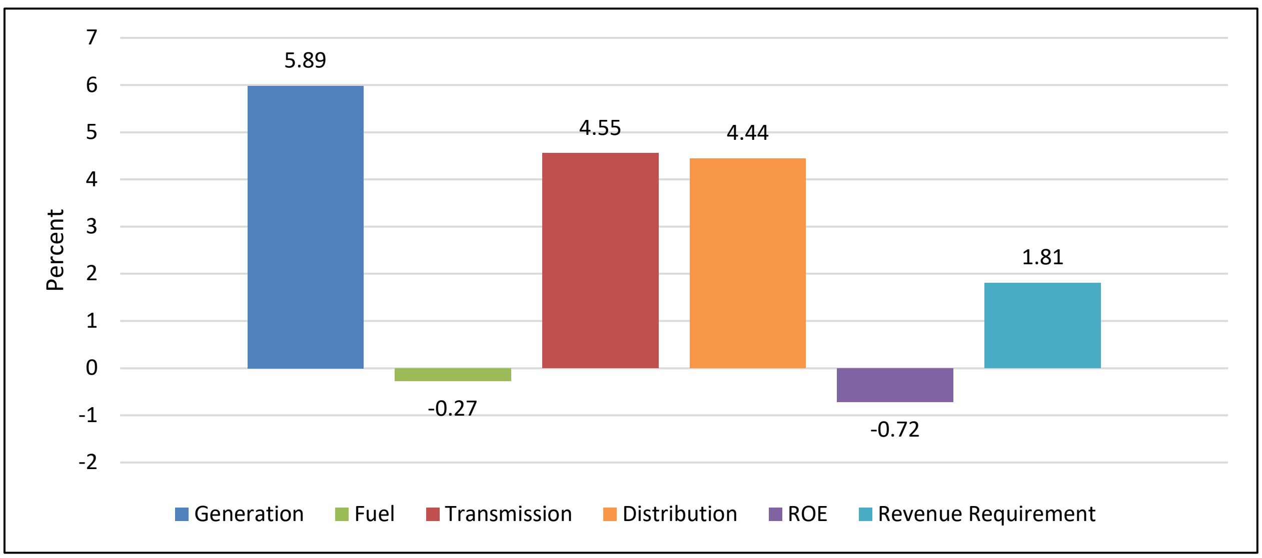
Declining usage trends can benefit individual customers by helping them reduce their energy bills. However, electric providers must still bear the costs of providing adequate and reliable service to all customers. If costs for a given provider grow at a higher rate than electric sales, the result can be a need for increased customer rates to absorb the higher costs.

Major Investor-Owned Utilities with Generation

Wisconsin's five largest IOUs,[46] who serve nearly 90 percent of the state's electric customers, provide most of their electric supply through utility-owned generation. The majority of the revenue requirements for each of these "Major IOUs" comes from generation, distribution, and transmission.

As shown in Figure 4-2, total revenue requirements for Major IOUs increased 1.8 percent between 2009 and 2018. Of the revenue requirement components, the Commission has direct control over generation, return on equity, and distribution investment for large projects. Fuel costs and transmission rates are mostly outside the Commission's control and represent pass-through expenses.

Figure 4-2 Ten-year Annual Growth Rate of Revenue Requirement Components—Major IOUs (%)



Both fuel costs and return on equity for IOU assets decreased between 2009 and 2018. Return on equity is set for each utility in their rate cases, but have generally trended down due in part to low interest rates during this time period. Fuel costs have generally declined due to reduced natural gas

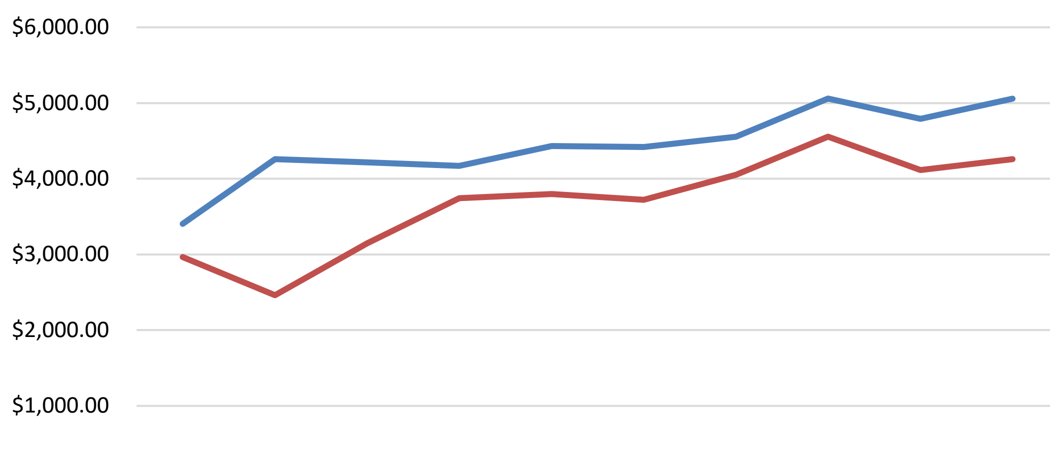
[46] MGE, NSPW, WEPCO, WP&L, and WPSC.

costs and the increased utilization of generating resources that incur no fuel costs, such as wind and solar.

Total fuel costs may continue to decline in future years as providers make further investments in wind and solar resources. By contrast, investments in new generation may result in further increases in generation and distribution costs for new utility-owned generation, which increased by approximately 5 percent between 2009 and 2018. The generation and distribution cost amount in revenue requirements reflects the amount of annual depreciation value from those investments authorized by the Commission in rate cases.

Transmission costs also increased at an annual rate of 4.5 percent between 2009 and 2018. These expenses are not under the direct control of IOUs or the jurisdiction of the Commission. Rather, they reflect transmission charges to each major IOU by Xcel Energy and American Transmission Company (ATC). Transmission rates are regulated by the Federal Energy Regulatory Commission (FERC) and charged through MISO's regional transmission tariffs. As shown in Figure 4-3, transmission charges have increased more than 40 percent in the last 10 years, with similar increases from both transmission providers. As noted in the Transmission chapter, Commission staff are participating in MISO transmission planning processes that influence transmission costs, including efforts to improve methods for allocating transmission costs among states.

Figure 4-3 MISO Schedule 9 Network Transmission Charges ($/MW-Month)[47]



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
ATC	$3,403.	$4,260.	$4,214.	$4,168.	$4,430.	$4,418.	$4,556.	$5,058.	$4,792.	$5,056.
Xcel (NSP System)	$2,962.	$2,460.	$3,144.	$3,744.	$3,795.	$3,720.	$4,050.	$4,555.	$4,116.	$4,259.1

ATC Xcel (NSP System)

Non-Major Investor-Owned Utilities and Municipal Utilities

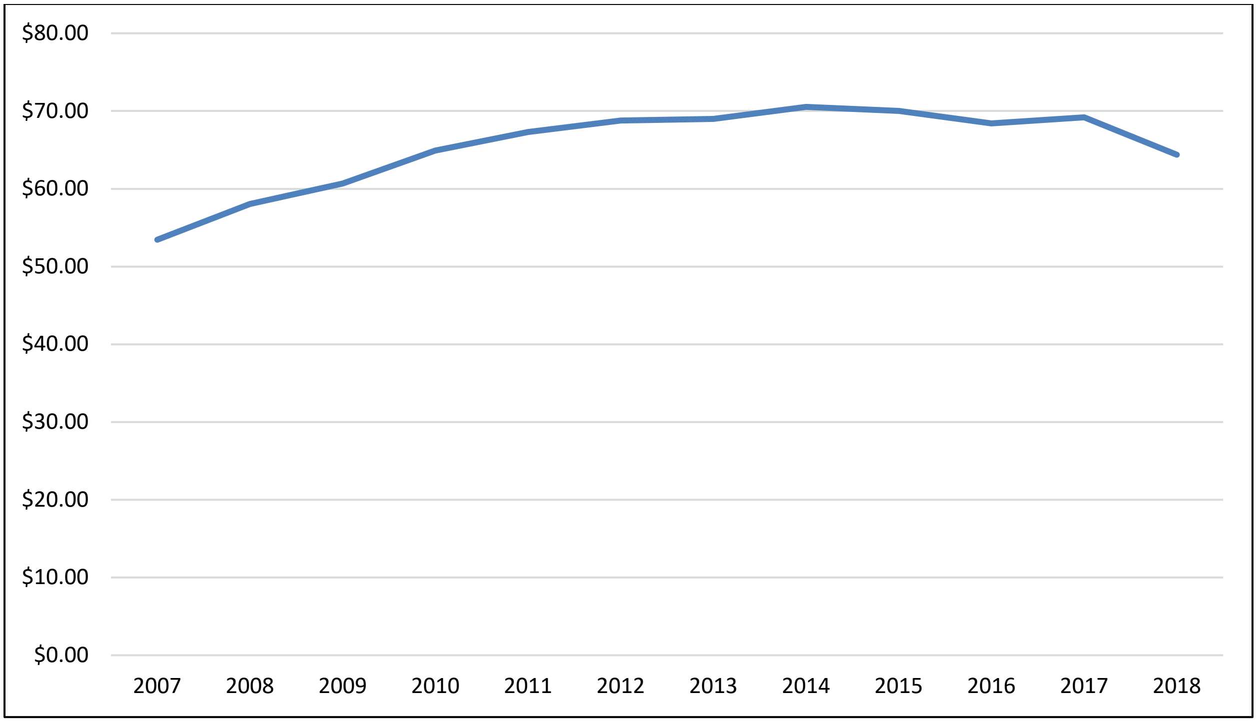
The other seven electric IOUs in Wisconsin, as well as the 81 municipally owned electric utilities regulated by the Commission, maintain most of the same cost components as the major IOUs.

[47] Source: MISO Open Access Tariff, Schedule 9.

However, most or all of their power supply comes through purchased wholesale power, rather than utility-owned generation. Therefore, wholesale power costs are the main driver of customer rates for these utilities.

Statewide, the average cost of purchased power has increased between 2009 and 2018, but remained relatively stable between 2014 and 2018 (see Figure 4-4). It should be noted that these costs do not match MISO day-ahead market prices (Appendix A, Figure A-1), because most utilities buy power under long-term contracts which also incorporate the embedded costs of transmission service.

Figure 4-4 Statewide Average Purchased Power Cost ($/MWh)[48]



Effects of Tax Reform on Investor-Owned Utilities

In December 2017, the federal Tax Cuts and Jobs Act (TCJA) implemented reforms to the federal tax code. Wisconsin IOUs are impacted by the TCJA's reduction of the corporate income tax rate to a flat rate of 21 percent, in place of a graduated structure with a maximum rate of 35 percent.[49]

The rates the Commission approved prior to 2018 for each IOU included the previously higher tax rate. As a result, IOUs began over-collecting tax revenue under those rates when the legislation took effect in 2018. To address these over-collections in a timely fashion, the Commission opened docket 5-AF-101 to review collections by all IOUs, reduce each IOUs' 2019 rates to account for the reform, and identify how each utility will return to customers the funds over-collected in 2018.

[48] Source: Monthly purchased power clause (PCAC) filings with the Commission.
[49] See Sec. 13001 at https://www.congress.gov/bill/115th-congress/house-bill/1.

The effects of tax reform will have short-term, intermediate-term, and long-term impacts on the costs included in revenue requirements.

- In the short term, a total of $110.3 million was immediately refunded to customers in 2018 and 2019, reflecting savings from utilities' 2018 tax expenses.
- In the intermediate term, an estimated additional $541.7 million will be returned to customers once each IOU files a rate case with the Commission. These funds represent income taxes collected in previous accounting periods that will not be paid to the IRS due to the reduction in the corporate tax rate, and can be applied to reduce customer rates in each utility's next rate case. In docket 5-AF-101, the Commission ordered that all IOUs must file a rate case by 2021 to ensure customers receive these benefits in a timely fashion.
- In the long term, nearly $1.5 billion additional dollars, previously collected in customer rates, will be applied to reduce future rates based on utility assets, such as owned power plants. Under federal tax law, these balances cannot be returned to customers any faster than the asset depreciates over its average remaining life. Given the long-lived nature of large utility capital investments, these balances will be gradually applied to reduce revenue requirements in each rate case over the next several years.

DETERMINING CUSTOMER RATES

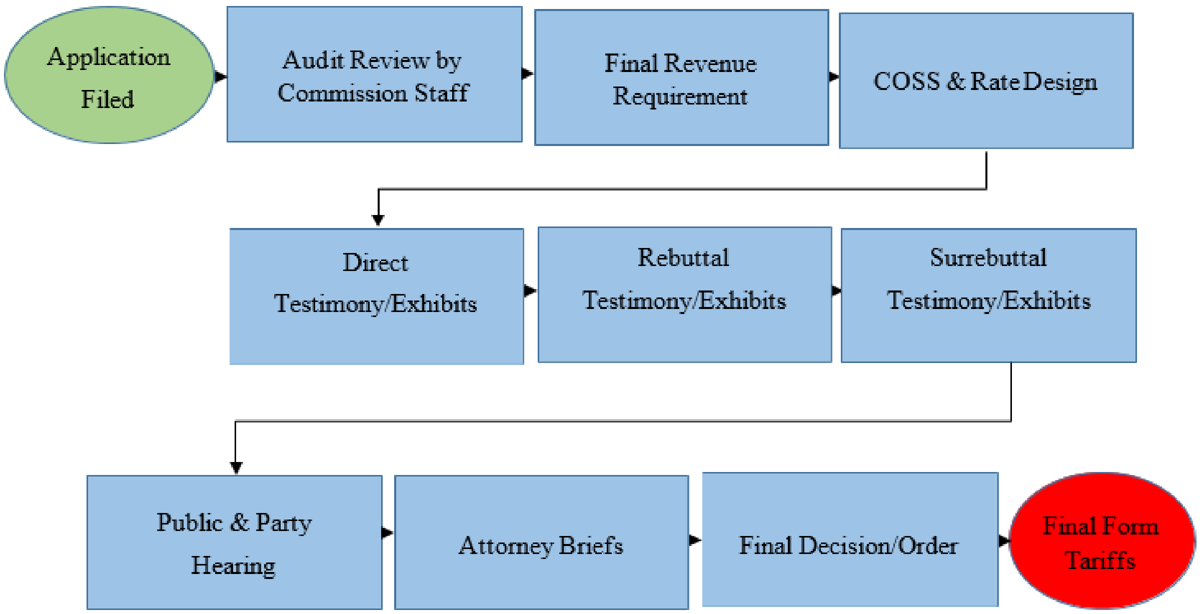
Customer rates are established by each electric provider to generate sufficient revenue to recover their costs. Ratemaking processes are intended to simulate for monopoly utilities the conditions of a free market; when rates are designed properly, the rate structure should signal to all different types of customers the actual cost of providing them reliable service and electricity.

Figure 4-5 summarizes the rate case process[50] that is followed by all electric providers regulated by the Commission, including all investor-owned and municipal electric utilities.[51]

[50] See also the Commission Proceedings webpage: https://psc.wi.gov/Pages/Regulatory/GuideToPSCProceedings.aspx.

[51] The rates of retail electric cooperatives are not regulated by the Commission. Uncontested municipal rate cases follow a simplified process.

Figure 4-5 Rate Case Process



Before a regulated utility can raise its customer rates, it must file an **application** with the Commission. The application proposes rates for a forward-looking test year, typically the first year of service the rates are expected to be in effect. Since this test year is usually either the current year or the year after the application is filed, the provider submits forecasts of the revenue requirement it projects it will need to cover its expenses and return on investment in that year and subsequent years, and proposes customer rates to allocate that revenue requirement among its customers.[52]

As the first step in application review, **Commission staff audit** the utility's revenue requirement by reviewing the application's forecasts and proposals and requesting additional information as needed. Commission staff analysis may focus on determination of values for key cost drivers such as asset depreciation, operations and maintenance costs, labor costs, rate of return, and sales forecasts. Based on audit findings, Commission staff may make adjustments to the proposed revenue requirement to more accurately reflect projected costs, and establish a **final revenue requirement** that will be used to determine rates.

Commission staff then use the final revenue requirement to review the utility's proposed **rate design**. Rate design analysis begins with a **cost-of-service study (COSS)** that seeks to meet the goal of charging actual costs to customers by estimating the allocation of utility costs among different customer classes, such as residential, commercial, industrial, and agricultural classes.[53]

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[52] In recognition of additional expenditures and reductions in revenue collections utilities may experience as a result of the COVID-19 pandemic, the Commission opened docket 5-AF-105 in March 2020 to collect information on the financial impacts related to the pandemic and the procedures to be used for financial accounting of those impacts.

[53] The COSS model applies many assumptions about how to classify, and allocate utility costs assumed in the revenue requirement. Utilities, Commission staff, and other rate case participants may reference best practices documented by

Utilities may submit one or more COSS models in their application, and Commission staff may design one or more additional models of their own. Using the COSS models, alternative rate designs can be proposed by the utility and Commission staff to fully recover the costs allocated to each class. (See the Components of Customer Rates section below for more detail on rate designs.)

Audit and rate design findings are then used as core evidence in a **rate case proceeding** that creates a record of evidence for Commissioners to evaluate, and allows many opportunities for public input. The proceeding includes:

- Submission of case evidence, including **testimony and exhibits** that summarize the audit and rate design work;
- Opportunities for **rebuttal and surrebuttal** testimony to initial evidence, which may be submitted by the utility and Commission staff as well as by other interested parties;
- At least one **public and party hearing** to receive testimony from all interested parties, including members of the public; and
- **Attorney briefs** to summarize the final positions of the applicant and other parties involved in the proceeding.

Commissioners then review the full record created by the rate case proceeding and issue a **final decision** approving, denying, or approving with modifications the proposed rates. As applicable, a final approval will also select from among the alternative decision options provided by the utility, staff, and other parties for decisions on specific components of the revenue requirement and rate design.

Wisconsin Stat. § 196.026, enacted in 2018, allows for the opportunity for utilities and parties to agree upon a resolution of some or all of the issues usually addressed by the Commission during full contested rate cases. Based upon a proposed utility rate settlement agreement, the rate case process described above may be modified in order for the Commission to gather and examine evidence related to the proposed settlement agreement, ensure settlement agreement conditions listed under Wis. Stat. § 196.026 are met, and make a determination on whether to approve the proposed settlement agreement. Multiple rate cases have been partially or completely resolved under these settlement provisions in the past two years. While the timing of settlement arrangements can vary, settlements to date have typically resolved some or all issues in advance of the later steps in the rate case process. To approve a settlement agreement, the Commission must find that parties to a docket have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, and that the public interest is adequately represented by the parties who entered into the settlement agreement. The Commission must also find that the settlement agreement represents a fair and reasonable resolution to the docket, is supported by substantial evidence on the record as a whole, and complies with applicable law, including that any rates resulting from the settlement agreement are just and reasonable.

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the National Association of Regulatory Utility Commissioners (NARUC) COSS Manual, as well as other external references and the practices used by the Commission and the utility in previous rate cases.

Components of Customer Rates

As described above, COSS are designed to assign to different customers the total amount of costs required to serve their customer class. Rates are designed to further link customer charges with the costs they create by including several different types of charges designed to recover different aspects of service costs.

All customers receive a **customer charge, or fixed charge,** of a flat amount per day or per month, regardless of how much energy they use. These charges are designed to reflect the minimum service for interconnection utilities must provide to serve customers regardless of energy usage level, such as each customer's energy meter, billing and customer service costs, and portions of the costs of the infrastructure needed to connect the customer's location with the electric grid. COSS studies seek to estimate these costs for each customer class, and then calculate the customer charges to recover those costs.

All customers also receive an **energy charge** per unit of electricity (kilowatt-hour) they use. These charges reflect the incremental costs associated with producing the next additional unit of energy a customer might need to use. For a customer of a utility that owns power plant generation, these costs are informed by the fuel costs and other costs needed to operate the plant. For utilities that do not own generating units, energy charges are informed by the per unit energy costs they use to purchase wholesale energy.

Demand charges are typically only charged to larger non-residential customers, such as commercial and industrial customers. Residential and small commercial customers have these demand costs embedded in energy charges instead. Demand may be measured using one of two separate methods.

- *Distribution (or customer) demand* reflects the distribution infrastructure costs associated with the customer's peak load use. The utility calculates a distribution demand charge by measuring the customer's highest usage level in a month, and then assigning a demand charge informed by the costs of the infrastructure needed to provide that volume of energy to the customer.
- *Coincident, or "billable", demand* reflects the costs to the utility of serving large customers during the utility's peak energy usage hours. Coincident demand charges reflect the service costs associated with making the generation, transmission, and distribution investments needed to provide adequate energy supply and transmission during system peaks.

Customer bills may also include **adjustments** to align customer charges with the variable costs of certain resources. IOUs that own generation units must provide fuel credits to customers when actual fuel costs are lower than forecasted in the utility's previous rate case, or fuel surcharges to recover costs higher than forecasted. IOUs submit annual fuel plans to the Commission, which approves the amount of the fuel credit or surcharge provided to customers in the following year. Customers of utilities receive credits or surcharges under the power cost adjustment clause (PCAC), which accounts for deviations from the municipal utility's forecasted costs of purchasing wholesale power.

Finally, other charges and credits may appear on the customer's bill if authorized by the Commission or state law. A recent example is the refunds associated with the 2018 tax reform (see the Utility Cost Drivers section above).

CURRENT RATES AND BILLS

Charges paid by utility customers reflect two inputs: the utility's Commission-approved rates, and the amount of energy used by the customer, which determines their total amount of energy and demand charges.

Residential Customers

Residential customers of all electric providers are typically billed almost entirely through customer and energy charges. Tables 4-2 and 4-3 summarize residential rates for investor-owned utilities and municipal utilities, based on the Commission-approved tariffs in place during 2019. For municipal utilities, the median customer charge is $7.50/month and the median energy charge is 10.28 cents per kilowatt-hour (kWh). IOUs have a median customer charge of $12.00/month and a median energy charge of 12.06 cents/kWh. On average, investor-owned utilities charge higher rates. Both tables also demonstrate that rates can vary based on the differing cost profiles faced by individual utilities, which can differ due to a wide variety of factors such as location, amount and condition of utility assets, and the mix of customers served.[54]

Table 4-2 Wisconsin Electric IOU Bill Components for Residential Customers, 2019

Summary Statistics	Energy (cents/kWh)	Customer Charge ($/month)*
Minimum	8.70	$8.00
25th Percentile	11.53	$9.50
Median	11.86	$12.00
Average	11.94	$13.29
75th Percentile	13.00	$16.75
Maximum	13.72	$21.00

** Note: Cents/kWh based on weighted average seasonal rates for MGE and NSPW.*

Table 4-3 Wisconsin Municipal Electric Utility Bill Components for Residential Customers, 2019

Summary Statistics	Energy (cents/kWh)	Customer Charge ($/month)*
Minimum	4.65	$5.00
25th Percentile	9.45	$7.00
Median	10.28	$7.50
Average	10.11	$8.99
75th Percentile	10.96	$11.50
Maximum	12.45	$16.00

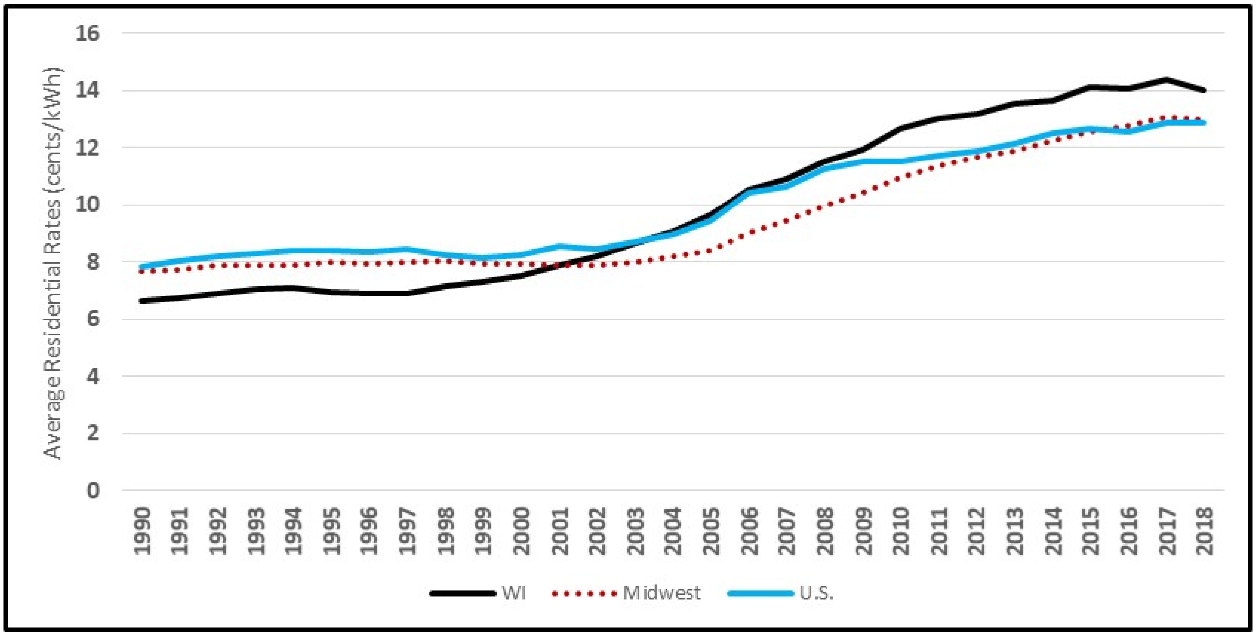
** Note: Customer charge data is for single-phase customers only.*

National data collected by the EIA permits comparison of Wisconsin rate levels to other states and regions. While direct rate comparisons between states should be made cautiously due to differences in energy market conditions and regulatory structures, available data indicates Wisconsin's residential

[54] Bill components for each provider can be found on the Commission website at: https://apps.psc.wi.gov/RATES/tariffs/default.aspx.

rates are higher than Midwest and national averages. Based on an overall, sales-weighted average of all electric utilities within each state, Wisconsin's average 2018 residential energy charges of approximately 14 cents/kWh exceed national and Midwest averages of approximately 13 cents/kWh. As shown in Figure 4-6, Wisconsin's average rates have exceeded national and Midwest averages for the past decade. Appendix C, Table C-1 provides more detailed comparisons, including charges for each individual Midwest state.

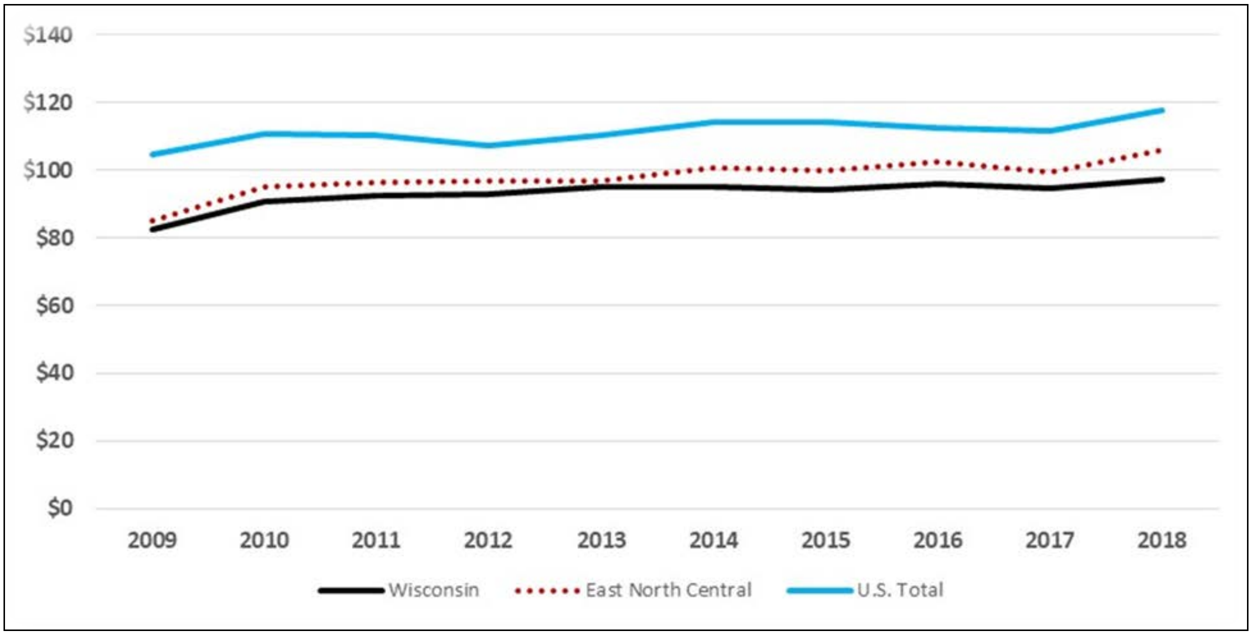
Figure 4-6 Average Residential Electricity Rates (1990-2018)[55]



EIA data also demonstrates that average monthly electric bills in Wisconsin have remained consistently lower than other states during the past decade. Wisconsin's average 2018 bill of $97.09 compares to Midwest average bills of $109.16 and national average bills of $117.65. (See Appendix C, Figure C-3 for more detailed comparisons of average bills by census region.)

[55] U.S. Energy Information Administration, Electricity Sales, Revenue, and Average Prices (Table 5A). Issued October 1, 2019. Accessed January 3, 2020 at https://www.eia.gov/electricity/sales_revenue_price/.

Figure 4-7 Historical Comparison of Average Monthly Residential Electric Bills (2009-2018)[56,-57]

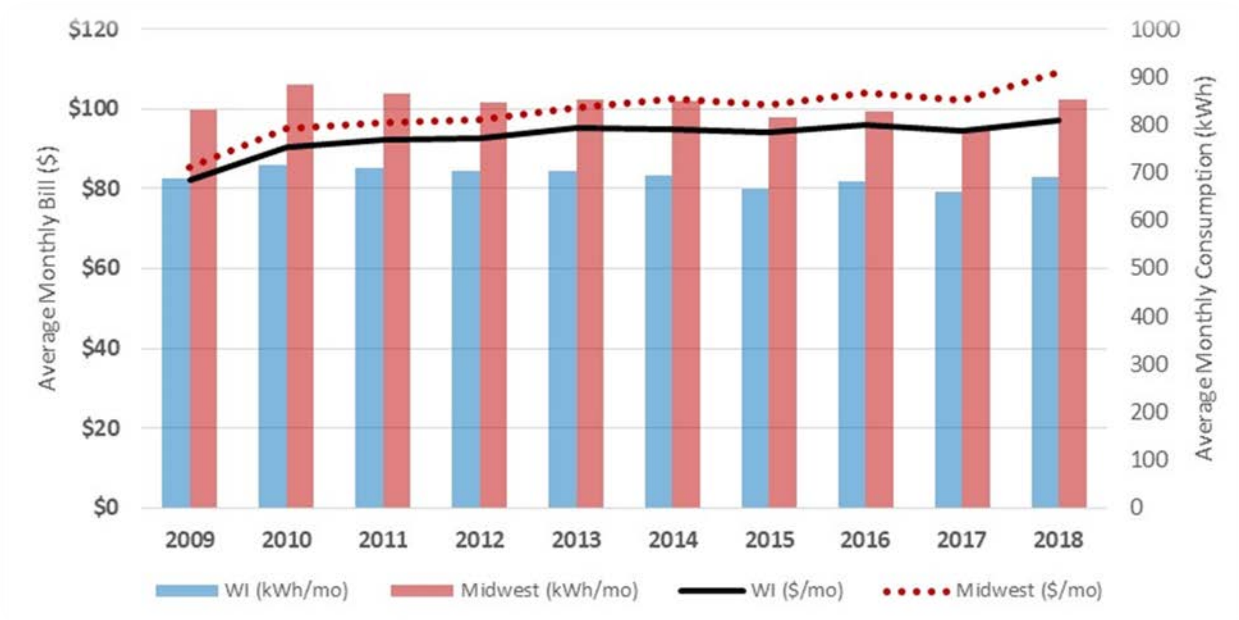


Wisconsin's lower bills reflect significantly lower average levels of electricity use. As shown in Figure 4-8, Wisconsin customers used an average of 690 kWh per month in 2018, compared to 853/kWh per month across other Midwest states. This usage difference has been present at consistent levels throughout the 2010s.

[56] According to the U.S. Energy Information Administration, the East North Central region is comprised of Illinois, Indiana, Michigan, Ohio, and Wisconsin.

[57] See previous editions of Residential Average Monthly Bill by Census Division and State at: https://www.eia.gov/electricity/sales_revenue_price/.

Figure 4-8 Monthly Residential Electricity Costs and Consumption in Wisconsin and the Midwest



Bills received by individual customers will vary based on their utility and the amount of individual energy use. At average usage levels, residential customer electric bills for different utilities in 2018 ranged from $37 to $114 per month (see Appendix C, Figure C-4).[58]

Non-Residential Customers

Based on national EIA data, Wisconsin's average 2018 energy rate for commercial customers of 10.67/kWh closely compares to the national average of 10.66 cents/kWh and exceeds the Midwest regional average of 10.14 cents/kWh (additional data can be found in Appendix C, Table C-2). However, drawing clear conclusions from rate and bill comparisons for non-residential customers is generally more difficult than for residential customers.

Reasonable comparisons can be made for municipal utility customers served under the Cp-1 rate schedule, which most municipal providers use to serve small and medium-sized commercial and industrial customers under a common rate structure. As shown in Table 4-4, municipal Cp-1 customers paid average energy charges of 7 cents/kWh, average customer charges of $45/month, and demand charges of $6.00-$8.00 per kW of demand in 2019. (More details on the analysis can be found in Appendix C, Figures C-6 and C-7 and Table C-4.) Similar comparisons of IOU rates, and of rates for larger municipal customers, cannot be made in simple terms due to greater variation in definitions of customer classes, in rate structures, and in methods for calculating charges, such as different definitions of peak periods used for demand charges.

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[58] Residential electric bill comparisons by provider can be performed on the Commission's Residential Monthly Bill Comparison web tool at: https://apps.psc.wi.gov/RATES/electricbill/default.aspx.

Table 4-4 Municipal Utility Bill Components for Cp-1 Customers, 2019

Summary	Energy (cents/kWh)	Distribution Demand $/kW)	Billable Demand ($/kW)	Customer Charge ($/month)*
Minimum	3.00	$0.25	$5.00	$20.00
25th Percentile	6.12	$1.00	$6.00	$34.00
Median	7.02	$1.50	$7.00	$50.00
Average	6.89	$1.36	$7.17	$44.86
75th Percentile	7.77	$1.50	$8.00	$50.00
Maximum	9.13	$2.00	$9.79	$100.00

** Note: Summary statistics include data from 73 municipal utilities that offer Cp-1 rates with a flat energy charge.*

Alternative Rate Options

While the substantial majority of customers in Wisconsin receive traditional rates, many Wisconsin electric providers offer additional, innovative rate options designed to help customers exercise control over their costs to reduce their energy bills.

Residential Time-of-Use Rates

A total of 76 electric providers in Wisconsin offer a time-of-use (TOU) rate option to residential customers, under which the customer's energy charge per kWh varies at different hours of the day. As shown in Figure 4-9, electric providers face higher costs for serving customers during peak afternoon hours of the day for multiple reasons, including the higher costs of operating peaking resources (see Supply chapter) and the greater availability of low-cost wind resources in the overnight hours.[59] By setting higher energy charges during higher-cost hours, TOU rates can encourage customers to move more of their energy usage to lower-cost hours. When TOU rates successfully shift usage, providers are able to reduce their total energy costs and pass savings along to customers through lower off-peak energy charges.

[59] Wholesale energy prices on the energy market are used for general illustration. While many providers do not buy electricity directly from this market, the price trends correspond with the prices a utility would pay to purchase from a different wholesale provider, as well as the costs a generation-owning utility would face for operating its own plants.

Figure 4-9 Time Varying Price of Electricity on an Average Summer Day in Wisconsin

All utilities with TOU rates offer them as optional alternatives in which customers may choose to enroll. This optional approach partially reflects concern over the impacts on customers with limited ability to shift the timing of their energy use. While many customers may benefit from TOU rates, mandatory TOU enrollment could cause bills to increase for those with high energy needs during on-peak hours. As shown in Table 4-5, approximately 34,000 customers of investor-owned and municipal electric utilities, or 1.5 percent of all residential customers, are currently enrolled in TOU rates.

Table 4-5 Enrollment in Standard and TOU Rates

Residential Rate Class	Total Enrollment	Percent of Total
Standard Rate	2,161,877	98.44%
TOU Rate	34,259	1.56%

The increasing use of new technologies in future years could help increase customers' ability to control their energy use, and accordingly enhance the benefits of enrolling in TOU rates. For example, installing smart thermostats and other smart appliances can make it easier for customers to shift the timing of energy use to off-peak periods. (See the Demand Response section for more information on the use of smart thermostats to control demand.) If electric vehicle use increases in the future, the use of charging equipment that allows customers to control charging time for vehicles could provide similar benefits. (See the Electric Vehicle section.)

Real-Time Pricing for Commercial and Industrial Customers

Twenty-six (26) Wisconsin electric providers offer "real-time pricing" rate options for commercial and industrial customers. These rate options typically incorporate wholesale prices for energy and demand, based on MISO's next-day electricity prices and transmission charges on demand, which serve as the primary influence on energy costs for customers with high energy use. Similar to TOU rates, these rate options are designed to account for the actual electricity prices faced by providers, to incent customers to modify their energy use and create potential shared cost savings for providers and customers.

Customer eligibility for real-time pricing depends on the type of rate options each provider offers. The most common option presently offered in Wisconsin is incremental load pricing, often labeled as a New Load Market Pricing (NLMP) rate or an Economic Development Rider (EDR). Incremental load pricing is only available to customers opening a new facility or expanding an existing facility. The additional electric load must also be substantial in size, typically greater than 500 kW of demand.

Incremental load enrollees are provided an incentive to control their energy use, and promote business growth, by receiving energy charges specific to their new load that vary each day based on day-ahead MISO market prices. Customers able to control the timing of their energy use can benefit by shifting energy use to days with lower day-ahead prices, and minimizing energy use on higher-priced days. New loads are typically eligible for incremental load enrollment for four years, before being placed on the standard rates.

Real Time Market Pricing (RTMP) enrollees are provided a similar incentive to NLMP/EDR enrollees to control their energy usage, but the pricing is applied to all consumption above a set level, rather than to new loads. Similar to NLMP/EDR customers, those who can control the timing of their energy use would be able to benefit the most from this type of rate. Enrollment on this rate generally begins with a multi-year contract that requires an advanced notice to the utility if the customer wishes to stop taking this type of service.

As shown in Table 4-6, 97 commercial and industrial customers were enrolled in real-time pricing rates in 2019, an enrollment rate of 1.5 percent. These enrollment levels reflect, in part, the restriction of eligibility to customers with large and (for NLMP) new loads. Moreover, eligible customers will only receive clear benefits if they are able to exercise significant control over their energy use; customers with less control over their load profile may not be able to achieve reduced costs through these rates.

Table 4-6 Enrollment in Incremental Load and Real-Time Pricing Rates

Industrial	Total Enrollment	Percent of Total
Standard Rate	6,596	98.55%
Incremental Load (NLMP/EDR)	76	1.14%
Real-Time Pricing (RTMP)	21	0.31%

AFFORDABILITY FOR LOW-INCOME CUSTOMERS

Low-income residential customers can often face challenges in paying their utility bills. By paying the same rates as all customers on more limited financial resources, low-income households often face a higher energy burden: they must pay a larger percentage of their total income to pay for the same amount of electric service. Customers earning the state median average household income of $62,629 would need to pay less than 2 percent of their total income to cover Wisconsin's average residential electric bill of $97.09 per month.[60] By contrast, the same average bill would require higher burdens for customers meeting common definitions for low-income status:

- Customers earning less than 200 percent of the federal poverty level (FPL), or less than $40,000 per year- the eligibility threshold for federal, state, and local low-income assistance programs- would have to pay at least 2.9 percent of their total income; and
- Customers in the lowest 20 percent of state income earners- or less than $25,000 per year- would have to pay at least 4.5 percent of their total income.

Table 4-7 compares Wisconsin's 2018 energy burdens at these income levels to average burdens in the U.S. and in other Midwest states. Low-income Wisconsin customers have generally faced slightly lower energy burdens, due to lower average bills associated with lower average usage. Burdens for individual low-income customers may vary based on the rates of their electric provider, as well as their usage needs. While some customers may be able to limit their burden by using below-average amounts of electricity, others may face higher burdens due to above-average energy demand driven by personal needs such as medical equipment, or difficulty controlling their usage in homes and apartments with low levels of energy efficiency.

Table 4-7 Average Residential Electricity Costs as a Percentage of Monthly Income for Wisconsin, Adjacent Midwest States, and U.S., 2018

2018	Median Income	200% FPL	20th Percentile
United States	2.23%	3.53%	5.51%
Illinois	1.62%	2.85%	4.45%
Iowa	1.91%	3.28%	5.12%
Michigan	2.06%	3.11%	4.86%
Minnesota	1.73%	3.10%	4.84%
Wisconsin	1.86%	2.91%	4.55%

Wisconsin electric providers and the Commission can help low-income customers manage their energy burden through multiple approaches, including through rate design, and by connecting customers with programs for low-income assistance and energy efficiency.

Alternative rate designs that allow customers to reduce costs by controlling their usage may be beneficial for some low-income customers. For example, TOU rates could reduce costs for low-income customers who are able to shift their usage to off-peak hours with lower energy charges. Some electric providers have also explored whether the implementation of residential demand charges could also benefit customers who can control their energy usage to minimize peak demand.[61] To support a successful implementation process, the implementation of demand charges

[60] Based on a household size of 3 persons.

[61] Wisconsin Power and Light Company was authorized by the Commission in docket 6680-UR-120 to implement demand charges for residential and small commercial customers, and has implemented residential rates with a group of primarily low-income customers. See PSC REF#: 385269, Appendix B for a March 2020 report on outcomes to date from implementation of demand charges.

is commonly accompanied by marketing and education efforts designed to help customers understand the calculation of the demand charge and their options for reducing their charges.[62]

Electric providers and Commission Consumer Affairs staff also seek to refer customers facing affordability challenges to multiple low-income assistance programs designed to meet energy needs.

- Electric utilities in Wisconsin are required to offer residential customers budget billing options that charge customers the same bill amount in all twelve months of the year, to help avoid the seasonal increases in energy charges most customers typically experience.
- Electric utilities are also required to offer Deferred Payment Agreements (DPA) to all residential customers who are unable to pay their bill in full. DPAs allow customers to provide a down payment on their outstanding balance and arrange an installment plan to pay the remaining balance over a specified time period.
- Households with incomes of less than 60 percent of the state median income are eligible for federally funded energy assistance through the Wisconsin Home Energy Assistance Program and the Public Benefits Energy Assistance Program. These programs can help customers pay a portion of their electric bills and provide weatherization assistance that can help customers reduce energy costs by increasing the efficiency of their home.
- Additional nonprofit and local programs are available to provide energy assistance. Many state electric providers financially support the Keep Wisconsin Warm/Cool Fund (KWWF), a statewide, non-profit effort that provides preventative services and financial assistance in response to energy emergencies. Heat for Heroes provides assistance to veterans facing service disconnections or other energy challenges. Customers may be able to find assistance through a variety of other local non-profits throughout Wisconsin, such as Aging and Disability Resource Centers, the Salvation Army, and local churches.

One reason low-income customers may experience a higher energy burden is because they live in older homes with less energy-efficient lighting, appliances, and heating and cooling systems. Referring customers to energy efficiency programs can also help low-income households manage their energy burden by increasing home efficiency and reducing their energy bills.

Focus on Energy, Wisconsin's statewide energy efficiency and renewable resource program, offers multiple program options that can benefit low-income customers. For example, all residential customers may register to receive a free kit of energy-efficient products, including lighting, power strips, and low-flow showerheads, and may purchase program-discounted lighting and appliances at retail stores. Low-income customers are also eligible for bonus incentives to help them conduct home energy audits and complete projects to replace heating and cooling appliances and install insulation. Three Wisconsin electric providers—Wisconsin Electric Power Company, Wisconsin Public Service Corporation, and Wisconsin Power and Light Company—operate additional energy

[62] Source: "Understanding Residential Demand Charges" presented by Philip Hanser, 2016, National Energy and Utility Affordability Coalition, http://neuac.org/wp-content/uploads/2016/06/1C-Philip-Hanser-UnderstandingResDmdCharges.pdf.

efficiency programs that provide further financial support to low-income customers conducting heating, cooling and insulation projects through Focus on Energy.[63]

Additional approaches for electric providers to support low-income customers have been identified in recent discussions, including:

- Energy efficiency financing programs, which could enhance low-income participation by reducing upfront project costs and allowing customers to pay those costs over time on their monthly bills.
- Designing programs to target renters and residents of multi-family housing; and
- Efforts to maximize benefits for low-income customers as part of larger initiatives, by collecting data and measuring performance specific to those customers.[64]

The most appropriate and effective approaches to serving low-income customers can vary by provider for a number of reasons, including differences in the characteristics of a provider's service territory and customer population.

Declining economic conditions associated with the rapid onset of the COVID-19 pandemic have increased affordability concerns for many utility customers. Moreover, access to utility services is essential to ensure citizens can abide by pandemic response guidelines. In March 2020, the Commission directed electric utilities to take several steps to address safety and affordability concerns for the duration of the public health emergency, including:

- prohibiting the disconnection of service to any customer unable to pay their bill;
- prohibiting the charging of late fees for failure to pay a bill; and
- requiring deferred payment agreements to be offered to all interested customers, including nonresidential customers;

The Commission also opened an investigation under docket 5-UI-120 to conduct ongoing review of appropriate steps to address safety, reliability, and affordability issues related to the pandemic. Based on the information collected under this docket, the Commission has extended the moratorium on utility disconnections beyond the initial public health emergency, to help customers maintain access to the services needed to maintain hygiene standards and abide by social distancing practices in light of the continuing prevalence of COVID-19.

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[63] WEPCO and WPSC operate the Residential Assistance Program (Commission dockets 5-EE-2020 and 6690-EE-2020). WP&L operates the Enhanced Low-Income Weatherization Program (Commission docket 6680-EE-2020).

[64] The WEDTI stakeholder group agreed on the value of considering enhanced programming for low-income customers, multifamily customers, and renters, and identified these as potential examples of innovative initiatives to reduce costs for those customers. See https://www.m-werc.org/wedti-report, Recommendation 5, p. 24.

CHAPTER 5 – CLEAN ENERGY PROGRAMS AND POLICIES

ENERGY EFFICIENCY

Energy efficiency programs provide incentives and technical assistance to residents and businesses to take steps to reduce energy use. Since 1999, state law has established Focus on Energy (Focus) as Wisconsin's statewide electric and natural gas efficiency and renewable resource program. Under 2005 Wisconsin Act 141 (Act 141), IOUs are required to fund Focus through contributions equal to 1.2 percent of annual operating revenues from retail sales. Act 141 also requires municipal utilities and retail electric cooperatives to collect an average of $8 per meter annually for energy efficiency programs. Municipal utilities and cooperatives have the option to contribute these funds to Focus or administer their own programs. As of 2019, all IOUs and municipal utilities participate in Focus. Of the 24 electric cooperatives in the state, 13 run their own programs while 11 participate in Focus. Some investor-owned and municipal utilities run voluntary energy efficiency programs that provide additional benefits to their customers beyond what Focus offers.[65]

Act 141 requires Focus to be operated by a third-party program administrator, under a contract established by IOUs and approved by the Commission.[66] APTIM has served as the third-party program administrator since 2011. Program administrator contracts are established on a 4-year basis, after the Commission completes a quadrennial planning process to determine program goals, policies, and priorities for the upcoming contract period. Most recently, the Commission approved updated program goals in 2018, to establish contract priorities for the 2019-2022 time period. Through a rebidding process, APTIM was selected to continue as program administrator through 2022.

Focus on Energy Programs

Focus offers a portfolio of programs that match energy efficiency products and services to appropriate customer segments, ensuring customers throughout the state have an equivalent opportunity to receive the benefits of the programs.

Focus on Energy includes separate portfolios of programs to target residential and nonresidential customers. To meet the differing needs of residential customers, separate residential programs ship energy-efficient products directly to customers free of charge, operate an online marketplace where customers can purchase energy efficient products which are then shipped to their home, offer retail discounts on efficient lighting and appliances, help customers recycle their old, low-efficiency appliances, work with contractors to support energy efficient repairs and installations, and work with homebuilders to increase the energy efficiency of new homes. Within Focus' non-residential portfolio, separate programs target the differing efficiency opportunities for different types of customers, including small businesses, commercial customers, schools and government facilities,

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[65] A voluntary energy efficiency program is run by the electricity provider with funding that is above and beyond what the electricity provider is required to collect pursuant to Wis. Stat. § 196.374.

[66] The IOUs created a nonprofit board to fulfill its duties under Act 141. The 9-member board is called the Statewide Energy Efficiency and Renewables Administration (SEERA).

agriculture customers, and large industrial facilities. As part of the 2018 Quadrennial Planning process, the Commission also allocated $8 million in annual funding to provide enhanced program offerings to rural residential, agricultural, and industrial customers. More specific information on program offerings can be found at www.focusonenergy.com.

While Focus accounts for the largest share of energy efficiency activity in the state, all electric providers in the state provide some degree of additional energy efficiency services. These services include educational and marketing activities, which do not have quantifiable savings of their own but can help increase Focus savings by informing customers of Focus offerings and encouraging participation. Some electric providers also fund and operate their own energy efficiency programs,[67] although, as shown below, spending and savings from those programs remain small relative to Focus' statewide activities.

Focus on Energy Outcomes

Independent program evaluators, led by the Cadmus Group (Cadmus), perform research and analysis to validate the energy savings from Focus programs. Cadmus works with program staff to manage Focus' Technical Reference Manual (TRM), which documents and explains the methods for calculating savings achieved from installing energy efficient measures. Savings calculations in the TRM take into consideration the lifecycle savings achieved as participants continue to use their efficient products and services for many years after implementation. Evaluators also seek to validate the amount of net savings that can be attributed to the influence of Focus programs, excluding the savings from "free-rider" participants who would have taken the same actions without Focus' support.

While energy-efficient products can reduce both energy use and total energy demand for customers, the Commission's quadrennial planning decisions have directed Focus to place primary priority on achieving savings in energy use. Demand savings are still tracked by the program, but are a secondary priority for Focus programs to achieve. In the 2015-2018 period, Focus achieved total life cycle verified net savings of 210.4 million MMBtu, the equivalent of the amount of energy to power more than two million typical Wisconsin homes for a year. Total savings exceeded the Commission's energy savings goals for the four-year period. These lifecycle savings will reduce CO_2 emissions by more than 28.5 million tons during the lifetime of the projects installed.

Focus' evaluators also validate whether the program meets its Commission requirement to operate cost-effectively, and achieve benefits in excess of costs. As directed by the Commission, Focus measures cost-effectiveness using a Modified Total Resource Cost (TRC) test that compares the benefits from reduced energy use and emissions to the costs of program administration, program implementation, and the higher costs of energy-efficient products to participants. For 2018, Cadmus's cost-benefit analysis concluded that for every dollar spent, Focus' full portfolio of

[67] NPSW, WEPCO, WP&L, WPSC, and WPPI Energy all operate Commission-approved "voluntary programs", using utility funds that are in addition to the funds they contribute to Focus. Some cooperatives associated with DPC use the $8.00 per meter they are required to collect for energy efficiency to operate their own programs instead of contributing those funds to Focus.

programs achieved $3.66 in lifecycle benefits.[68] A recent national study of energy efficiency programs found that Wisconsin ran the most cost-effective efficiency programs of any state in the country, achieving the highest rate of energy savings per dollar spent.[69]

Future Focus on Energy Spending and Outcomes

Annual IOU contributions to Focus on Energy are based on utility revenues, and therefore can vary based on weather conditions and other influences on revenue levels. Commission decisions on program offerings can also impact Focus' available funding and annual expenditures. As shown in Figure 5-1, Focus' actual electric energy efficiency expenditures declined by more than $15 million from 2018 to 2019. This decline reflects the Commission's use of previously unallocated surplus Focus funds in 2017 and 2018 to support programs targeting rural customers. Most excess funds were spent in the two-year period, and expenditures in 2019 and future years return to levels consistent with annual utility contributions. (Figure 5-1 only addresses Focus' electric activities and excludes spending associated with natural gas efficiency, which annually accounts for approximately $20 million in additional program activity.)

The projections do include a smaller-scale decline in electric expenditures from 2019 to 2020, which reflects a decrease in utility contributions. Commission staff calculate each IOU's required contribution based on historical revenue averages. Beginning in 2020, the historical calculation no longer includes utility revenues from 2014, when extremely cold polar vortex conditions led to unusually high energy use and revenues. As a result, program contributions are projected to decline. IOUs project generally stable contribution levels between 2021 and 2026, with only slight increases over the five-year period. Spending on additional utility programs is also projected to remain stable.

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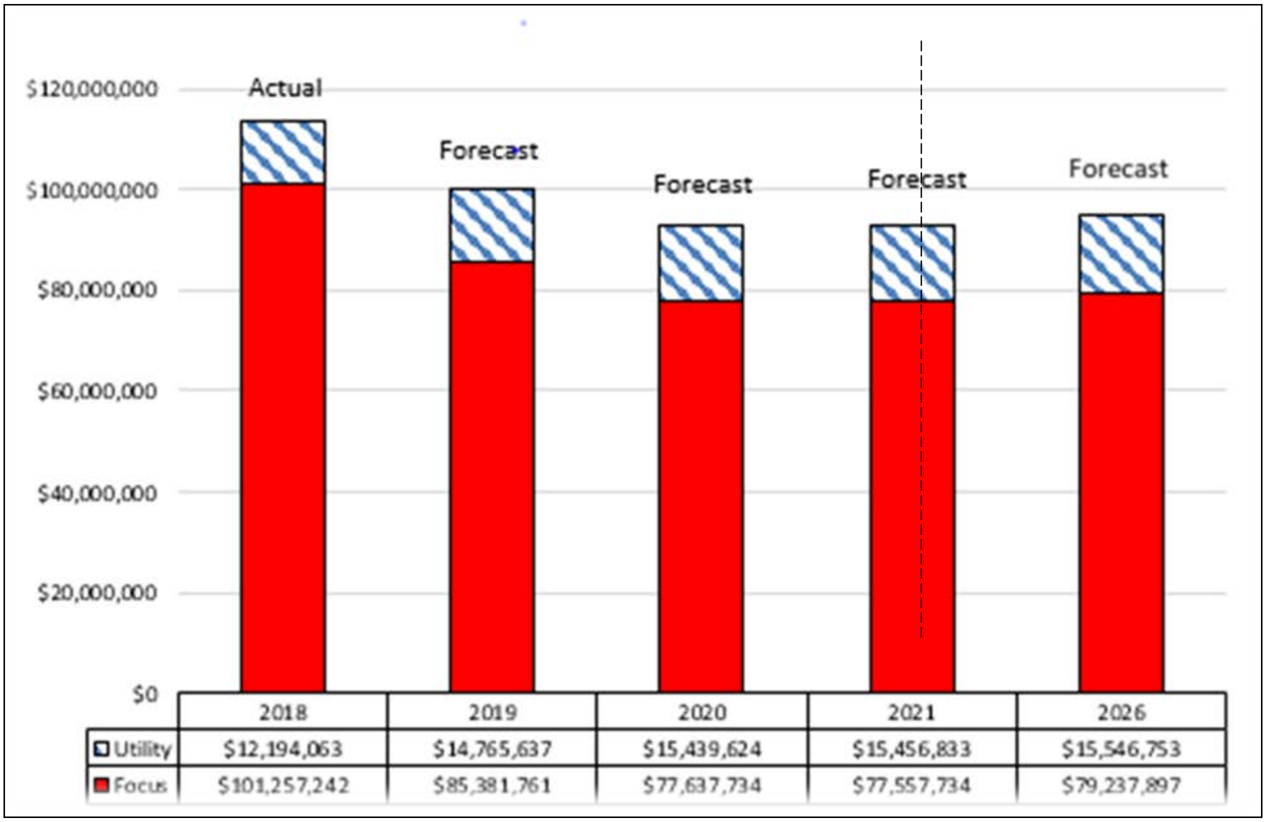
[68] For informational purposes, Cadmus also conducts an "expanded TRC" test which incorporates the economic benefits created by Focus. In 2018, the program evaluator's expanded TRC analysis found that Focus created net economic benefits of nearly $348 million and achieved $5.16 in benefits for every $1.00 in costs.

[69] Report available at: [http://www.swenergy.org/Data/Sites/1/media/lbnl-cse-report-june-2018.pdf.](http://www.swenergy.org/Data/Sites/1/media/lbnl-cse-report-june-2018.pdf)

Figure 5-1 Actual and Projected Annual Electric Energy Efficiency Expenditures 2018-2026[70]



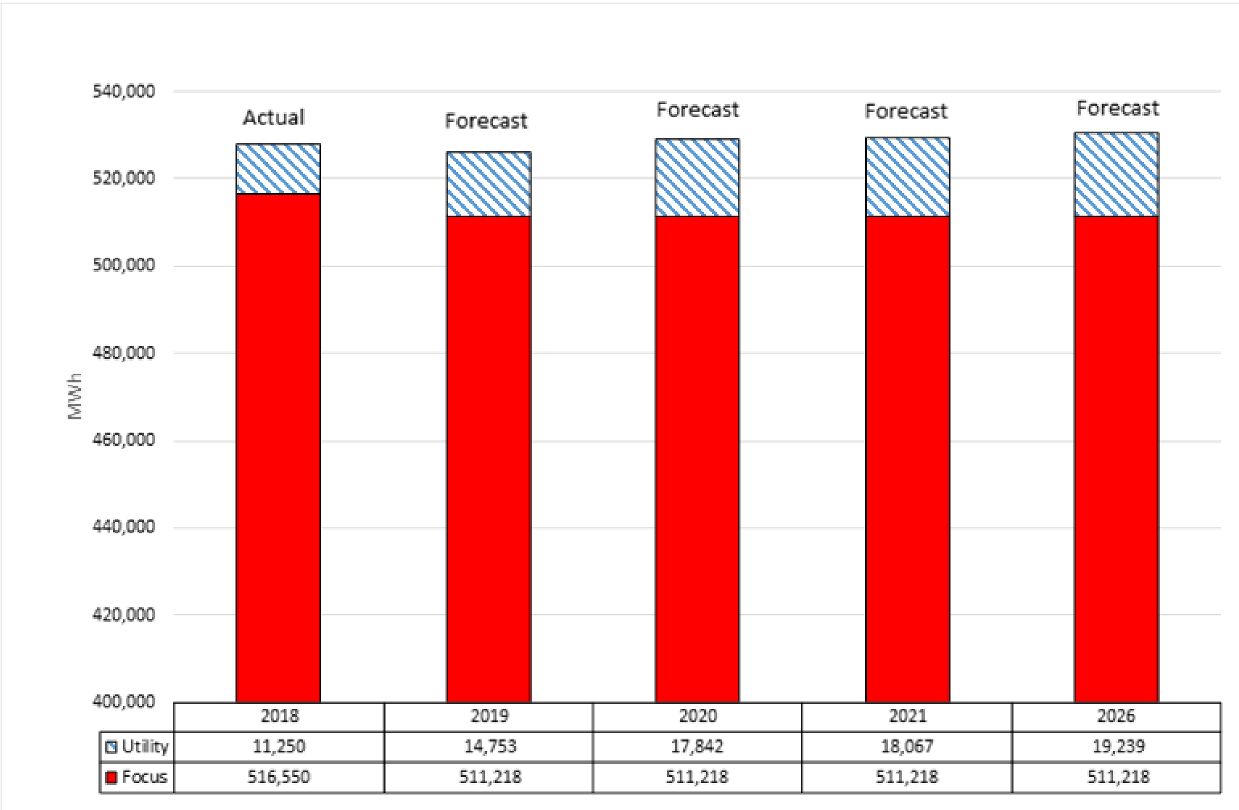
To inform the determination of savings goals for the 2019-2022 quadrennial period and beyond, the Commission authorized the independent program evaluators in 2017 to conduct a potential study projecting the amount of future energy efficiency savings Focus could achieve. The final study, completed in 2017, used data on customers' existing energy use practices and available efficient technologies to assess achievable energy savings under a variety of scenarios, including a "business as usual" scenario that maintained Focus' existing funding level and program policies. In its 2018 quadrennial planning decisions, the Commission approved savings goals based on the business as usual scenario, consistent with other decisions to continue existing program policies.

The potential study concluded that Focus should be able to continue achieving energy savings consistent with historical levels in the 2019-2022 period. These potential estimates are reflected in Figure 5-2, which maintains electric savings estimates closely comparable to achieved savings in 2018. Beginning in 2020, the Focus program deployed a restructured portfolio intended to simplify and enhance the customer experience, reduce administrative costs, and target opportunities for increased energy savings. The reorganization is intended to help support Focus' ability to maintain overall program savings levels with reduced funding, while also maintaining cost-effectiveness and

[70] Sources: Aggregated electricity provider data responses, docket 5-ES-110; Focus on Energy 2018 Evaluation Report; Focus on Energy 2019 to 2022 Program Administration Contract.

improved service to rural customers. Projected energy savings from other utility programs are projected to remain stable through 2026.

Figure 5-2 Actual and Projected First-Year Annual Energy Savings 2018-2026[71]



The Commission has authorized the Focus program evaluator to perform an updated potential study to inform the next quadrennial planning process. The study will be conducted in 2020-2021 and focus on assessing savings potential for the 2023-2026 quadrennial period, as well as longer-term potential in subsequent years. Along with reviewing appropriate levels for future program goals, the study will also collect additional information to help inform the Commission's quadrennial planning review. For example, the study will assess in more detail Focus' potential future impacts on reducing carbon emissions, and assess Focus' future potential for demand savings, to help the Commission assess whether the program's current primary emphasis on energy savings should be maintained or modified.

DEMAND RESPONSE

Demand response programs provide customers with incentives to reduce energy demand during peak periods and create financial savings for electric providers and customers. Demand response programs are most commonly deployed in the summer months, to reduce peak energy usage during

[71] Sources: Aggregated electricity provider data responses, docket 5-ES-110; Focus on Energy 2018 Evaluation Report; Focus on Energy 2019 to 2022 Program Administration Contract; 2017 Focus on Energy Potential Study.

the highest-demand periods of the year. Demand response programs may also be operated at other times of a year to support a balance between demand and available supply, such as to reduce usage during smaller winter peak periods or to address demand on days when available generation is limited due to plant outages. As noted in the Reliability and Resilience chapter, practices for maintaining reliability are also likely to evolve in connection with the increasing deployment of renewable resources, and demand response programs could accordingly play an evolving role in broader system management.[72]

Wisconsin electricity providers presently operate two types of demand response programs:[73]

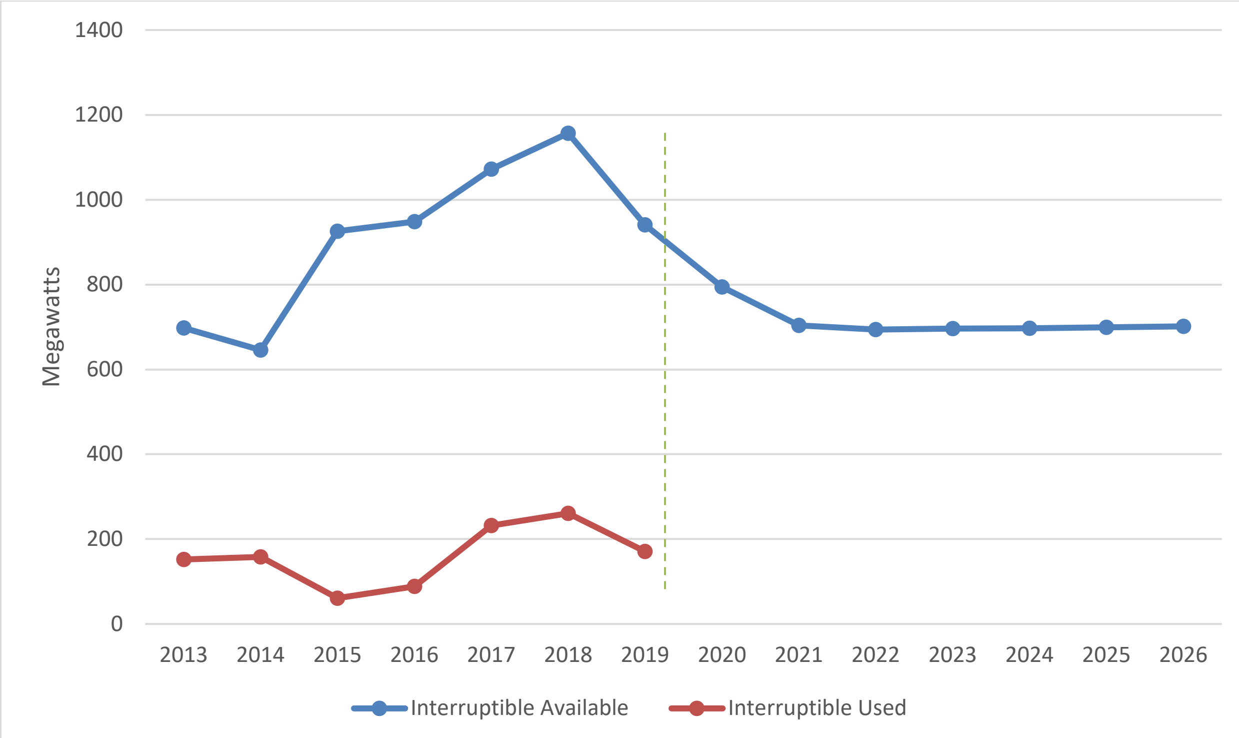
- **Interruptible service** programs enable customers to receive a lower energy charge in return for allowing their electric provider to interrupt load during periods of peak demand. Interruptible load programs are typically targeted to industrial customers.
- **Direct load control** programs enable electric providers to turn off or reduce the energy use of specific customer equipment, such as residential air conditioners. Customers receive an upfront financial incentive to encourage their participation and share in the financial savings that can be achieved through successful demand reductions.

As shown in Figure 5-3, available interruptible service capacity reached a historic high of 1,156 MW in 2018, nearly 8 percent of statewide peak demand. Figure 1 also shows that electric providers have deployed no more than 24 percent of available resources in any year since 2013. Providers' projected amount of available interruptible resources through 2026 declines to about 700 MW per year, or approximately 5 percent of peak demand, driven largely by recent provider decisions to cease enrolling new customers in their interruptible tariffs due to low customer demand. At these reduced levels, the amount of available interruptible resources statewide still significantly exceeds the amount of interruptible service historically used.

[72] The WEDTI stakeholder group supported further exploration of new demand response opportunities. See https://www.m-werc.org/wedti-report, Recommendation 8, pp. 27-28.

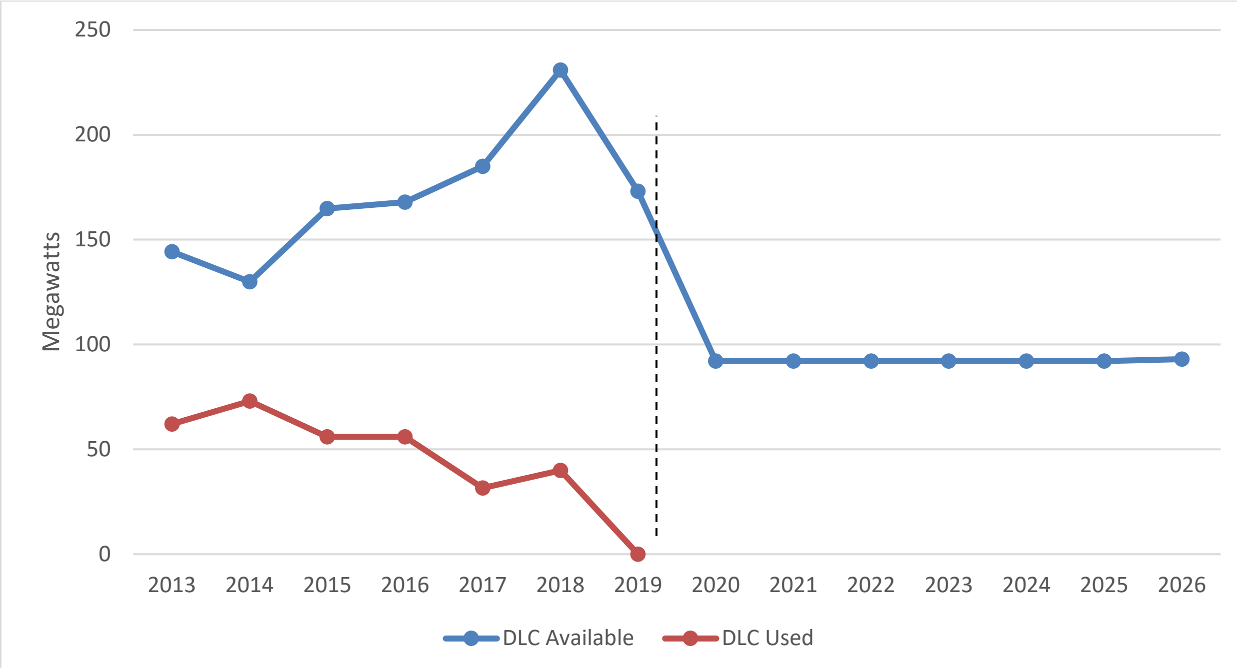
[73] Some definitions of demand response include other types of approaches that can help reduce demand, such as time-of-use rates and energy efficiency programs designed to achieve demand savings. This section focuses on the distinct program models that are not already addressed elsewhere in the report.

Figure 5-3 Interruptible Service in Wisconsin



Available direct load control resources in recent years have totaled between 150-230 MW, or slightly more than 1 percent of statewide peak demand. As shown in Figure 5-4, approximately 33 percent of available resources were deployed annually since 2013. Providers forecasted direct load control capacity to decline below 100 MW annually, driven in part by provider decisions to close programs due to low enrollment and increasing technical difficulties in maintaining the control equipment. However, actual figures in future years may remain higher than projections; at least one provider with significant program activity in recent years did not forecast any future load control due to program uncertainty, but still may continue to operate programs. As with interruptible programs, available capacity statewide would still exceed historical levels of direct load control under the reduced projections.

Figure 5-4 Direct Load Control in Wisconsin



Historically, direct load control programs have used equipment to remotely turn off participating technologies (such as air conditioners and water heaters) on a temporary basis. Two recent Commission-approved programs, MGE's Smart Thermostat Demand Response Pilot[74] and NSPW's AC Rewards program,[75] have started using new program models that control usage through customers' wi-fi-enabled smart thermostats. Both programs use software to set participant thermostats at a higher temperature setting during peak demand events, and also provide "pre-cooling" before peak demand hours to help participants remain comfortable during the event. As the deployment of smart thermostats continue to increase, these program models may be able to support further development of direct load control programs, as well as provide opportunities for integration with energy efficiency programs that support smart thermostat installation.

RENEWABLE ENERGY

The primary driver for utility-scale renewable resource development by Wisconsin electric providers over the last decade has been compliance with Wisconsin's Renewable Portfolio Standard (RPS) law. However, declining costs, environmental benefits, and customer interest, frequently in mitigating the impacts of climate change, are driving increased renewable deployment above RPS requirements, including through growth in provider offerings such as community solar programs, and through individual customers' increased use of renewables.

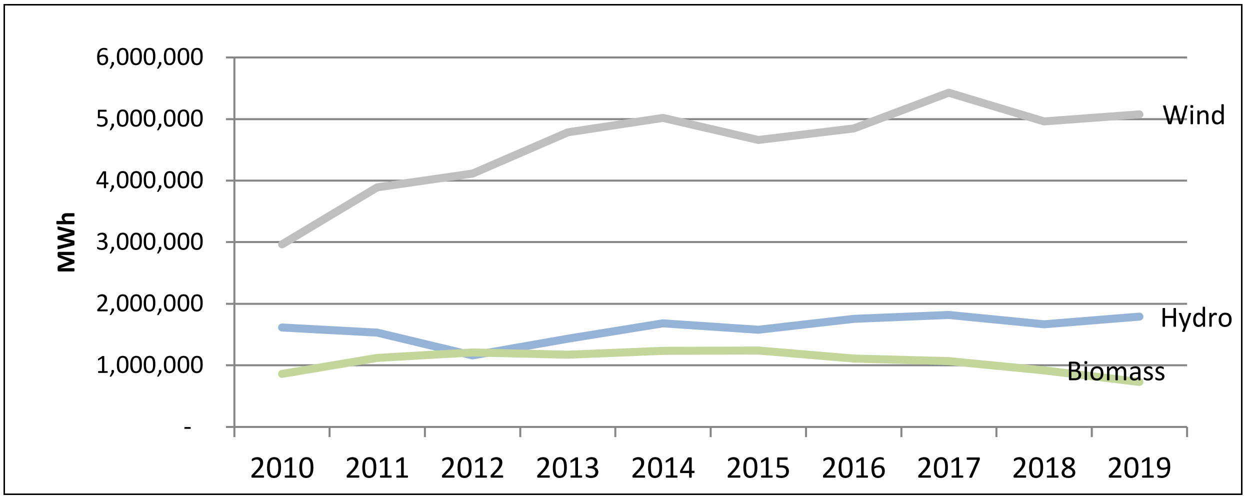
[74] Commission dockets 3270-TE-121 and 3270-TE-106.
[75] Commission docket 4220-TE-103.

Renewable Portfolio Standard

Wisconsin's present RPS law, established by 2005 Wisconsin Act 141, requires each electric provider to increase the share of renewable energy resources it uses to serve retail customers, in order to achieve a statewide goal for renewable resources to provide at least 10 percent of energy generation by 2015.[76]

Individual electric providers have met their requirements every year since 2006, and the statewide goal of 10 percent of electricity has been achieved every year since 2013. As shown in Figure 5-5, wind energy accounts for the largest share of renewable resources providers have deployed to comply with the RPS, and accounts for nearly all of the increases in deployment since 2010 that have been required to attain RPS compliance.

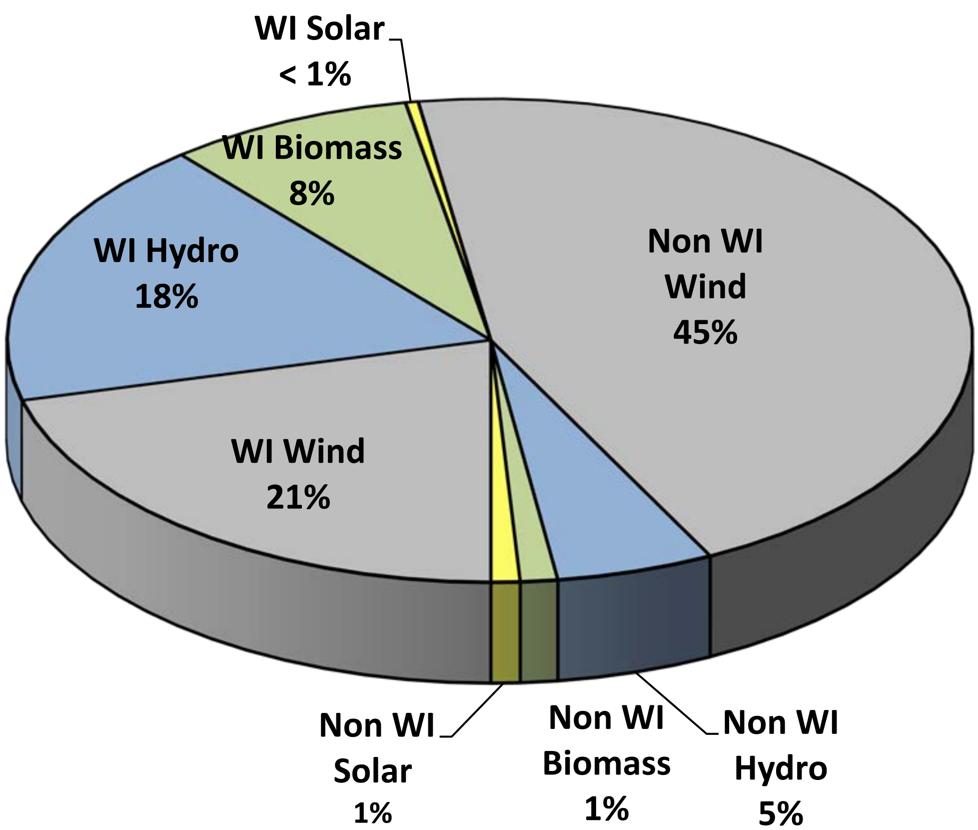
Figure 5-5 Renewable Energy by Resource 2010-2019



As shown in Figure 5-5, wind energy accounted for nearly two-thirds of total renewable energy generation serving Wisconsin customers. Most of that wind energy is supplied through the transmission system from out-of-state facilities located west of Wisconsin, where more consistently windy weather conditions support more cost-effective generation. Solar resources accounted for approximately 1 percent of total renewable generation deployed by electric providers in 2019. (These figures do not include solar generation used by individual customers, which is described in the Customer-Scale Renewables section below).

[76] To achieve the statewide 10 percent standard, the RPS requires each electric provider to increase their percentage of renewables, relative to their 2001-2003 baseline, by 2 percent by 2010 and 6 percent by 2015.

Figure 5-6 2019 Renewable Energy by State and Resource



Electric Provider Solar Initiatives

As outlined in the Supply chapter, significant declines in the cost of solar energy, as well as the environmental benefits of deploying zero-carbon resources, are leading Wisconsin electric providers to add multiple sources of solar generation in the coming years, over and above the resources required for RPS compliance. Electric providers also cite business case reasons for investing in new renewable resources, such as hedging against volatility in fuel prices and investing in resource diversification. Most electric utilities have also established carbon reduction targets, which have led them to invest more heavily in renewable energy resources, including solar energy.

As shown in Table 5-1, approved solar construction projects would result in the addition of 750 MW of in-state solar generation by 2022, and increase the total statewide share of renewable generation by approximately 2 percent.[77]

[77] Construction of Badger Hollow, Two Creeks, Point Beach, and Badger State have been approved by the Commission. While the Richland County solar farm falls below the 100 MW capacity threshold for Commission approval, the project has received approvals at the county level.

Table 5-1 Approved Solar Additions in Wisconsin and Expected Renewable Energy Generation and Percentage

Statewide Retail Sales (MWh)	Solar Facility Additions	Expected In-Service	Expected Renewable Annual Generation (MWh)	Statewide Renewable Energy
Statewide 2019: 69,185,670			Statewide: 7,705,538	11.14 %
	Badger Hollow	2020	630,720	
	Two Creeks	2020	315,360	
	Richland County Solar Farm	2021	104,069	
	Point Beach	2021	210,240	
	Badger State	2022	313,258	
Statewide 2023: 71,000,000			Statewide: 9,211,783	13.0%

The implementation of additional planned solar construction projects would result in further increases. For example, Wisconsin Power and Light Company (WP&L) applied to the Commission in May 2020 for authorization of six new solar facilities. If those projects are approved and implemented by 2023, they would increase the share of expected renewable generation in Table 5-1 to more than 14 percent. Further increases could result from approval of other solar proposals pending before the Commission.

The status of the federal Investment Tax Credit (ITC) for solar development may have a significant influence on the timing and scale of solar investment decisions. Under current law, solar facilities must be placed into service by the end of 2023 to qualify for the ITC, and the value of the credit is higher if construction begins in earlier years.[78] Absent future federal action to extend or modify the current credits, the current ITC provides incentives to move forward with renewable energy planning and construction in the near term.

Utility-scale solar construction projects will increase the share of renewable generation provided to all customers. An increasing number of electric providers have also established community solar programs for individual customers interested in procuring a larger share of their own energy use from renewables. Community solar programs allow residential, and sometimes commercial customers, to pay a subscription fee for a specific amount of energy produced by solar facilities on the provider's system. Most commonly, customers pay the subscription fee upfront, and then receive monthly bill credits to reflect the solar energy production associated with their subscription.

Electric providers that offer this type of an upfront payment community solar program include NSPW, WP&L, and the WPPI municipal members River Falls and New Richmond.[79] MGE's Shared Solar program uses an alternative program structure under which customers can receive a guaranteed retail rate associated with the costs of the solar facilities for the duration of their participation. A community solar program for SWL&P, in which SWL&P will offer three subscription options to include an upfront payment option, a monthly flat subscription payment

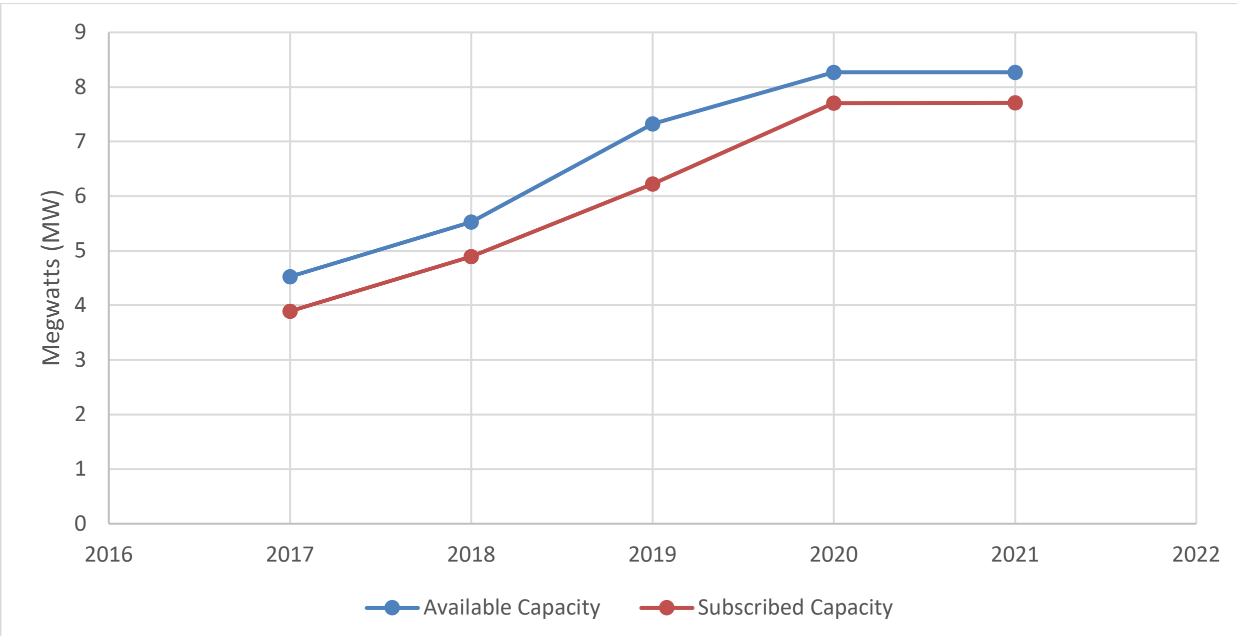
[78] Projects can be "safe harbored" through equipment purchases or by commencing construction. Projects which meet these criteria in 2019 qualify for a 30 percent tax credit; projects which meet those criteria in 2020 qualify for a 26 percent tax credit; and projects which meet those criteria in 2021 qualify for a 22 percent tax credit.

[79] Some DPC members also offer community solar options, but the Commission does not regulate or collect information on those programs.

option, or a guaranteed retail rate payment option like MGE offers, is pending final Commission consideration.[80]

As shown in Figure 5-7, total capacity offered by Wisconsin community solar programs has increased 61 percent from 2017 to 2019. Further additions planned for 2020 will increase total available community solar capacity to 8.3 MW. Customer subscriptions have consistently exceeded 85 percent of available capacity.

Figure 5-7 Community Solar Capacity in Wisconsin



Four electric providers also offer "renewable rider" programs for large customers to contract for a defined amount of utility-provided renewable resources for their use. The renewable rider uses a similar concept as Community Solar, but allows the electric provider to define larger portions of either distribution or transmission-interconnected renewable facilities for specific customers through individual contracts.

Customer-Owned Renewables

Customers may also procure renewable resources by installing their own sources of generation and reduce the amount of electricity they otherwise would have needed to purchase from their electric provider (or provide energy back to the grid).

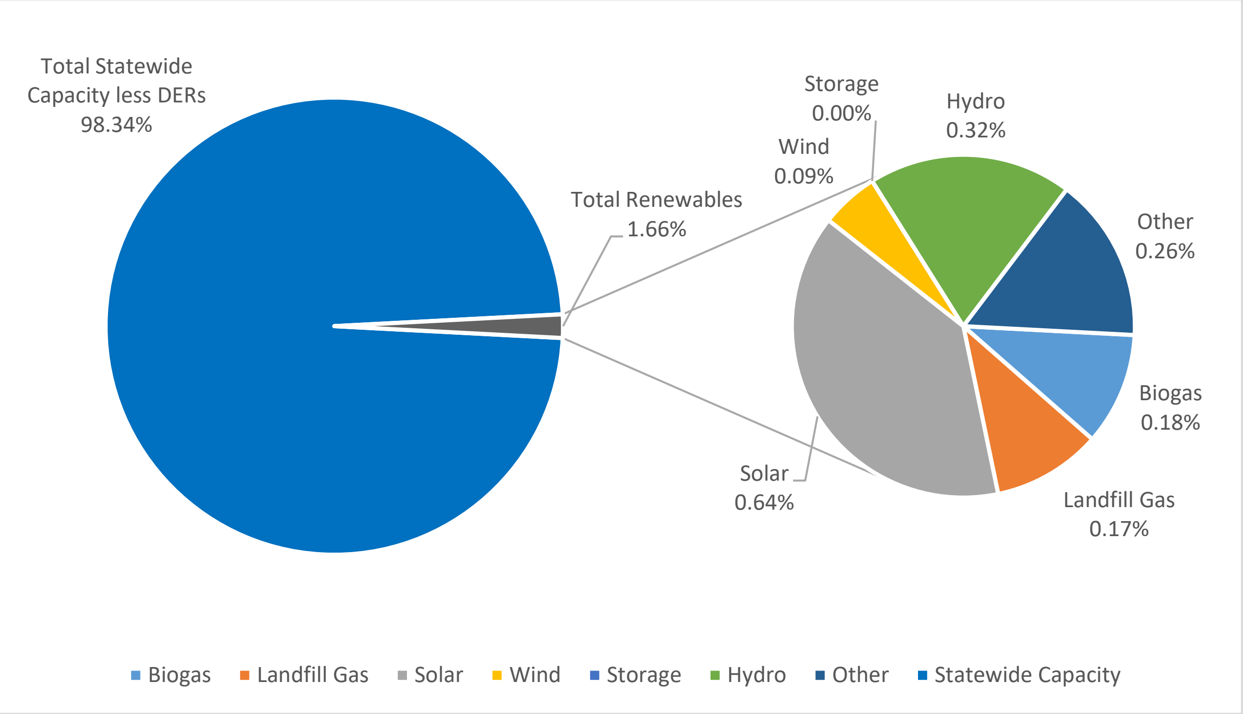
Starting in 2016, each SEA has asked all electric providers in Wisconsin to report data on the number, type, and generation capacity of all non-utility generation, or Distributed Energy Resources (DER), used by their customers, including historical data extending back to 2008. Customer-owned DER data reported by utilities include all customer-owned generation, including from non-renewable sources such as diesel-fueled generators. Since non-renewable sources account for

80 See docket 5820-TE-100.

only 10 percent of total customer-owned DER capacity, the analysis below focuses on renewable customer-owned DERs.

Customer-owned renewable generation capacity in Wisconsin totaled 258 MW (DC) in 2019, which amounts to 1.66 percent of total statewide capacity, as shown in Figure 5-8.[81] Customer-owned solar installations account for the largest share by source. At a total capacity of slightly more than 100 MW (DC), customer-owned solar accounts for nearly 40 percent of renewable DER capacity and 0.64 percent of total statewide electric capacity.[82]

Figure 5-8 Capacity of Customer-Owned Renewables in Wisconsin, 2019

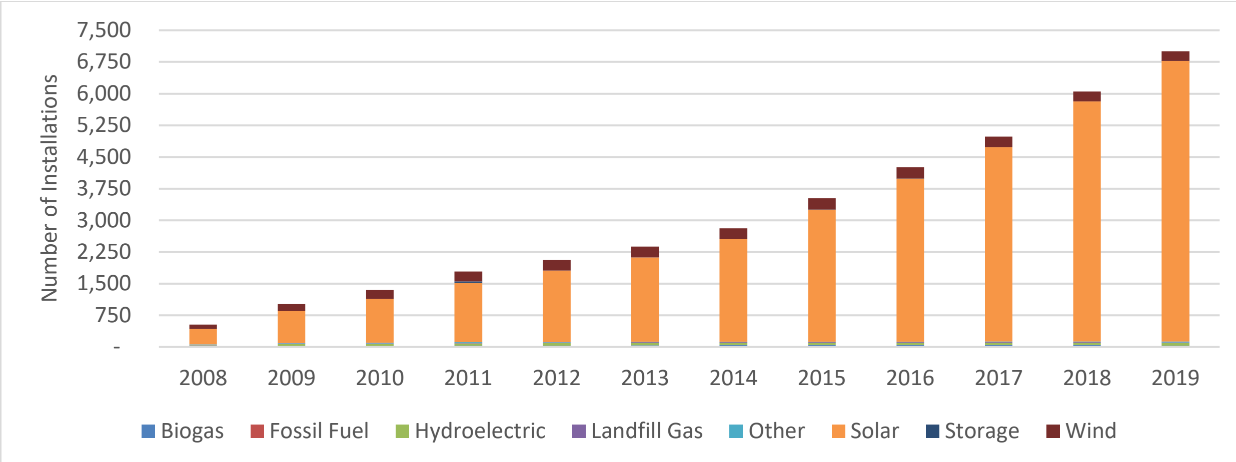


As shown in Figure 5-9, the number of customer-owned renewable installations has increased consistently over the past decade, from 528 in 2008 to 7,004 in 2019. The increase has been driven almost entirely by increased deployment of solar resources, with an average annual growth rate of more than 20 percent per year. The 6,646 solar installations reported in 2019 account for 95 percent of all customer renewable DER installations in Wisconsin. As shown in Appendix D, more than 90 percent of all customer renewable DERs are small-scale installations of less than 20 kW (Figure D-1). A majority of DER installations are used by residential customers, and the share of

[81] DER analysis in previous SEAs has reported the amount of generation (MWh) rather than the amount of capacity (MW). However, the generation data electric providers are able to report reflects the amount of energy purchased by the utility, which can understate the scale of DER use and deployment by excluding energy directly used by the customer. Capacity figures are provided here with the intent to quantify the general scale of DER deployment across the state.
[82] SEA data collection requirements direct providers to report solar capacity based on the Direct Current (DC) capacity of the panels, rather than the Alternating Current (AC) capacity of the inverters. AC capacity values are lower than DC values, so capacity reported in AC would result in lower values than reported here.

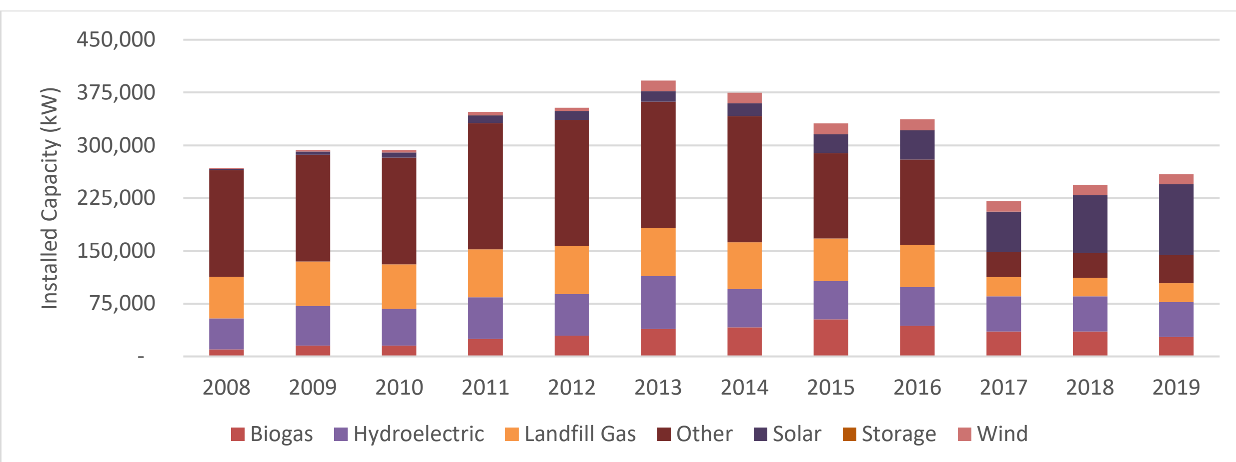
installations by residential customers has gradually increased over time, reaching 75 percent in 2019 (Figure D-2).

Figure 5-9 Number of Renewable DER Installations by Technology



By contrast, the 258 MW in total installed (DC) capacity from customer-owned renewables represents a decline from levels in the first half of the 2010s, as shown in Figure 5-10. The decline reflects customer decisions to discontinue operation of a small number of very large DER installations, primarily in the industrial sector. As a result, the share of renewable DER capacity categorized as landfill gas or other renewable sources has declined, offset only partially by capacity growth from small-scale solar installations. As shown in Appendix D, large installations with capacity in excess of 1,000 kW continue to account for the majority of installed capacity, although their share has decreased in recent years (Figure D-3). Although the share of residential capacity has gradually increased due to the increased deployment of small-scale residential solar, commercial and industrial installations still account for nearly 90 percent of Wisconsin's total (DC) DER capacity (Figure D-4).

Figure 5-10 Installed Capacity of Renewable DER Installations by Renewable Source



Eligible customers who own generation can receive bill credits for providing excess energy production from their generation back to their electric provider. Some providers offer certain customers- typically limited to those with small-capacity distributed energy resources- bill credits that match the retail rate charged to the customer, an arrangement often termed "net metering." Other customers receive lower rates connected with the avoided cost to the provider associated with receiving energy from the customer's DER rather than from its own resources. Rates and eligibility thresholds for different buyback rate arrangements can vary by provider.

In June 2020, the Commission opened an investigation in docket 5-EI-157 to broadly examine the purchase rates associated with customer DERs. The Commission has solicited stakeholder feedback on the appropriate approaches to calculating avoided costs and the factors and barriers that influence customer decisions to invest in DERs, and also requested detailed information from electric providers on the data sources and methods used to establish their existing rates. The Commission will identify further steps in the investigation later in 2020.

ELECTRIC VEHICLES

Large-scale use of EVs could have significant implications for Wisconsin's electric system, by increasing total electric demand, modifying timing and location of energy use, and presenting new considerations for determining customer rates and service arrangements. Fewer than 10,000 EVs were operated in Wisconsin in 2019, and the effects on electric system demand to date remain limited. The speed and scale of future increases in EV use is also uncertain. However, the Commission and electric providers have initiated research and programming to serve current customers with EVs and to begin exploring a range of relevant issues in advance of expanded EV use.

In February 2019, the Commission opened an investigation in docket 5-EI-156 to consider future policies and regulations related to EVs and their associated infrastructure, including the home and public charging stations required for customers to operate their vehicles. To establish a collaborative, stakeholder-driven process for the investigation, the Commission has solicited written comments from interested stakeholders on the full range of EV policy and regulatory issues, and organized a workshop supporting expanded small-group discussion of the issues. The Commission received substantial input and feedback through both processes, receiving 42 written comments and input from more than 60 workshop attendees.

Several electric providers have already taken steps to address EV-related customer demand, by establishing new electric rates for vehicle charging and offering financial incentives for the installation of charging infrastructure. Feedback submitted from a range of stakeholders, including electric vehicle owners, identifies a range of priorities as the Commission and electric providers continue to consider further future activities. As shown in Figure 5-5, multiple topic areas were identified by commenters as priorities for continued consideration.

- The most commonly cited issue was **access to charging infrastructure.** Commenters identified insufficient access as the most significant barrier to EV use, associated with the "range anxiety" drivers may feel due to limited public charging options during travel.

- Commenters also cited interest in appropriate **pricing and rate design.** Setting rates for EV charging will require new analysis of how to allocate charging-specific costs to participants, and how to design rates that are cost-effective for customers and providers.
- **Load management** refers to the issues, associated with increased electric demand from significant expansions in electric vehicle use. Additional demand could result in increased costs for generation and transmission. Opportunities may also exist to manage the increased load cost-effectively, by using time-of-use rates and "managed charging" programs that encourage customers to shift charging use away from periods of peak demand.
- While few Wisconsin providers currently offer **subsidies and incentives** specific to EV infrastructure, a growing number of providers nationwide have initiated offerings to encourage growth in electric demand and support cost-effective load management.
- Many commented in the investigation that **third-party ownership** of public EV charging stations should not require the owner to be regulated as a public utility. However, the potential application of the statutory definition of a public utility to an EV charging station has not yet been analyzed by the courts in this state, and EV charging stations present novel legal scenarios. Further discussion by the Commission, regulated utilities, the Legislature, and other parties active on EV issues may be appropriate to clarify these legal uncertainties.

Figure 5-5 Areas of Interest

Workshop participants reinforced their interest in the range of topics above. A number of participants also highlighted their interest in a regulatory approach from the Commission that supports regulatory clarity for providers and encourages pilot programming to serve existing EV users and improve understanding of relevant issues in advance of future increases in EV deployment.

Informed by feedback from the comments and the workshop, the Commission issued a draft order in August 2020 that, if implemented, would require large providers to submit pilot program proposals for Commission approval, and establish a framework setting clear expectations for the information any provider must include in proposing EV programs to the Commission. To continue the stakeholder-driven nature of the investigation, the draft order has been issued for public comment. The Commission will review all feedback received before determining a final course of action on the proposal in late 2020.

Commission staff are also conducting additional technical research to model the potential effects of expanded EV deployment on the electric system. Initial findings suggest that expanding electric vehicle use to 5 percent of Wisconsin's total vehicle mix, which is well above current levels of 0.1 percent, would still have minimal effects on system metrics such as transmission capacity and wholesale market energy costs.

CHAPTER 6 – ELECTRIC SYSTEM EMISSIONS

The burning of fossil fuels results in emissions of numerous pollutants. Wisconsin electric providers have achieved substantial reductions in the local pollutants that cause environmental impacts in areas near generation sources, such as nitrous oxide (NO_2), sulfur dioxides (SO_2), particulate matter, and carbon monoxide (CO). Statewide, electric providers reduced total emissions from those sources by more than 60 percent between 2007 and 2017,[83] largely through investments in emissions control projects and reductions in the share of coal generation. (See Supply chapter.)

In recent years, customer interest has grown in reducing emissions of carbon dioxide (CO_2) to mitigate the effects of climate change. Electric providers in Wisconsin and nationwide, as well as many businesses, and state and local governments, have established new CO_2 reduction goals to reduce emissions. CO_2 emissions occur from the use of coal and natural gas for electricity generation, as well as from transportation fuels and from fossil fuel use outside of the electric system, such as propane use. As shown in Figure 5-6, transportation emissions currently represent the largest contributor to nationwide CO_2 emissions. In 2017, the most recent year for which complete data is available, transportation accounted for 37 percent of U.S. CO_2 emissions, compared to 33 percent from electric generation.

By contrast, electric generation accounts for the largest share of carbon emissions in Wisconsin. In 2017, electric generation represented 42 percent of CO_2 emissions in Wisconsin, while transportation emissions represented 29 percent of emissions and industrial use represented 13 percent.[84]

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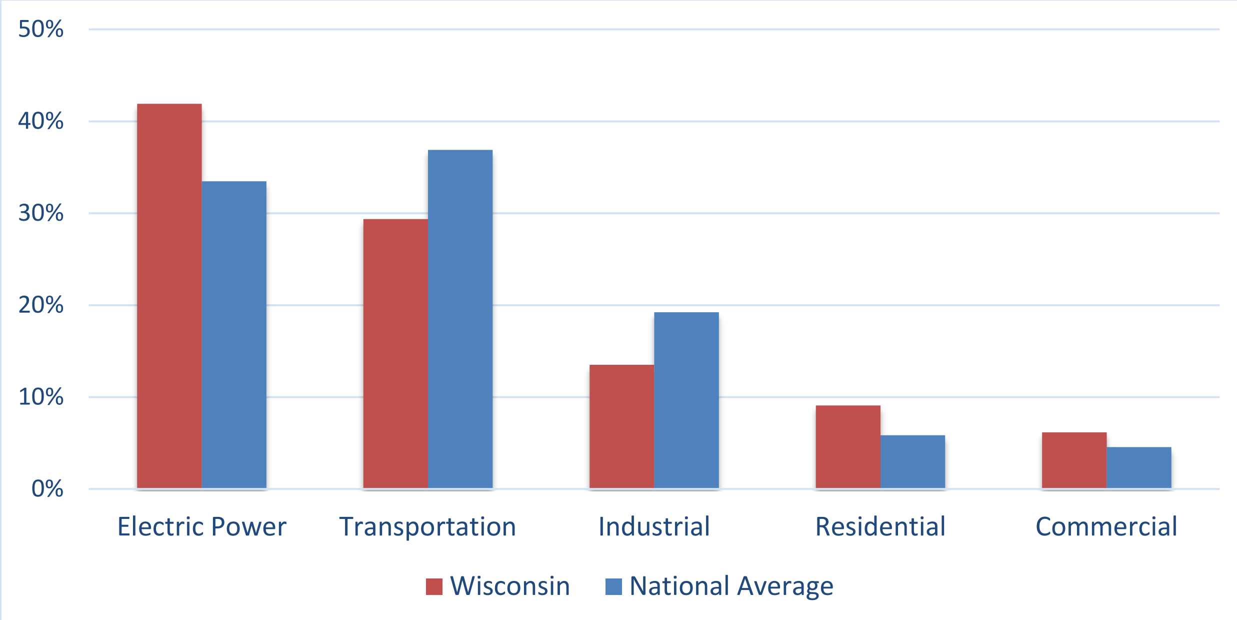
[83] 2017 Wisconsin Energy Statistics Book. https://psc.wi.gov/Documents/OEI/WisconsinEnergyStatistics/ENVIRONMENT_AND_EMISSIONs.pdf, p. 1.

[84] U.S Energy Information Administration (EIA) State Carbon Emissions Data. https://www.eia.gov/environment/emissions/state/.

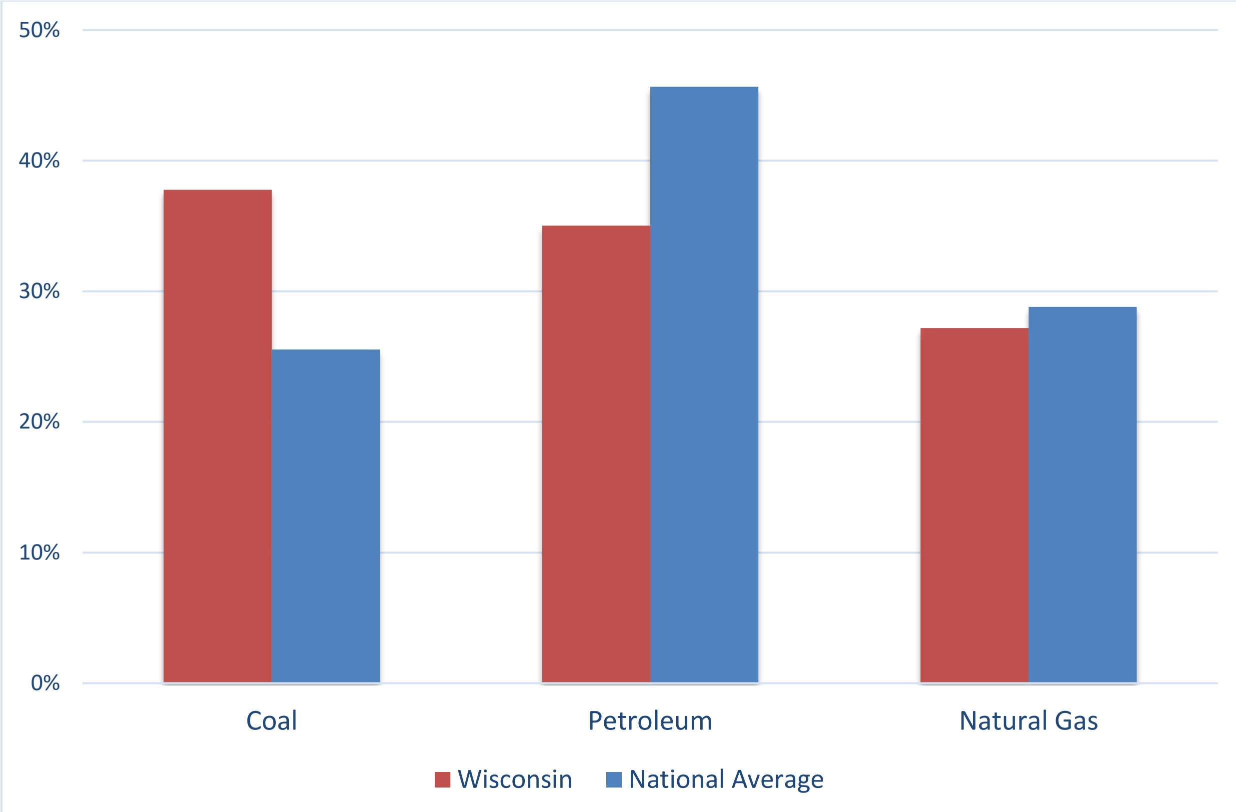
Figure 6-1 Comparison of CO_2 Emissions by End Use in Wisconsin vs. National Average



One driver of Wisconsin's differences from the national average is the continuing status of coal as a leading source of electric generation (see Supply chapter.) As shown in Figure 6-2, 38 percent of Wisconsin's total CO_2 emissions in 2017 resulted from coal emissions, almost all of which was for electricity generation, compared to 26 percent of emissions nationwide.[85]

[85] *Id.*

Figure 6-2 Comparison of CO_2 Emissions by Fossil Fuel Type in Wisconsin vs. National Average



ELECTRIC PROVIDERS' CARBON REDUCTION GOALS

As noted above, goals to reduce CO_2 emissions have been established by a wide range of entities, including businesses and governments as well as electric providers. In Wisconsin, Executive Order 38, promulgated in 2019, directs utilities and state agencies to work in partnership towards a goal of achieving 100 percent carbon-free electricity consumption in the state by 2050. The order also establishes the Office of Sustainability and Clean Energy and directs the office to lead the development of a clean energy plan to pursue that goal, with participation by the Commission and electric providers as well as a range of other state agencies and stakeholders. Work on the clean energy plan has been initiated in 2020.

To document the role of electric providers to date in pursuing carbon reductions, the Commission asked each major electric provider for information on the definition of any CO_2 reduction goals it has set, as part of its data request for the SEA. The request also asked each provider to document its current and projected emissions levels, regardless of whether the provider has set a formal reduction goal.[86]

[86] Major electric providers, also termed "primary respondents," include DPC, Great Lakes Utilities, MGE, Manitowoc Public Utilities, NSPW, SWL&P, WEPCO, WP&L, WPSC, and WPPI Energy. Other providers, such as municipal utilities and smaller IOUs, were not required to respond to this component of the Commission's data request.

As of August 2020, Wisconsin's five largest electric providers have all established goals to reduce CO_2 emissions 100 percent by 2050, as shown in Table 6-1. Four of the five providers also set interim goals to reduce 2030 emissions by at least 50 percent. Three of the providers (We Energies, WP&L, and WPSC) announced enhanced reduction goals in summer 2020, which increased their percentage reduction goals from previous levels of 40 percent in 2030 and 80 percent in 2050.[87] Providers differ in their methods for measuring reductions. For example, WP&L's goal applies reductions from its owned generation, while NSPW measures emissions from all electricity used to serve its customers, including owned generation as well as purchased power.

Table 6-1 Carbon Dioxide Reduction Goals of Wisconsin Electric Providers

Provider	2030 CO_2 Reduction Goal	2050 CO_2 Reduction Goal
Northern States Power Company-Wisconsin (Xcel)	80%	100%
Madison Gas and Electric Company		100%
Wisconsin Electric Power Company (We Energies)	70%	100%
Wisconsin Power and Light Company (Alliant)	50%	100%
Wisconsin Public Service Corporation	70%	100%

The five electric providers with CO_2 reduction goals provide approximately 85 percent of total electric service in Wisconsin.[88] As a result, achievement of these goals would reduce statewide emissions from electric generation by 85 percent from the 2005 baseline. Further reductions could be achieved from other electric providers. For example, while DPC has not set a quantified goal, it has recently announced plans to close a coal plant in favor of lower-emission energy sources. (See Supply chapter.)

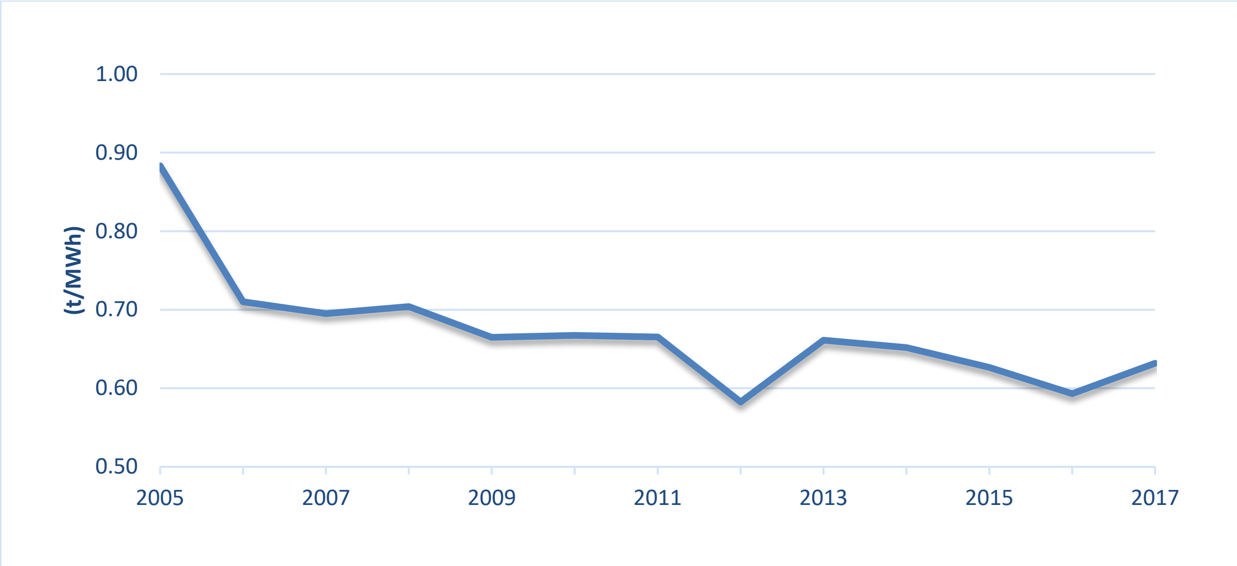
HISTORICAL ELECTRIC SYSTEM EMISSION TRENDS

Statewide Wisconsin CO_2 emissions from electricity generation declined 16.4 percent from 2005 to 2017. In response to the Commission's data request, the five electric providers with carbon reduction goals reported a comparable average reduction of 18.5 percent between 2005 and 2018.

These emission reductions have occurred despite overall growth in electric generation since 2005. As shown in Figure 6-3, these changes have instead reflected a decline in carbon emissions per unit of electricity generated, or "carbon intensity." As shown in Figure 6-3, total carbon intensity declined 28.4 percent between 2005 and 2017.

[87] See: https://www.alliantenergy.com/AlliantEnergyNews/NewsReleases/NewsRelease072220 (WP&L) and https://www.wecenergygroup.com/csr/cr2019/wec-corporate-responsibility-report-2019.pdf (We Energies, WPSC).
[88] Source: Aggregated electricity provider data responses, docket 5-ES-110.

Figure 6-3 Wisconsin Electric CO_2 Emissions per MWh, 2005-2017



Three factors have made significant contributions to the decline in carbon intensity. First, Wisconsin coal generators have become more carbon efficient due to a variety of changes, including the installation of emissions controls. On average, coal facilities in Wisconsin reduced their carbon intensity by 14 percent from 2005 to 2017.

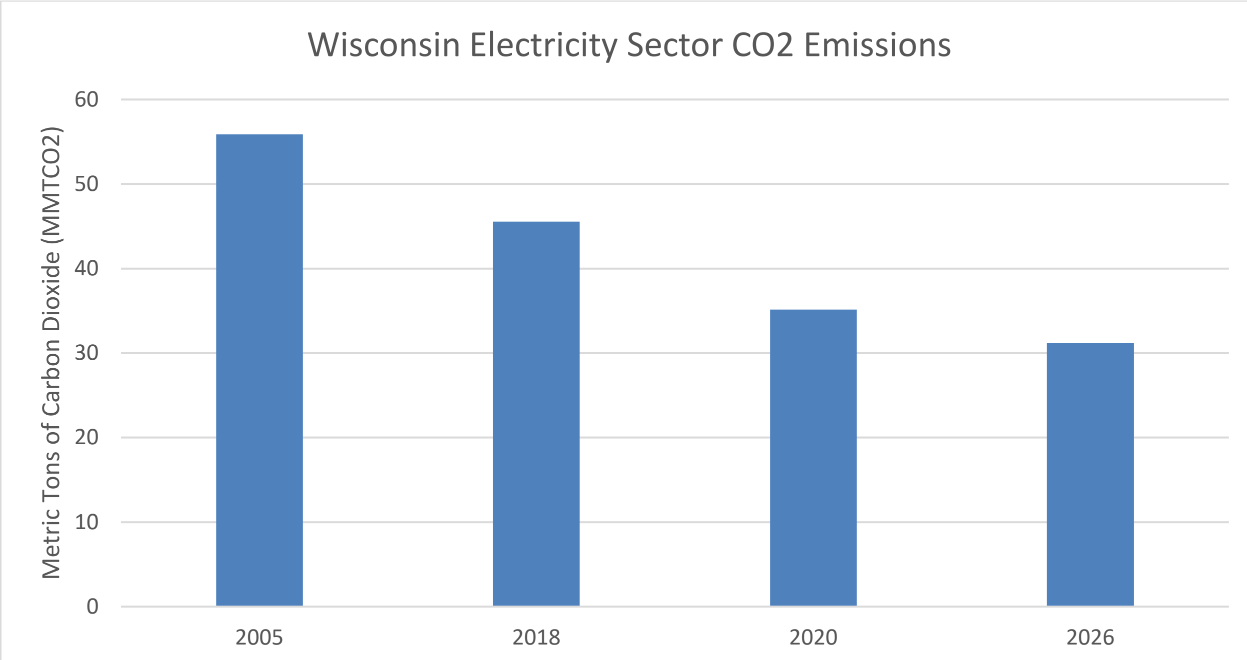
Second, Wisconsin electric providers have increasingly used natural gas as a generation source in place of coal. Compared to coal, natural gas emits approximately 50 percent less CO_2 per unit of energy. As noted in the Supply chapter, declines in natural gas prices have supported a significant increase in natural gas generation since 2010, and a corresponding reduction in the share of generation from coal.

Third, electric providers have also increased their use of zero-carbon generation sources, including nuclear power and renewable energy, from 2005 levels. The amount of increased generation from zero-carbon sources equates to more than half of Wisconsin's total increase in generation needs between 2005 and 2017, needs that likely would have otherwise been met by additional coal or natural gas generation.

PROJECTED EMISSIONS REDUCTIONS

The Commission's data request asked major electric providers to identify as of November 2019 their projected CO_2 emissions in 2020 and 2026, in addition to providing their most recently measured carbon emissions in 2018. Figure 6-4 summarizes total emissions from all reporting utilities. As noted above, average 2018 emissions reported by providers decreased 18.5 percent from 2005 levels. Providers projected additional emissions reduction of 22.9 percent between 2018 and 2020, resulting in 2020 emissions levels 37.1 percent below 2005. Providers reported more limited reductions between 2020 and 2026, projecting emissions levels 44.2 percent lower than 2005.

Figure 6-4 Wisconsin Electric Sector CO_2 Emissions



Multiple providers identified coal plant retirements as a significant driver of reduced emissions between 2018 and 2020. Nearly 1,800 MW of coal generation capacity will be retired within the two-year period, including the retirements of generating units at Pleasant Prairie, Pulliam, and Edgewater (Unit 4).

Providers also consistently identified multiple additional factors driving emissions reductions in both 2020 and 2026, including:

- Deployment of new natural gas plants in place of coal-fired generation, including 1,214 MW of capacity from Commission-approved plants at West Riverside and Nemadji Trail Energy Center;
- Deployment of new utility-owned solar resources, including 1,464 MW of new capacity reported by providers;
- Increased zero-carbon energy deployment on MISO's regional grid, which will reduce emissions from the purchased power providers obtain through power purchase agreements and wholesale purchases on the regional market; and
- Continued increases in conservation and energy efficiency.

These projections were provided before the onset of the COVID-19 pandemic, and it appears likely that 2020 emissions levels will fall below these projections, given the effects of the pandemic in reducing electricity demand. (See Supply chapter.) It is less clear at this time how the pandemic may affect emissions in future years; while continued pandemic response measures could continue to result in lower emissions, a return closer to pre-pandemic conditions could increase emissions closer to the 2020 levels projected above.

The limited amount of emissions reductions projected between 2020 and 2026 largely correspond to specific future generation additions and retirements reported by providers. (See Supply chapter). Total emissions reductions may exceed the projections if further additions of zero-carbon generation or retirements of fossil fuel generation take place before 2026. Although projected goal compliance varies by individual provider, the aggregate projected emissions reductions of 44.2 percent by 2026 would surpass the 40 percent reduction target multiple providers had previously set for 2030, while remaining short of those providers' updated goals to reduce 2030 emissions by 50 to 80 percent.

APPENDIX A – SUPPORTING DATA, ELECTRIC SUPPLY

Table A-1 Assessment of Electric Demand and Supply Conditions, Monthly Non-Coincident Peak Demands, MW[89] (using SEA monthly peak demand and previous SEA)

Year HISTORICAL:	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2003	10,739	10,498	10,291	9,602	9,048	12,725	13,319	13,694	11,937	10,136	10,450	11,302
2004	10,924	10,384	10,091	9,400	10,273	12,486	12,958	12,437	12,161	9,902	10,557	11,478
2005	11,127	10,678	10,433	9,610	10,000	14,020	13,832	14,323	13,224	11,912	10,833	11,581
2006	10,622	10,556	10,174	9,550	11,527	12,559	15,006	14,507	11,060	10,320	10,909	11,553
2007	10,958	11,419	10,682	9,946	11,343	13,834	14,163	14,461	13,693	12,033	11,091	11,503
2008	11,249	11,167	10,437	9,899	9,583	12,283	13,256	12,883	13,111	10,216	10,279	11,438
2009	11,273	10,681	10,246	9,209	9,606	13,694	11,051	12,260	10,846	9,454	9,944	11,075
2010	10,671	10,226	9,611	9,030	12,490	12,495	13,069	14,098	11,662	9,608	10,170	11,101
2011	10,552	10,645	9,824	9,311	10,668	13,601	14,870	13,553	13,092	9,624	9,955	10,520
2012	10,614	10,020	9,779	9,005	10,394	13,974	15,105	13,439	12,927	9,681	10,186	10,475
2013	10,685	10,182	9,720	9,171	10,221	11,937	14,347	14,162	13,428	9,647	9,814	10,897
2014	11,299	10,656	10,272	9,150	10,117	11,793	13,290	12,270	11,255	9,339	10,403	10,514
2015	11,107	10,710	10,153	9,072	9,871	11,243	12,860	13,308	13,065	9,207	9,694	9,986
2016	10,755	10,139	9,659	9,049	10,190	12,500	13,730	13,851	13,030	9,695	9,574	10,900
2017	10,842	10,245	9,720	9,166	10,047	13,143	13,230	12,474	13,123	10,178	9,972	10,804
2018	10,977	10,414	9,674	9,375	12,739	14,143	13,655	13,373	13,118	10,357	10,155	10,220
2019	11,207	10,561	10,649	9,334	9,770	11,970	14,023	12,779	11,500			
FORECASTED:												
2019										9,775	10,083	10,683
2020	10,845	10,574	10,060	9,398	10,421	13,112	14,277	13,968	12,471	9,814	10,169	10,746
2021	10,795	10,578	10,025	9,362	10,369	13,127	14,307	14,003	12,510	9,852	10,217	10,837
2022	10,916	10,706	10,141	9,478	10,489	13,252	14,420	14,108	12,599	9,913	10,274	10,889
2023	10,944	10,732	10,170	9,506	10,522	13,298	14,469	14,160	12,636	9,952	10,311	10,919
2024	10,987	10,791	10,209	9,543	10,561	13,343	14,517	14,205	12,688	9,979	10,341	10,956
2025	11,017	10,824	10,241	9,574	10,597	13,387	14,561	14,248	12,729	10,015	10,373	10,988
2026	11,047	10,858	10,273	9,636	10,633	13,429	14,601	14,288	12,769	10,049	10,404	11,017

Table A-2 Wisconsin Aggregated Supply and Demand[90]

Report Line MISO Description Capacity (MW)	2020	2021	2022	2023	2024	2025	2026
High Certainty Resources	12,736	12,719	12,719	12,719	12,695	12,719	12,719
Low Certainty Resources	8	0	0	0	24	0	0
Behind the Meter	353	315	315	315	314	314	310
Demand Response Resources	886	796	786	789	789	792	795
New Capacity	442	581	861	1318	1341	1722	1815
Local Resource Zone (LRZ) Internal Transfer - In	1881	2036	2026	1611	1611	1611	1611
LRZ Internal Transfer – Out	(661)	(821)	(801)	(536)	(514)	(514)	(514)
Net Imports	395	430	430	430	430	297	297
Retired	(401)	(693)	(1087)	(1093)	(1294)	(1369)	(1418)
Net Capacity (MW)	15,640	15,363	15,248	15,552	15,396	15,571	15,613
Demand (MW)							
Non-Coincident Load Serving Entities (LSE) Peak gross of DR	14,532	14,465	14,513	14,559	14,606	14,693	14,759
Full Responsibility Transactions	(168)	(168)	(169)	(169)	(169)	(169)	(169)
Zonal Coincident Factor	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Coincident LSE Peak with Zonal Peak	14,448	14,381	14,429	14,474	14,521	14,604	14,668
MISO Coincident Factor	0.9597	0.9597	0.9597	0.9597	0.9597	0.9597	0.9597
Expected Demand: Coincident LSE Peak to MISO Peak	14,196	14,131	14,178	14,223	14,270	14,349	14,410
Reserve Requirement (MW)							
Local Clearing Requirement	13,878	13,772	13,830	13,778	13,826	14,105	14,118
Planning Reserve Requirement	14,974	14,902	14,954	15,008	15,032	15,166	15,255
Average UCAP Planning Reserve Margin	1.07	1.07	1.08	1.08	1.08	1.08	1.08
Resources above local clearing requirement	1,762	1,591	1,418	1,774	1,570	1,466	1,495
Resource above planning reserve requirement	666	461	294	543	364	405	358
UCAP Planning Reserve Margin	10.17%	8.71%	7.54%	9.34%	7.89%	8.52%	8.35%

[89] Source: Aggregated electricity provider data responses, docket 5-ES-110.

[90] Source: Aggregated electricity provider data responses, docket 5-ES-110.

Figure A-1 MISO System-Wide Average Monthly Day-Ahead and Real-Time LMPs $/MWh

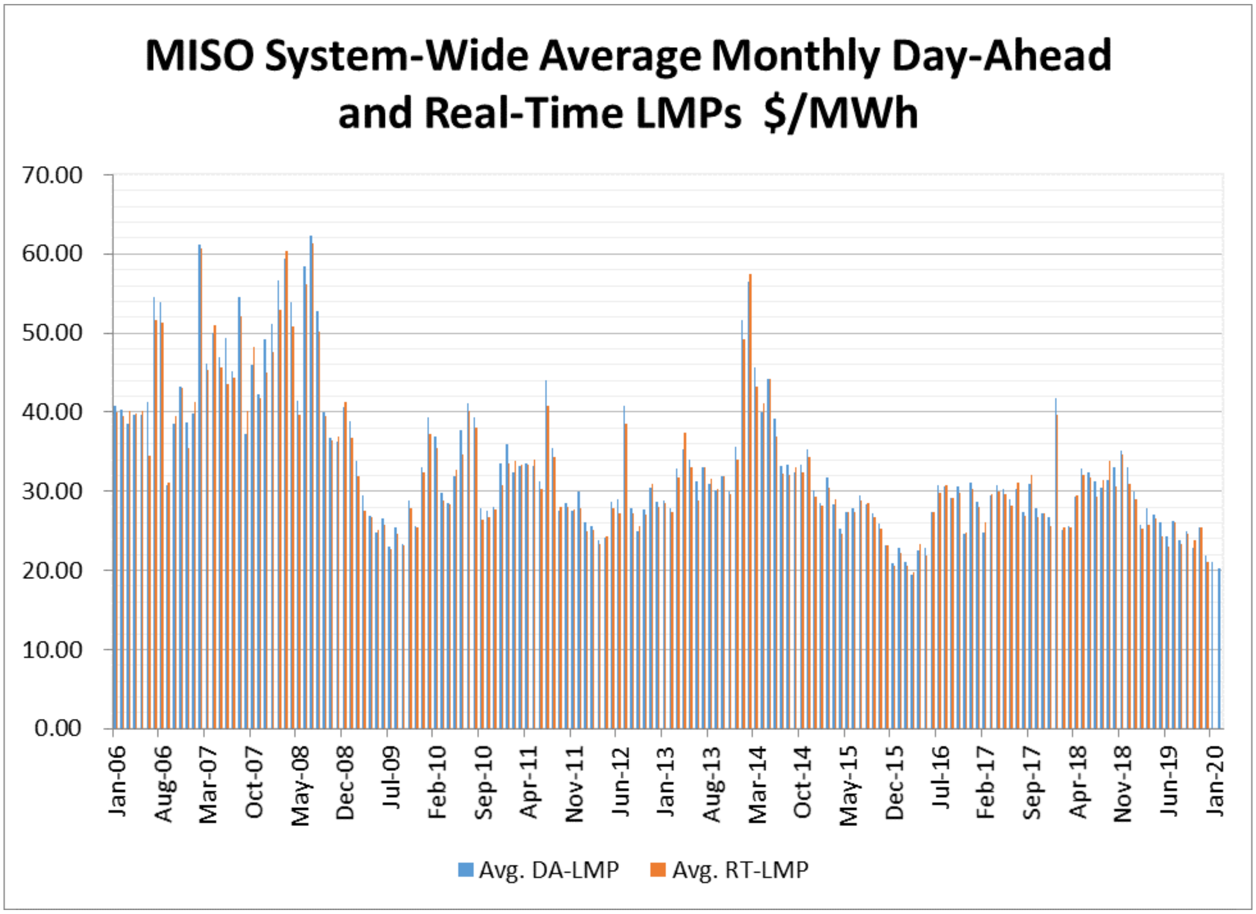


Figure A-2 Forecasted Levelized Cost of Electricity in $/MWh per NREL in 2019

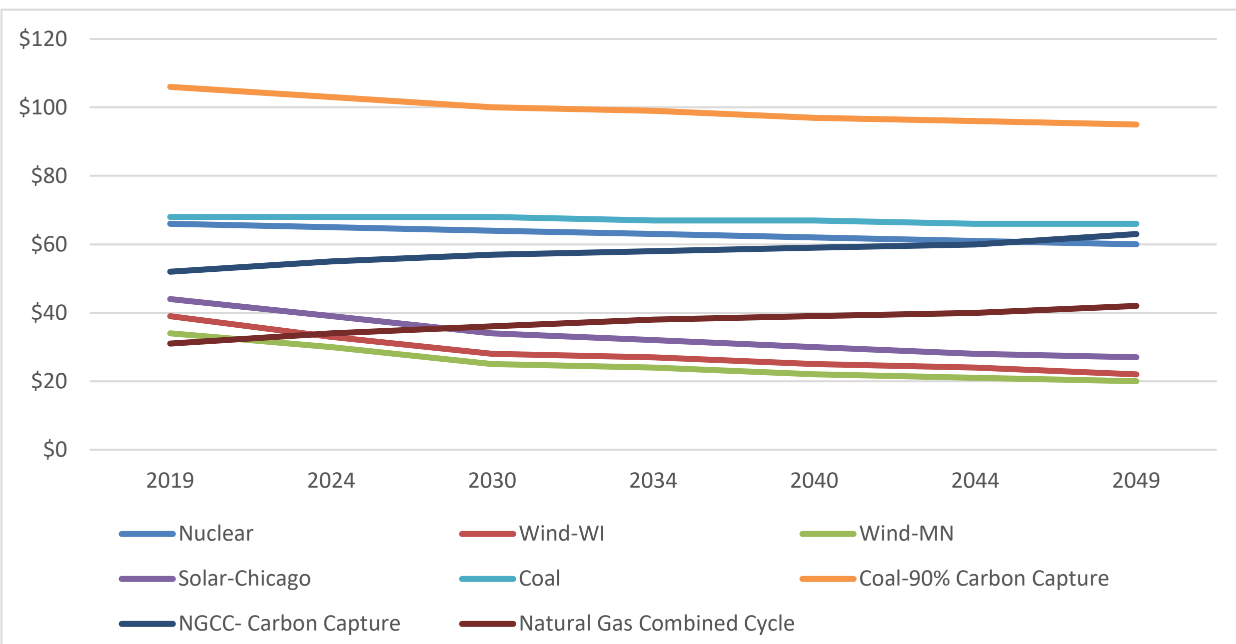
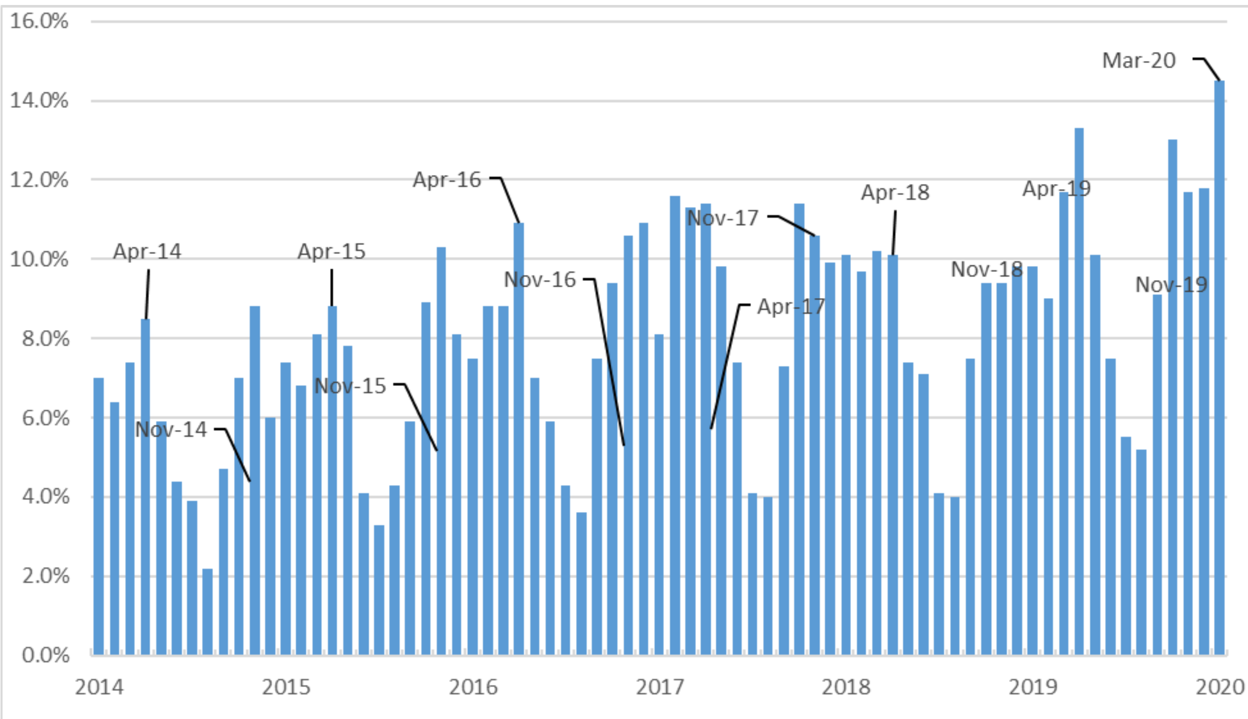


Table A-3 Data for Figure A-2

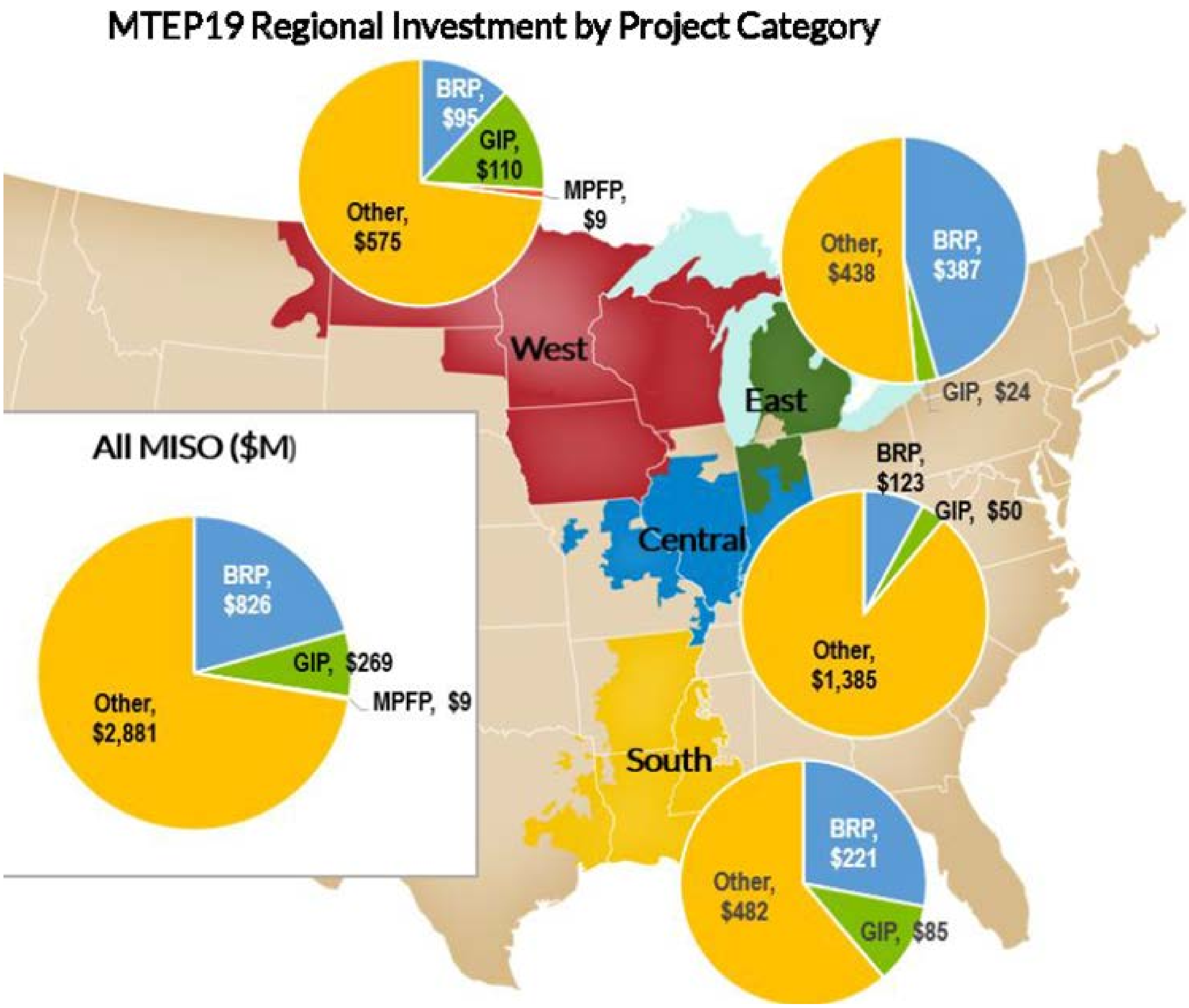
Year	Nuclear	Wind-WI	Wind-MN	Solar-Chicago	Coal	Coal-90% Capture	NGCC w/ CCS	NGCC no CCS
2019	$66	$39	$34	$44	$68	$106	$52	$31
2024	$65	$33	$30	$39	$68	$103	$55	$34
2030	$64	$28	$25	$34	$68	$100	$57	$36
2034	$63	$27	$24	$32	$67	$99	$58	$38
2040	$62	$25	$22	$30	$67	$97	$59	$39
2044	$61	$24	$21	$28	$66	$96	$60	$40
2049	$60	$22	$20	$27	$66	$95	$63	$42
	Change from 2019 to 2030:							
	-3%	-28%	-26%	-23%	0%	-6%	10%	16%
	Change from 2019 to 2049:							
	-9%	-44%	-41%	-39%	-3%	-10%	21%	35%

Figure A-3 Wind Energy as Percent of Total Energy in MISO Region, 2014-2019



APPENDIX B – SUPPORTING DATA, ELECTRIC TRANSMISSION

Figure B-1 MTEP19 Regional Investment by Project Category



APPENDIX C – SUPPORTING DATA, CUSTOMER RATES AND BILLS

Figure C-1 Weather-Normalized Annual Use, per Residential Customer (kWh)[91]

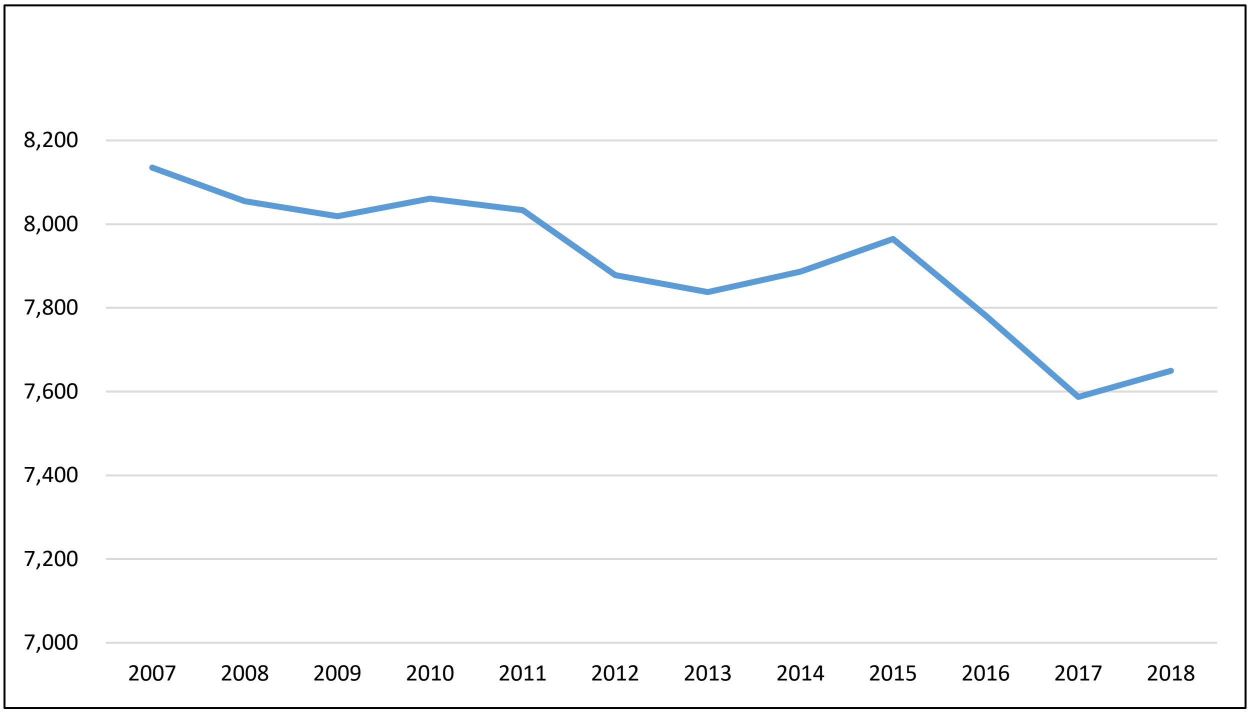
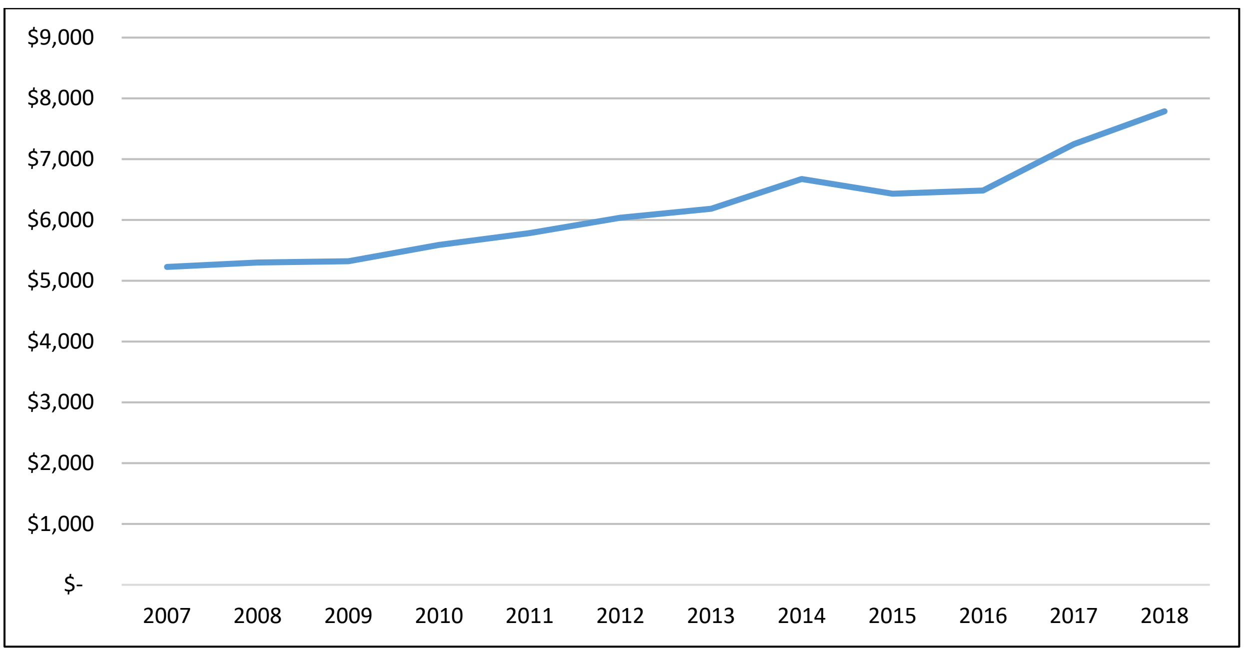


Figure C-2 Energy Intensity – Non-Residential Sales ($ of GDP/MWh)[92]



[91] Utility annual reports filed with the Commission.

[92] Utility Annual Reports filed with the Commission; U.S. Bureau of Economic Analysis.

Appendix Table C-1 Residential Average Rates in the Midwest and U.S. (cents/kWh)

State	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Illinois	11.07	11.27	11.52	11.78	11.37	10.63	11.91	12.50	12.54	12.95	12.77
Indiana	8.87	9.50	9.56	10.06	10.53	10.99	11.46	11.57	11.79	12.29	12.26
Iowa	9.49	9.99	10.42	10.46	10.82	11.04	11.16	11.63	11.94	12.34	12.24
Michigan	10.75	11.60	12.46	13.27	14.13	14.59	14.46	14.42	15.22	15.40	15.45
Minnesota	9.74	10.04	10.59	10.96	11.35	11.81	12.01	12.12	12.67	13.04	13.14
Missouri	8.00	8.54	9.08	9.75	10.17	10.60	10.64	11.21	11.21	11.63	11.34
Ohio	10.06	10.67	11.31	11.42	11.76	12.01	12.50	12.80	12.47	12.63	12.56
Wisconsin	11.51	11.94	12.65	13.02	13.19	13.55	13.67	14.11	14.07	14.35	14.02
Midwest	9.94	10.44	10.95	11.34	11.67	11.90	12.23	12.55	12.74	13.08	12.97
U.S. Average	11.26	11.51	11.54	11.72	11.88	12.13	12.52	12.65	12.55	12.89	12.87

Appendix Table C-2 Commercial Average Rates in the Midwest and U.S. (cents/kWh)

State	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Illinois	9.25	9.04	8.88	8.64	7.99	8.14	9.26	9.02	9.02	9.09	9.12
Indiana	7.82	8.32	8.38	8.77	9.14	9.60	9.96	9.78	10.01	10.54	10.60
Iowa	7.18	7.55	7.91	7.85	8.01	8.44	8.67	8.92	9.17	9.46	9.68
Michigan	9.17	9.24	9.81	10.33	10.93	11.06	10.87	10.55	10.64	11.00	11.15
Minnesota	7.88	7.92	8.38	8.63	8.84	9.42	9.85	9.44	9.86	10.48	10.38
Missouri	6.61	6.96	7.50	8.04	8.20	8.80	8.90	9.16	9.26	9.47	9.40
Ohio	9.23	9.65	9.73	9.63	9.47	9.35	9.83	10.07	9.97	10.05	10.11
Wisconsin	9.28	9.57	9.98	10.42	10.51	10.74	10.77	10.89	10.77	10.87	10.67
Midwest	8.30	8.53	8.82	9.04	9.14	9.44	9.76	9.73	9.84	10.12	10.14
U.S. Average	10.26	10.16	10.19	10.24	10.09	10.26	10.74	10.64	10.43	10.66	10.67

Appendix Table C-3 Industrial Average Rates in the Midwest and U.S. (cents/kWh)

State	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Illinois	7.34	7.01	6.82	6.42	5.80	5.94	6.85	6.67	6.51	6.47	6.80
Indiana	5.46	5.81	5.87	6.17	6.34	6.70	6.97	6.86	6.97	7.54	7.38
Iowa	4.81	5.27	5.36	5.21	5.30	5.62	5.71	5.90	6.05	6.21	6.45
Michigan	6.73	6.98	7.08	7.32	7.62	7.72	7.68	7.02	6.91	7.19	7.10
Minnesota	5.87	6.26	6.29	6.47	6.54	6.98	6.72	7.02	7.37	7.37	7.53
Missouri	4.92	5.42	5.50	5.85	5.89	6.29	6.36	6.44	7.12	7.33	7.22
Ohio	6.20	6.72	6.40	6.12	6.24	6.22	6.77	7.02	6.98	6.92	7.01
Wisconsin	6.51	6.73	6.85	7.33	7.34	7.40	7.52	7.58	7.49	7.49	7.33
Midwest	5.98	6.28	6.27	6.36	6.38	6.61	6.82	6.81	6.93	7.07	7.10
U.S. Average	6.96	6.83	6.77	6.82	6.67	6.89	7.10	6.91	6.76	6.88	6.92

Figure C-3 Average Monthly Residential Bills by Census Division (2018 EIA Data)[93]

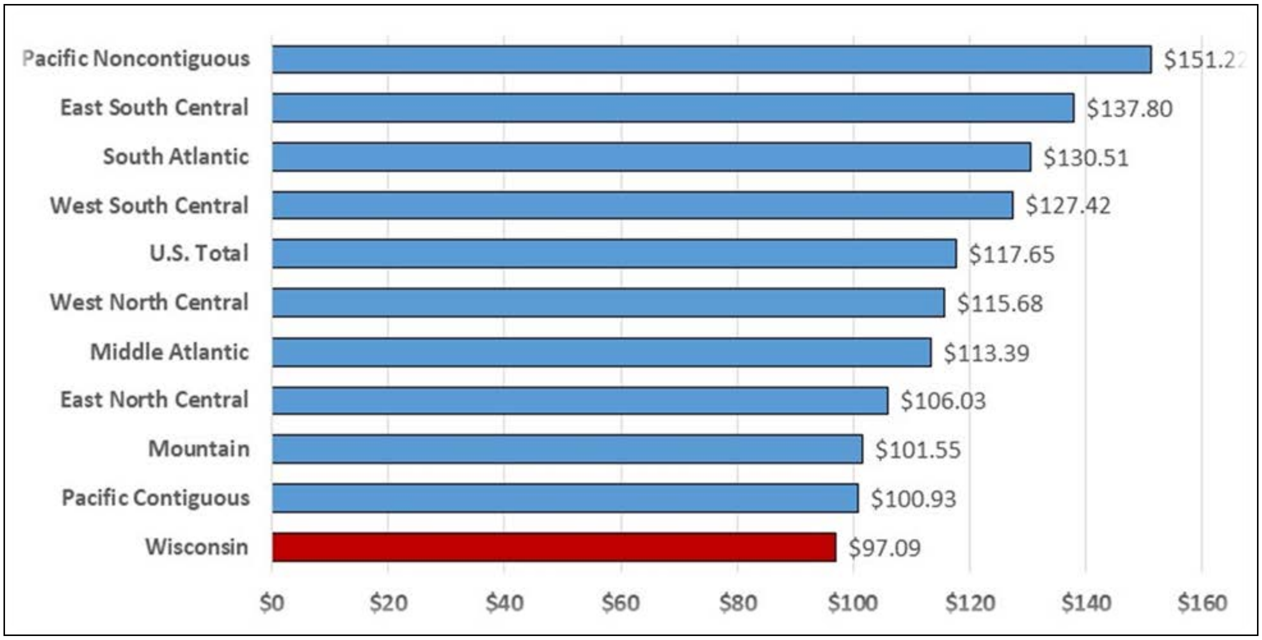
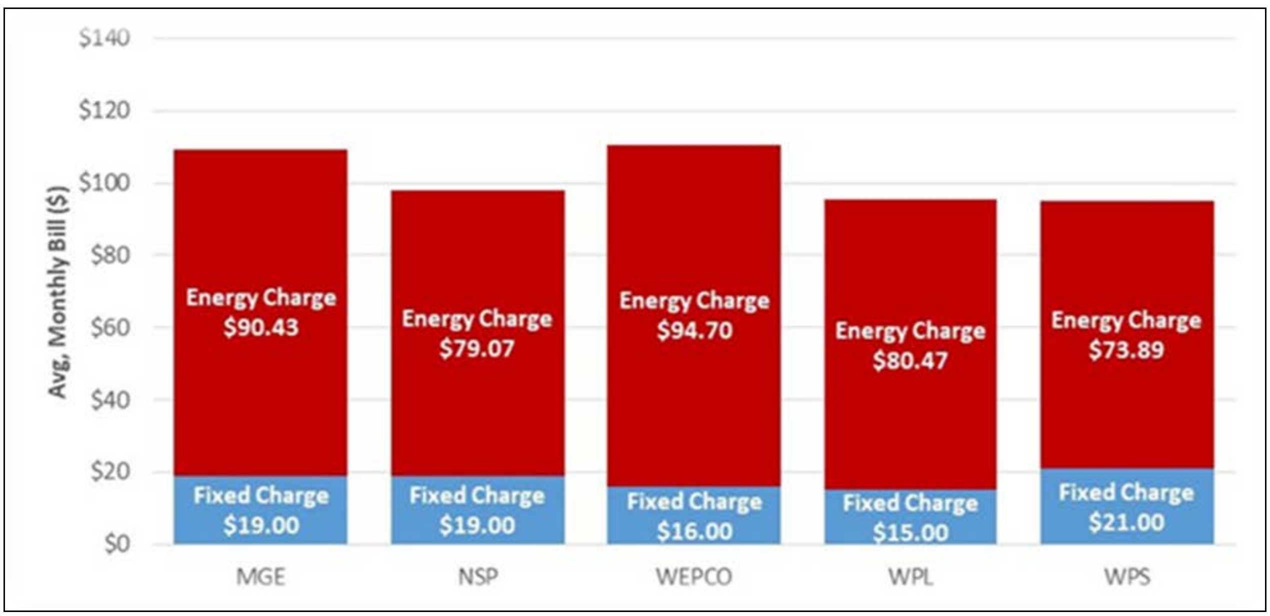


Figure C-4 Monthly Residential Electricity Bills for Wisconsin's Largest IOUs[94]



[93] U.S. Energy Information Administration. 2018 Average Monthly Bill – Residential. https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf. Accessed 2 January 2020.

[94] Source: Major utility tariffs filed with the Commission, http://apps.psc.wi.gov/vs2010/tariffs/default.aspx

Figure C-5 Distribution of Monthly Residential Electricity Bills for Municipal Utilities[95]

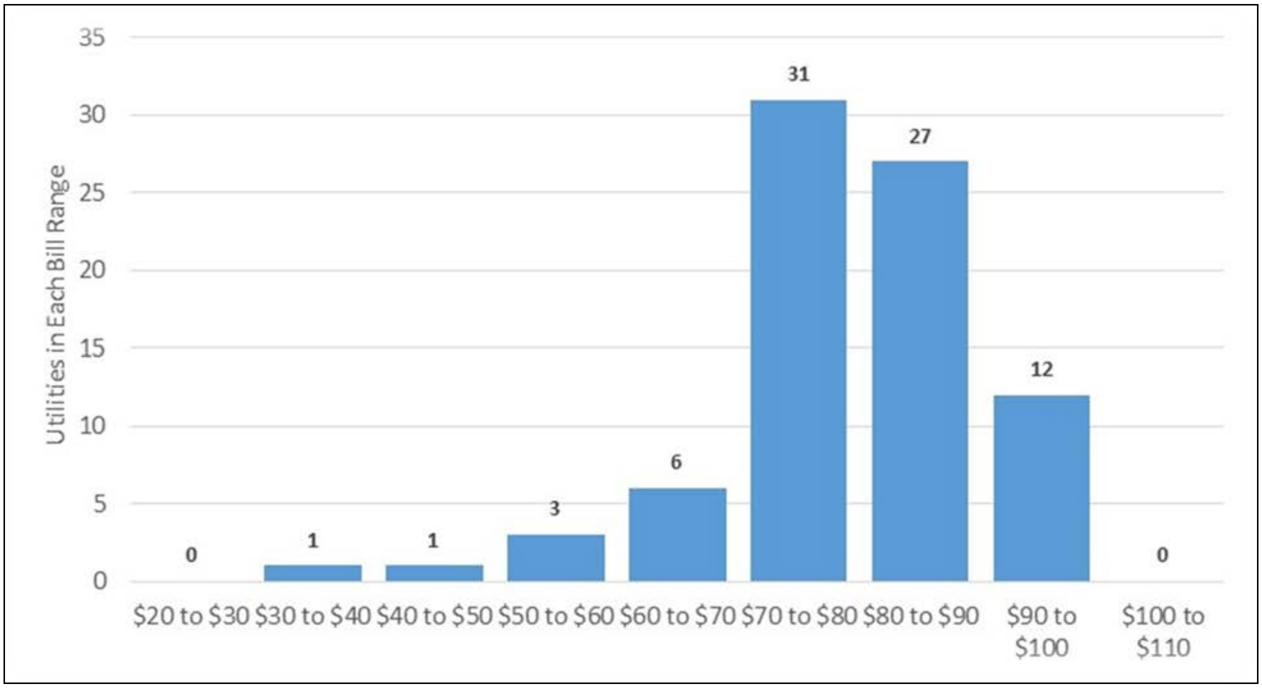
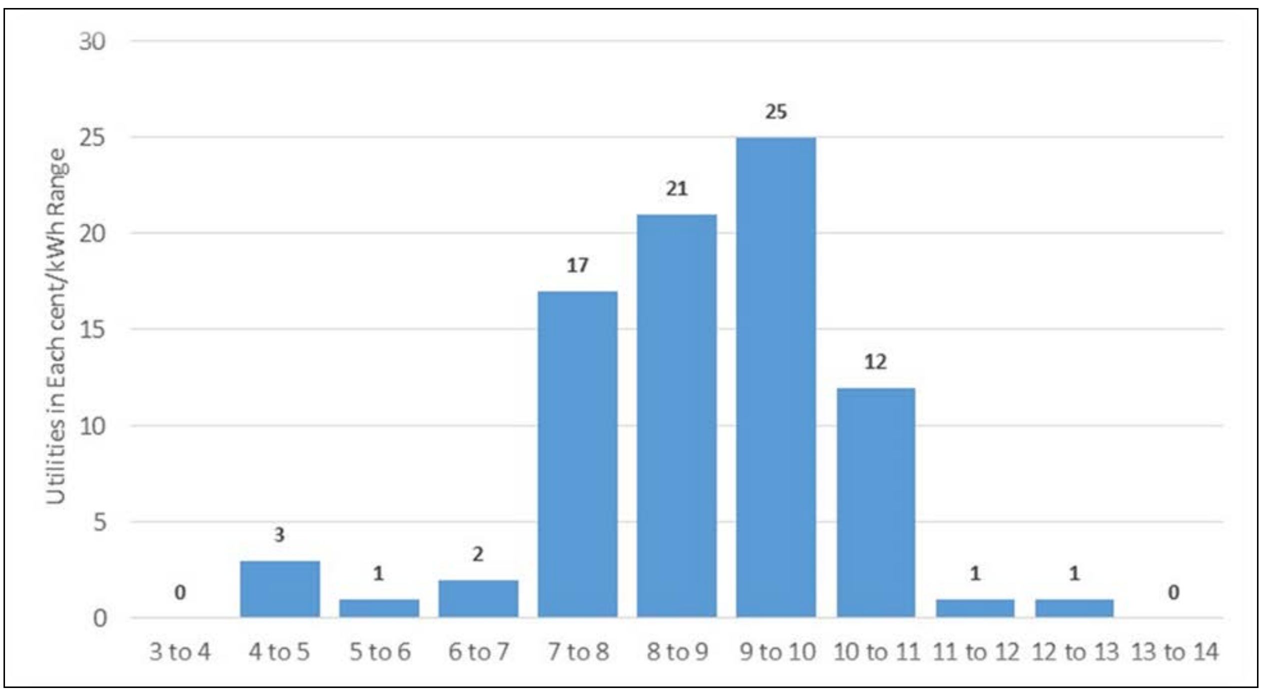
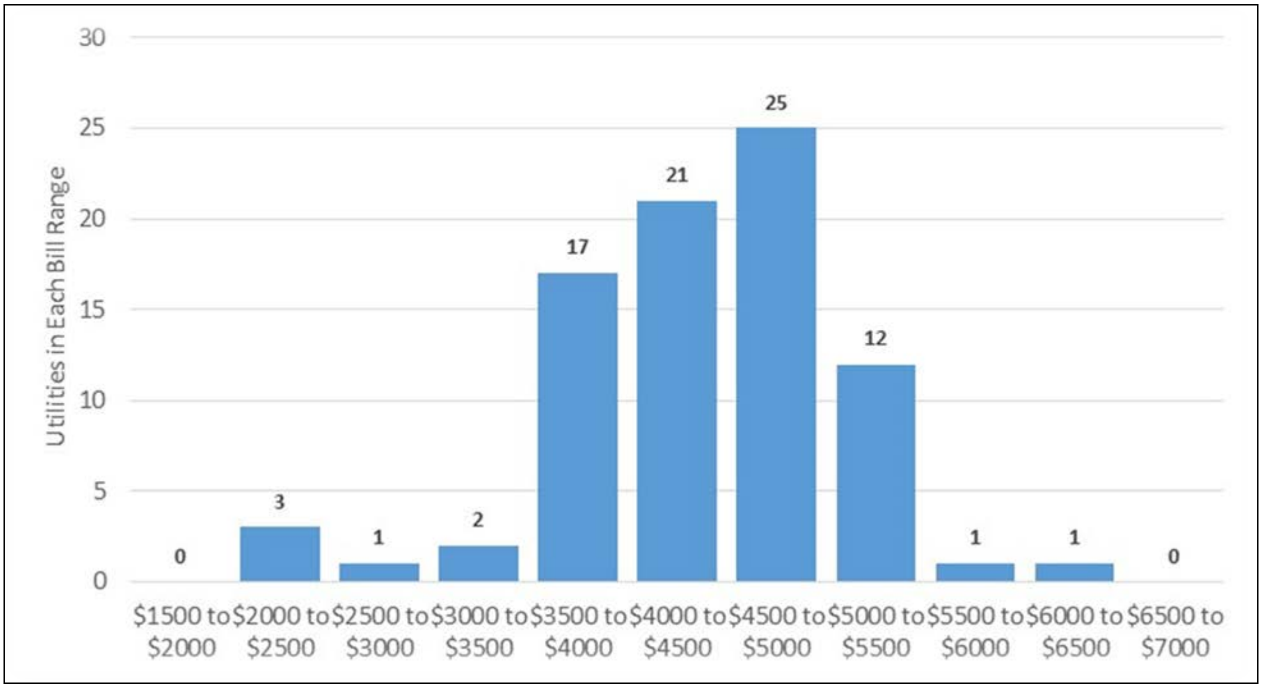


Figure C-6 Distribution of Commercial (CP-1) Costs in cents/kWh for Municipal Utilities[96]



[95] Source: Major utility tariffs filed with the Commission, http://apps.psc.wi.gov/vs2010/tariffs/default.aspx
[96] Source: Major utility tariffs filed with the Commission, http://apps.psc.wi.gov/vs2010/tariffs/default.aspx

Figure C-7 Distribution of Monthly Commercial (CP-1) Bills for Municipal Utilities[97]



The monthly costs summarized in Figure C-6 and Figure C-7 are based on the following assumptions for commercial customers billed under the CP-1 tariff schedule:

- Monthly consumption of 50,000 kWh or 600,000 kWh/year (this represents an average load factor of 68.5 percent based on a peak load of 100 kW)
- Peak/Off-Peak split of 60 percent (peak) and 40 percent (off-peak)
- Monthly peak demand of 100 kW (typically CP-1 range is 50-200 kW)
- Municipal utilities with a CP-1 classification threshold below 50 kW are not included in the distribution plot shown in Figure C-7 (only one utility has a threshold below 100 kW and two others do not have a CP-1 schedule in their effective tariff).

Table C-4 Estimated Monthly Bill Data for Municipal Utility Cp-1 Customers

Summary	Total Cost (cents/kWh)*	Estimated Bill ($/month)*
Minimum	4.19	$2,095
25th Percentile	7.75	$3,873
Median	8.89	$4,443
Average	8.74	$4,437
75th Percentile	9.69	$4,847
Maximum	11.38	$5,690

** Note: The Total Cost (cents/kWh) is the sum of all bill components (monthly fixed charge, energy charge, distribution demand, and billable demand) divided by monthly energy use.*

[97] Source: Major utility tariffs filed with the Commission, http://apps.psc.wi.gov/vs2010/tariffs/default.aspx

APPENDIX D – SUPPORTING DATA, CLEAN ENERGY PROGRAMS AND POLICIES

Figure D-1 Number of Renewable DERs Installed by Capacity

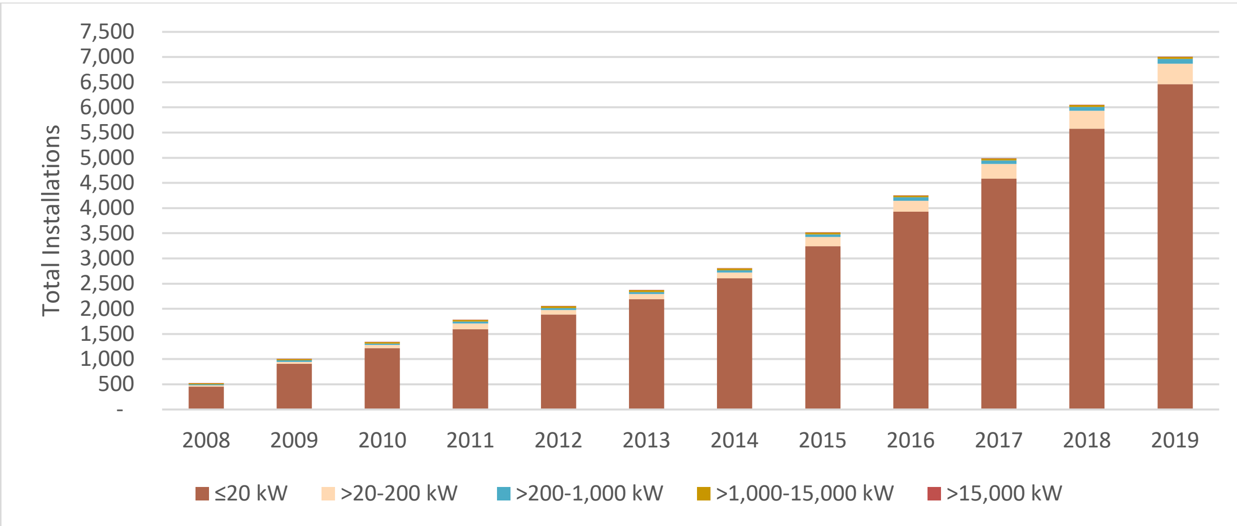
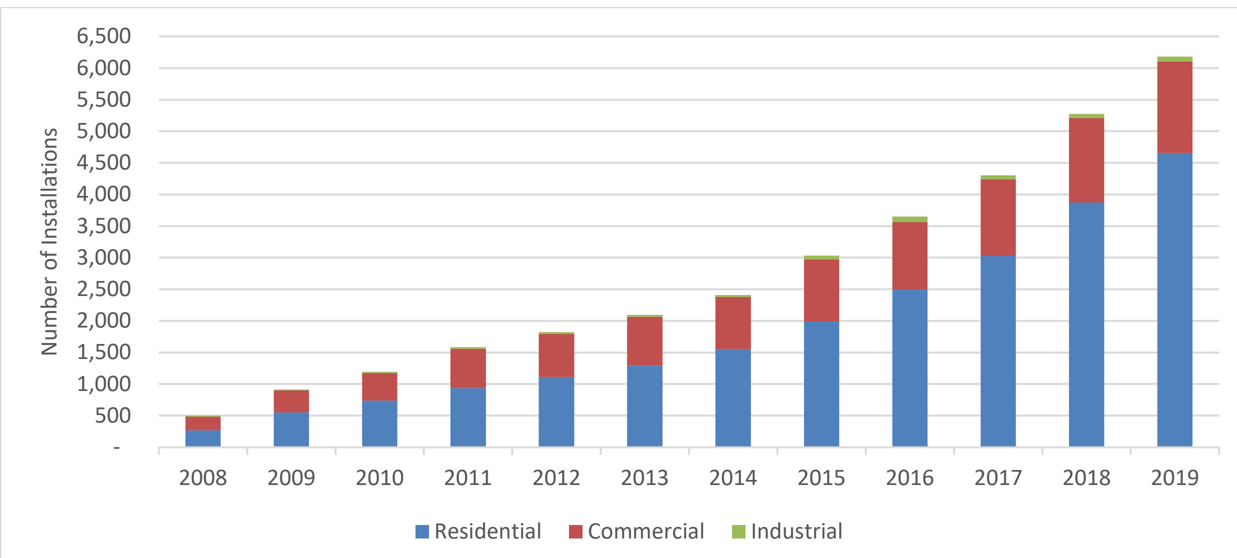


Figure D-2 Number of Renewable DERs Installed by Customer Type[98]



[98] Some providers did not report DER installations by customer type. As a result, the number of total DER installations by customer type is presented with lower values than those provided for other DER data.

Figure D-3 Installed Capacity of Renewable DERs by Capacity Range

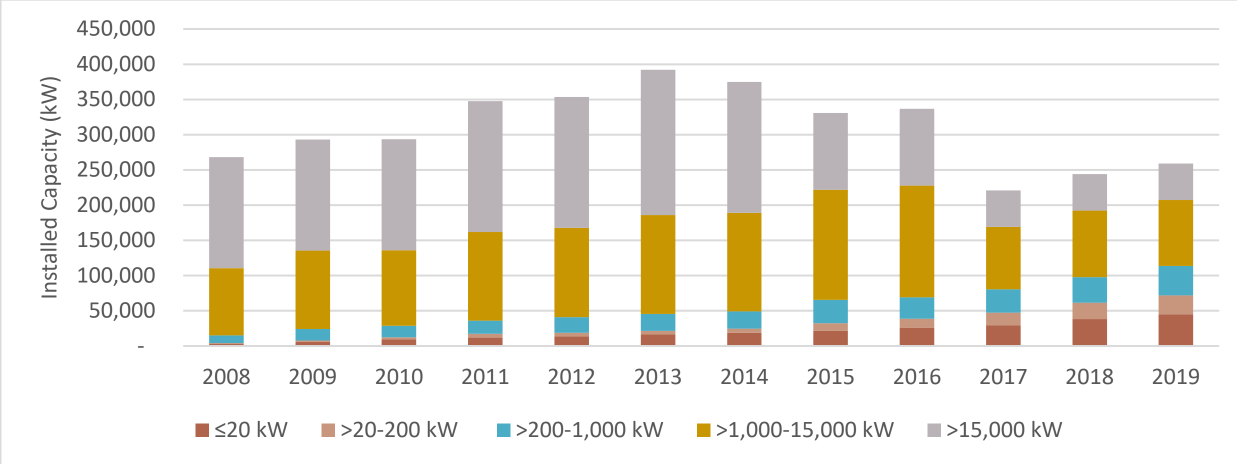
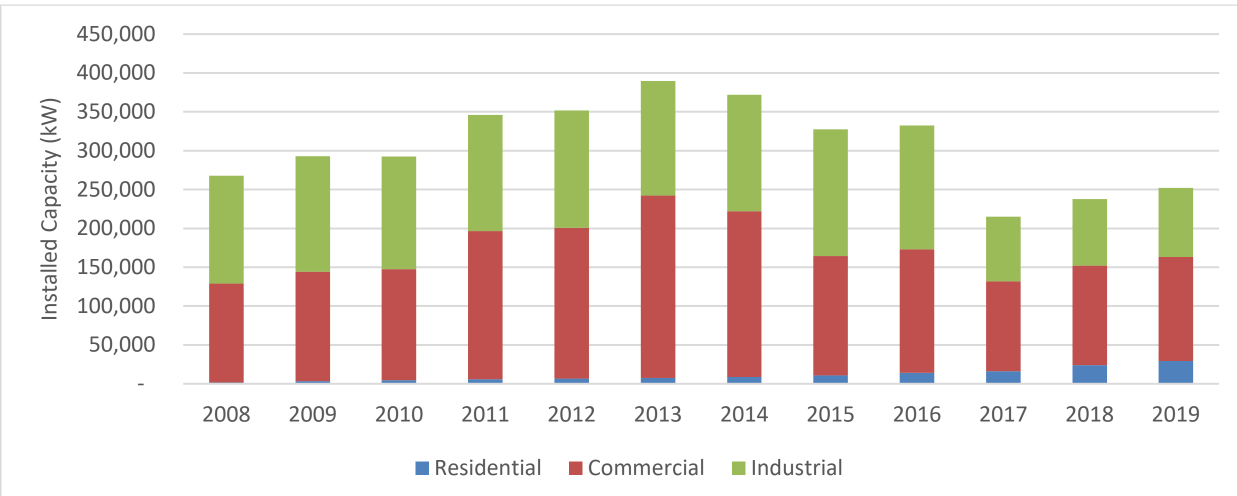


Figure D-4 Installed Capacity of Renewable DERs by Customer Type[99]



[99] Some providers did not report DER installations by customer type. As a result, total DER capacity by customer type is presented with lower values than those provided for other DER data.

APPENDIX E – ACRONYMS

§	Section
AMI	Advanced metering infrastructure
AMR	Automated meter reading
APTIM	formerly Chicago Bridge and Iron
ATC	American Transmission Company LLC
BRP	Baseline Reliability Project
CAA	Clean Air Act
CAIAI	Customer Average Interruption Duration Index
Cadmus	Cadmus Group
CB&I	Chicago Bridge and Iron
CC&B	Customer Care and Billing System
ch.	Chapter
CIS	Customer information systems
CME	Centuria Municipal Electric Utility
Commission	Public Service Commission of Wisconsin
CO_2	Carbon Dioxide
CSAPR	Cross State Air Pollution Rule
DER	Distributed Energy Resources
DNR	Department of Natural Resources
DPC	Dairyland Power Cooperative
EDR	Economic Development Rate
EIA	U.S. Energy Information Administration
ELG	Effluent Limitations Guideline
EPA	U.S. Environmental Protection Agency
EV	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
Focus	Focus on Energy
fps	Feet per second
GIP	Generator Interconnection Project
GW	Gigawatt
ICAP	Installed Capacity
ICE	Improved Customer Experience
IEEE	Institute of Electric and Electronic Engineers
IGCC	Integrated Gasification Combined-Cycle
IMM	Independent market monitor
IOU	Investor-owned utility
IPL	Interstate Power and Light Company
ITC	Investment Tax Credit
JOA	Joint Operating Agreement
kV	kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LMP	Locational Marginal Pricing

LMR	Load Modifying Resources
LOLE	Loss of load expectations
LRZ	Local Resource Zone
LSE	Load Serving Entity
LTRA	Long-Term Resource Assessment
MATS	Mercury and Air Toxics Standard
MEP	Market Efficiency Project
MGE	Madison Gas and Electric Company
MISO	Midcontinent Independent System Operator, Inc.
MTEP	MISO Transmission Expansion Plan
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NEV	Neutral-to-earth voltage
NO_X	Nitrogen oxides
NRC	Nuclear Regulatory Commission
NSPM	Northern States Power Company-Minnesota
NSPW	Northern States Power Company-Wisconsin
NWE	Northwestern Wisconsin Electric Company
OMS	Organization of MISO States
PCAC	Power cost adjustment clause
PPA	Purchased power agreements
PRB	Power River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PY	Planning Year
RER	Renewable Energy Rider
RIIA	Renewable Integration Impact Assessment
ROW	Right-of-way
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCPC	Supercritical pulverized coal
SCR	Selective catalytic reduction
SEA	Strategic Energy Assessment
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SWL&P	Superior Water, Light and Power Company
TMEP	Targeted Market Efficiency Projects
TOU	Time-of-Use
TRC	Total Resource Cost

TRM	Technical Reference Manual
UCAP	Unforced Capacity
VOC	Volatile organic compounds
WEC	Wisconsin Energy Corporation
WEM	Wisconsin Emergency Management
WEPCO	Wisconsin Electric Power Company
WG	Wisconsin Gas LLC
Wis. Admin. Code	Wisconsin Administrative Code
Wis. Stat.	Wisconsin Statutes
WP&L	Wisconsin Power and Light Company
WPPI	WPPI Energy
WPSC	Wisconsin Public Service Corporation
Xcel	Xcel Energy, Inc.

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