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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. The SEA provides this evaluation in the context of four primary goals maintained by Wisconsin electricity providers and the Commission:

- **Adequate** electric supply that maintains sufficient total power to meet customers' total electric demand (i.e. resource adequacy);
- **Reliable** electric supply that provides all customers access to electricity at all times, avoiding outages whenever possible;
- **Affordable** electric supply that offers adequate and reliable energy at the lowest feasible cost for customers; and
- **Environmentally responsible** electric supply that minimizes the negative effects of electric generation on the natural environment.

A note on the SEA and data updates: As part of the biennial SEA process, in November 2025, 10 electric providers operating in Wisconsin submitted to the Commission certain historical information up to Fall 2025 and forecasted information from Fall 2025 through 2032 on electric system operations. Utilities updated this information, where applicable, in the fall of 2026 to provide historical information up to year-end 2025 and forecasted information from 2026 through 2032. The SEA has been updated to reflect this more current information.

A note on two attachments to the final SEA: In an effort to increase transparency and to make data used in the creation of the SEA more easily accessible to the broader public, two attachments to the final SEA have been included. Attachment 1 includes all Tables from the final SEA in excel format. Attachment 2 includes an aggregation of data schedules, that are provided by each utility individually, into a state-wide roll-up in Excel format.

Electricity Generation in Wisconsin Today

Wisconsin, much like the rest of the country, has seen a transition in its electric supply from the 2010s to present. As once emergent renewable energy technologies became more cost-effective, and the environmental impacts of energy generation became a global priority, Wisconsin experienced an increase in the adoption of renewable energy generation sources like wind and particularly solar. Over the same time period, the share of natural gas generation increased as coal fired generation declined, with no plans for new coal generation and the phased retirement of many existing coal generators, largely due to environmental concerns and mandates, and increasing operating costs.

The energy landscape is again changing in Wisconsin, as the emergence of large data center loads and, to a lesser extent, the move toward electrification of heating and the growth of electric vehicles (EV), is dramatically increasing energy supply needs in the near-term. This rapid and considerable actual and forecast growth in energy demand will require unprecedented energy supply and related transmission and distribution system infrastructure investments.

Wisconsin peak load is expected to grow from approximately 14.2 gigawatt (GW) in 2026 to 20 GW by 2032, an increase of nearly 5.8 GW, or over 40 percent, in a six-year period (see Figure 1-1 and Table 1-1). Approximately 4.12 GW,[1, 2] or approximately 71 percent, of this peak load increase is associated with three active data center developments in the service territories of two Wisconsin utilities, namely Wisconsin Power and Light Company (WP&L) and Wisconsin Electric Power Company (WEPCO). These load forecasts illustrate the outsized impact data center development is anticipated to have on the energy landscape in Wisconsin in the coming years.

Wisconsin electric providers plan to provide electric generation capacity sufficient to meet projected customer demand, plus an additional reserve margin to ensure supplies are adequate if actual demand exceeds projections. Wisconsin's largest investor-owned utilities' total aggregated capacity exceeds seasonal reserve requirements in both 2025 and 2026.

Wisconsin electric providers seek to provide reliable electric supply by limiting both the frequency and duration of service outages. In 2025, the average customer of the state's five largest utilities experienced slightly more than one outage per year, with an average duration of approximately 3 hours and 58 minutes.

Historically, coal made up the largest share of electricity generation in Wisconsin, the proportion of total state-wide energy produced by coal decreased from approximately 54 percent in 2015 to 33 percent in 2025. Natural gas resources increased in generation share from 19 percent in 2015 to 33 percent in 2025 and wind resources increased from 6 percent in 2015 to 9.5 percent in 2025. Solar generation accounted for less than 0.1 percent of the generation mix in 2015 and increased to 6.3 percent in 2025. Nuclear power provides over 15 percent of Wisconsin's electricity generation.

Reduction of carbon dioxide (CO_2) emissions remains a priority for maintaining environmentally responsible electric service, due to the primary role of CO_2 emissions in contributing to climate change. Governor Tony Evers and each of Wisconsin's five largest electric providers have established goals to achieve 100 percent reductions in CO_2 emissions from electricity providers by 2050. Wisconsin electric providers reported CO_2

[1] WPL application for an Individual Contract Rate Electric Service Agreement, stated maximum contract demand. Pg. 1. (PSC REF#: 589144)

[2] https://finance.yahoo.com/quote/WEC/earnings/WEC-Q2-2026-earnings_call-660815.html?guccounter=1

emission reductions of 39 percent in 2025 compared to the 2005 emission levels commonly used as a baseline. Coal facilities accounted for more than 67 percent of CO_2 emissions from provider-owned facilities, driven by coal generation's significant annual electricity generation output and its higher emissions rate compared to natural gas, which accounted for over 30 percent of state-wide CO_2 emissions.

Future Electricity Generation in Wisconsin

Wisconsin electric providers reported plans to retire approximately 1,100 megawatts (MW) of in-state generation between 2025 and 2032. Providers plan to fully retire Oak Creek, one of the seven utility-scale coal facilities currently still operating in Wisconsin and which has a remaining capacity of approximately 640 MW, after two of the units at the site already retired at the end of 2024. In April 2026, We Energies announced full retirement of the remaining Oak Creek units would be delayed until the end of 2027.[3] The Oak Creek coal units will be replaced by natural gas fired combustion turbine units, a construction project approved by the Commission in 2025.[4] The retiring Wheaton units listed below will also be replaced by new electric generation units with natural gas fueled resources at the same site, as previously approved by the Commission in 2024.[5]

Wisconsin electric providers also reported plans to retrofit approximately 3,400 MW of existing electric generation facilities to burn natural gas instead of coal by 2032.

Plans to add approximately 14,400 MW of new nameplate capacity were reported by Wisconsin electric providers, including 5,835 MW of new solar energy capacity, 5,230 MW of new natural gas capacity or upgrades to existing natural gas facilities, nearly 1,420 MW of new wind capacity, and approximately 1.900 MW of energy storage capacity, 1,200 MW of which is expected to be paired with existing solar energy installations, by 2032.

If all additions and retirements are implemented as planned, coal will decline from 31 percent of Wisconsin generation in 2024 to 2percent in 2032, natural gas will increase from 36 percent to 50 percent, wind will increase from 11 percent to 17 percent, and solar resource will increase from 5 percent to 16 percent.

The exact way in which energy infrastructure will be built out to meet the significant forecast load increases outlined above and the planned generation retirements discussed in this section, is not fully known. In Wisconsin, utilities and generation providers independently choose the types of generation projects they will pursue to meet customer demand. While utility regulatory agencies in many states use Integrated Resource Planning (IRP) or other long-term planning processes to review energy providers'

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[3] We Energies delays retirement of aging Oak Creek coal units to the end of 2027 - WPR.
[4] Final Decision in docket 6630-CE-317 (PSC REF#: 552626)
[5] Final Decision in docket 4220-CE-185 (PSC REF#: 504195)

generation and capital spending plans, and in some cases to exercise regulatory authority over final addition and retirement decisions, in Wisconsin, there is no IRP process and the Commission does not prescribe the type of generation resource power providers retire or seek approval to build.

IRP processes are typically established through legislative authorizations, which do not currently exist in Wisconsin. In the late 1990's, the Wisconsin Legislature moved away from Wisconsin's prior IRP process and replaced it with the SEA. To support more transparent resource planning within Wisconsin's existing regulatory construct and SEA process, Commission staff request additional information from providers on their resource planning analysis associated with announced additions and retirements and incorporated independent staff analysis on statewide resource planning consideration.

Electric providers reaffirmed their own internal resource planning incorporates the four goals of adequacy, reliability, affordability, and environmental responsibility. Multiple providers also identified that their goals included maintaining a diverse set of generation sources located in Wisconsin and controlled by the providers, to support adequacy and reliability as well as pursue additional goals to maintain rate stability and support resiliency. While no electric providers provided capacity expansion plan modeling results for this specific SEA, all providers have been performing some type of resource plan modeling for their individual needs, some with relative frequency due to the changing nature of the electric system landscape and shifting regulatory and policy priorities. Thus, all providers have some form of modeling pertaining to their respective future plans, some details of which have been shared for the purposes of analysis in this SEA.

Commission staff conducted capacity expansion modeling under a variety of different sensitivities with associated input parameters and identified the lowest cost set of generation sources that serve customer load and meet adequacy and reliability standards, while achieving any applicable CO_2 reduction targets. In the Net Zero emissions by 2050 scenario modeled by staff the model was set to prioritize meeting rapid and significant load growth with resources that maintained emissions reductions on a net zero by 2050 path.

The capacity expansion models selected a significant amount of natural gas initially, only to be replaced by new nuclear capacity in later years. The model selecting new nuclear is likely a result of prioritizing the need for significant amounts of emissions free baseload generation in a Net Zero by 2050 scenario. Additionally, for this more aggressive decarbonization scenario, modeling also identified the need for "clean flex" resources. "Clean flex" resources have the dispatchability of reciprocating internal combustion engine (RICE) units but have high fuel costs and zero carbon emissions. Equivalent technology could include reserved battery storage, traditional RICE units coupled with carbon capture and sequestration, RICE units powered by hydrogen and any combination

of the previously mentioned technologies. The clean flex units are selected by the model during the transition period from natural gas units to new nuclear, as shown in Figure 2-8.

These planning considerations and cost assumptions may evolve over time if cost profiles for existing resources change or if future technological developments, such as long-duration energy storage or emerging nuclear technologies, support the emergence of other cost competitive generation options.

Clean Energy Programs and Policies

Focus on Energy (Focus), Wisconsin's statewide energy efficiency and renewable resource program, provides a portfolio of programs to help customers reduce their energy use. In 2024 and 2025 combined, Focus achieved energy savings equivalent to the amount of energy needed to power nearly 1.3 million typical Wisconsin homes for a year, and reduced CO_2 emissions by 12.8 million tons. Evaluations of Focus programs show these impacts were achieved while also maintaining a high level of customer satisfaction. A 2025 study analyzed Focus savings potential under alternative policy scenarios and concluded that there are significant cost-effective energy savings that can be achieved beyond what current program funding will support.[6] The study found that Focus's current budget and program approach are expected to capture 50 percent of available savings.

Wisconsin electric providers operate demand response programs that provide customers with incentives to reduce energy demand during peak periods, to support reliability and create financial savings for providers and customers. Wisconsin electric providers reported more than 140,000 customer enrollments in interruptible tariffs and direct load control programs, including more than 100,000 at Dairyland Power Cooperative's (DPC) member cooperatives.

Demand response capacity available through those offerings totaled 701.37 MW in 2025, equal to approximately 5 percent of Wisconsin's total peak demand during the period. Interruptible tariffs accounted for approximately 80 percent of available capacity reduction opportunities in each year, and direct load control programs accounted for the remaining 20 percent. Wisconsin providers have dispatched a limited fraction of their available demand response capacity in recent years, reflecting that demand response offerings are often only utilized under specific conditions, such as during emergency grid conditions or certain economic conditions.

Historically, a primary driver for utility-scale renewable resource development by Wisconsin electric providers has been compliance with Wisconsin's RPS law. However, declining project costs, combined with increasing customer interest, as well as the

[6] 2021 Focus on Energy Quad V Planning Study (2027-2030): Assessment of Energy Savings Potential. December 2025. Cadmus. (PSC REF#: 571434)

benefits of renewables in helping meet emissions reductions goals, have driven renewable energy deployment beyond Wisconsin's RPS requirement. Three separate factors have contributed to this increase: greater deployment of utility-scale renewable facilities, growth in provider offerings such as community solar programs, and increased installations of customer-owned renewables. Wisconsin had 27,152 customer-owned renewable generation installations in the state as of 2025, totaling 464 MW of capacity. Customer-owned solar alone totaled 318 MW in 2025, up from 201 MW in 2023 and 137 MW in 2021.

Increasing adoption of EVs may have 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. The number of EVs registered in Wisconsin as of June 2025 totalled 35,052 which is significantly more than the 25,457 reported in June 2024, and the 17,084 reported in June 2023. The Wisconsin Department of Transportation (WisDOT) has been tasked with administering the funds available through the National Electric Vehicle Infrastructure (NEVI) program. Under Wisconsin's program, referred to as the Wisconsin Electric Vehicle Infrastructure (WEVI) Program, the state is eligible to receive approximately $78 million in NEVI formula funds over five years beginning in federal fiscal year 2023. In November 2025, WisDOT announced Round 1.5 WEVI Awards, allocating approximately $14 million in NEVI funds to 26 additional charging station locations across the state to fill gaps and advance corridor build-out, bringing the total awards to more than 78 projects funded under the WEVI Program to date.

Electric Transmission in Wisconsin

Wisconsin electric providers and transmission owners participate in MISO's regional transmission system, which is an integrated electric grid across 15 states that supports long-distance transmission of electricity. Participating in MISO allows Wisconsin to access low-cost energy resources located in nearby states through wholesale electricity markets and affords an opportunity to access additional resources that providers may use to maintain adequate electric supply and increases reliability of electric service by pooling risk over a broader geographic footprint.

Due to increased transmission line development and construction costs, transmission expenses have significantly increased since 2005 and accounted for an increasing portion of electric providers' total operating expenses and customer bills. A key factor has been the implementation of MISO's Multi-Value Project (MVP) portfolio, a set of large-scale transmission projects approved by MISO in 2011 to alleviate congestion caused by rapid growth in wind generation. More recently, MISO has identified the need for additional long range transmission projects to reliably move energy across the MISO region for all hours of the year while accommodating changes to the planned resource mix such as generation

plant retirements and significant amounts of new generation additions, and expected load increases throughout the region.

To date, MISO has approved two additional "Long Range Transmission Planning (LRTP) Tranches" of MVP portfolios, each with projects in Wisconsin. Projects approved by the MISO Board require the affected transmission owner(s), selected developer(s), or other designated entities to design, plan, and seek any required state or federal regulatory approvals. High voltage transmission lines going through Wisconsin are required to receive Commission approval under state law prior to any construction occurring in the state.[7] The transmission line review process involves rigorous reporting and analysis, as well as opportunities for public participation.

Tranche 1 projects to be sited partially or completely in Wisconsin have been approved by the Commission under dockets 1515-CE-103, 5-CE-158, and 5-CE-157, respectively, with expected in-service dates between 2028 and 2030. Tranche 2.1 projects to be sited partially or completely in Wisconsin are being developed and are expected to come before the Commission for construction approval. MISO is expected to develop other large-scale transmission projects through the LRTP process in the future.

Customer Rates and Bills

One of the Commission's key responsibilities as the utility regulator is to set rates so that customers receive reliable power at the lowest cost under applicable law, thus supporting affordable electric supply. In this process, the Commission also grants utilities a fair opportunity for recovery of and reasonable return on prudent investments. Total revenue requirements for Wisconsin's largest electric providers increased 4.16 percent per year between 2015 and 2024, driven primarily by increased costs for generation and distribution, which in turn was associated with continued provider investments in generation resources and distribution infrastructure.

National data shows that Wisconsin had an average 2025 residential energy charge of approximately 18 cents per kilowatt-hour (kWh). Average charges in the Midwest were approximately 15 cents per kWh and National averages were approximately 17 cents per kWh. However, Wisconsin residential customers pay less on their average monthly bills, due to lower average levels of energy use. Comparisons between states should be made cautiously due to differences in energy market conditions, regulatory frameworks, and regional geography and climate.

Many Wisconsin providers offer innovative rate options designed to help customers exercise control over their costs and reduce their energy bills. For example, approximately 38,000 customers of investor-owned and municipal electric utilities, or 1.49 percent of all

[7] Wis. Stat. § 196.491

residential customers, are currently enrolled in residential time-of-use (TOU) rates. Total TOU enrollment has increased by approximately 7,000 customers since 2018. TOU 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.

Energy Affordability

Low- and moderate-income residential customers often face challenges paying their utility bills, due to a higher energy burden, in which they must pay a larger percentage of their total income for service as compared to higher-income customers. The Commission has increased its efforts to assess energy burden, review affordability programs, take regulatory action, and expand the options available to help customers address affordability challenges.

In September 2020, the Commission ordered every utility in the state to submit an arrearage management plan (AMP) to the Commission by January, 2021. Then, in 2021, the Commission directed that large utilities provide detailed energy burden information in their annual reports to the Commission. Information shows that energy burden varies throughout geographic regions of the state, particularly when looking at smaller geographic areas such as census tracts. The Commission continues to work with utilities to improve collection and analysis of energy burden data. Other indicators of whether energy bills are affordable can include the amount of arrears, the uptake of energy assistance programs, and the number of customers receiving disconnection notices and disconnections of service. In 2022, the Commission began requiring large utilities to report annually on disconnections, disconnection notices, and arrears. The Commission opened investigation dockets[8] into ways to improve affordability for customers for four of Wisconsin's Investor-Owned Utilities (IOU) and is working with utilities and stakeholders on exploring options to reduce energy burden for those most impacted.

Regulated electric and natural gas utilities in Wisconsin are required to offer Deferred Payment Agreements (DPA)to residential customers, allowing those customers to provide a down payment on unpaid bills and arrange an installment plan to pay the remaining balance.[9] The state's largest electric providers offer additional low-income assistance programs, many of which are AMP that forgive portions of participants' overdue utility bills under certain conditions.[10] Electric providers and Commission staff also refer customers facing affordability challenges to available governmental community assistance programs, including state energy assistance benefits administered by the Wisconsin Department of

[8] Dockets 5-UI-121, 6690-UI-101, 6680-UI-100, and 3270-UI-101
[9] See Wis. Admin. Code §§ PSC 113.0404, PSC 134.063.
[10] See Wis. Admin. Code §§ PSC 113.0505, PSC 134.13(5).

Administration (DOA) and energy efficiency offerings available through Focus, the Inflation Reduction Act (IRA) Home Energy Rebate (HER) programs, and other programs.

Chapter 1 – Electricity Generation in Wisconsin Today

Wisconsin electric providers must balance multiple goals to provide:

- **Adequate** electric supply that maintains sufficient total power to meet customers' total electric demand (i.e. resource adequacy);[11]
- **Reliable** electric supply that provides all customers access to electricity at all times, avoiding outages whenever possible;[12]
- **Affordable** electric supply that offers adequate and reliable energy at the lowest feasible cost for customers; and
- **Environmentally responsible** electric supply that minimizes the negative effects of electric generation on the natural environment.

Wisconsin, much like the rest of the country, has seen a transition in its electric supply since the 2010s to present. As once emergent renewable energy technologies became more cost-effective, and the environmental impacts of energy generation became a global priority, Wisconsin experienced an increase in the adoption of renewable energy generation sources like wind and solar. Over the same time-period, the share of natural gas generation increased as coal fired generation declined, with no plans for new coal generation and the phased retirement of many existing coal generators, largely due to environmental concerns and increasing operating costs.

The energy landscape is again changing in Wisconsin, as the emergence of large data center loads and, to a lesser extent, the move toward electrification of heating and the growth of EVs, is dramatically increasing energy supply needs in the near-term. This rapid and considerable forecast growth in energy demand will require unprecedented energy supply and related transmission and distribution system infrastructure investments.

Defining Supply Needs

To ensure adequate electric supply, Wisconsin electric providers must procure enough total power to meet customers' demands at all times. One of the ways electric providers plan to meet customer demand is by constructing resources to meet their customers'

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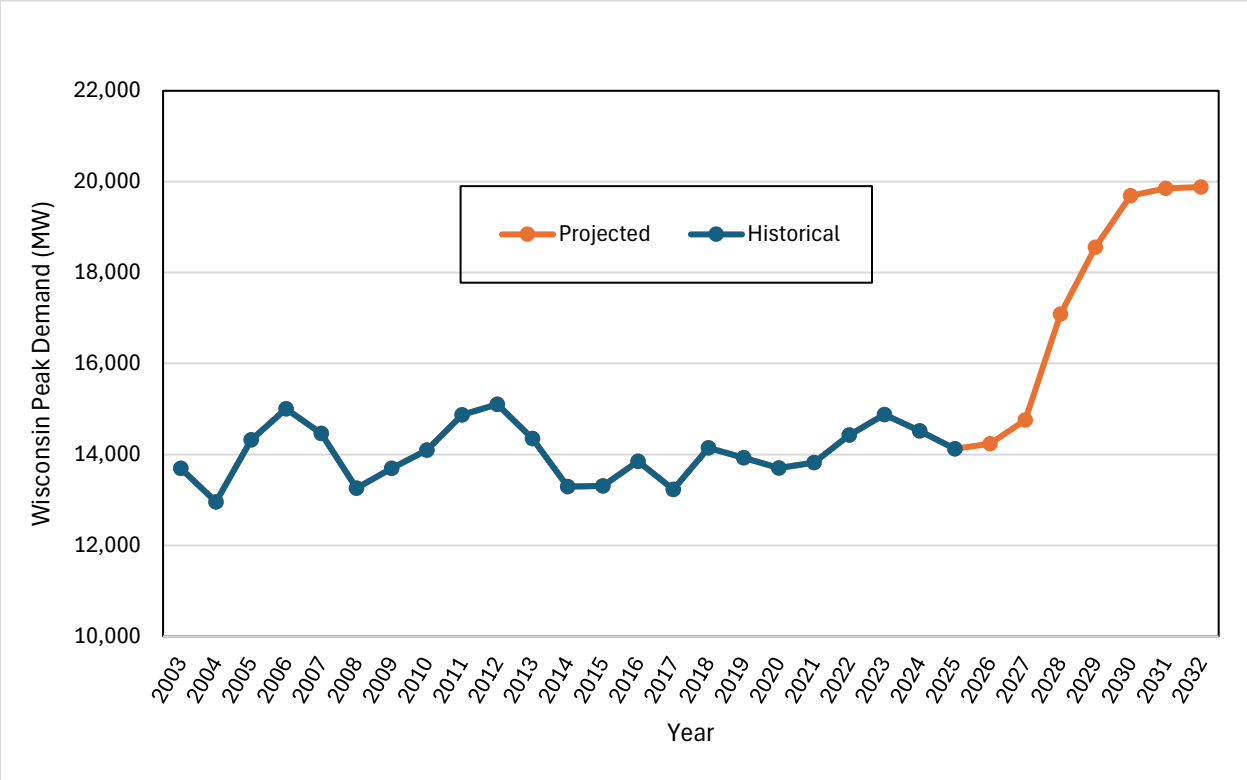
[11] Variations of this definition exist. The National Association of Regulatory Utility Commissioners NARUC define resource adequacy as a "measure of whether there are sufficient electric resources available to serve customer demand." pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3. MISO more specifically defines resource adequacy as the "ability of the bulk electric system to serve electricity demand while also providing enough excess supply to achieve a threshold level of grid reliability." MISO Draft Resource Accreditation Design White Paper628865.pdf (misoenergy.org).

[12] MISO's current Loss of Load Expectation (LOLE) on an annual basis is one-day loss of load in 10 years (0.1 day/year), which is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year). To align with its seasonal construct, MISO further distributes the annual 0.1 LOLE across its four seasons.

forecasted seasonal peak demand, which are the highest levels of electric demand that could occur at any point during a given year, plus a percent reserve margin. Prior to MISO's shift to a seasonal construct, which it began using in the 2023-2024 Planning Year, providers were only required to procure enough total power to be able to meet an annual peak demand, which typically occurred in the summer. Regardless of the shift to a seasonal construct, an analysis of historical and annual peak demand provides general information on annual trends in customer demand.

Figure 1-1 shows Wisconsin peak load is expected to grow from approximately 14.2 GW in 2026 to 20 GW by 2032, an increase of nearly 5.8 GW, or over 40 percent, in a six-year period. Approximately 4.12 GW,[13, 14] or approximately 71 percent, of this peak load increase is associated with three active data center developments in the service territories of two Wisconsin utilities, namely WP&L and WEPCO. These load forecasts illustrate the impact data center development is anticipated to have on the energy landscape in Wisconsin in the coming years.

Figure 1-1 Historical and Forecasted Maximum Peak Demand by Year, MW



[13] WP&L application for an Individual Contract Rate Electric Service Agreement, stated maximum contract demand. Pg. 1. (PSC REF#: 589144)

[14] https://finance.yahoo.com/quote/WEC/earnings/WEC-Q2-2026-earnings_call-660815.html?guccounter=1

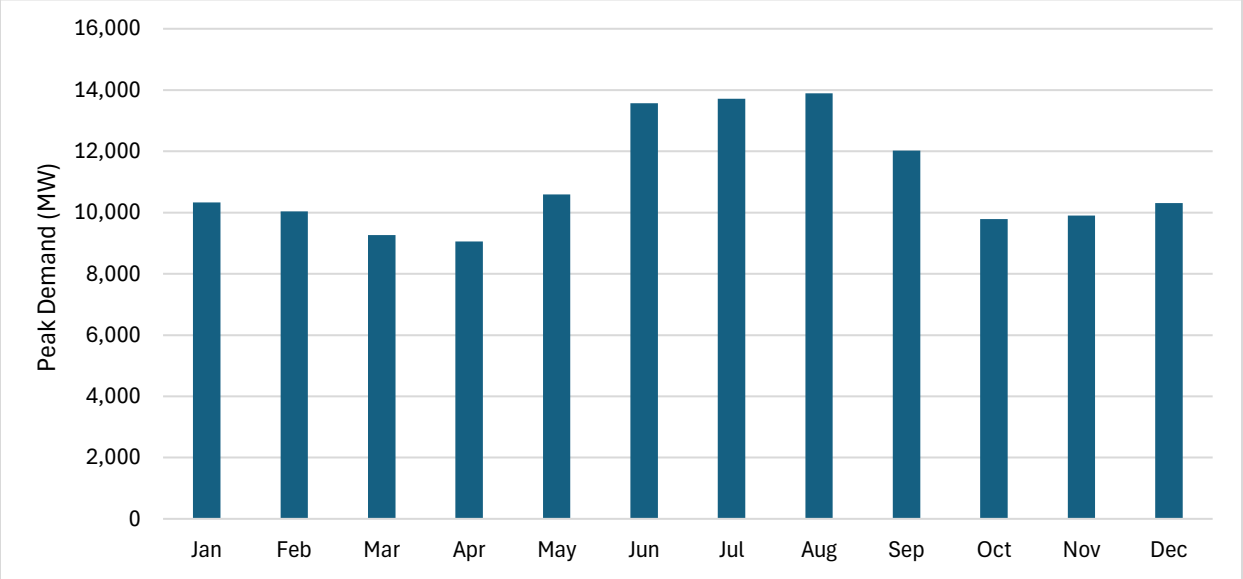
While Figure 1-1 accounts for data center projects already under active development, Wisconsin utilities indicate that data center developers are considering additional prospective data centers across the state, suggesting additional increases to peak load beyond the forecasts provided in Figure 1-1 may be realized in the future if some of these prospective projects proceed to construction.

Table 1-1 Utility Reported Expected Maximum Annual Peak Demand, with Percent Change from Previous Year

Year	Maximum Monthly Peak Load (MW)	Percent change from previous year (%)
2023	14,873	-
2024	14,516	-2.40%
2025	14,126	-2.69%
2026	14,234	0.77%
2027	14,760	3.69%
2028	17,086	15.76%
2029	18,559	8.62%
2030	19,694	6.12%
2031	19,852	0.81%
2032	19,883	0.16%

As shown in Figure 1-2, peak demand for the years 2021 to 2025 occurred in the summer months of June, July, and August, influenced largely by air conditioner use. Smaller peaks occurred in the winter, in part due to higher heating loads, fewer daylight hours, and the use of holiday lighting.

Figure 1-2 Average Non-Coincident Peak Demand per Month, 2021-2024



Reserve Margins and Total Required Electric Supply

Forecasts of energy demand coincident with the region's peak serves as the foundation for determining the amount of electricity supply needed to meet customer demand in each season. To account for uncertainties, adequate supply must include resources above projected peak levels to reduce the risk of loss of load events (i.e., blackouts) resulting from insufficient generation. The capacity above co-incident peak is known as a reserve margin.

Wisconsin electric providers generate and purchase energy supplies within MISO, which operates an integrated electric grid across Wisconsin and several other states. (See *Chapter 4 – Electric Transmission in Wisconsin* for more information on MISO.) Wisconsin electric providers assess capacity supplies relative to MISO's Planning Reserve Margin (PRM), a value determined through statistical modeling designed to identify the amount of excess capacity necessary to minimize the probability of loss of load events. The PRM, a percent, is directly related to a corresponding quantity in MW called the PRM Requirement (PRMR). MISO's modeling considers a range of scenarios and weather patterns. MISO publishes the study results with the PRM values in its annual Loss of Load Expectation (LOLE) report.[15]

MISO received Federal Energy Regulatory Commission (FERC) approval to adopt a Reliability-Based Demand Curve (RBDC) in June 2024. The RBDC was first implemented in MISO's Planning Resource Auction (PRA) in 2025. MISO stated its intention with the RBDC was to establish a mechanism to price capacity in a way that better reflects its value and in turn support resource investment and retirement decisions through improved price signals. The RBDC allows MISO to clear capacity beyond what would be cleared just based on the PRM. Therefore, MISO now calculates an Initial PRMR, based on the PRM, and a Final PRMR, based on the RBDC clearing price. The Initial PRMR is directly tied to MISO's LOLE study as it is the result of multiplying the PRM (a percentage) and the forecasted co-incident peak demand for each season. In contrast, the Final PRMR is rooted in MISO's process to establish a seasonal capacity price signal. Therefore, the SEA analyses related to resource adequacy all reference the Initial PRMR as a point of reference, as it is the value directly tied to the PRM and MISO's LOLE study, rather than financial incentives.

MISO's PRM is tabulated in Table 1-2 for years 2025 and 2026. Wisconsin largest investor-owned utilities' total aggregated capacity[16] exceeds seasonal reserve requirements in both 2025 and 2026. (More detailed reserve margin calculations, including projections for

[15] Planning Year 2026/2027 Loss of Load Expectation Study Report, MISO; https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf

[16] Data from Madison Gas and Electric, Wisconsin Electric Power Company, Wisconsin Public Service Corporation, Northern States Power Company, and Wisconsin Power and Light was compiled into Table 1-2.

future years, can be found in Appendix A, Table A-2.) These figures show that in all seasons in 2025 and 2026, Wisconsin providers had capacity above the Initial PRMR.

Table 1-2 Wisconsin Aggregated Supply and Demand, MW

Year[17]	Season	2025	2026
Projected Net Capacity (MW)[18]	Summer	14,240	14,546
Forecasted Peak Demand (MW)[19]	Summer	11,644	11,827
WI Utilities' Initial PRMR (MW)	Summer	12,709	12,949
Resources above Initial PRMR (MW)	Summer	1,531	1,597
MISO PRM (%)	Summer	7.9%	7.9%
Projected Net Capacity (MW)	Fall	13,910	13,892
Forecasted Peak Demand (MW)	Fall	9,948	10,044
WI Utilities' Initial PRMR (MW)	Fall	11,585	11,408
Resources above Initial PRMR (MW)	Fall	2,324	2,484
MISO PRM (%)	Fall	14.9%	11.6%
Projected Net Capacity (MW)	Winter	12,847	13,071
Forecasted Peak Demand (MW)	Winter	8,556	8,986
WI Utilities' Initial PRMR (MW)	Winter	10,265	10,910
Resources above Initial PRMR (MW)	Winter	2,582	2,160
MISO PRM (%)	Winter	18.4%	18.9%
Projected Net Capacity (MW)	Spring	13,879	14,860
Forecasted Peak Demand (MW)	Spring	9,083	9,504
WI Utilities' Initial PRMR (MW)	Spring	11,524	11,914
Resources above Initial PRMR (MW)	Spring	2,354	2,946
MISO PRM (%)	Spring	25.3%	23.4%

Electric providers have stated their own internal resource planning seeks to meet minimum resource adequacy requirements, while avoiding building excess capacity that could increase costs to ratepayers. Chapter 2 outlines providers' announced future generation retirements and additions and assesses the project impacts of those plans on resource adequacy in future years. In addition, Appendix A: Table A-2 shows Wisconsin's projected seasonal aggregated supply and demand between 2026 and 2032.

[17] MISO Planning Years run from June 1 to May 31. Listed years represent the first calendar year in the planning year (i.e. PY 2025 is June 1 2025-May 31, 2026).

[18] Net capacity numbers include projected future generation reported by utilities and projected net imports and exports; whether and when the resource additions are implemented may vary based on factors including federal and state regulatory approvals and construction timelines.

[19] Defined by MISO as coincident Load Serving Entity (LSE) peak to MISO peak gross of demand response net Full Responsibility Transaction (FRT).

Reliability

All electric providers in the U.S. assess reliability using three standard metrics defined by the Institute of Electric and Electronic Engineers:

- **System Average Interruption Duration Index** (SAIDI), which identifies a utility's average outage duration in a year for each customer served;[20]
- **Customer Average Interruption Duration Index** (CAIDI), which identifies the average outage duration that any given customer would experience, which can also be viewed as the average length of time required for providers to restore service;[21] and
- **System Average Interruption Frequency Index** (SAIFI), which identifies the average number of outages a customer experiences during a year.[22]

The use of multiple metrics provides insight into both the frequency and duration of service outages. A provider experiencing 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.

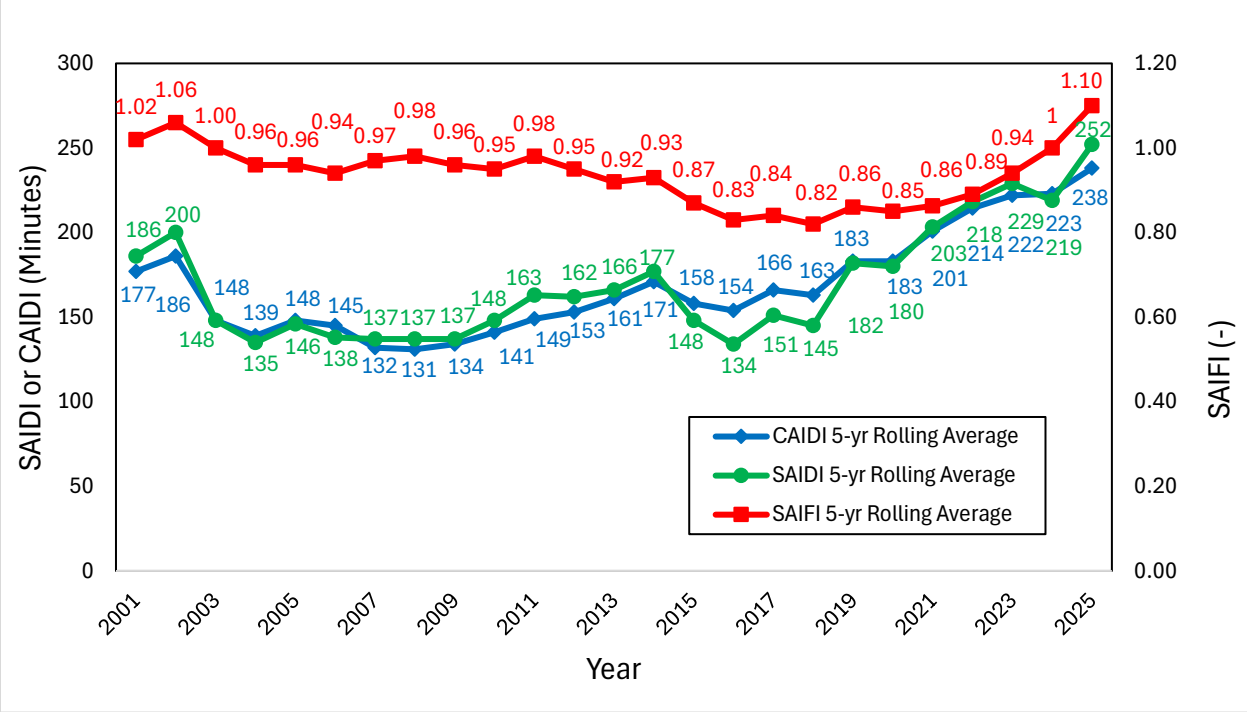
Electric providers with more than 100,000 customers must report annually to the Commission on their performance on the above reliability metrics. Figure 1-3 shows combined SAIFI, SAIDI, and CAIDI since 2001 for the five largest IOUs in Wisconsin subject to the reporting requirement. In 2024, the average customer of the five largest IOUs experienced one outage per year (SAIFI = 1), with an average duration per outage of three hours and 43 minutes (CAIDI = 223 minutes). In 2025, the average customer of the five largest IOUs experienced slightly more than one outage per year (SAIFI >= 1), with an average duration per outage of three hours and 58 minutes (CAIDI = 238 minutes). The average frequency of outages, SAIFI, was trending downwards until 2018, but has been gradually increasing for the last five years. In addition, both SAIDI and CAIDI values have been increasing over the past six years.

All electric utilities must file reports with the Commission documenting significant service interruptions and providing information on their location, duration, and when known, the cause of the interruption. The 2025 Outages Reports submitted by utilities indicate fallen branches, trees, equipment failures, and vehicle collisions as common causes of outages.[23] Additionally, several of the major IOUs identified an increase in vegetation-

[20] SAIDI equals the annual sum of customer-minutes of interruption divided by the total number of customers served during the year.
[21] CAIDI equals the annual sum of customer-minutes of interruption divided by the annual number of customerinterruptions.
[22] SAIFI equals the annual sum of customer interruptions divided by the number of customers served during the year.
[23] Wis. Admin. Code § PSC 113.0606. *See* docket 5-GF-2025.

related outages in relation to increased severe weather events.[24] Providers have reported taking steps to maintain high levels of reliability, including investing in equipment upgrades at locations with aging equipment or a history of reliability issues, seeking improvement to vegetation management practices that reduce the risk of outages from branches, and trees and placing an increasing amount of distribution infrastructure underground.[25]

Figure 1-3 Five-Year Rolling Average SAIFI, SAIDI, and CAIDI Values for Major IOUs



Sources of Energy Supply

Wisconsin electric providers can meet their planning reserve (capacity) requirements by either owning and operating their own generation plants, entering into long-term purchased power agreements (PPA) with other utilities and independently owned "merchant plants," or purchasing electricity from MISO's regional wholesale market, which operates a day-ahead market and a real time market.[26]

Figure 1-4 depicts Wisconsin electric providers' in-state operating resources as of December 2025, including all owned generation facilities and large-scale merchant

[24] Responses to Data Request-PSC-Stein-4 (PSC REF#: 606140, PSC REF#: 606169, PSC REF#: 606123)
[25] Responses to Data Request-PSC-Taylor-1, docket 5-GF-113
[26] Day-ahead markets permit providers to purchase energy one day in advance at binding prices, to procure energy as needed to meet anticipated demand. Real-time markets permit providers to purchase energy as needed during the operating day, at prices based on available supply and demand. While the day-ahead and real time markets serve as theprimary platforms for providers to meet supply needs, MISO also operates transmission rights and ancillary services markets to support grid operations.

plants.[27] (For additional maps broken out by fuel type, see Appendix A, Figures A-1 through A-8.) While this map reflects most Wisconsin-providers' resources, some providers also own or contract with generation facilities in other nearby states. For example, providers received electricity supplies from several wind facilities in MISO region states west of Wisconsin, not pictured in Figure 1-4, where windier conditions exist.

Figure 1-4 Electric Providers' Generation Resources in Wisconsin, December 2025

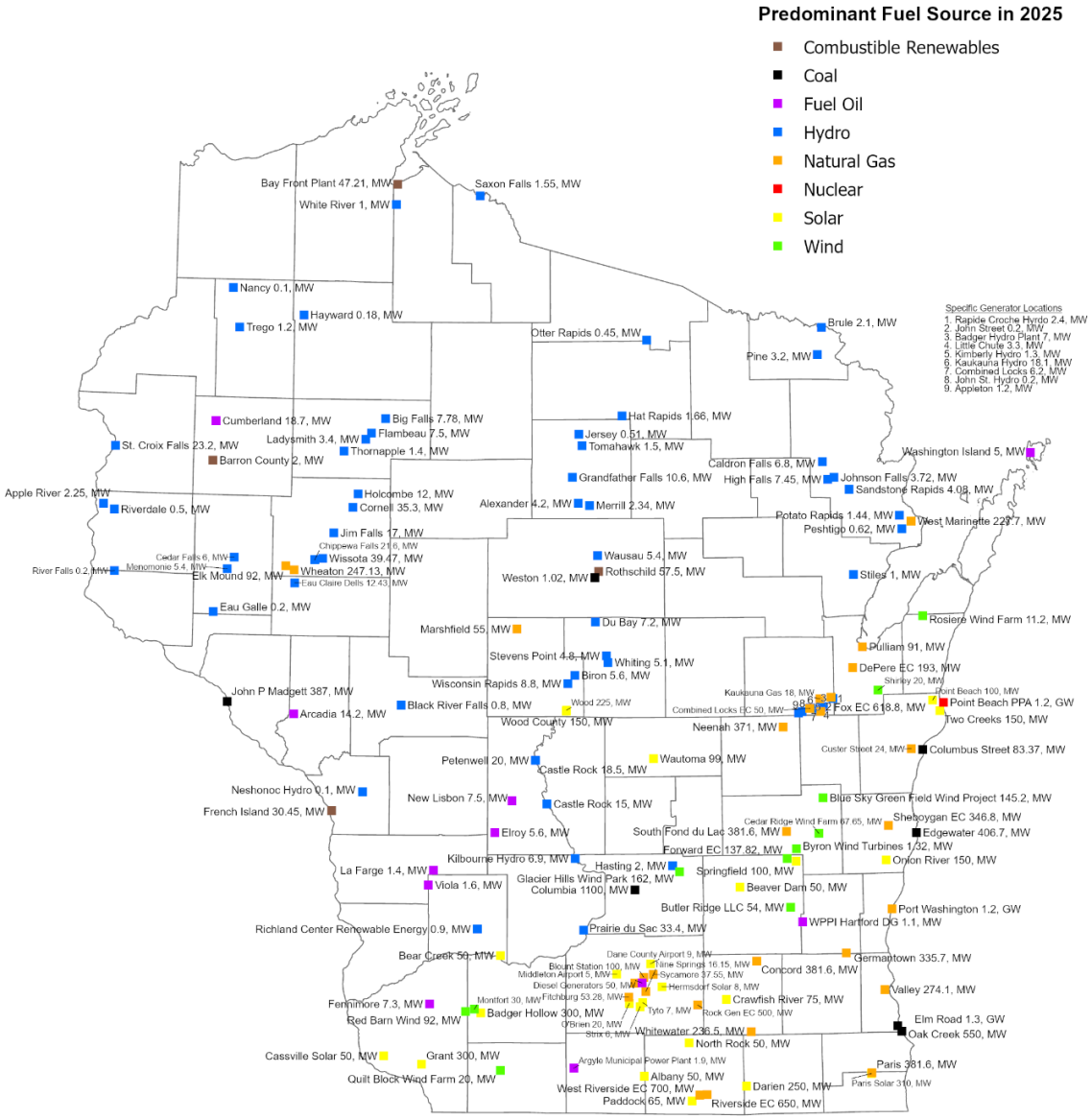


Figure 1-5 breaks down the total capacity of Wisconsin provider-owned and merchant plants generation by fuel source, as of December 2025. Natural gas accounted for the

[27] For simplicity and clarity, the figure does not include merchant plants from which providers report less than 5 MW of capacity purchased.

largest share of total generation capacity at 40 percent, followed by coal at 30 percent. Zero-carbon energy sources accounted for approximately 27 percent of capacity; 10.5 percent from solar energy, 8.1 percent from wind energy, 5.5 percent from nuclear energy, and 3.2 percent from hydropower.

Figure 1-5 Wisconsin Electric Provider Capacity by Resource, 2025

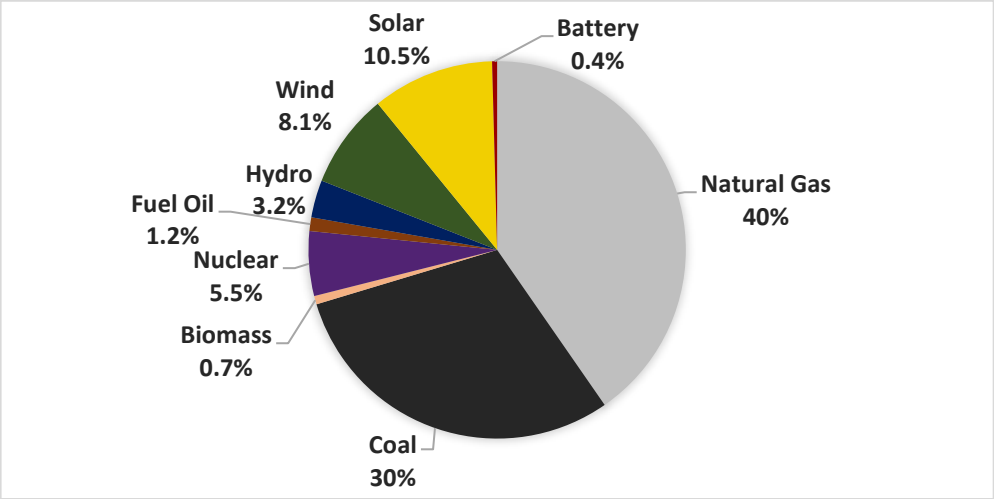
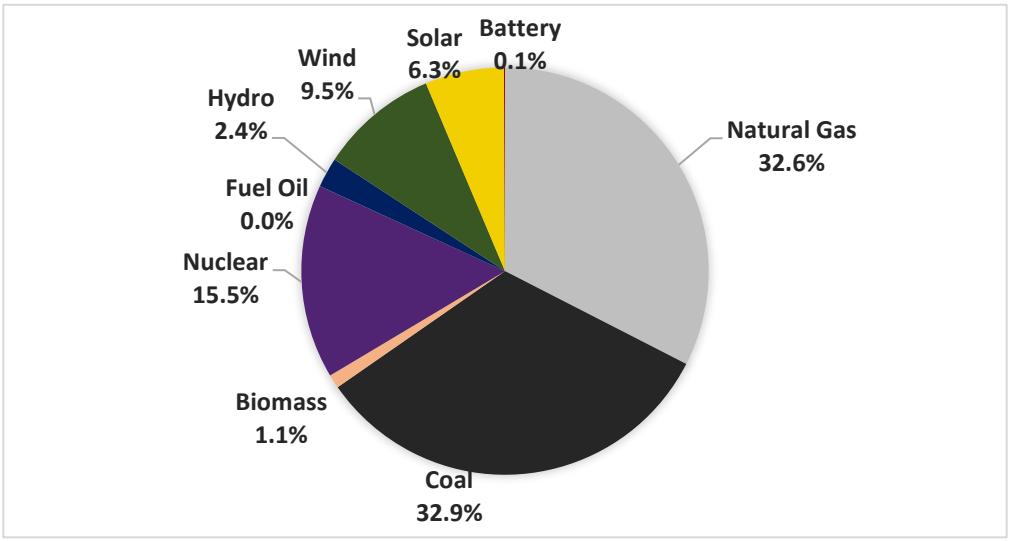


Figure 1-6 depicts each actual energy generation by resource type as of calendar year 2025. Different facilities operate with different capacity factors; a ratio of the actual energy output over a period of time compared to the maximum possible output over that same period. Coal and nuclear energy facilities typically operate on a consistent, ongoing basis, meaning they have a relatively high capacity factor. In 2025, coal facilities accounted for roughly 33 percent of all electricity generated in Wisconsin, natural gas generated roughly 33 percent as well, nuclear energy generated 16 percent, wind generated roughly 6.5 percent, solar 6.3 percent, and hydroelectric 2.4 percent.

Figure 1-6 Wisconsin Electric Provider Energy Generation by Resource, 2025



Emissions

Reduction of CO_2 emissions has emerged as a leading priority for maintaining environmentally responsible electric service, due to the primary role of CO_2 emissions in contributing to climate change. In 2019, Governor Evers issued Wisconsin Executive Order 38, directing utilities and state agencies to work in partnership towards a goal of achieving 100 percent carbon-free electricity consumption in the state by 2050. As shown in Table 1-3, each of the state's five largest electric providers have set their own internal net-zero greenhouse gas emissions by 2050 goal and most have set interim goals to achieve a specified percentage of carbon dioxide reductions by 2030. In the previous SEA, WEPCO and Wisconsin Public Service Corporation (WPSC) reported an 80 percent 2030 CO_2 reduction goal. WEPCO and WPSC have announced they are reconsidering their near-term emissions goals due to a combination of factors, including tightening energy supply requirements and a stated focus on reliable and affordable energy sources.[28, 29] Madison Gas and Electric Company (MGE) has provided a range of near-term emissions reduction trajectories for this SEA while maintaining a long-term goal of net zero emissions by 2050.[30, 31]

Table 1-3 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 Energy, Inc.)	80%	100%
Madison Gas and Electric Company[32]	NA	100%
Wisconsin Electric Power Company	NA	100%
Wisconsin Power and Light Company (Alliant)	50%	100%
Wisconsin Public Service Corporation	NA	100%
Dairyland Power Cooperative	50%	NA

Other Wisconsin electric providers have announced their intent to reduce CO_2 emissions. For example, WPPI is targeting net-zero carbon electricity by 2050, subject to its ability to

[28] WEPCO Response (PSC REF#: 574644); WPSC Response (PSC REF#: 574472)
[29] WEC Investor Update September 2025. Pg. 26. WEC Energy Group
[30] Appendix B Figure B-1 provides MGE's forecasted range of CO_2 emissions from 2024 to 2050.
[31] MGE Response (PSC REF#: 570772)

maintain reliability and affordability. DPC has set a goal to achieve a 50 percent reduction by 2030 in its CO_2 intensity rate.[33, 34]

As it did for the SEA 2030, the Commission collected from all electric providers information on their progress toward achieving CO_2 reductions, compared to the 2005 emission baseline. As shown in Table 1-4, 2025 reported emissions reductions ranged from 6% to 63% relative to 2005 emissions levels. As outlined in individual providers' responses, methods for calculating emission reductions differ. For example, WP&L's goal applies to reductions from its owned generation, while Northern State Power Company-Wisconsin measures emissions from all electricity used to serve its customers, including purchased power. For providers that operate across multiple states, the figures in Table 1-4 reflect their reported Wisconsin share of emissions.

Table 1-4 Carbon Dioxide Reduction for 2025 (% Compared to 2005 Carbon Dioxide Emissions)

Providers	2005 CO_2 Emissions (Million metric tons)	2025 CO_2 Emissions (Million metric tons)	2025 CO_2 Reduction (%)
Northern States Power Company - Wisconsin (Xcel Energy)	4.1	1.5	63%
Wisconsin Electric Power Company[35]	35.7	19.2	46%
WPPI	3.97	2.25	43%
Wisconsin Power and Light Company (Alliant)	8.8	8.273	6%
Madison Gas and Electric Company	3.55	2.2	38%
Dairyland Power Cooperative	4.43	3.873	13%
Manitowoc Public Utilities[36]	0.463	0.217	53%
All Providers	61.01	37.51	39%

[33] The CO_2 intensity rate measures the amount of emissions per unit of energy generated (lbs. CO2/MWh produced).

[34] A primary influence on emissions rates at individual facilities is their generating efficiency, also known as heat rate: the amount of fuel energy consumed per unit of generation produced. Heat rate can vary considerably based on the size of the facility, the frequency (capacity factor) by which the facility runs, and the operating properties of facilities.

[35] Wisconsin Electric Power Company and Wisconsin Public Service Company are subsidiaries of Wisconsin Electric Company (WEC). Carbon emissions are tracked at the WEC energy group level.

[36] In 2024, generation dispatch of MPU's largest solid fuel generation facility was limited to necessary testing and MISO's explicit direction. As a result the CO_2 emissions reported by MPU decreased significantly from MPU's 2022 CO_2 emissions. MPU expects future emissions to be closer to the emissions reported in 2022. (PSC REF#: 574086)

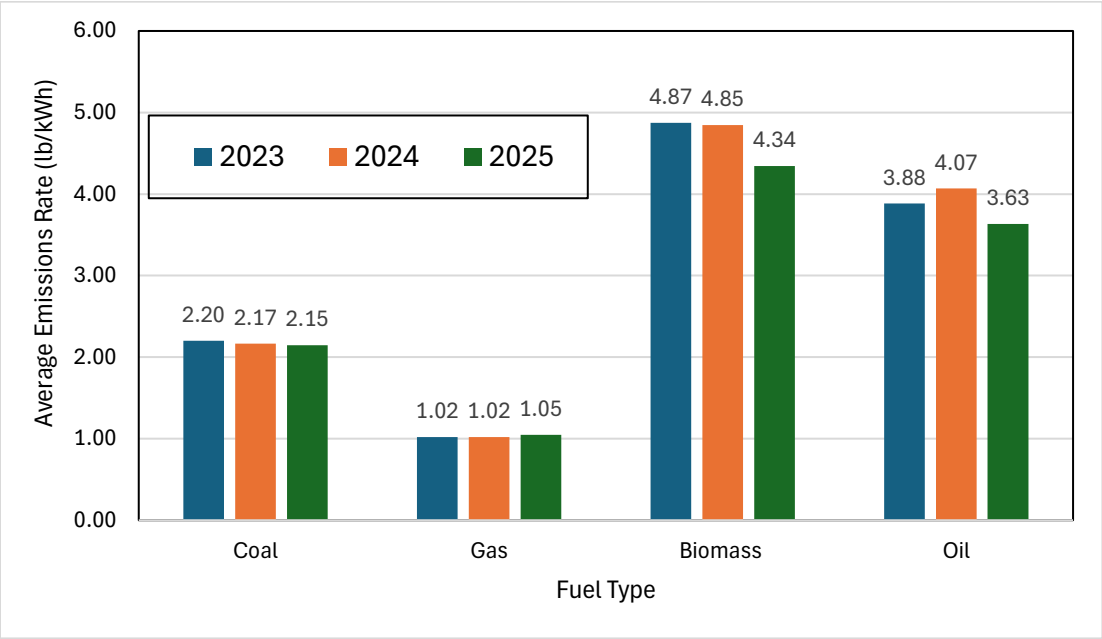
To provide further detail on emissions, electric providers submitted information on the CO_2 emissions for each generation facility owned by Wisconsin providers in 2023, 2024, and 2025. Total emissions of provider-owned facilities provided through this request did not match the emissions reported for calculating percentage reductions above, in large part because many procure a substantial share of their total energy through power purchased from third party providers and include emissions from those sources in calculating their own emission reduction goals and outcomes.

However, reviewing provider-owned facility CO_2 emissions can provide additional insight on provider emission profiles. Total emissions of provider owned facilities reflect the combination of two factors: total electric generation at the facility and the emissions rate, or the amount of CO_2 emitted, per unit of energy generated. As shown in Figure 1-7, CO_2 emissions rates differ significantly by fuel type.[37] Carbon dioxide emissions rates from Wisconsin providers' natural gas facilities equaled approximately 47 percent of the emissions rates from coal facilities in 2024 and 2025. Oil and biomass generation also have higher direct CO_2 emissions rates than natural gas, although their overall impact is limited because they account for a smaller share of total generation. It should be noted that the emissions rates shown in Figure 1-7 do not account for externalities such as emissions associated with fuel extraction and procurement. There may be circumstances in which biomass is grown, harvested, and combusted in a carbon neutral fashion.[38]

[37] Wisconsin providers also report emissions from a small number of biomass facilities. An average is not provided in Figure 1-9 because biomass emissions rates vary significantly across individual facilities, based on the source and production methods of the biomaterial used for generation. See U.S. Environmental Protection Agency, "Greenhouse Gas Inventory Guidance: Direct Emissions from Stationary Combustion Sources," Section 1.2. https://www.epa.gov/sites/default/files/2016-03/documents/stationaryemissions_3_2016.pdf

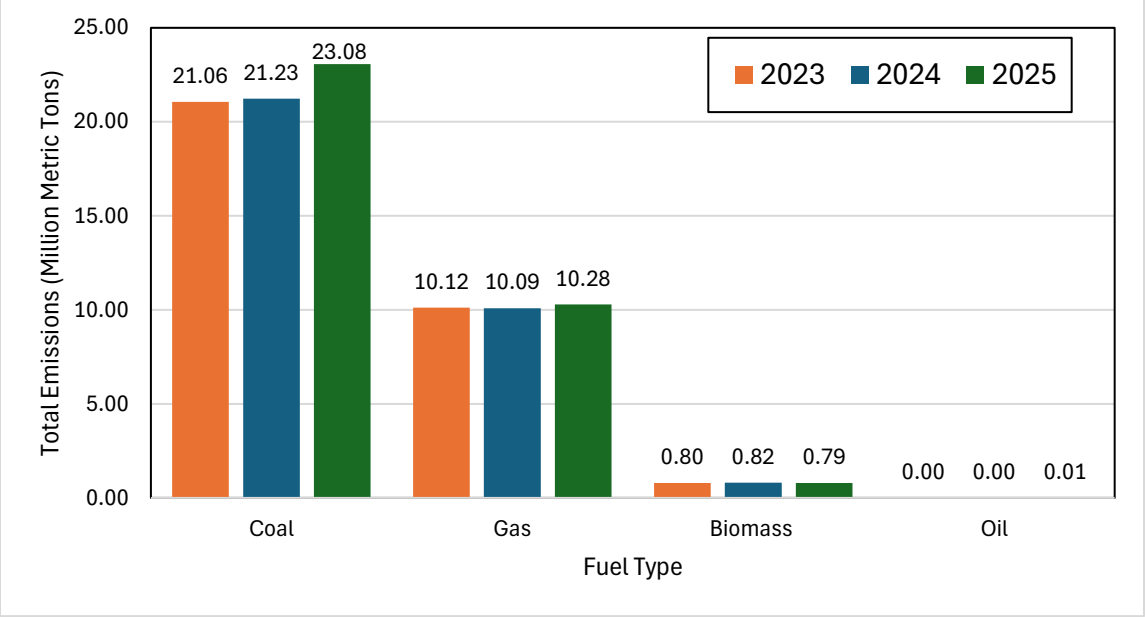
[38] Net emissions rates associated with biomass generation can vary significantly across individual facilities, depending on the specific biomaterial used and its source and production methods. See U.S. Environmental Protection Agency, "Greenhouse Gas Inventory Guidance: Direct Emissions from Stationary Combustion Sources," Section 1.2. https://www.epa.gov/sites/default/files/2016-03/documents/stationaryemissions_3_2016.pdf

Figure 1-7 CO_2 Emissions Rates by Fuel Type at Provider-Owned Facilities, 2023-2025



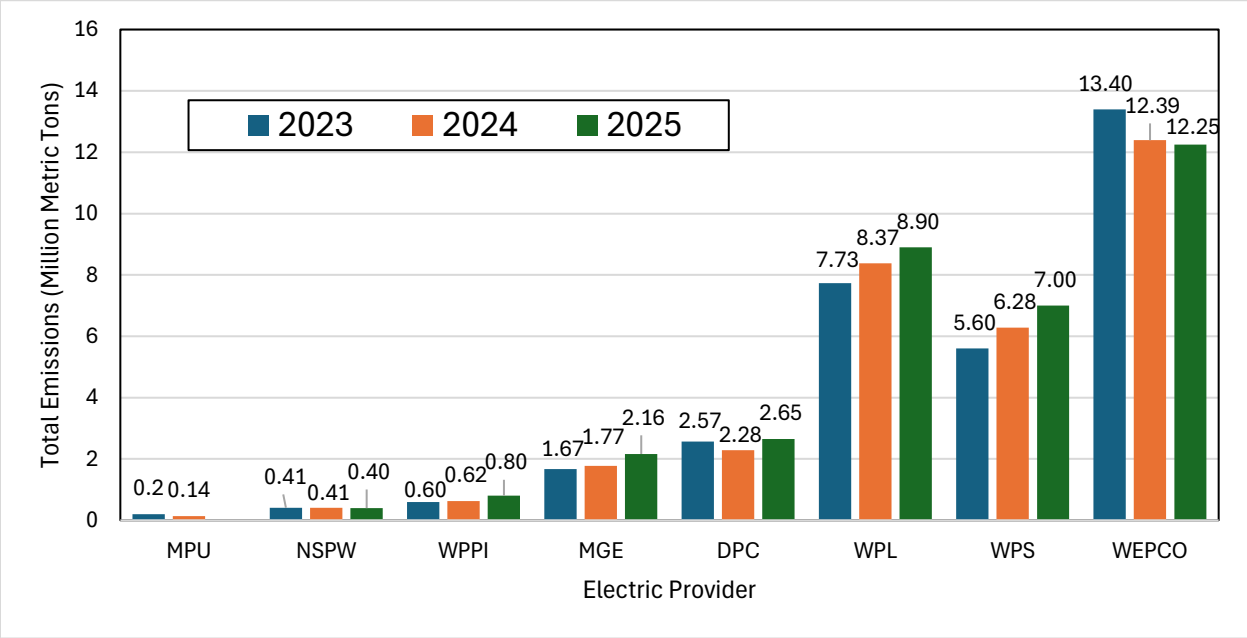
As shown in Figure 1-8, coal facilities accounted for a majority of 2023, 2024, and 2025 CO_2 emissions from provider owned facilities, driven by its status as the largest share of total in-state energy production (see Figure 1-6 above) and its higher emissions rate than natural gas. Overall, CO_2 emissions between 2023 and 2025 have remained relatively stable. This trend is further emphasized in Figure 1-8, where emissions from major fuel type generation units remain relatively stable between 2023 and 2025.

Figure 1-8 Total CO2 Emissions by Fuel Type at Provider-Owned Facilities, 2023-2025



As shown in Figure 1-9, providers' CO_2 emissions from owned facilities largely corresponded with providers' total share of generation. WEPCO, WPSC, and WP&L together accounted for over 82 percent of CO_2 emissions in Wisconsin for 2023, 2024, and 2025. However, differences in emission rates also influence provider comparisons. Appendix A includes more information on emissions rates and individual facilities. As noted above, total emissions by provider may differ from calculations focused on provider-owned facilities, in part because several providers procure a substantial share of their energy from third-party providers.

Figure 1-9 Total Emissions by Electric Provider in WI, 2023-2025



While natural gas generation emits less CO_2 than coal generation, natural gas generation also emits methane, a more potent greenhouse gas that eventually converts into CO_2 through oxidation. MGE has a goal of net-zero methane emissions by 2035. No other Wisconsin utilities have reported any methane specific emissions goals.[39]

[39] Data Request-PSC-Stein-3 (PSC REF#: 578878)

Chapter 2 – Future Electricity Generation in Wisconsin

Wisconsin, much like the rest of the country, has seen a transition in its electric supply since the 2010s to present. As once emergent renewable energy technologies became more cost-effective, and the environmental impacts of energy generation became a global priority, Wisconsin experienced an increase in the adoption of renewable energy generation sources like wind and solar. Over the same time-period, the share natural gas generation increased as coal fired generation declined, with no plans for new coal generation and the phased retirement of many existing coal generators, largely due to environmental concerns and increasing operating costs.

Not two decades later the energy landscape is again changing in Wisconsin, as the emergence of large data center loads and, to a lesser extent, the move toward electrification of heating and the growth of EVs, is dramatically increasing energy supply needs in the near-term. This rapid and considerable growth forecast is anticipated to require significant investment in new and upgraded energy infrastructure.

In light of the large-scale and rapid pace of energy generation changes, this chapter reviews Wisconsin utilities' resource planning analyses used to support announced additions and retirements and provides Commission staff's independent analysis assessing the statewide impacts of generation changes on Wisconsin's electric system.

Generation Retirements and Additions

As shown in Table 2-1, Wisconsin electricity providers reported plans to retire approximately 1,100 MW of in-state generation between 2025 and 2032. Providers plan to fully retire Oak Creek, one of the seven utility-scale coal facilities still operating in Wisconsin, which has a remaining capacity of approximately 640 MW, after two of the units at the site retired at the end of 2024. In April of 2026, We Energies announced full retirement of the remaining Oak Creek units would be delayed until the end of 2027[40]. The Oak Creek coal units will be replaced by natural gas fired combustion turbine units, a construction project approved by the Commission in 2025.[41] The retiring Wheaton units listed below will also be replaced by new electric generation units with natural gas fueled resources at the same site, as approved by the Commission in 2024.[42]

[40] We Energies delays retirement of aging Oak Creek coal units to the end of 2027 - WPR.
[41] Final Decision in Docket 6630-CE-317 (PSC REF#: 552626)
[42] Final Decision in Docket 4220-CE-185 (PSC REF#: 504195)

Table 2-1 Planned Utility-Owned or Leased Generation Capacity Retirement through 2032

Year	Name	Capacity (MW)	Fuel	Owner/Leaser
2025	Wheaton 1, 2, 3, 4, 6	56, 68, 56, 61, 70	Natural Gas and Fuel Oil	NSPW
2027	Rosiere Wind Farm	11	Wind	MGE
2027	Oak Creek 7, 8	318, 324	Coal	WEPCO
2030	French Island 3, 4	157 (total)	Natural Gas	NSPW

The Commission does not have direct authority over power plant retirement decisions. Providers must receive MISO approval to proceed with unit retirements. The generation retirement process at MISO begins when a provider submits an Attachment Y Notice to MISO requesting to either retire or suspend the operations of a unit.

MISO then convenes a retirement study with transmission owners to assess the reliability of grid operations in the absence of that unit. If MISO's analysis concludes that retirement of the unit would not have negative effects on the reliability of the regional grid, it issues an approval of retirement or suspension to the provider. However, if MISO identifies reliability concerns, it designates the facility as a System Support Resource (SSR) which requires the facility to continue operating until a timely alternative to resolve the reliability is presented.[43] While no Wisconsin facilities larger than 100 MW are currently operating as a designated SSR,[44] future retirements could potentially be foregone or delayed in response to findings by MISO that continued operation is needed.[45]

As shown in Table 2-2, Wisconsin electric providers reported plans to retrofit approximately 3,400 MW of existing electric generation facilities to burn natural gas instead of coal by 2032. The largest of these retrofits would take place at the Elm Road Generating Station facility, one or both of the Columbia Energy Center units, Edgewater Unit 5, and Weston Unit 4. If all of these retrofits are completed as planned, only two coal generating sites would remain in Wisconsin as of 2032.

[43] When alternatives are identified, MISO provides an assessment through its Open Access Same-Time InformationSystem (OASIS).

[44] Lakefront Unit 9 previously received an SSR designation, though that designation has since been suspended. https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Lakefront_9_SSR_status_update.pdf

[45] Providers who are considering a retirement or suspension may also opt to submit an Attachment Y2 form to MISO,which requests analysis of the potential adequacy and reliability effects and a nonbinding indication of whether an SSR designation would be considered. Providers who submit Attachment Y2 requests would still need to submit a subsequent Attachment Y Notice to receive formal approval to retire or suspend the facility.

Table 2-2 Planned Utility-Owned or Leased Generation Fuel Switch Retrofits through 2032

Switch Year	Name	Capacity (MW)	Existing Fuel	Proposed Fuel	Owner/Leaser
2029	Elm Road 1, 2[46]	650, 650	Coal	Natural Gas	WEPCO
2030	Columbia 1, 2[47]	566, 565	Coal	Natural Gas	WP&L, WPSC, MGE
2030	Edgewater 5[48]	406	Coal	Natural Gas	WP&L
2030	Weston 4	595	Coal	Natural Gas	WPSC

As shown in Table B-8 and Figure 2-1, Wisconsin providers reported plans to add a total of approximately 14,400 MW of new nameplate capacity, including 5,835 MW of new solar energy capacity, 5,230 MW of new natural gas capacity or upgrades to existing natural gas facilities, nearly 1,420 MW of new wind capacity, and approximately 1,900 MW of energy storage capacity by 2032.[49] Approximately 1,200 MW of the 1,900 MW of storage is expected to be paired with existing solar energy installations, while the remaining 700 MW would be "stand alone" storage, or was not otherwise specified. The Commission has authority over investments in new resources and an outline of the review process used by the Commission for consideration of new construction projects is provided in Appendix B.

Planned generation additions by utility are tabulated in Appendix B[50] and consist of the following overall changes:

- WEPCO reported plans to add 4,079 MW of new solar capacity, 694 MW of new wind capacity, 4,593 MW of new natural gas capacity, and 1,200 MW of new energy storage capacity.
- WPSC reported plans to add 558 MW of new solar capacity, 87 MW of wind electric generation capacity, 28 MW of new natural gas capacity, and 76 MW of energy storage capacity.
- WP&L reported plans to add 100 MW of new solar capacity, 570 MW of new wind capacity, 356 MW of upgraded gas capacities at three existing sites, and 110 MW of new energy storage capacity.
- MGE reported plans to add 349 MW of new solar capacity, 68 MW of new wind electric generation capacity, and 139 MW of new energy storage capacity.

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[46] MGE announces its intent to convert Elm Road Generating Station from Coal to Natural Gas Coal-Fired Generation - Madison Gas and Electric

[47] Wisconsin energy companies announce plan to continue operations at Columbia Energy Center, commit to exploring conversion to natural gas. Alliant Energy - Wisconsin energy companies announce plan to continue operations at Columbia Energy Center, commit to exploring conversion to natural gas

[48] Alliant Energy announces its intent to convert Edgewater 5 to natural gas. Alliant Energy - Alliant Energy takes next step in the company's energy transition

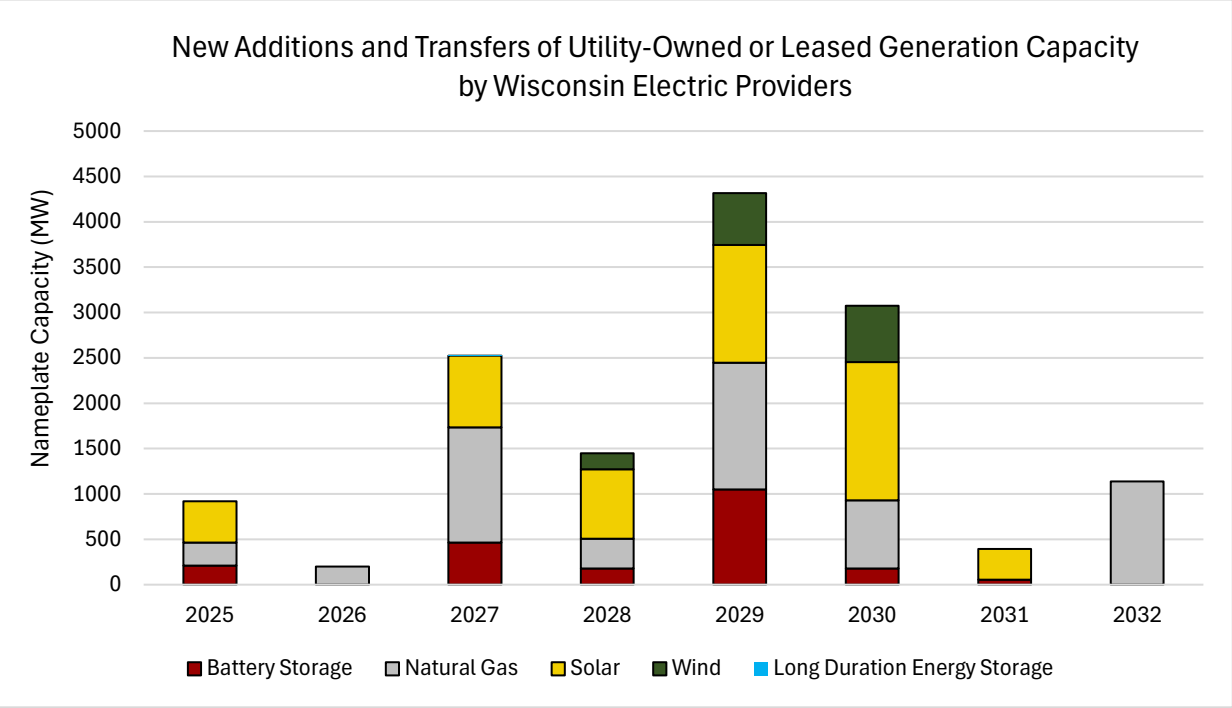
[49] The figure for natural gas capacity does not include the ownership shares of out-of-state providers for 275 MW of the total capacity of the Nemadji Trail Energy Center, which may not be constructed.

[50] For the individual additions, please refer to Table B-8 in Appendix B.

- Northern States Power Company-Wisconsin (NSPW) reported plans to add 600 MW of new solar capacity and 255 MW of new natural gas electric generation capacity, as well as 377 of new energy storage capacity.
- DPC reported plans to add 149 MW of new solar capacity.

Since planned additions were initially reported, providers have announced delays in the completion date of multiple projects, due in part to supply constraints that have delayed materials procurement. Additionally, a number of announced new facilities divide their total capacity between multiple providers through co-ownership arrangements, which are outlined in footnotes to Table B-8 in Appendix B.

Figure 2-1 New Additions and Transfers of Utility-Owned or Leased Generation Capacity by Wisconsin ElectricProviders 2025 through 2032



Effects on Resource Adequacy

Whether or not Wisconsin's electric service providers maintain compliance with reserve margin requirements will be significantly influenced by those providers' additions and retirements. Electric providers' responses to Organization of MISO States (OMS) MISO Resource Adequacy Survey, conducted in 2025 indicated that expected capacity levels throughout the MISO region could be at risk of falling below the local reserve margin requirement in future years. As part of this study, MISO conducts modeling to analyze resource adequacy under different scenarios. MISO provided different methods for projecting levels of future resource additions, such as examining projects with signed Generator Interconnection Agreements, estimating new additions based on historical rates of additions, or basing projected additions on utility plans. In some of these

scenarios, there were shortfalls, but in other scenarios, there were not. In addition to the challenge of making methodological choices that best capture the levels of future resource additions, MISO is developing new methods for how to best forecast demand from large spot loads such as data centers.

For instance, FERC approved MISO's Tariff changes for a new Direct Loss-of-Load (DLOL) accreditation methodology. This method is intended to better reflect resource availability in times of need, and consequently accreditation under DLOL may require utilities to consider different types of resources that must be procured to meet their planning reserve margin requirements, including some resource types they may not have used historically. However, this accreditation methodology has not been incorporated into the PRM and PRMR values listed in Table 2-4 and Figure 2-2 since, MISO's updated accreditation methodology will not be implemented until Planning Year 2028-2029.

The projected seasonal positions of the five largest investor-owned utilities in Wisconsin for the years 2026 through 2032 have been tabulated in Table 2-3.[51] As shown in Table 2-3, the MISO Seasonal PRM is expected to stay relatively consistent in future years for all seasons after increasing slightly in the immediate two years.

As shown in Figure 2-2 and Table 2-3, the five largest investor-owned utilities in Wisconsin project their total potential seasonal generation capacity (taking into account projected additions and retirements) to generally be above MISO's projected Initial PRMR. Wisconsin providers' total potential capacity does appear to fall short of MISO's initial PRMR in winter of 2029. These results may be reflective of significant increasing demand and substantial coal facility retirements, though in recent years such potential retirements have been subject to change.

[51] Data was compiled from Wisconsin's 5 largest investor-owned utilities assuming MISO's current accreditation method for *all* planning years. The MISO accreditation method does not change to Direct Loss of Load until planning year 2028.

Table 2-3 Seasonal Wisconsin Aggregated Supply and Demand, MW

Summer	2026[52]	2027	2028	2029	2030	2031	2032
Projected Net Capacity[53]	14,547	15,554	17,077	18,809	20,999	22,821	23,982
Expected Forecasted Peak Demand[54]	11,827	12,424	14,636	16,460	17,345	17,460	17,489
WI LSE's Initial PRMR (MW)[55]	12,949	13,782	16,439	18,608	19,557	19,669	19,641
Resources above Initial PRMR (MW)	1598	1772	638	201	1442	3151	4342
MISO PRM (%)[56]	7.9%	9.4%	11.0%	12.5%	12.4%	12.3%	12.3%
Fall	2026	2027	2028	2029	2030	2031	2032
Projected Net Capacity	13,893	14,841	16,708	18,006	20,219	21,855	22,508
Expected Forecasted Peak Demand	10,044	11,070	13,004	14,533	15,485	15,537	15,563
WI LSE's Initial PRMR (MW)	11,408	12,755	15,186	17,112	18,166	18,196	18,162
Resources above Initial PRMR (MW)	2484	2086	1522	895	2053	3659	4345
MISO PRM (%)	11.6%	13.4%	15.2%	17.1%	16.9%	16.7%	16.7%
Winter	2026	2027	2028	2029	2030	2031	2032
Projected Net Capacity	13,071	13,640	15,283	15,653	18,271	19,218	19,945
Expected Forecasted Peak Demand	8,987	10,466	12,214	13,587	14,378	14,428	14,453
WI LSE's Initial PRMR (MW)	10,911	12,754	14,934	16,545	17,465	17,457	17,488
Resources above Initial PRMR (MW)	2,160	886	350	-892	806	1,761	2,458
MISO PRM (%)	18.9%	19.7%	20.4%	21.2%	21.1%	21.0%	21.0%
Spring	2026	2027	2028	2029	2030	2031	2032
Projected Net Capacity	14,861	16,167	17,827	19,733	22,904	24,054	24,110
Expected Forecasted Peak Demand	9,505	11,500	12,921	14,220	14,805	14,836	14,858
WI LSE's Initial PRMR (MW)	11,915	14,737	16,941	18,954	19,660	19,599	19,628
Resources above Initial PRMR (MW)	2,946	1,430	887	779	3,244	4,455	4,482
MISO PRM (%)	23.4%	26.5%	29.6%	32.7%	32.4%	32.1%	32.1%

[52] MISO Planning Years (PY) run from June 1 to May 31. Listed years represent the correspond to the calendar year in which a season falls in (i.e. PY 2024-25 is Summer 2024, Fall 2024, Winter 2024, and Spring 2025).
[53] 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.
[54] Defined by MISO as coincident LSE peak to MISO peak gross of demand response net FRT.
[55] Initial PRMR is calculated as described in Section 3.1 of MISO's Business Practice Manual 11: Resource Adequacy.

Figure 2-2a Wisconsin Net Capacity Compared to Planning Reserve Requirements for Summer

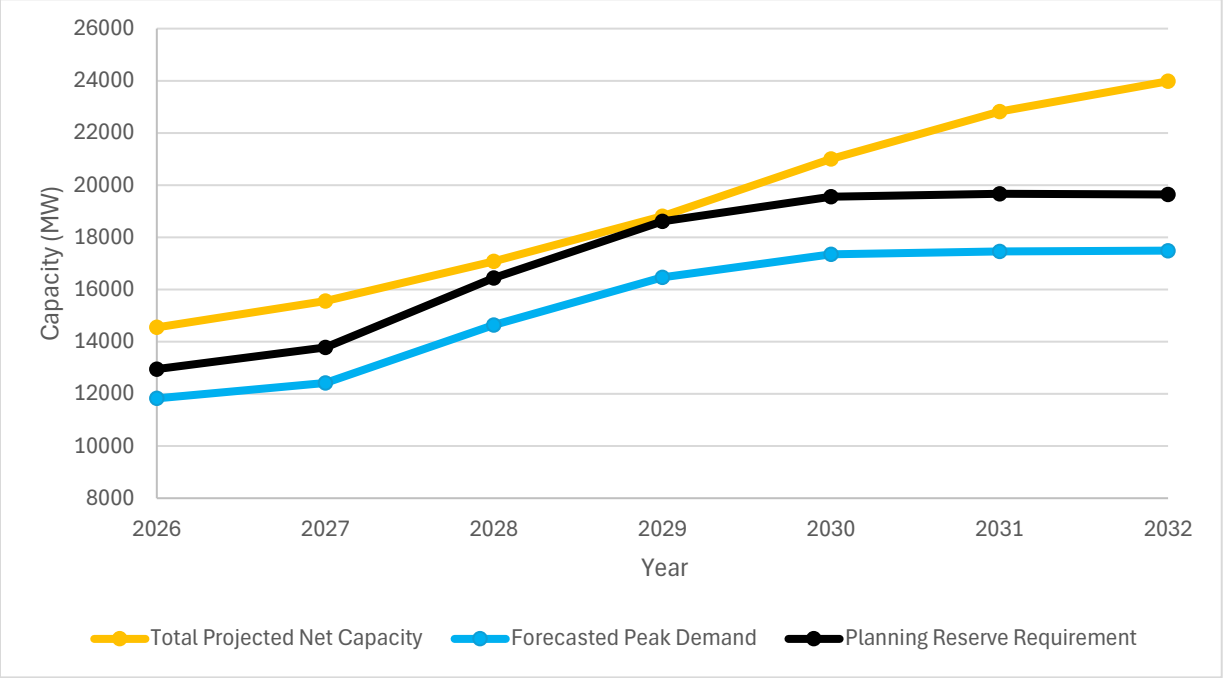
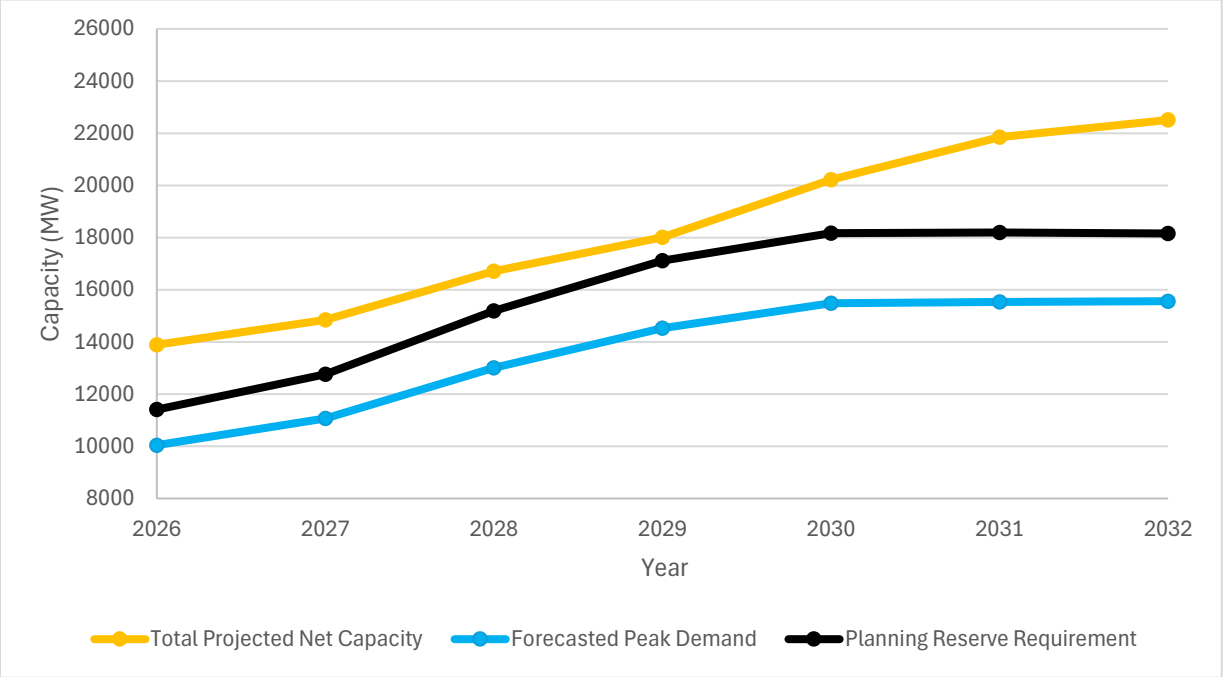


Figure 2-2b Wisconsin Net Capacity Compared to Planning Reserve Requirements for Fall



[56] The PRM values are retrieved from MISO's estimated outyear PRM values available in MISO's 2026-2027 Loss of Load Expectation Study Final Report; https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf.

Figure 2-2c Wisconsin Net Capacity Compared to Planning Reserve Requirements for Winter

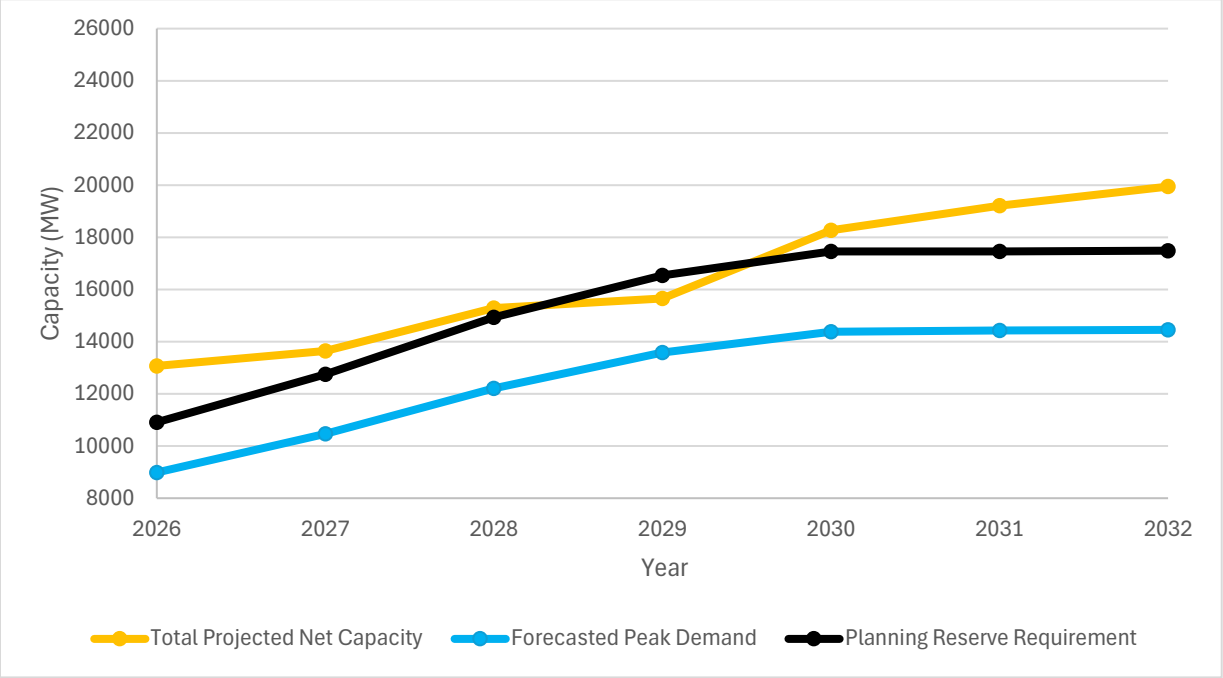
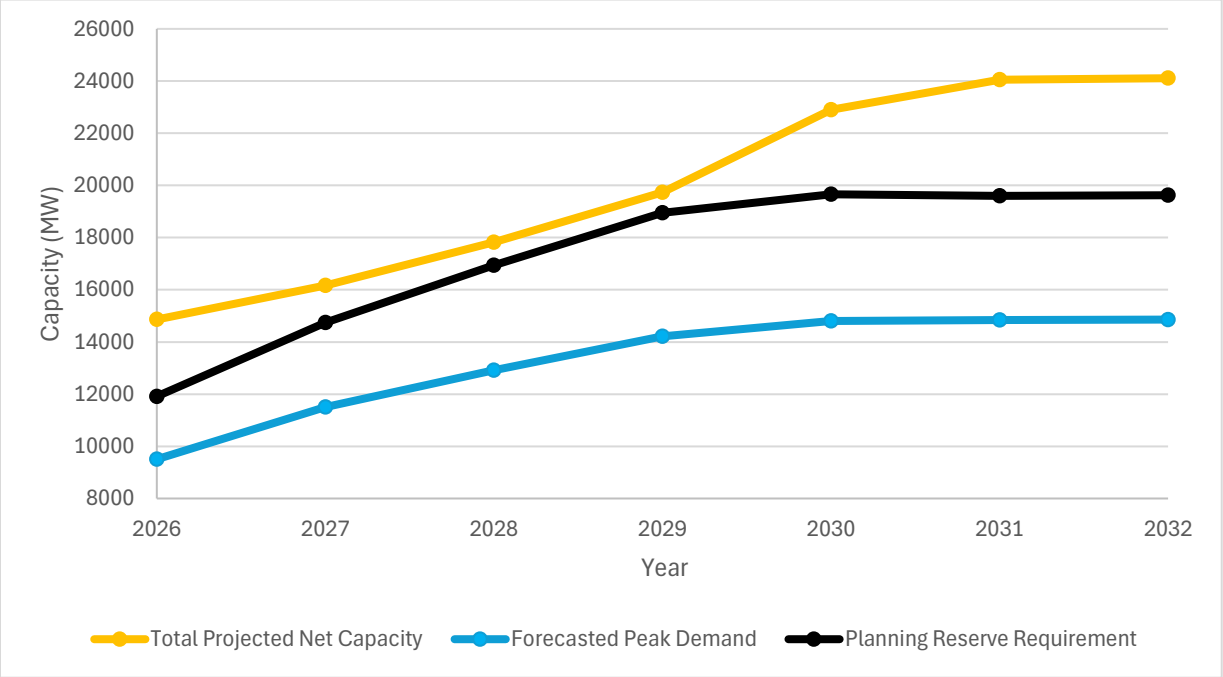


Figure 2-2d Wisconsin Net Capacity Compared to Planning Reserve Requirements for Spring



Projected net capacity represents all existing and projected future generation resources available to meet MISO's planning reserve margin requirement (PRMR), which is the amount of capacity MISO's statistical modeling indicates is necessary to minimize the

probability of loss of load events throughout the MISO region. Forecasted peak demand is the amount of load serving entities (LSE) demand that is coincident with MISO's peak demand.

These projections indicate that Wisconsin's electric service providers may be able to meet the projected Initial PRMRs solely with resources they own or have secured PPAs with except in Winter 2029-30. However, the providers in need of additional capacity may be able to purchase that capacity in the MISO PRA. Further, the actual accredited capacity of providers' resources and Initial PRMR as determined by MISO in a given Planning Year may be different than these projected values.

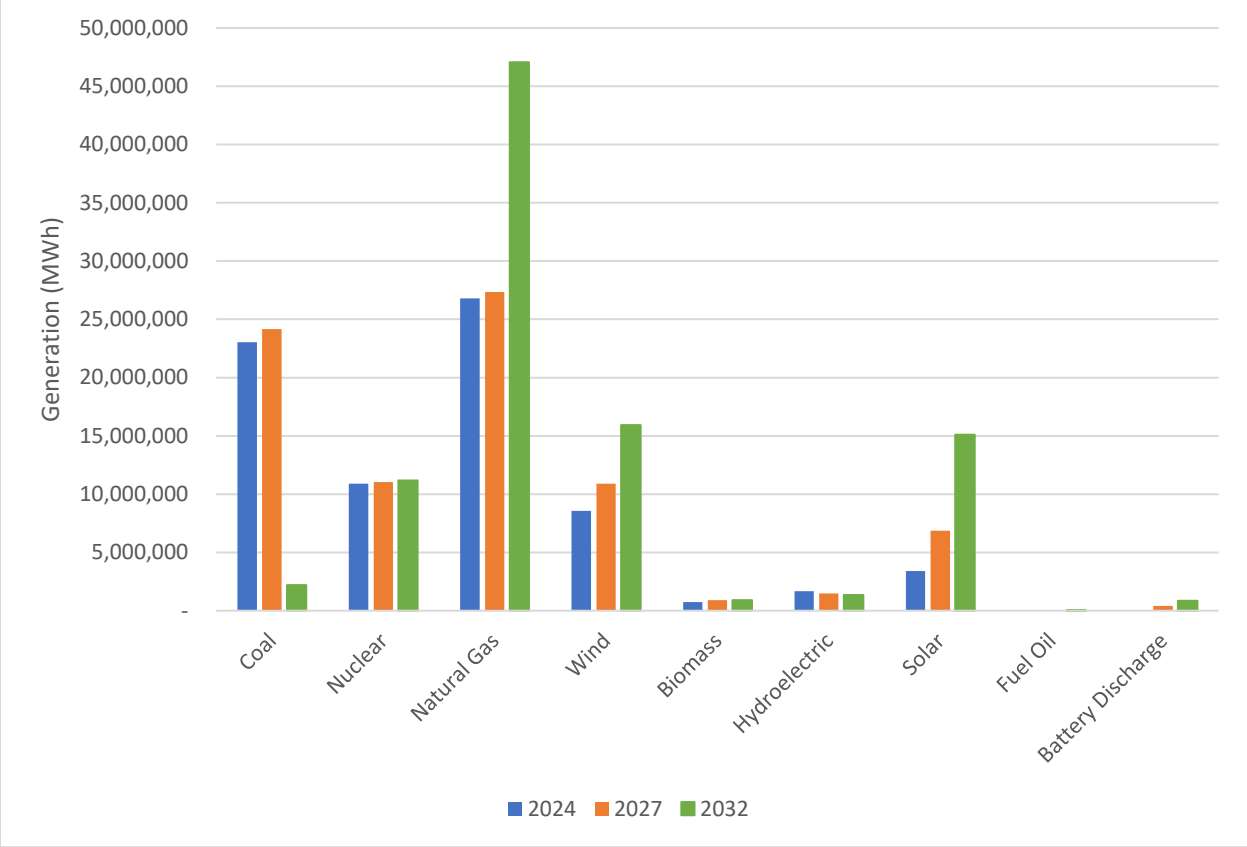
Also of note, these projections of PRMs are subject to change in future years. Numerous factors can result in different PRMs, including how MISO's LOLE study observes risk across the four seasons. In that study, a set level of acceptable risk is distributed (0.1 LOLE) across the seasons, and changes in this LOLE distribution can in turn impact PRMs.

In August 2023, the Commission opened docket 5-EI-161 to conduct a generic investigation into resource adequacy standards and requirements. The Commission is investigating current and ongoing resource adequacy initiatives, including a review of newer metrics and requirements established and proposed by MISO and other states, regional transmission organizations or independent system operators, and other related entities, and review the state-level PRMR of 14.5 percent installed capacity (ICAP) established by the Commission's Order in docket 5-EI-141 and whether that guideline remains appropriate. Relevant to this discussion is that MISO adopted the RBDC beginning in planning year (PY) 2025-2026. While the RBDC does not change how the PRM is set, the RBDC may result in an LSE having a marginally higher or lower requirement in a given season, with the Final PRMR based on the RBDC clearing. The RBDC clearing depends on the availability and value of surplus capacity in MISO's planning resource auction. The Commission will continue to monitor resource adequacy issues and seasonal variability to ensure sufficient PRM targets are appropriately met in future years.

Effects on Sources of Energy Supply

As shown in Figure 2-3, if all additions and retirements are implemented as planned by electric providers, coal resources will decline from 31 percent of Wisconsin's generation in 2024 to 2 percent in 2032, natural gas resources will increase from 36 percent to 50 percent, wind resources will increase from 11 percent to 17 percent, and solar resources will increase from 5 percent to 16 percent. The recently announced delays in coal plant retirement dates would maintain coal generation near current levels through 2026, but providers continue to anticipate that one plant will be fully retired by 2027, with another three fuel switching, or partially retiring, before 2030. The share of renewable resources in Wisconsin providers' generation portfolios may further increase if Wisconsin providers secure PPAs with independently-developed projects or procure more of these resources.

Figure 2-3 Generation Comparison by Resource, 2024, 2027, and 2032



Effects on Emissions

As shown in Table 2-4, providers project that announced additions and retirements will help drive additional CO_2 reductions between 2026 and 2032. Total projected emissions for 2026 from the state's largest providers show a CO_2 emissions reduction of approximately 40 percent relative to 2005 baseline levels. Among the utilities that provided 2032 emissions forecasts, statewide CO_2 emissions are projected to decrease by 61 percent relative to 2005 baseline levels. Statewide emissions are expected to decrease 21 percent between 2026 and 2032 relative to 2005 levels. As discussed in Chapter 1, WEPCO and WPSC have announced they are reconsidering their near-term emissions reductions goals and MGE has provided a range of near-term emissions reduction trajectories for this SEA.[57, 58, 59, 60]

[57] WEPCO Response (PSC REF#: 574644); WPSC Response (PSC REF#: 574472)
[58] WEC Investor Update September 2025. Pg. 26. WEC Energy Group
[59] Appendix B Figure B-1 provides MGE's forecasted range of CO2 emissions from 2024 to 2050.
[60] MGE Response (PSC REF#: 570772)

Table 2-4 Projected Carbon Dioxide Reductions from Owned Generation in 2026 and 2032 by Utility

Utility	2005 CO_2 Emissions (Million metric tons)	2026 CO_2 Emissions (Million metric tons)	2026 CO_2 Reduction (% from 2005)	2032 CO_2 Emissions (Million Metric tons)	2032 CO_2 Reduction (% from 2005)
Northern States Power Company - Wisconsin (Xcel Energy)	4.1	1.8	56%	0.6	85%
Wisconsin Electric Company	35.7	17.9	50%	N/A	N/A
WPPI	3.97	2.27	43%	2.06	48%
Wisconsin Power and Light Company (Alliant)	8.8	8.8	0%	4.49	49%
Madison Gas and Electric Company	3.55	1.9	47%	N/A	N/A
Dairyland Power Cooperative	4.43	3.7	16%	1	77%
Manitowoc Public Utilities	0.463	0.246	47%	0.27	41%
All Providers	**57.46**	**34.72**	**40%**	**8.42**	**61%**

As shown in Tables 2-1, 2-2, and as demonstrated in Table B-8 in Appendix B for new resources, electric providers plan to meet their goals by retiring existing coal-fired power plants, fuel switching from coal to cleaner fuels at other power plants and adding renewable resources to generation portfolios. Individual utility emissions reduction goals are shown in Table 1-4.

Resource Planning in Wisconsin

Utility resource decisions are generally expected to balance the goals of adequacy, reliability, affordability, and environmental responsibility. Effective resource planning is especially important during a period of rapid change. Commissions in numerous other states use IRP processes to review providers' generation plans, and in some cases to exercise regulatory authority over final addition and retirement decisions.

In Wisconsin, there is no IRP process and the Commission does not prescribe the type of generation resource power providers retire or seek approval of. In the absence of an IRP process, Commission staff request additional information from providers related to their resource planning analysis associated with announced additions and retirements as part of the SEA process. Complementary to those data gathering efforts, this SEA includes independent Commission staff analysis on statewide resource planning considerations, that expands on similar considerations presented in the last SEA.

Provider Resource Planning

The resource planning information requested for this SEA covers content commonly addressed in IRPs. NSPW also provides information to Commission staff directly from the IRP they prepare as required by the State of Minnesota, where it also operates. Commission staff directed electric providers in Wisconsin that own more than 5 MW of generation to submit supplemental information on three broad topics, including carbon reduction activities, reliability impacts of potential unit retirements, and utility resource planning. The utility resource planning information requested responses to the following items:

- A narrative describing the factors leading to additions and retirements;
- The analysis methods used to assess how different additions and retirements occur;
- The inputs and assumptions used in the analysis to set initial values for the models used and how those inputs were developed; and
- A description of the generation scenarios considered and a presentation of the results, including discussion of how the presented scenario was better than the alternatives.

Table 2-5 summarizes the responses from nine electric providers, submitted in December 2025. The amount of detail provided varied by respondent. Providers with few or no planned additions and retirements provided comparatively limited information. NSPW provided references to where IRP documents could be found or provided a version of the IRP document to this docket, noting that the analysis and findings were also relevant to its resource decisions in Wisconsin. Extensive submissions were provided by WEPCO, WPSC, and WP&L, consistent with their responsibility for the majority of announced additional generation capacity statewide.

Table *2-5* ***Resource Planning Responses: November 2025***

Provider	Response	Additional Responses/Notes
DPC	PSC REF#: 567612	PSC REF#: 567613
GLU	PSC REF#: 567954	
MPC	PSC REF#: 568377	
NSPW	PSC REF#: 567939, PSC REF#: 567940, PSC REF#: 567943	
MGE	PSC REF#: 570772	
WEPCO	PSC REF#: 567851, PSC REF#: 567852, PSC REF#: 567881	Same information as WPSC filing
WP&L	PSC REF#: 569483	
WPSC	PSC REF#: 567884, PSC REF#: 567885, PSC REF#: 567889	Same information as WEPCO filing
WPPI	PSC REF#: 567945	

In the prior SEA, electric providers confirmed that their planning accounted for the four main goals of adequacy, reliability, affordability, and environmental responsibility.[61] In response to the utility resource planning narrative for this SEA, the electric providers reaffirmed the same concepts and identified specific metrics used to assess performance on those goals. While no electric providers provided capacity expansion plan modeling results for this specific SEA, all providers have been performing some type of resource plan modeling for their individual needs, some with relative frequency due to the changing nature of the electric system landscape and shifting regulatory and policy priorities. Thus, all providers have some form of modeling pertaining to their respective future plans, some details of which have been shared for the purposes of analysis in this SEA.

Electric providers identified key goals in the establishment of their utility resource plans, including reduction of costs to customers, stability of electric rates, maintenance of generation reliability and flexibility, increasing system resiliency, and reduction of CO_2 emissions. Some providers discussed anticipated customer growth from new large customers. Multiple providers discussed diversification of resources as a strategy to provide increased resiliency of their resource portfolios. All electric providers discussed the reduction or elimination of coal from their generation mix, with replacement by other resources with fewer emissions concerns, including fuel switches from coal to natural gas or biomass. Most providers have corporate goals or aspirations to eliminate CO_2 emissions from their systems by certain future dates, which assisted in the consideration of which resources may be retired and which were considered for addition. Electric providers also discussed large capital expenditures that otherwise may have been required to maintain the operability of aging generation resources, particularly when these avoided costs could be used to pursue newer technology options with potentially greater reliability and fewer emissions.

As part of the analysis of how resource additions and retirements are selected, the electric providers discussed differing levels of the use of software tools as part of the evaluation process. Traditionally, electric providers have used three types of modeling software to assess resources against their defined goals.

- **Capacity expansion models** to identify the optimal portfolio of generating assets (or load reduction such as energy efficiency) for a defined electric system to meet future demand and other goals incorporated into the model, such as those listed above.
- **Production cost models** to assess the costs associated with generating the electric supply needed to meet demand for a defined generation portfolio during a defined time period, typically one year. Modeled costs include fuel used, fixed and variable operations and maintenance costs, transmission system losses and congestion, among others.

[61] Strategic Energy Assessment 2024-2030 (pg. 36) (PSC REF#: 523854)

- **Dispatch models** to identify the order in which generating assets will be deployed to meet electric demand and other defined goals.

Electric providers reported using a variety of different software packages to conduct modeling which are listed in Table 2-6. Historically, many providers have commonly used Electric Generation Expansion Analysis System (EGEAS), a capacity expansion model, and PROMOD, a production cost model. However, several providers have procured new modeling software in recent years that they report offers more detailed functionality and ease of use. For example, providers noted that PLEXOS and EnCompass offer the ability to conduct integrated capacity expansion and production cost modeling, and that EnCompass allows more detailed and effective reliability assessments by modeling system operations on an hour-by-hour basis.

Table 2-6 Primary Resource Planning Models Used by Wisconsin Electric Providers

Provider	Response
DPC	EnCompass
NSPW	EnCompass
MGE	EGEAS
WEPCO	PLEXOS
WP&L	AURORA
WPSC	PLEXOS

The providers' modeling analysis incorporated the goals outlined above, as well as other inputs identifying future conditions relevant to making generation choices. These inputs and assumptions were provided to these capacity expansion programs, with the goal of developing optimal resource plans for each electric provider.

Among the key inputs identified by the providers included load forecasts, pricing of fuel types such as natural gas and coal, expected market pricing for capacity and energy, capital and operating costs of new generator and storage technologies, flexibility and resiliency of resource portfolios, physical location of resources, and emissions, among other considerations. Some providers allowed these key inputs to randomly vary over a range of possible values to perform a more probabilistic analysis, generating hundreds or thousands of modeling runs before reviewing results. Some providers also discussed the implementation of the seasonal construct, evaluating how different resources are accredited in various seasons, with potentially different resource outcomes for the individual portfolios.

After defining inputs, the providers ran models to identify the retirement and addition choices that performed best and aligned with goals and metrics. Given that many key inputs were projections of future conditions, several providers reported running multiple scenarios that changed the values of key inputs, to assess the impacts of different conditions on model outcomes. The most common scenarios include alternative

projected natural gas cost values, alternative forecasts of customer demand, and scenarios that assumed additional costs that could be associated with more stringent future environmental regulations. Commission staff independently performed similar modeling scenarios for the entire state of Wisconsin, as discussed below. Some providers specified that their goal was to select final resource options that performed strongly across multiple scenarios to identify resource decisions that could be expected to perform well even if future conditions varied from the provider's primary set of projections.

Providers affirmed that their announced additions and retirements had been guided by the results of their previous modeling work as discussed in the prior SEA, with updates to reflect changes to the state's electrical transmission and distribution system, as well as factoring in legislative and regulatory changes at the state and federal level. WP&L's announced generation changes reflect the results of its updated Energy Blueprint planning process, which emphasized the need for additional resources, including "new natural gas generation, renewables, battery storage and the proposed retirement and/or fuel switching of various [electrical generation units]." WP&L asserted that their modeling indicates wind and storage are selected by the model on economic grounds through 2030. In their updated Energy Blueprint, WP&L identified these additional resource needs while balancing its goals of achieving carbon reduction, limiting costs, and supporting rate stability, reliability, and resource flexibility. These new resources also will reduce reserve margin requirements constraints, which were identified as they considered the seasonal construct modality.

WEPCO and WPSC continue to indicate that their plans to retire coal units at Columbia and Oak Creek were due to those plants having reached the end of their useful lives and continued operations would require significant additional costs in maintenance and potential environmental compliance, despite announced delays to those retirements to ensure short term system reliability. Those providers reported that modeling analysis for new additions to replace the retired coal capacity identified a mix of resources, including renewable and storage units that could take advantage of cost declines to perform well on affordability metrics, as well as some gas-fired generation that would help the portfolio achieve resource diversity and resilience. Additionally, retrofitting coal units to use natural gas as a fuel is planned at several generation sites, as demonstrated in Table 2-2. Similar to WP&L, the WEPCO and WPSC plans have been updated to account for market developments and the potential for new loads coming into its service territories. The first round of construction and buy/sell Commission authorizations have been reviewed and approved by the Commission, with a second grouping of projects currently pending a Commission decision, informed by the utilities' ongoing analysis.

While WP&L, WEPCO, and WPSC accounted for the largest share of planned retirements and additions, reports from other utilities struck similar themes. For example, NSPW reported that modeling indicated it is implementing a successful approach for meeting carbon reduction goals while controlling costs. NSPW also received approval from the

Minnesota Public Utilities Commission to extend the life of the Monticello nuclear energy facility. DPC reported on a "balanced and pragmatic" approach to its resource portfolio, including retirement of coal assets, additions of renewable and natural gas resources.

Commission Resource Planning Analysis

As part of the SEA, the Commission collects resource planning narratives from individual providers and conduct additional modeling analysis to provide an independent perspective on state-wide energy system planning. The analysis is focused on conducting capacity expansion modeling through EGEAS, and comparing the generation additions the model identifies to achieve adequacy, reliability, emission reductions, and affordability under multiple scenarios.

The Commission has historically used EGEAS and PLEXOS to review generation expansion planning information provided as part of individual project applications, though in recent years other programs such as EnCompass and AURORA have been utilized by various utilities as alternatives to EGEAS and PLEXOS.[62] The Commission does not maintain a general statewide EGEAS dataset, which can take substantial time to construct and validate. As an alternative, staff requested and received regional EGEAS datasets maintained by MISO for modeling associated with its 2023 MISO Transmission Expansion Planning (MTEP) and LRTP processes as part of the last SEA process.[63] In the last SEA, the Commission narrowed down the regional data to Wisconsin specific data, through steps that included reducing active facilities to those operated by or serving Wisconsin providers, and reducing the scale of general inputs, such as total energy use and peak demand, from regional to state level values. For this SEA, the Commission updated the last SEA's data set with updated assumptions about expected demand and load growth, including the expansion of load due to the development of data centers, as well as new generation and energy storage projects that have been approved by the Commission.[64] Updated MISO MTEP data for 2025, to be provided for the first time using the PLEXOS model, was not available at the time of analysis and modeling for this SEA. As a result, the Commission did not have the information needed to utilize PLEXOS in this SEA and instead continued to use EGEAS, as done in past SEAs.

The EGEAS model uses resource adequacy and reliability information provided by Commission staff as minimum baseline requirements. MISO's dataset defines resource adequacy as compliance with MISO's planning resource margin requirements, which are described in Chapter 1. Reliability is addressed through modeling parameters that identify

[63] See Chapter 4 for more information about the MTEP process and MTEP23 and its potential impacts on Wisconsin.

[64] Updated MISO MTEP data for 2025, was provided for the first time using the PLEXOS model. The analysis window did not correspond to the data's arrival date. Resulting in the Commission's continued use of EGEAS, as done in prior SEAs.

the likelihood of potential outages or performance issues at existing plants and assess whether customer demand could be met even if these issues occur. EGEAS modeling results only identify outcomes for which these resource adequacy and reliability requirements can be met. Moreover, EGEAS is an annual model and does not allow for the granularity of seasonal reliability requirements. Hence, Commission modeling concentrated around the summer season, which has historically been the constraining season for most electric providers in the state and the season MISO's PRM imposes the most conservative reliability requirement. Due to this limitation, the Commission did not evaluate other seasons.

MISO's MTEP23 datasets support capacity expansion modeling through 2044 under a future scenario that set different values for emission reductions and growth in electric demand than was used in the previous SEA. For this SEA, the Commission used demand and energy growth assumptions in line with the more current MISO Series 2 Future 1 that reflects utility forecasts and includes modest load growth from drivers such as adoption of EVs, data centers, and electrification of end uses currently using other fuels, such as heating. Under these assumptions annual state-wide demand and energy growth is assumed to be 1.1 percent and 1.9 percent, respectively.

Capacity expansion modeling was conducted under each sensitivity with associated input parameters. The model identified the lowest cost set of generation sources that serve customer load and meet adequacy and reliability standards, while achieving any applicable CO_2 reduction targets. These analyses are informed by assumptions regarding the relative costs of different generation sources, which staff confirmed to be consistent with cost assumptions used in other recent Commission dockets. The base cost assumptions were developed by staff utilizing data from MISO, U.S. Energy Information Administration (EIA), and National Laboratory of the Rockies (NLR).[65] Generation and storage resources selectable by the model also account for the different reliability and adequacy properties of different generation sources. For example, EGEAS assesses overall resource adequacy and reliability requirements against the intermittent characteristics of solar and wind generation, with solar available during daylight hours and wind often reaching its highest generation during overnight hours. Generating resources available to the capacity expansion model utilized Wisconsin-specific generating characteristics, as the modeling was limited to in-state resources.

Another important parameter for the modeling analysis was the MISO seasonal accreditation methodology and implementation of DLOL considerations for generation and storage resource classes. Due to the limitations of the EGEAS model discussed earlier, the Commission concentrated on the summer season and annualized considerations for

[65] The cost assumptions implemented are specified in the MISO Series 2 Futures Redesign Assumptions Book (published in December 2025), EIA's Assumptions to the Annual Energy Outlook 2025 (published in April 2025), and NLR's Electricity Annual Technology Baseline (published in June 2024).

the entire year based on that season's characteristics. Furthermore, the Commission analysis built in assumptions about changes to DLOL resource classes that MISO has forecasted with initial projections for values and how those values may change in the future, and are also subject to being updated. An important takeaway is that certain resource classes, particularly standalone photovoltaic (PV) and wind generation, have lower DLOL class accreditation values, and contribute less toward meeting the PRM, than other resources like natural gas facilities, nuclear facilities, battery energy storage systems (BESS) and other comparable resources. As a result, the EGEAS model selected less PV and wind generation than other resources.

On July 8, 2024 the EPA enacted new greenhouse gas standards and guidelines for fossil fuel-fired power plants under the Clean Air Act.[66] These standards may impact the cost assumptions used for new and existing natural gas plants by setting CO2 limits for newly constructed gas-fired combustion turbines and emission guidelines for existing coal, oil and gas-fired steam generating units. Also noteworthy is the EPA's new carbon dioxide emission performance standards for new base-load combustion turbines are based on using carbon capture and storage. These technologies have not traditionally been used with combustion turbines and could potentially increase operational expenses. Overall, the federal standards remain in a state of change, with evolving goals under the new federal administration. For instance, on September 14, 2026 the EPA announced the repeal of greenhouse gas emissions standards for fossil fuel-fired power plants promulgated under Section 111 of the Clean Air Act.[67]

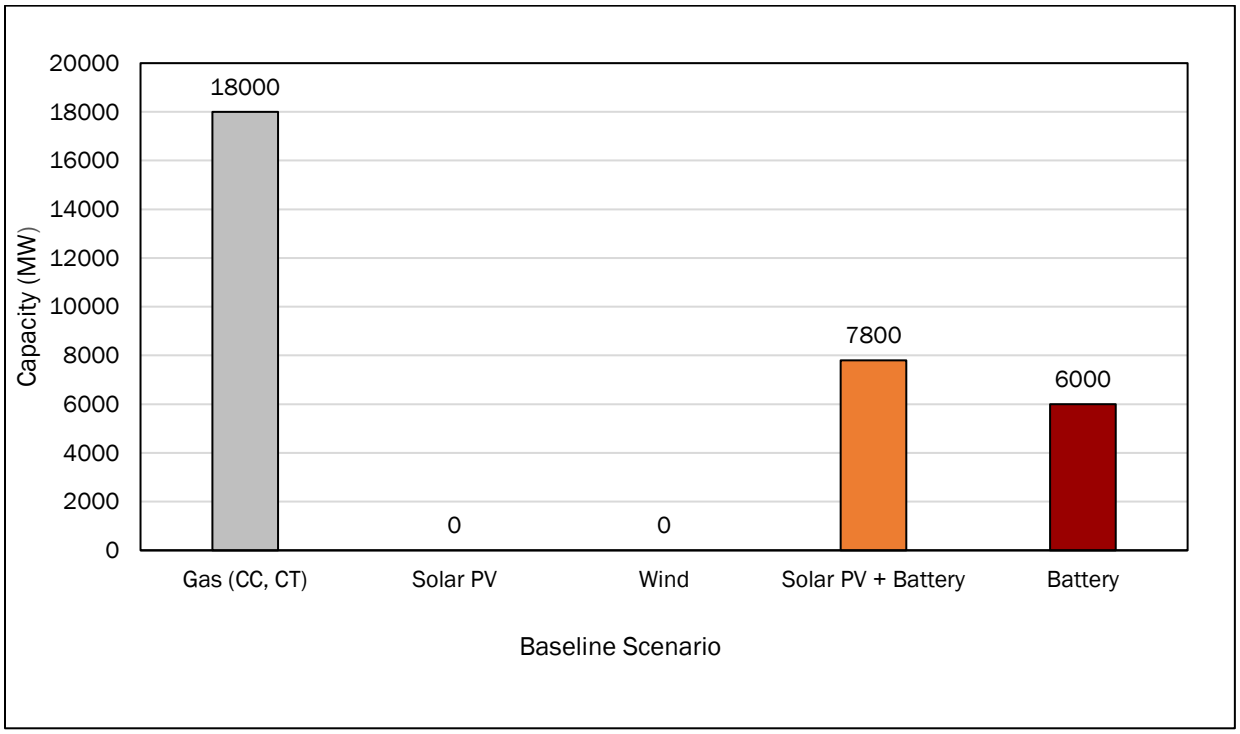
In Wisconsin, the Governor's stated goal of achieving net zero emissions by 2050 remains in place. The Commission evaluated a range of different future modeling parameters to understand what the state-wide generation and storage resource mix may look like under different future conditions, including various assumptions for generation and storage resources, varying fuel costs, and emissions considerations. Different sensitivities were applied that reflect these different policy, economic, and technological futures. These scenarios are discussed more below.

Figure 2-4 illustrates the generation portfolio selected for the "base case" future. (Detailed results can be found in Appendix B:Table B-2.)

[66] Federal Register: New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, These rules are currently being challenged in federal courts.

[67] EPA Finalizes Repeal of 2024 Power Plant Regulations, Delivering $300+ Billion in Savings, Proposes Repeal of All Remaining Greenhouse Gas Emissions Standards for Power Plants | US EPA

Figure 2-4 EGEAS Capacity Expansion Results, 2044



The Commission's base case model included several assumptions consistent with the previous SEA, while also incorporating updated generation and storage resources, as well as expected peak demand and load growth from data centers and electrification.

The base model is oriented to select generation resources that best meet load growth and reliability needs in a cost-efficient manner. Emissions reductions goals are not accounted for in the base case, while maintaining expected fuel costs and extant generation and storage resource types. The base model predominately selected natural gas resources to meet the needs identified by some upcoming coal unit retirements or fuel switches during the late-2020s to early-2030s, as well as longer term needs created by anticipated load growth. A significant amount of solar/battery hybrid units and battery energy storage system were also chosen, partially due to their more favorable accreditation characteristics when compared to otherwise comparable solar PV and wind resources. These results were also partially driven by the model's view of the reliability and resource adequacy advantages of natural gas, which can be deployed at any time, without the intermittent properties of solar and wind. Particularly in the future years reviewed in the modeling, significant peak demand and load requirements are realized, driving the need for dispatchable resources. The model selected adding a smaller number of natural gas plants to meet resource adequacy and reliability requirements over more costly alternatives such as wind or solar plus BESS, which would require constructing a much larger number of facilities to meet these same requirements. The way MISO summer seasonal accreditation values for wind and solar and MISO DLOL forecasts are applied to these resources in EGEAS, may result in an underestimation of the amount of solar and

wind resources that could be built under the base case. A more advanced model, such as PLEXOS, which can fully evaluate seasonal characteristics of resources may have selected more solar PV and wind resources than chosen by the EGEAS modeling.

The Commission also modeled the base case with an additional sensitivity to high and low natural gas prices. The EGEAS model continued to select the same amount of natural gas, solar plus battery, and stand-alone battery units that were selected in the base case model. The Commission modeled a broad range of natural gas prices that escalated over time.[68] Even under higher natural gas prices, the model continues to select predominantly new natural gas generation, and solar plus battery or stand-alone battery, as these resources offer dispatchable capacity. This outcome demonstrates the model's invariance to natural gas costs, suggesting that other factors, such as the accredited capacity of resource types, may be the reason for the EGEAS resource selections. Selection of individual units by year and generation source for these scenarios can be found in Appendix B, Tables B-3 and B-4.

Figure 2-5 EGEAS Capacity Expansion Modeling Results for Low and High Natural Gas Prices ($/MMBTU), 2044

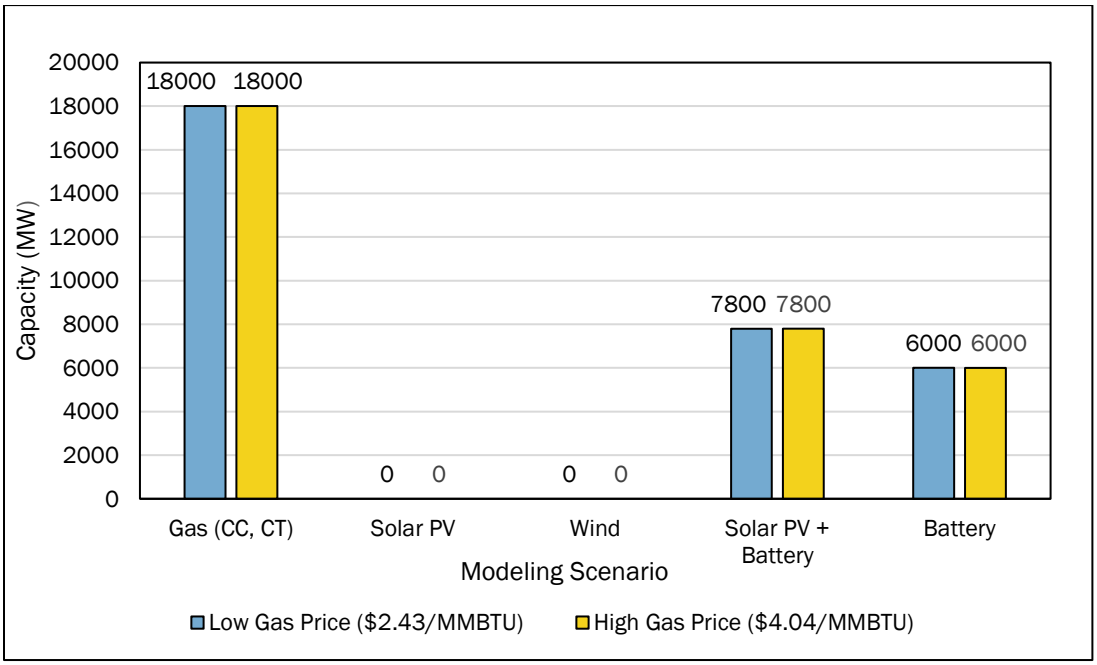


Figure 2-6 provides the results of the Commission's solar capacity accreditation sensitivity. In this modeling scenario, the solar capacity accreditation percentage is not

[68] The low price scenario establishes a $2.43/MMBtu natural gas price at the beginning of the modeling period, with annual increasesover the modeling period consistent with the trends assumed for other scenarios. The high price scenario establishes a $4.04/MMBtu natural gas price at the beginning of the modeling period, with annual increases over the modeling period consistent with the trends assumed for other scenarios.

allowed to drop below 20 percent, meaning the firm capacity given to solar PV is higher and the model may be more likely to select generation resources of that type.[69] This scenario uses the base case load growth. The model continues to select the maximum amount of natural gas resources and the same amount of battery. The model selects less solar PV and battery resources and more individual solar PV resources, as shown in Figure 2-6. Selection of individual units by year and generation source for this scenario can be found in Appendix B, Table B-5.

Figure 2-6 EGEAS Capacity Expansion Modeling Results for Higher Solar Capacity Accreditation Sensitivity, 2044

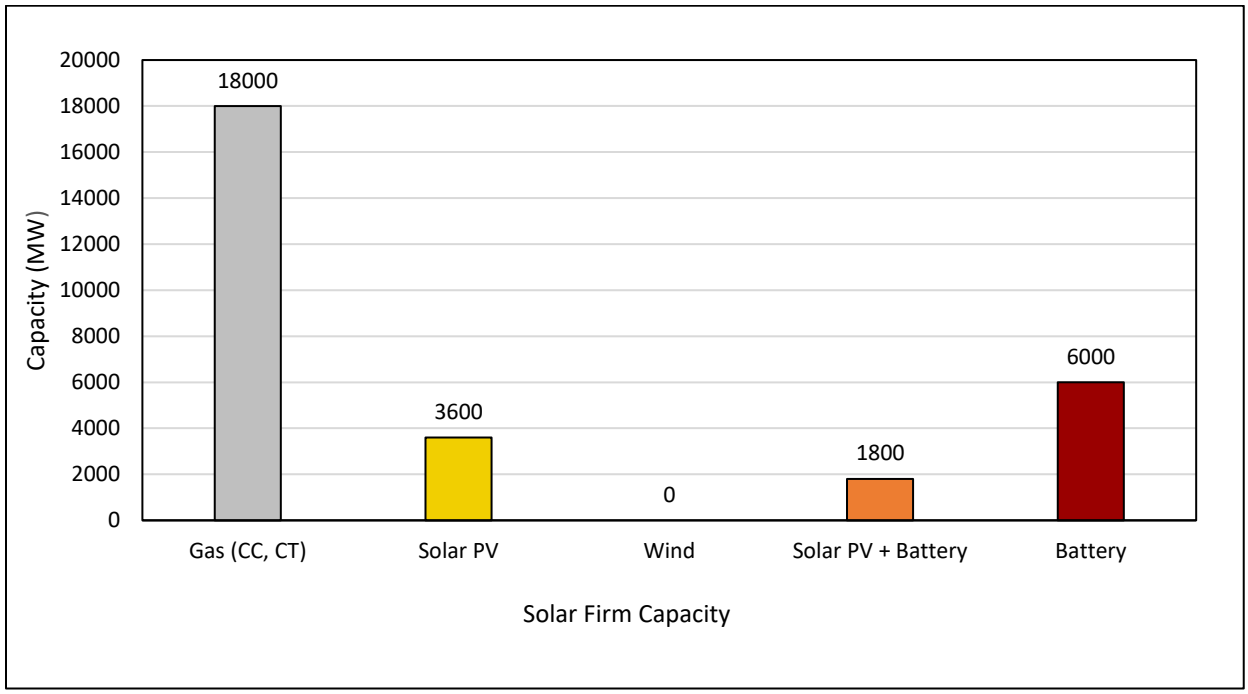


Figure 2-7 provides the results of the Commission's decarbonization sensitivity scenario. This scenario uses MISO's Future 2A, which assumes CO_2 reductions based on aggregated goals from across MISO, including legislative and executive goals from the various states and stated goals of utilities within the footprint. In order to tailor the model to Wisconsin specific assumptions, Commission analysis included a pathway that seeks to reduce CO_2 to Net Zero by 2050 (NZ2050). To perform this sensitivity, the Commission took reported utility carbon dioxide production for the year 2025 and reduced it in a straight line to zero in the year 2050, resulting in a four percent reduction each year from the reported 2025 value.

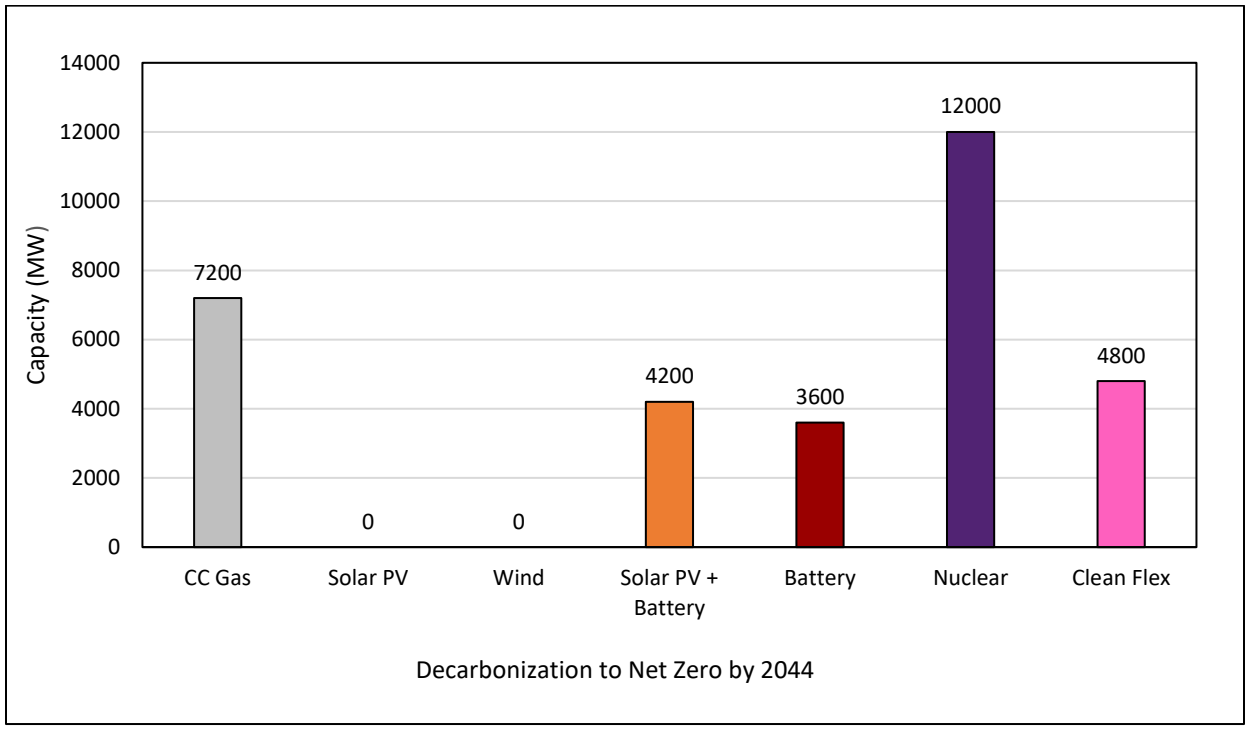
[69] Base case accreditation assumptions are retrieved from Planning Year 2025-2026 Indicative DLOL Results Report for planning year 2025. https://cdn.misoenergy.org/Indicative%20DLOL%20Results%20PY%202025-2026667100.pdf. Planning years 2030, 2033 and 2043 are retrieved from MISO's 2024 Regional Resource Assessments Technical Appendix. https://cdn.misoenergy.org/2024%20RRA_Technical%20Appendix676208.pdf. Accreditation values are interpreted between provided planning years.

As outlined in Table 2-3, above, providers' announced expansion plans include a significant share of solar and battery storage. Any projects that have been approved by the Commission, or are currently before the Commission for review as part of a docketed proceeding at the time this analysis was conducted, were included in the modeling of the Net Zero 2050 (NZ2050) scenario. New combined cycle units fired on natural gas, with dispatch capabilities and the ability to produce large amounts of energy, were only made available until the year 2032, at which time they were no longer available for selection by the model.

In addition to the above resources, the EGEAS results identified the need for additional low-emission and flexible ("clean flex") units, a unit type uniquely selectable in the decarbonization sensitivity runs. Clean flex units have the dispatchability characteristics of RICE units, but without any carbon emissions, resulting in a high cost resource that would only be dispatched when absolutely needed. These units do not currently exist as a specific commercial technology and the high cost reflects the price signal that is likely needed to drive development of these types of technologies to achieve NZ2050. Equivalent technology could include, but would not be limited to, long duration battery storage, traditional RICE units coupled with carbon capture and sequestration, RICE units powered by hydrogen, and other emergent technologies. The dispatchability of the "clean flex" resources indicates the importance of the ability to meet load requirements in a timely manner that is not subject to the intermittency of renewable resources like solar and wind. The "clean flex" units maintained the same modeled characteristics of those modeled in the previous SEA, with availability starting in 2031 to provide access to this resource over the period where newly constructed gas combined cycle units are projected to be taken out of service.

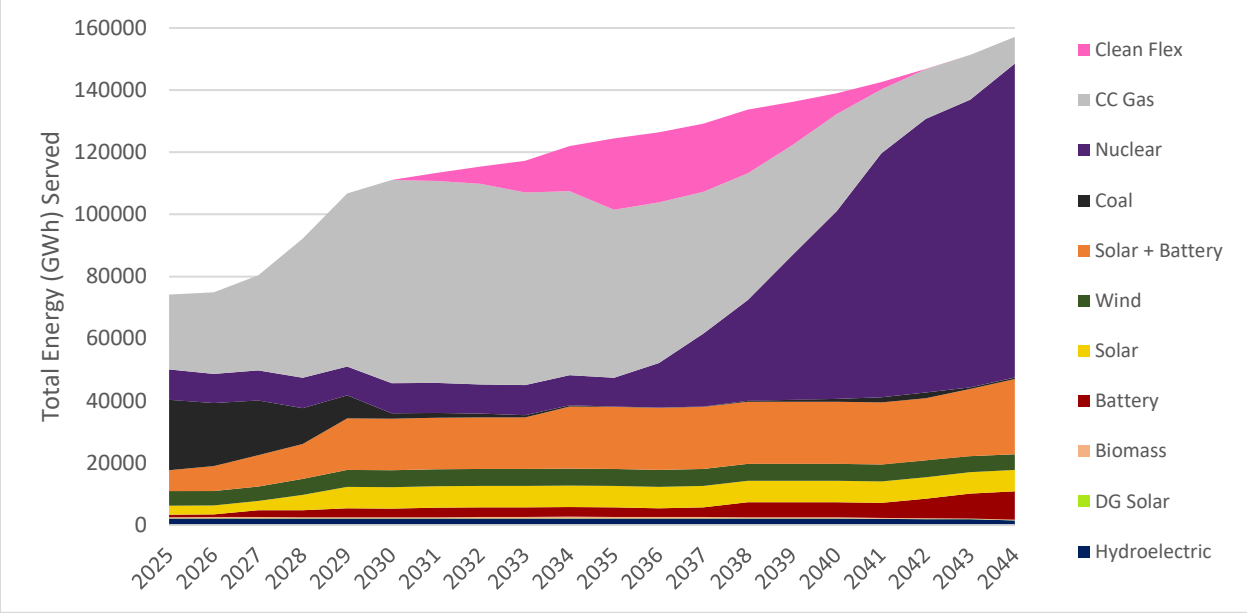
Lastly, nuclear units were assumed to be available starting in 2036. Nuclear units have a variety of characteristics that can be helpful in a carbon free scenario, including; no emissions, high amounts of energy production, reliability, and relatively high capacity accreditation. Nuclear units are also limited in their ability to ramp up or down to meet changes in load, serving primarily as baseload power, and require considerable investment and lead time to construct. Late in the NZ2050 sensitivity, nuclear units were liberally chosen by the model, demonstrating the model seeking a resource that can meet rapid and significant load growth with zero emissions as a priority. Selection of individual units by year and generation source for this scenario can be found in Appendix B, Table B-6.

Figure 2-7 EGEAS Capacity Expansion Results - Net Zero CO_2 Reduction by 2050



Given the significant buildout of the "clean flex" unit type in the decarbonization sensitivity, it is important to examine the actual energy provided by resources of the various classes in the NZ2050 modeling. Figure 2-8, below, shows the breakdown of energy generated by each unit class in the NZ2050 model from 2025 to 2044. EGEAS outputs these values directly in GWh. These results have therefore been normalized to the total produced system energy in that year.

Figure 2-8 EGEAS Energy Production by Class - Net Zero CO_2 Reduction by 2050



The model shows a 2025 baseline where natural gas units provide a significant fraction (33 percent) of the total energy generated in the state, followed by coal, then nuclear, solar PV, solar PV plus battery, and wind. In the 2025 base year, solar PV, hydro and battery units are collectively responsible for only 8 percent of the energy generated.

As Figure 2-8 demonstrates, the energy profile changes significantly over time from the model baseline in 2025. The decarbonization scenario features a significant increase in generation from solar PV plus battery resources in the early years of the model, which supply approximately 20 percent of the energy generated by 2032. The percentage of energy generated by coal decreases over time, dropping to 1 percent in 2032 and essentially zero in 2037, a result of curtailment of theoretical coal generation to ensure sufficient CO_2 reductions.

Generation from gas resources increases through the early 2030s, before dropping down again to about 5.5 percent of energy production in 2044, showing the influence of the NZ2050 pathway. The clean flex units appear to pick up aspects of the lowering natural gas generation in the mid-term years, with a 5 percent energy share in 2032 expanding to a 17 percent share in 2037, which emphasizes the importance of dispatchable, emissions free generation resources as part of the optimal portfolio of Net Zero 2050 to make sure energy is served. Similarly, nuclear resources become an important part of the energy mix as new nuclear units become available in 2036, rising from a 13 percent share of generation in 2025 to an 18 percent share by 2037. New nuclear units continue getting picked by the model in following years to meet rising load requirements, replacing the CO_2 emitting natural gas resources and the high-priced clean flex resources, resulting in 64 percent of total generation by 2044 coming from nuclear resources.

Chapter 3 – Clean Energy Programs and Policies

Energy Efficiency

Energy efficiency programs provide incentives and technical assistance to energy consumers to take steps to reduce energy use. In 1999, the Wisconsin State Legislature established Focus as Wisconsin's statewide electric and natural gas efficiency and renewable resource program. Wisconsin Stat. § 196.374, repealed and recreated in 2005, requires IOUs to fund Focus through contributions equal to 1.2 percent of annual operating revenues from retail sales, and requires municipal utilities and retail electric cooperatives to collect an average of $8 per meter annually for energy efficiency programs. Municipal utilities and cooperatives can contribute these funds to Focus or administer their own programs. As of 2025, 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. Additionally, several IOUs and municipal utilities run voluntary energy efficiency programs that provide additional benefits to their customers beyond what Focus offers.[70]

Wisconsin Stat. § 196.374(2)(a)1. requires Focus to hire a third-party program administrator to operate Focus under a contract established by IOUs and approved by the Commission.[71] Aptim Government Solutions, LLC (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. The Commission evaluated and approved updated program goals in 2025 for the remainder of 2023-2026 time period through docket 5-FE-104, *Quadrennial Planning Process IV* (QPP IV).

The Commission also began *Quadrennial Planning Process V,* in docket 5-FE-105. Quadrennium V (Quad V) of Focus will cover the time period from 2027-2030. This docket began with a Quad V Planning Study (Planning Study) performed by the Focus independent third-party evaluator, the Cadmus Group (Cadmus). The Planning Study estimates potential program impacts to inform program and policy decisions for Focus. The Planning Study estimated the energy savings, energy demand, and carbon emissions impacts by customer segment from program interventions, policy choices, and market conditions. The Planning Study was designed to explore transitional priorities identified by the Commission during QPP IV including: (1) make measurable progress toward a transition to greater emphasis on reducing carbon emissions, (2) assess strategies for achieving greater demand savings and better understand the additional value of demand savings, (3) increase the program's emphasis and role in promoting beneficial electrification

[70] Focus on Energy

[71] The IOUs created a nonprofit board to fulfill its duties under Wis. Stat. § 196.374(2)(a)1. The nine-member board is called the Statewide Energy Efficiency and Renewables Administration (SEERA).

statewide. (PSC REF#: 453081.) The study team held six stakeholder meetings between June 2024 and December 2025.[72] Cadmus delivered the Planning Study final report in December 2025. (PSC REF#: 571434.) An additional study ordered by the Commission in its QPP IV Final Decision, a Market Transformation Assessment Study, was also delivered by Cadmus in December 2025. (PSC REF#: 571447, PSC REF#: 571448.) This study's objectives were to identify and prioritize potential market transformation opportunities for Focus and develop a roadmap for implementing energy efficiency market transformation in Wisconsin.

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 includes separate portfolios of programs that target residential and nonresidential customers.

For residential customers, Focus delivers a comprehensive suite of energy efficiency programs designed to help Wisconsin households save energy and lower utility costs, while ensuring equitable access to benefits across the state. The residential portfolio encompasses a broad range of offerings tailored to different customer needs and participation levels. These include rebates and instant discounts for energy-efficient heating, cooling, water heating, insulation, air sealing, smart thermostats, and other efficiency measures. In addition, the program offers free energy-saving product packs and an online marketplace with discounted efficient products that can be shipped directly to customers. The program also provides support for homeowners through a network of registered independent contractors (known as Trade Allies) who install and maintain equipment while offering information and incentives from the Focus program. The residential portfolio also offers incentives for building highly efficient new homes and installing solar PV systems at customer homes.

For income-qualified households, Focus provides enhanced incentives, including expanded moderate-income incentives beginning in 2026 to better align with customer needs and broaden access to rebates. In addition, the program connects participants with resources such as home energy assessments, a residential rebate finder tool, and educational materials.

Focus also delivers the Inflation Reduction Act HER programs funded through the U.S. Department of Energy.[73] As of early 2026, Wisconsin is one of six states, and the District of Columbia, to launch both the Home Efficiency Rebates (HOMES) and Home Electrification

[72] Quad V Planning Study. https://focusonenergy.com/about/quad-v-planning-study
[73] https://focusonenergy.com/home-energy-rebates

and Appliance Rebates (HEAR) programs. The programs offer significant rebates for energy-saving home improvements like insulation and air sealing as well as for heating and cooling equipment, appliances, and electrical panel upgrades. In total, $149 million has been awarded to Wisconsin to implement the IRA HER programs. According to the legislation, the programs can operate up until Sept 30, 2031.

Within Focus' non-residential portfolio, separate programs target different efficiency opportunities for different types of customers, including small businesses, commercial customers (including multifamily buildings), schools and government facilities, agricultural customers, medium sized industries, and large industrial facilities.[74]

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 can inform customers of Focus offerings and encourage participation. Some electric providers also fund and operate their own energy efficiency programs,[75] although as shown in Figures 3-1 and 3-3 below, spending and savings from those programs remain small relative to Focus statewide activities.

Focus on Energy Outcomes

The independent program evaluation team, led by Cadmus, performs research and analysis to validate energy savings from Focus programs. Cadmus works with program staff to manage Focus' Technical Reference Manual, which documents and explains the methods for calculating savings achieved from installing energy efficient measures. Savings calculations in the Technical Reference Manual 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 have historically been a secondary priority for Focus programs to achieve. As of calendar year (CY) 2025, the Focus Program achieved verified gross lifecycle savings equal to 97 percent of its quadrennial lifecycle therm savings goal, 68 percent of its lifecycle kWh savings goal, 70 percent of its kW savings goal, and

[74] Additional information on program offerings can be found at www.focusonenergy.com.

[75] 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 contributingthose funds to Focus.

82 percent of the combined electric + gas (MMBtu) lifecycle savings goal. In CY 2025, the program's lifecycle savings achievements reached 367.8 million therms, 7,007,760,268 kWh, 65,937 kW and 60,693,900 MMBtu. The program also maintained a high level of customer satisfaction, achieving a portfolio average rating of 9.4 out of 10.[76]

Focus' evaluators also assess 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 test that compares thebenefits 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 2025, Cadmus's cost-benefit analysis concluded that for every dollar spent, Focus' full portfolio of programs achieved $2.38 in life cycle benefits.[77]

In docket 5-FE-104, *Quadrennial Planning Process IV*, the Commission set Key Performance Indicators (KPI) for the program administrator. A KPI was set for increasing the number of low-income qualified (Tier II applications) by six percent compared to those received during the prior quadrennium. Low-income customers between 60 to 80 percent of State Median Income qualify for the Tier II program. A KPI was also set for a target of 31 percent of incentive spend for rural customers (residential and nonresidential), which is proportional to the 31 percent of rural customers in the designated zip codes set for 2023 and 2024.

The Focus Evaluator, Cadmus, verified KPIs related to customer satisfaction, MMBtu savings achievement, income qualified applications, and rural incentive spending in the 2024 Evaluation Report to assess the achievement of these KPIs.[78] Those results are outlined below in the table from that report.

[76] https://assets.focusonenergy.com/production/docs/evaluation/Focus-on-Energy-CY-2025-Vol-I_Final.pdf
[77] For informational purposes, Cadmus also conducts an "expanded TRC" test which incorporates the economic benefits created by Focus. In 2025, the program evaluator's expanded TRC analysis found that when economic benefits are included, Focus achieved $4.08 in benefits for every $1.00 in costs.
[78] Evaluation-CY-2024-Vol-I_FINAL.pdf at pg. 45.

Table 3-1 Focus on Energy Quad IV KPI Achievements

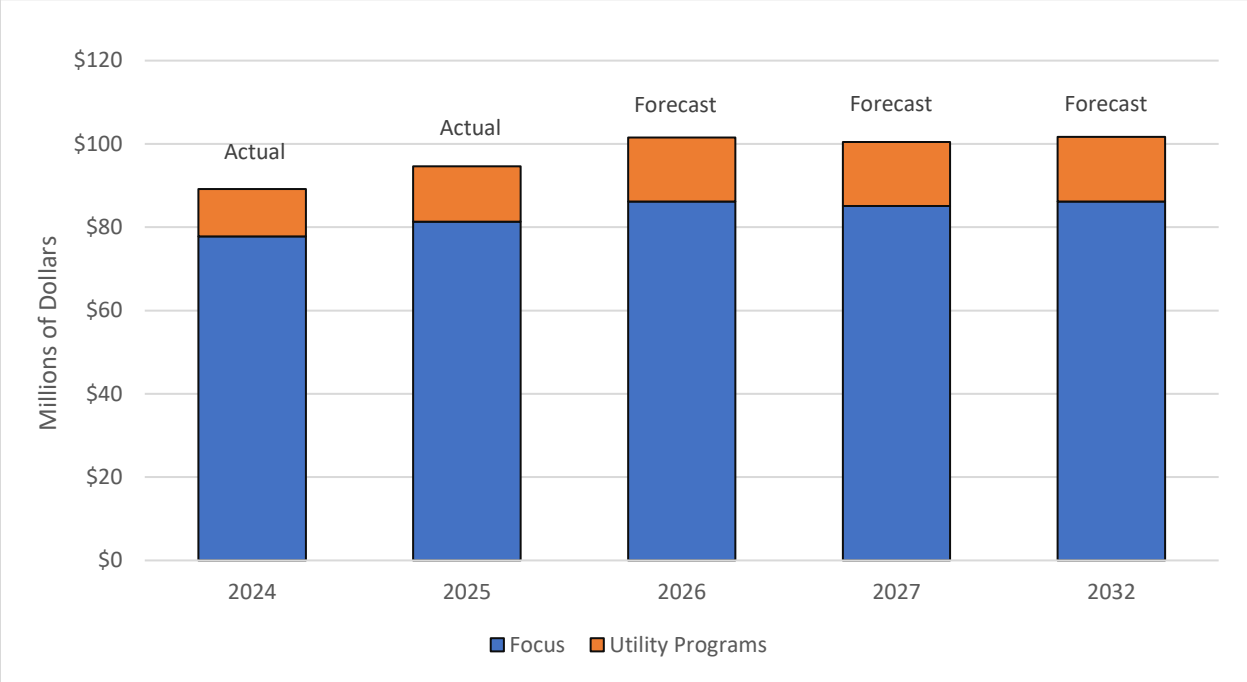
KPI	Description	KPI Target Thresholds	Verified Results
Customer Satisfaction	Maintain high customer satisfaction at the portfolio level	50% of bonus ≥9.0 75% of bonus ≥9.1 100% of bonus ≥9.2	Participation-weighted average satisfaction across the portfolio was 9.4 in CY 2024.
MMBtu Achievement	Achieve a minimum of 40% of the Quadrennium IV gross lifecycle MMBtu goal by the end of 2024	40% of Quadrennium IV lifecycle MMBtu goal	Total gross lifecycle MMBtu savings across the portfolio was 55,978,211 in CY 2024, which was 83% of the Quadrennium IV goal.
Income Qualified Applications	Increase the number of applications received by the income qualified program by 6% by 2024 over an average baseline from Quadrennium III	50% of bonus at ≥6% 75% of bonus at ≥7% 100% of bonus at ≥8%	952 income qualified applications were received by the program in CY 2024, which was a decrease of 41% over the Quadrennium III average.
Rural Incentive Spend	Ensure that incentives paid to rural customers are proportional to the percentage of rural customers in the state	50% of bonus ≥31% 75% of bonus ≥32% 100% of bonus ≥33%	Rural incentives accounted for 33% of all incentives disbursed in 2024.

Future Focus on Energy Budgets and Outcomes

Annual IOU contributions to Focus are based on utility revenues and therefore can vary year-to-year. Figure 3-1 shows Focus' actual and projected energy efficiency contributions from electric operations from 2024 through 2032. Historically, approximately 77 percent of Focus' annual contributions are derived from IOU electric revenues and contributions from municipal electric utilities and retail electric cooperatives. The remaining 23 percent of Focus' annual contributions are from IOU natural gas revenues.

The Commission calculates each IOU's required contribution based on a three-year rolling average of operating revenues multiplied by 1.2 percent. Following a period of generally stable contributions, IOU annual contributions to Focus from electric operating revenues increased nearly 11 percent between 2024 and 2026 as recent years with higher IOU revenues have begun to factor into the three-year rolling average calculation. In their data submissions for this SEA, IOUs projected flat Focus contribution levels from electric revenues between 2026 and 2032. Expenditures may exceed these projections as new data center loads are expected to significantly increase utility revenues and thereby increase contributions to Focus. Spending on additional utility programs and activities are projected to increase modestly from 2025 to 2026, then remain stable through 2032.

Figure 3-1 Actual and Projected Annual Energy Efficiency Expenditures from Electric Utility Operations, 2024-2032[79]



The Planning Study,[80] completed in 2025, analyzed energy savings potential and associated avoided electric generation emissions for each hour of the day over 12-years, from 2027 through 2038, a period that covers three Focus quadrennial planning cycles. The study used simulation modeling to estimate energy efficiency measure adoption over time, leveraging primary research on customer decision-making, project payback periods, and market maturity of Focus programs.

To ensure that scenario impacts are comparable to Focus' historical performance, the study calibrated the baseline portfolio design to current offerings and worked with Focus stakeholders to understand the potential impacts of adapting future program designs to emphasize impacts beyond energy savings. To achieve this objective, the study's analysis centers on six potential program design scenarios:

1. Baseline: Maintaining current offerings and budget distributions.
2. Emissions Focused: Emphasizing measures with maximum emissions reduction potential.
3. Summer Electric Peak Focused: Emphasizing measures that reduce summer electric peak demand.

[79] Aggregated electricity provider data responses, docket 5-ES-113; Focus Fiscal Agent annual financial statements.
[80] PSC REF#: 571434

4. Summer Electric Peak Focused with Load Shifting Program: Adding a program to Scenario 2 that specifically focuses on electric load shifting.
5. Electrification Focused: Expanding baseline offerings to include additional electrification measures.
6. Cost-Effectiveness Focused: Emphasizing the most cost-effective measures.

These scenarios, developed in consultation with Focus stakeholders, present the impacts and trade-offs from modifying the current program delivery approach to emphasize potential policy priorities for Focus.

Figure 3-2 is an excerpt from the final Planning Study report showing the estimated cumulative lifecycle energy savings for each program scenario for the 2027-2030 Quad V period.[81] It should be noted that the savings shown in Figure 3-2 are the combined electricity and natural gas savings associated with each scenario.

Figure 3-2 Focus on Energy Quad V Planning Study Scenario Results

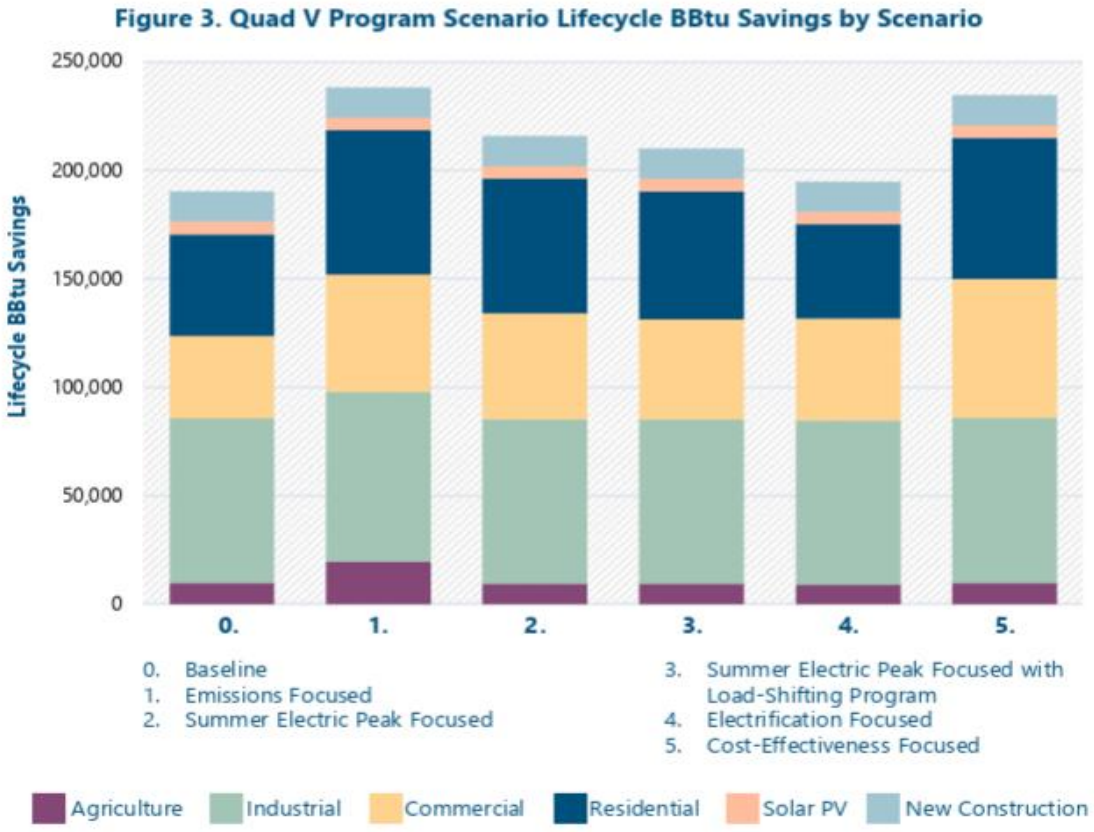
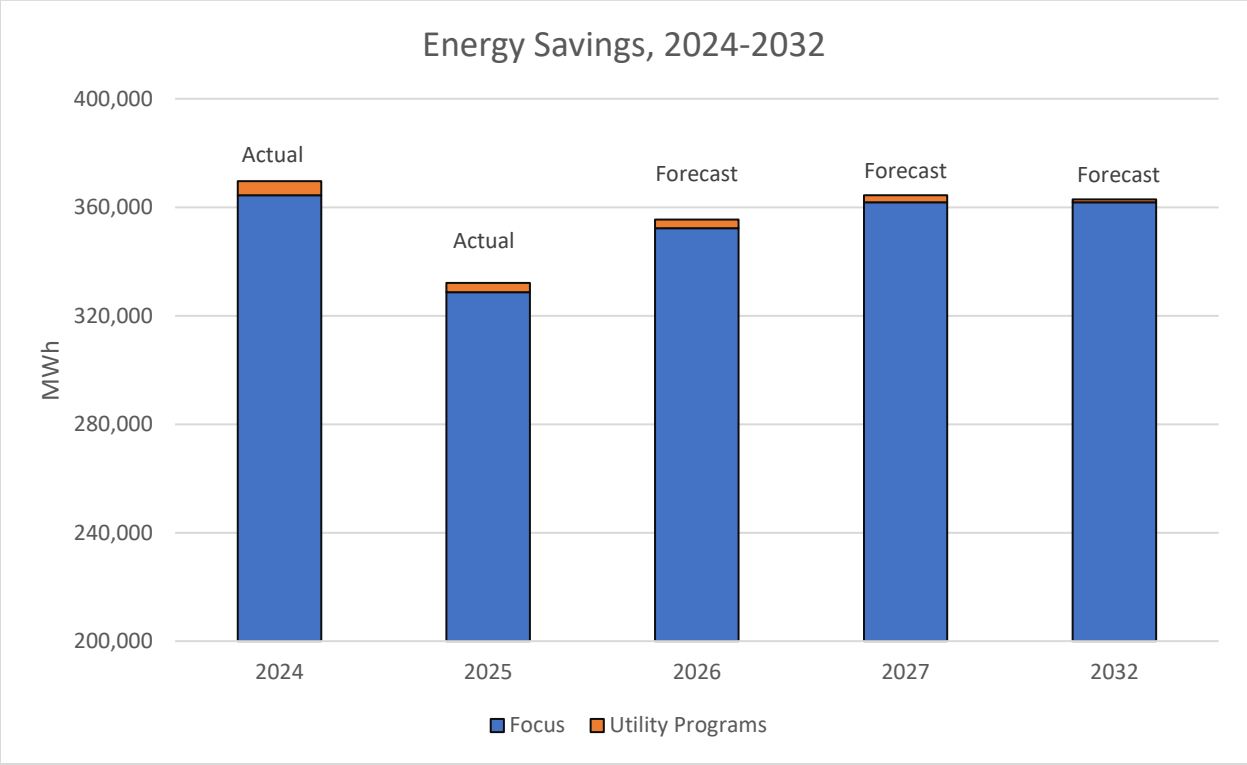


Figure 3-3 shows actual and projected electric energy savings for Focus and utility-operated programs with savings that are incremental to Focus. Forecasted electric

[81] *Ibid* at 6.

savings for Focus align with first-year electric savings modeled under the Planning Study's Baseline scenario. Modeling results indicate electric savings are likely to become more expensive in the future. Therefore, the amount of electric savings that may be achievable with Focus' budget is forecast to decline under a scenario where program design and budget allocations by program are maintained. This may be expected due to the impacts of Federal LED lighting efficiency standards on claimable electric savings and customer interest in space and water heating electrification measures. Utility program savings are projected to decline, mostly due to lower levels of forecasted savings reported by DPC, which has members that do not participate in Focus.

Figure 3-3 Actual and Projected First-Year Electric Energy Savings 2024-2032[82]



In early 2026, the Commission approved Quadrennial Planning Process V scope topics as the following: Savings Goal Priorities, Renewables, Peak Demand Priorities, Market Transformation Priorities, Program Evaluation Priorities and Underserved Customer Priorities,[83] and staff issued a memo for public comment on those topics in April 2026.[84] The Commission made decisions to set the overall priorities for Quad V of Focus in May 2026. The Commission made decisions to set the goals and measurable targets for

[82] Sources: Aggregated electricity provider data responses, docket 5-ES-113; Focus on Energy 2024 Evaluation Report; Quad V Planning Study, Baseline Scenario Annualized First-Year Electric Savings.
[83] PSC REF#: 580871.
[84] PSC REF#: 587165.

Quad V of Focus in October 2026 following APTIM's submission of a Quad V portfolio plan and public comment period seeking input on the proposed plan.

Demand Response

Demand response programs provide customers with incentives to reduce energy usage during peak periods, to support reliability and create financial savings for electric providers and customers. Historically, utilities deploy demand response programs primarily in the summer months, to control demand on very hot days where increased air conditioner use creates high energy demand. However, utilities may also use these programs for other circumstances, where they can help ensure a cost-effective balance between demand and available supply.

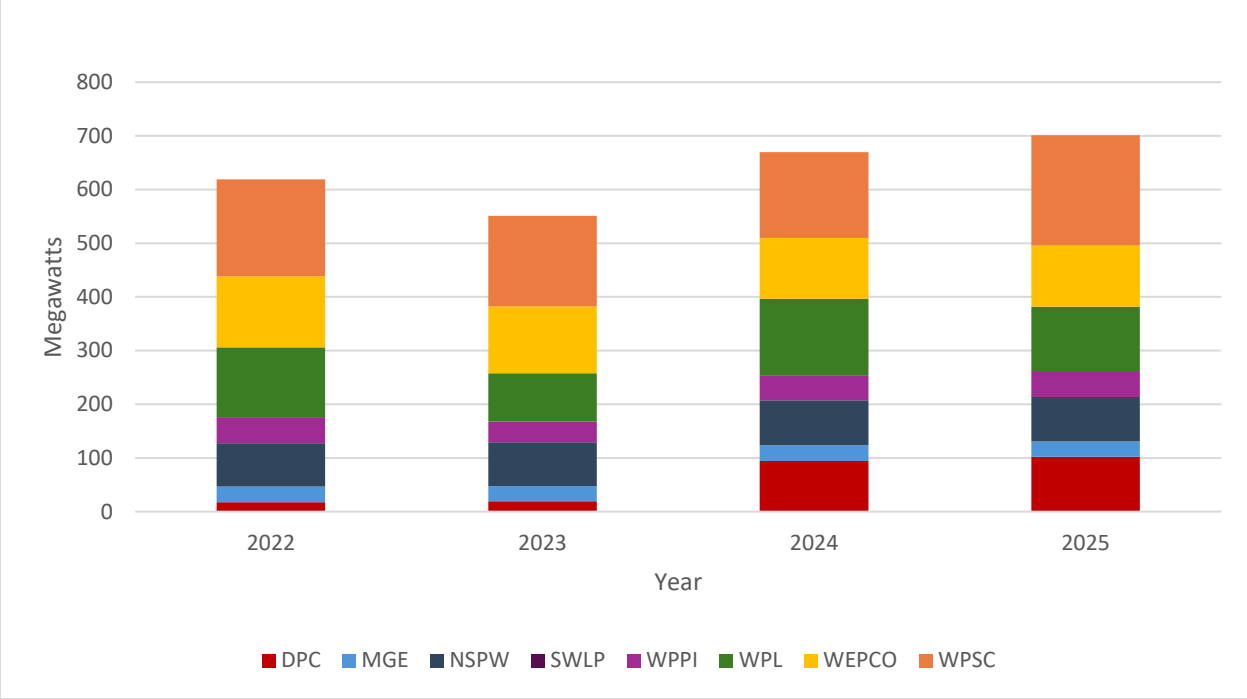
A wide range of initiatives can be categorized as demand side management, including time of-use rates, demand bidding, behavioral demand response, and timed water heating. In Wisconsin, electricity providers pursue demand response through two primary mechanisms: direct load control programs and interruptible load tariffs.[12]

- **Direct load control** gives electricity providers the ability to control the use of customer equipment, such as residential air conditioners, to reduce load on the system. In return, participating customers receive a financial incentive. While direct load control programs historically operated through remote shut-offs of participant technologies, new program models control usage through customers' smart thermostats, using software to set thermostats at a higher temperature during peak demand periods, and in many cases, providing "pre-cooling" before peak demand hours to help customers remain comfortable during the event.
- **Interruptible tariffs** enable participating customers (typically industrial customers) to receive lower energy charges by agreeing to allow the electricity provider to interrupt load during periods of peak demand.

Wisconsin electric providers reported more than 140,000 customer enrollments in interruptible tariffs and direct load control programs, including more than 100,000 at DPC's member cooperatives. Appendix C provides more information on demand response participation by provider, and by individual demand response offerings available from each provider.

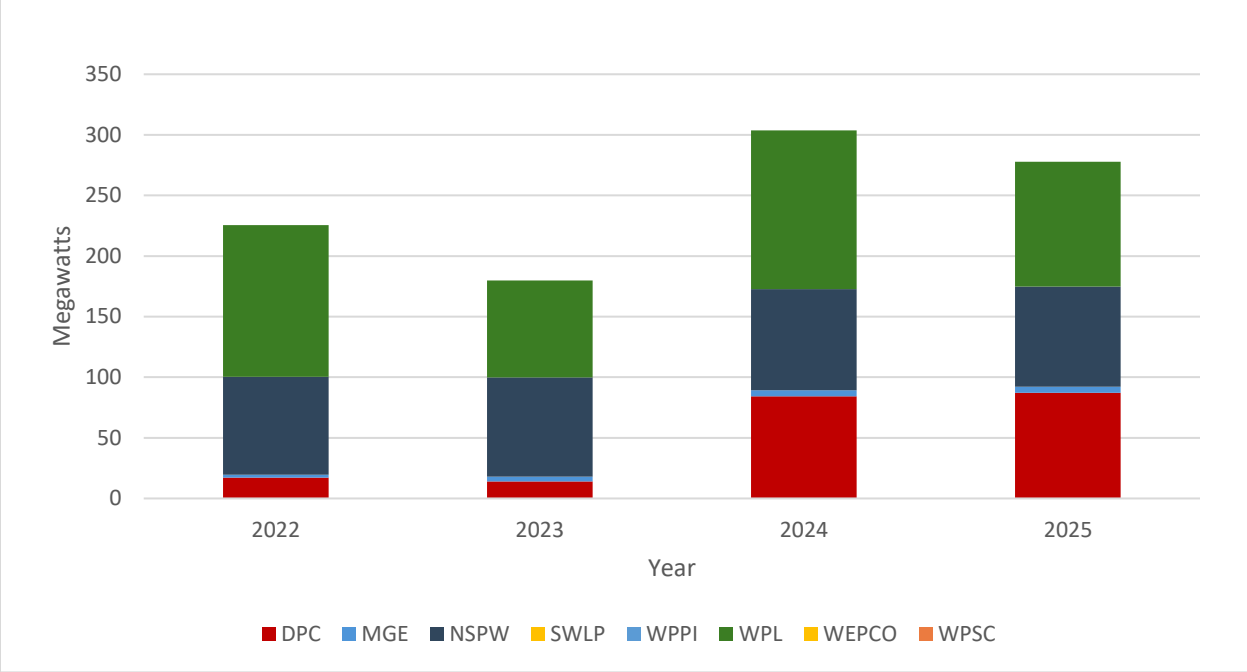
As shown in Figure 3-4, demand response capacity available through those offerings 701.37 MW in 2025, equal to approximately 5 percent of Wisconsin's total peak demand during the period. (See Chapter 1, Figure 1-1.) Interruptible tariffs accounted for approximately 80 percent of available capacity in each year, and direct load control programs accounted for the remaining 20 percent.

Figure 3-4 Demand Response Capacity (MW) in Wisconsin by Provider, 2022-2025



As shown in Figure 3-5, Wisconsin providers dispatched a limited fraction of their available demand response capacity in recent years. These dispatch rates largely reflect that demand response offerings are only utilized under specific programmatic conditions that vary by utility. In some cases, providers may dispatch demand response economically. In contrast, some interruptible load in Wisconsin is only dispatched if MISO calls on it to deploy, such as when the grid is experiencing emergency conditions, as specified in many providers' interruptible load tariffs. In these cases, Wisconsin providers offer reduced rates to interruptible tariff participants in return for registering their demand response capabilities with MISO, most commonly as Load Modifying Resources (LMR). MISO can obligate LMRs to respond in emergencies, and in return MISO credits the demand response capabilities of LMRs toward the providers' resource adequacy requirements (see Chapter 2 for more discussion on resource adequacy). Of the demand response resources registered with MISO as LMRs, Wisconsin providers reported a total of 515.17 MW in Seasonal Accredited Capacity (an average across seasons). These numbers are different than the total capacity of demand response reported in Figure 3-4 as not all direct load control and interruptible demand response programs are registered with MISO. This is also not the total value for all LMRs in Wisconsin, as resources other than demand response use that participation option also.

Figure 3-5 Demand Response Capacity (MW) Dispatched by Provider, 2022-2025



MISO has recently proposed numerous reforms related to its demand response products, some of which have been accepted already by FERC, which may impact participation in these programs in Wisconsin. These include Dockets Nos. ER25-1729, ER25-2050, ER25-2845, ER26-148-000

MISO is also working toward preparation for FERC Order 2222, with implementation planned for 2029. Through Order 2222, FERC ruled that injecting aggregated Distributed Energy Resources (DER), including from third-party aggregators, must be allowed to participate in wholesale markets. FERC still allows states to prohibit aggregations consisting only of demand response from participating in wholesale markets, consistent with its rulings in Orders Nos. 719 (2008) and 719-A (2009) from 2008 and 2009. ARCs can participate in the MISO wholesale regional market on behalf of retail customers of Wisconsin LSE) that have distributed over four million megawatt-hour (MWh) of energy in the previous year and are rate regulated by the Commission. The four utilities that meet these criteria are NSPW, WP&L, WEPCO, and WPSC. For all other utilities for which the Commission regulates rates, ARCs may not independently operate in their service territory unless and until the Commission permits them to do so.[85]

Renewable Energy

Historically, a primary driver for utility-scale renewable resource development by Wisconsin electric providers has been compliance with Wisconsin's RPS law. However,

[85] Commission order issued January 8, 2026, in docket 5-EI-163 (PSC REF#: 572541)

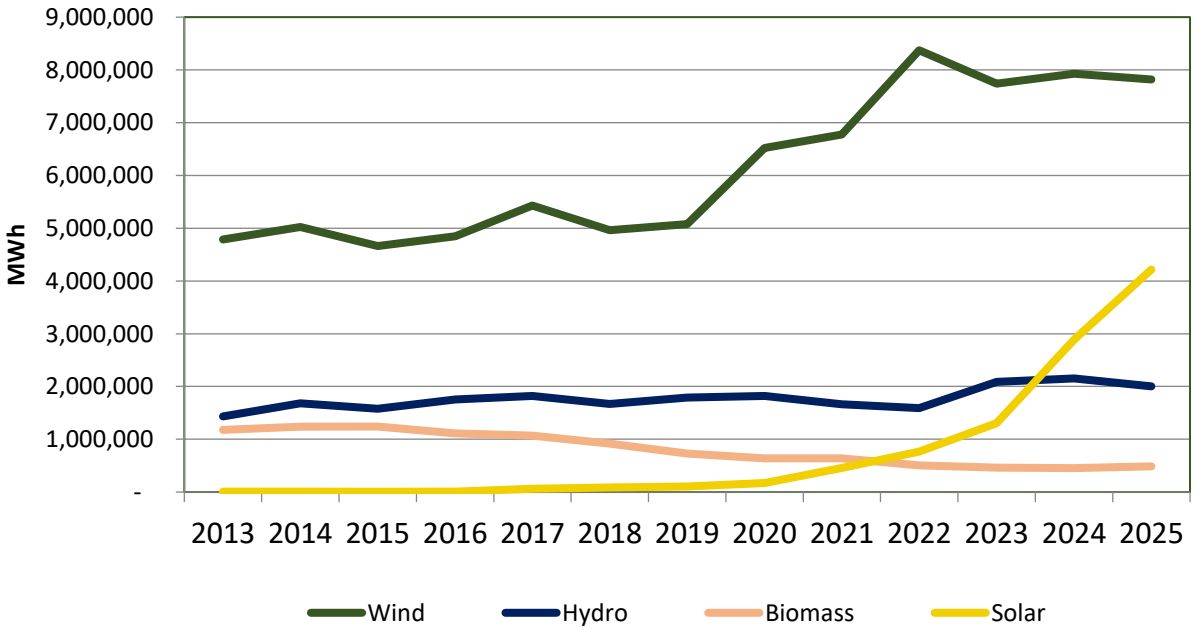
declining project costs, combined with increasing customer interest, as well as the benefits of renewables in helping meet emissions reductions goals, have driven renewable energy deployment beyond Wisconsin's RPS requirement. Three separate factors have contributed to this increase: greater deployment of utility-scale renewable facilities, growth in provider offerings such as community solar programs, and increased installations of customer-owned renewables.

Renewable Portfolio Standard

Wisconsin Stat. § 196.378, repealed and recreated in 2005, requires each electric provider to increase the share of renewable energy resources it uses to serve retail customers to achieve a statewide goal for renewable resources to provide at least 10 percent of energy generation by 2015.[14]

Individual electric providers have met their requirements every year since 2006, and the statewide goal of 10 percent of electricity coming from renewable sources has been achieved every year since 2013. As shown in Figure 3-6, wind energy accounts for the largest share of renewable resources providers have deployed to comply with the RPS.

Figure 3-6 Renewable Energy Generation by Resource, 2013-2025

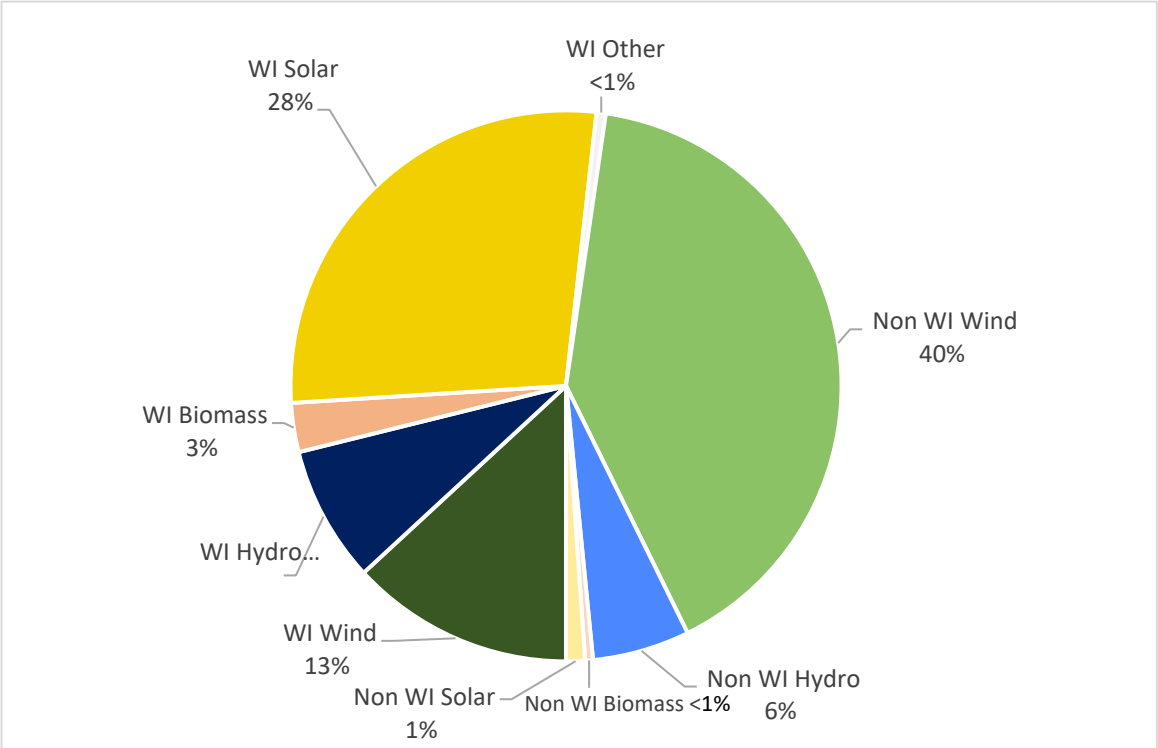


As shown in Figure 3-7, wind energy accounted for more than two-thirds of total renewable energy generation serving Wisconsin customers. Most of that wind energy, and more than half of Wisconsin's total renewable energy, is supplied through the transmission system from out-of-state facilities located west of Wisconsin, where more consistently windy weather conditions support cost-effective generation. Solar resources accounted for approximately 29 percent of total renewable generation serving Wisconsin customers in

2025, an increase from 11.2 percent in 2023. (These figures do not include solar generation used by individual customers, which is described in the Customer-Scale Renewables section below).

As discussed in Chapter 2, Wisconsin electric providers reported plans to add more than 7,600 MW of new electric capacity from renewable sources between 2024 and 2030, nearly all from solar energy. Providers reported that these planned additions reflect their preferred options, informed by resource planning analysis, to meet energy needs while balancing resource adequacy, reliability, affordability, emissions reductions, and other goals. If these additions are installed as planned, total renewable resources deployed in Wisconsin will continue to increase substantially beyond minimum RPS requirements. The phase-out of investment tax credits (ITC) and production tax credits (PTC) for renewable resources may result in lower renewable generation build-out than was anticipated when these incentives were available.

Figure 3-7 2025 Renewable Energy Generation by State and Resource



Electric Provider Solar Initiatives

Utility-scale solar construction projects increase the share of renewable generation provided to all customers. An increasing number of electric providers have also established 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 subscribe to energy produced by solar facilities on the provider's system.

Most commonly, customers pay a 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 program structure include NSPW, WP&L, and the WPPI municipal members River Falls and New Richmond. WP&L expanded its program in 2026, reserving subscription blocks for both first-time homebuyers and low-and-moderate income (LMI) customers. 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. By 2024, the Shared Solar program was fully subscribed and had a waitlist, prompting the application and subsequent approval of the Shared Solar II program. Superior Water, Light and Power Company's (SWL&P) Community Solar Garden structure offers customers the option to pay upfront, through a flat monthly fee, or a guaranteed retail rate. In 2022, the Commission approved Manitowoc Public Utilities' (MPU) application under docket 3320-TE-112 for a community solar program wherein customers would be charged monthly based on their share of the project's costs and receive a monthly credit that reduces energy charges based on their share of energy produced by the solar facility.[15] This project was expanded from 1,000 kW to 1,500 kW in docket 3320-TE-115 in 2023. Wisconsin Electric Power Corporation (WEPCO) offers a commercial "Solar Now" Solar PV System Hosting Pilot Program where commercial and industrial customers can host a utility owned solar PV system and receive monthly payments in exchange.[86]

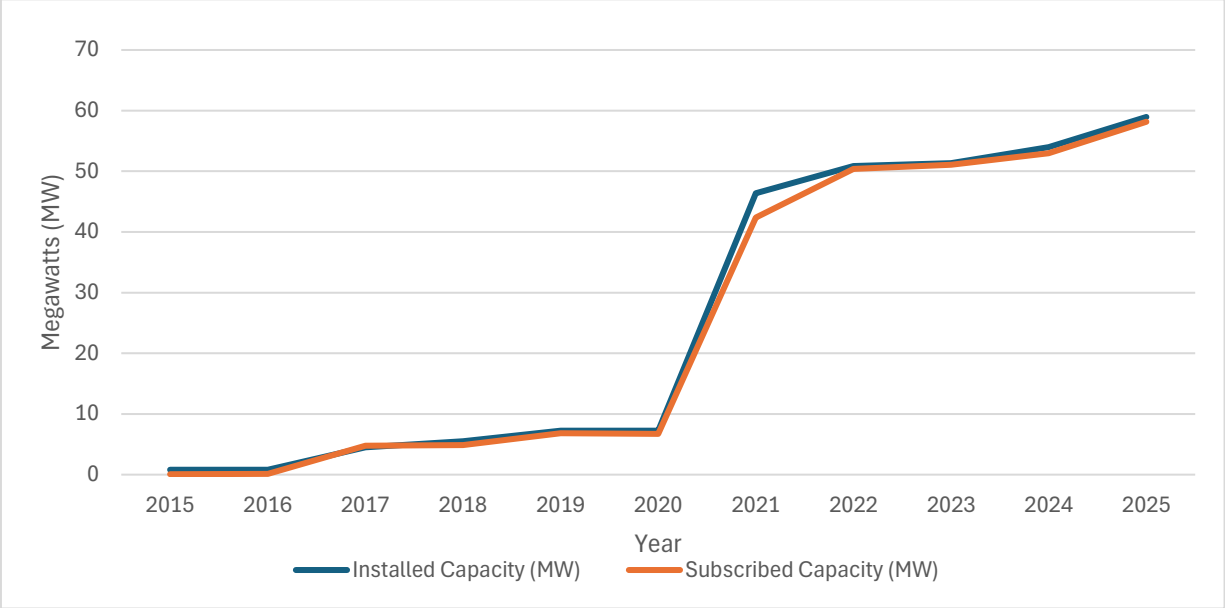
Although the number of utilities proposing community solar programs has plateaued since 2023, the capacity offered by these programs has increased. As shown in Figure 3-8, total capacity offered by Wisconsin community solar programs has increased slightly in recent years (between 2023 and 2025). Between 2023 and 2025, customer subscriptions were 98 percent to 99 percent of the available capacity in each year. In 2025, total subscribed installed capacity reached a high of 58 MW. This capacity is a substantial increase compared to levels in 2017, where installed capacity was approximately 4 MW. Some providers report plans to add or expand programs, which if implemented would further increase total community solar capacity in the coming years.

As another example of ongoing expansion of community solar, the Office of Energy Innovation (OEI) has received the first reported results of a community solar initiative with two electric cooperatives to increase the number of qualified low-income customers subscribing to new community solar projects. Couleecap, operating their Energize Wisconsin program in partnership with Vernon Electric Cooperative and West CAP in

[86] Wisconsin Electric Power Company - electric rates

partnership with Pierce Pepin Electric Coop have delivered significant results in the form of bill credits, delivered directly to the program participants, on a monthly basis.[87] [88] [89]

Figure 3-8 Community Solar Capacity in Wisconsin



Over forty 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. For example, MGE's O'Brien solar field in Fitchburg, authorized in docket 3270-CE-129, provides 20 MW of capacity, serving seven customers. In total, MGE's renewable energy rider program has led to 38.5 MW of solar capacity additions spanning four distinct projects.[90]

Customers may also procure renewable resources by installing their own sources of generation to 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, the Commission has asked all electric providers in Wisconsin to report data on the number, type, and generation capacity of all non-utility DERs used by their customers, including historical data. DERs are resources located on the distribution system and generally produce energy that is intended to be consumed on-site. Utilities and Independent Power Producers (IPPs) may also own DERs, however, the following analysis

[87] Couleecap 2024 Report: (PSC REF#: 583205)
[88] Couleecap 2025 Report: (PSC REF#: 583206)
[89] West CAP 2025 Report: (PSC REF#: 583207)
[90] Dockets 3270-TE-102: (PSC REF#: 374716); 3270-CE-128: (PSC REF#: 390034); 3270-CE-129: (PSC REF#: 398239); 3270-TE-130: (PSC REF#: 413525)

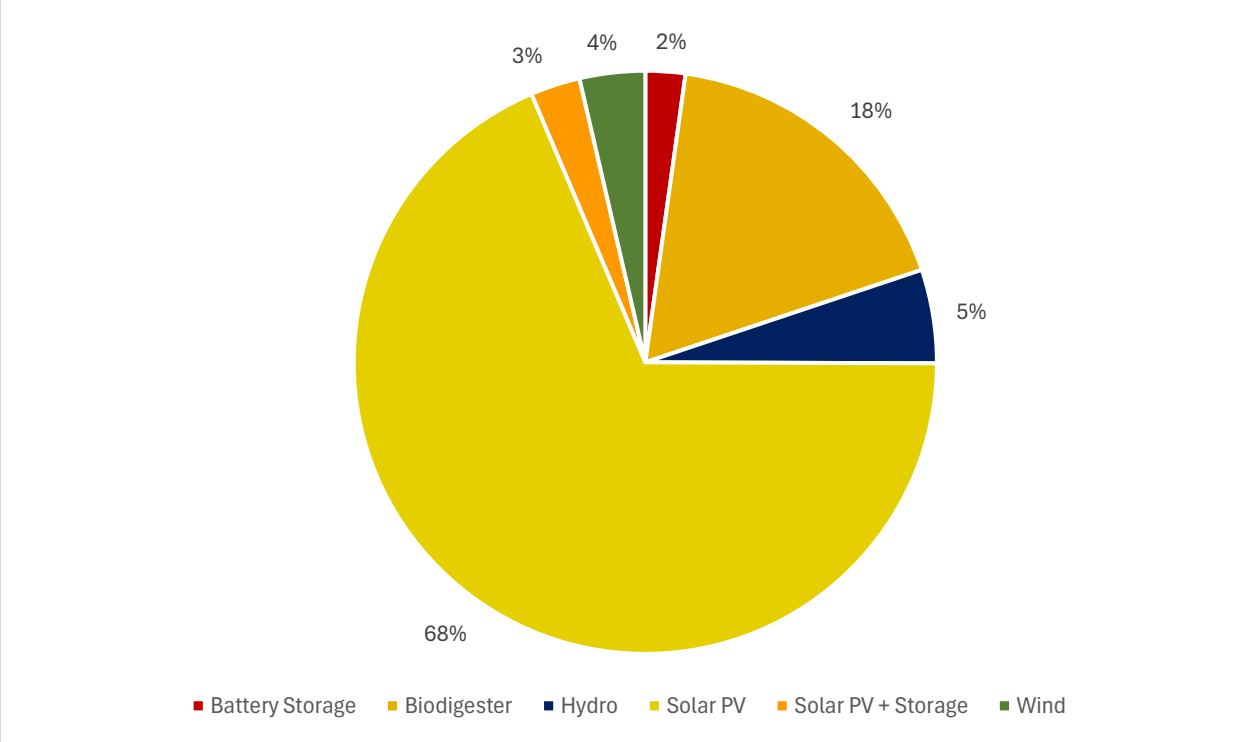
only focuses on DERs that are customer-owned, with the exception of some reporting provided for additional context.

Customer-owned DER data reported by utilities includes customer-owned generation that is from both renewable and non-renewable sources. Capacity numbers provided are nameplate, unless resources were accredited with MISO in which case the capacity value reported is the Seasonal Accredited Capacity (SAC) value (an average across seasons).

Non-renewable sources included 10 MW (AC) from gas turbines, 67 MW (AC) from internal combustion, and 22 MW (AC) from diesel. There were also 22 MW (AC) of "Other" DER that were reported.

Customer-owned renewable generation capacity in Wisconsin totaled 464 MW (AC) in 2025. The contribution of each renewable resource type to that total is shown in Figure 3-9.19 Customer-owned solar installations account for the largest share by source. At a total capacity of 318 MW(AC), customer-owned stand-alone solar accounts for 68 percent of renewable DER capacity. Such capacity increased compared to 2023 values, where it totaled 201 MW and from137 MW (AC) in 2021. The wind category also includes the limited number of resources reported as wind plus storage, wind plus solar PV, or wind plus solar PV plus storage.

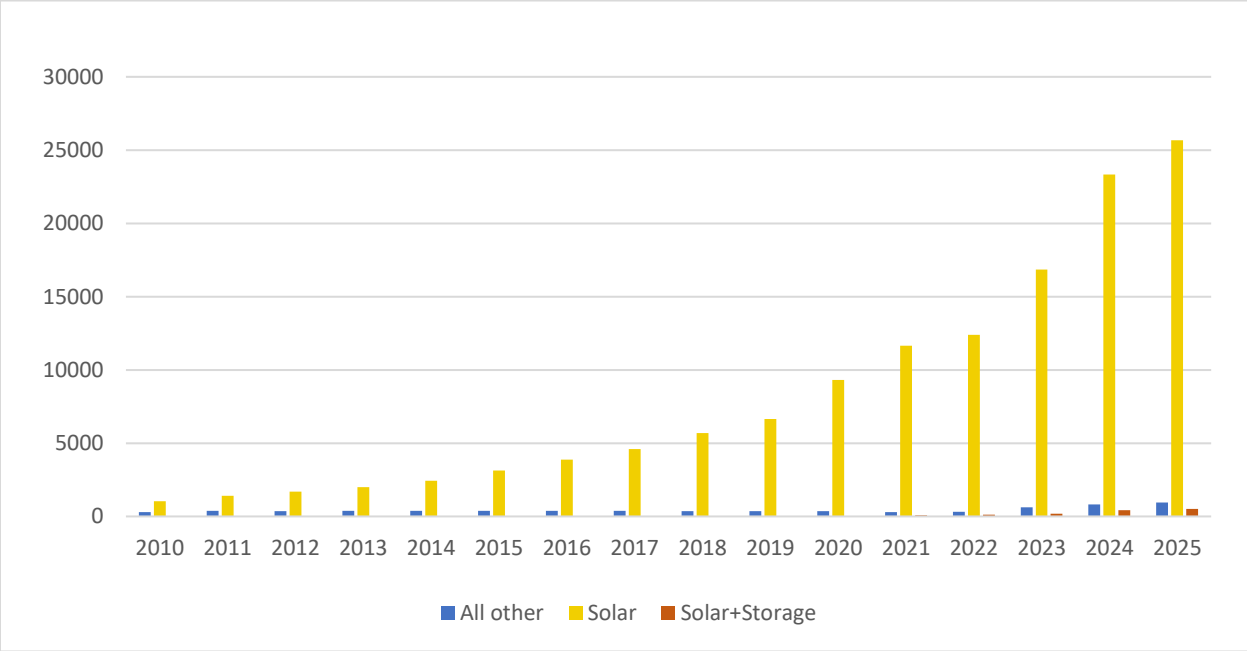
Figure 3-9 Proportions of Capacity of Customer-Owned Renewables in Wisconsin, 2025



As shown in Figure 3-10, the number of customer-owned renewable installations increased from 1,346 in 2010 to 27,152 in 2025. The most common category of installation

is solar, with 25,679 solar installations in the state as of 2025 (up from 16,486 reported solar installations in 2023). There were also 512 installations of solar plus storage, in 2025, an increase from 183 installations in 2023. Among other reasons, the increase in installations in recent years were likely driven by investment and production tax credits for residential and commercial customers available under the IRA. Future trends in customer-owned renewable installation may be impacted by provisions in the One, Big, Beautiful Bill (OBBB) signed into law July 4, 2025. The OBBB ended the 30 percent residential federal tax credit for customer-owned renewable systems installed after December 31, 2025 and phases out tax credits for commercial projects that are placed in service after December 31, 2027, or that begin construction after July 4, 2026.

Figure 3-10 Number of Customer Owned Renewable DER Installations, 2010-2025



As shown in Table 3-2, residential customers owned a large majority of total stand-alone solar installations in 2025. As most residential installations are small-capacity systems, commercial and industrial installations account for a similar quantity of capacity as the residential units. For additional context, the table also lists solar DER from utilities, including those identified by utilities as community projects that they support.

Table 3-2 2025 Solar DER Snapshot by Category

Category	Number of Installations	Capacity (MW-AC)
Residential	22,989	161.68
Commercial and Industrial	2,690	156.31
Utility-backed Community Projects	14	21.02
Utility-owned	46	29.90
Total	25,739	368.91

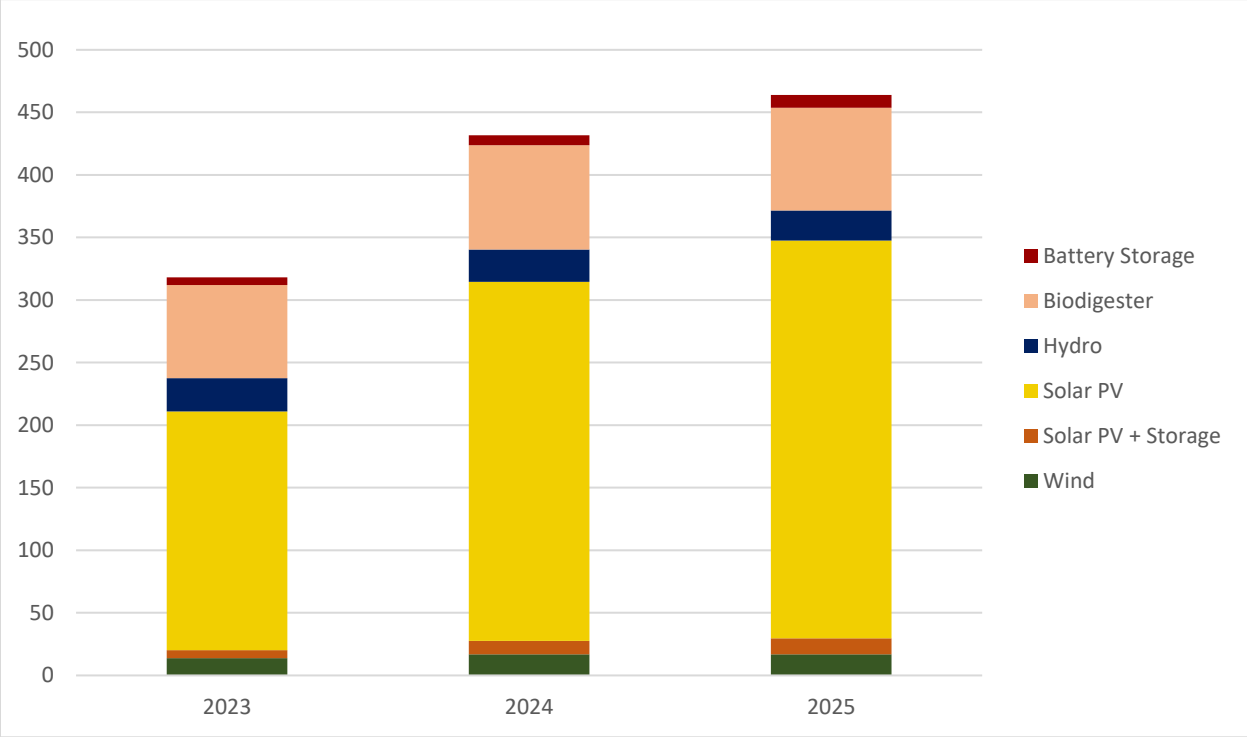
There are also a growing number of solar *plus* storage installations, as shown in Table 3-3, particularly in the residential category. (See Appendix C, Figure C-1 for further information on all customer—owned renewable installations by customer class.)

Table 3-3 2025 Solar Plus Storage DER Snapshot by Customer Category

Category	Number of Installations	Capacity (MW-AC)
Residential	475	6.60
Commercial and Industrial	37	6.16
Utility-owned	1	.01
Total	513	12.77

As shown in Figure 3-11, capacity from all customer-owned renewables has increased since 2023. As previously clarified, the wind category also includes the limited number of resources reported as wind plus storage, wind plus solar PV, or wind plus solar PV plus storage.

Figure 3-11 Capacity MW-AC of Renewable DER Installations by Renewable Source, 2023-2025



Eligible customers who own generation can receive bill credits for providing excess energy production from their generation back to their electric provider, this is typically called net-energy-metering (NEM). The rate paid (i.e. the credit received) for excess generation

provided to the grid under NEM is commonly set at the customer's retail rate of electricity. In recent years, certain jurisdictions are transitioning away from NEM at retail rates to successor tariffs more closely aligned with utility cost-of-service.

In August 2025, in docket 5-EI-157, the Commission directed staff to continue its investigation into parallel generation purchase rates and conduct a review of solar PV adoption rates, analysis of various net metering rate designs, and an evaluation of the impacts these net metering rate designs have on adoption rates, affordability, and other factors. Work remains ongoing in this investigation.

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. The number of EVs registered in Wisconsin as of June 2025[91] has surpassed 35,052 which is significantly more than the 25,457 reported in June 2024,[92] and the 17,084 reported in June 2023.[93]

Wisconsin Electric Vehicle Infrastructure (WEVI) Program.

WisDOT has been tasked with administering the funds available through the NEVI program. In November 2021, the Bipartisan Infrastructure Law (BIL) was signed, designating $7.5 billion to build a national EV charging station network. The NEVI Program includes $5 billion of this funding, laying the groundwork for formula funding designation and use. NEVI is specifically intended to build out the EV charging system along federally designated Alternative Fuel Corridors (AFCs). WisDOT is required by the Federal Highway Administration (FHWA) to develop and submit a state plan as a prerequisite to accessing federal funding for EV infrastructure deployment. Wisconsin's 2025 NEVI Plan was submitted in September 2025 and was approved by FHWA on September 18, 2025.

Under Wisconsin's program, referred to as the WEVI Program, the state is eligible to receive approximately $78 million in NEVI formula funds over five years beginning in federal fiscal year 2023. Under NEVI Program Requirements, WisDOT must fully build out its EV AFCs with EV charging stations. Currently, in Wisconsin, these include five Interstates: I-90, I-94, I-43, I-41, and I-535; seven U.S. Highways: US 8, US 41, US 53, US 151, US 2, US 51, and US 141; and one State Highway: WIS 29. Once the designated AFCs are certified as fully built out by FHWA, Wisconsin will have more discretion in determining the location of new charging stations funded under the NEVI Formula Program.

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[91] https://wisconsindot.gov/Documents/dmv/shared/rpt-25-fiscal-25.pdf
[92] https://wisconsindot.gov/Documents/dmv/shared/rpt-25-fiscal-24.pdf
[93] https://wisconsindot.gov/Documents/dmv/shared/rpt-25-fiscal-23.pdf

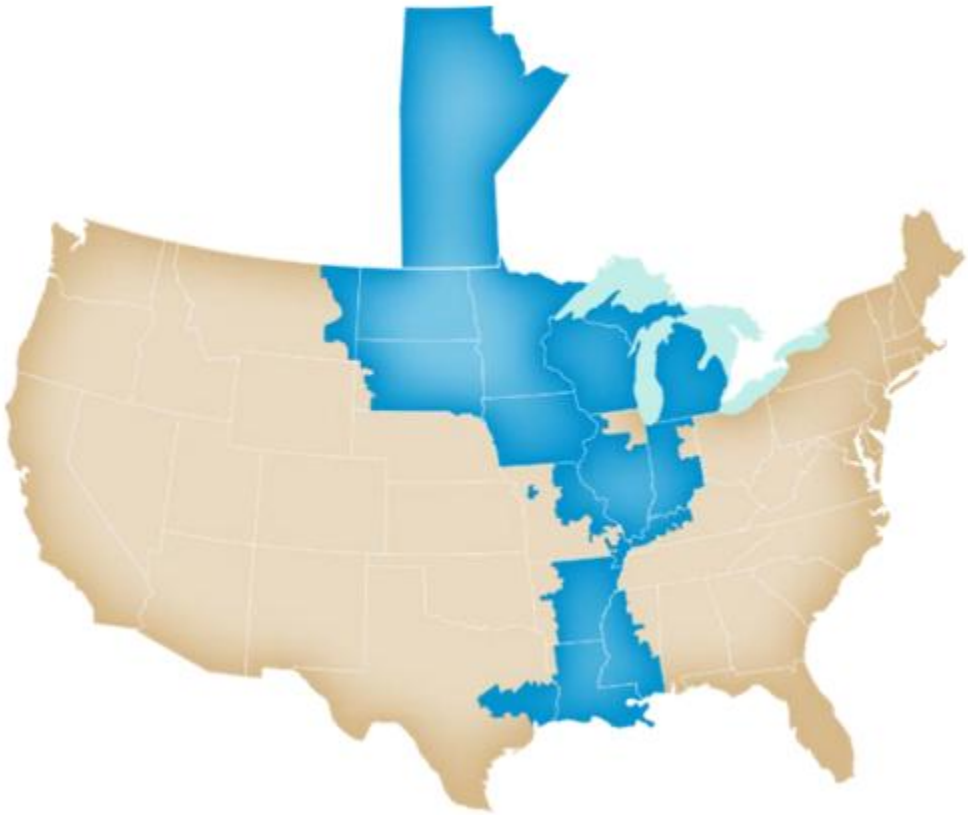
WisDOT issued its first WEVI Program Request for Proposals (RFP) in early 2024, identifying up to 65 locations along AFCs needed to meet NEVI build-out requirements. The first round of awards, announced in May 2024, provided roughly $23 million in federal NEVI funding for 52 charging station projects across the state.

In November 2025, WisDOT announced Round 1.5 WEVI Awards, allocating approximately $14 million in NEVI funds to 26 additional charging station locations to fill gaps and advance corridor build-out. These sites continue to meet NEVI requirements, such as a minimum of four ports per station with at least 150 kW per port, with most also including NACS connectors and amenities like pull-through parking and proximity to adjacent 24-hour services. These combined rounds bring total awards to more than 78 projects funded under the WEVI Program to date as Wisconsin works toward comprehensive AFC coverage.

Chapter 4 – Electric Transmission in Wisconsin

Wisconsin electric providers are responsible for providing 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 4-1.

Figure 4-1 Map of MISO Regional Transmission System



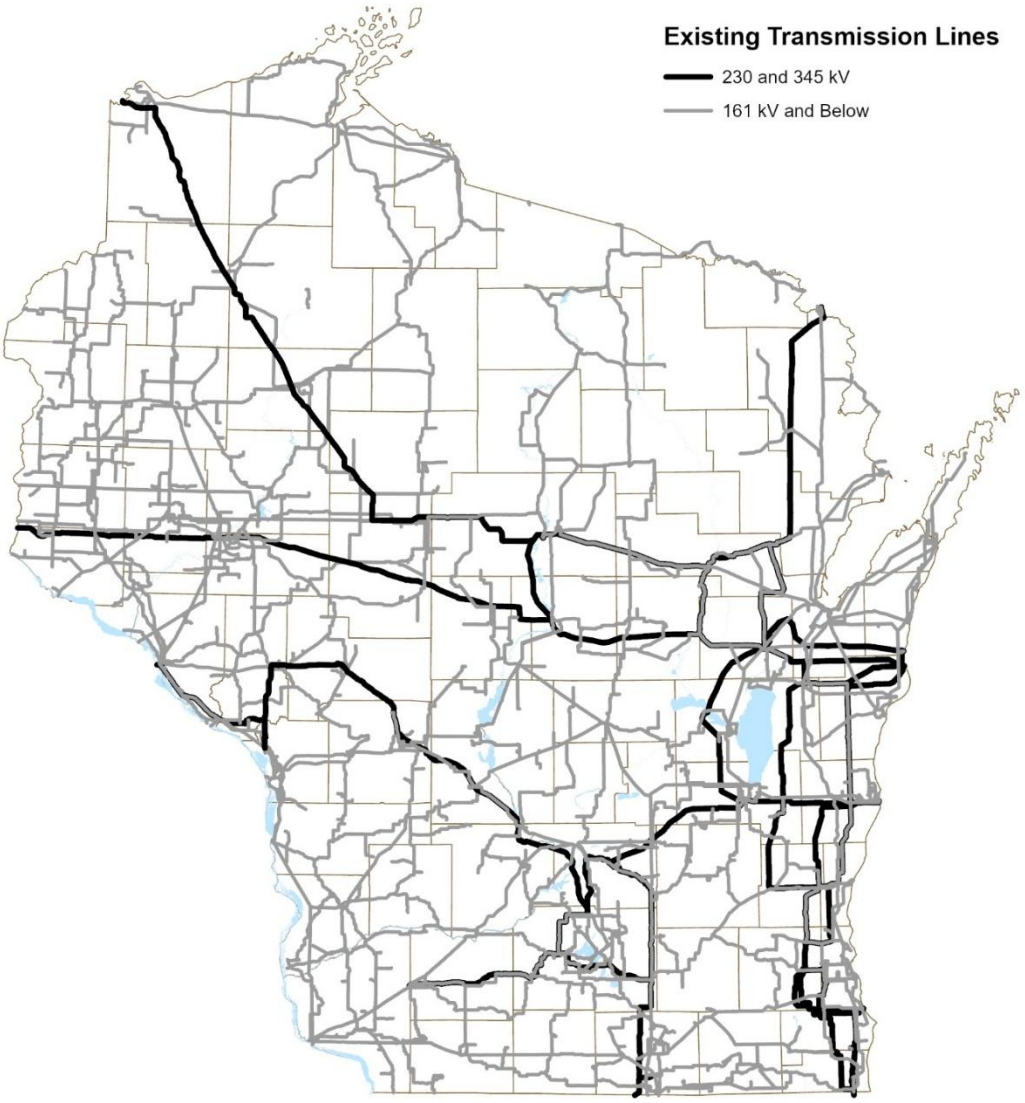
Participation in MISO helps Wisconsin's electric system access additional benefits within a larger regional context, including:

- Accessing less expensive wholesale energy and capacity resources available outside of Wisconsin;
- Reducing the generation capacity reserves any single provider may need to meet peak customer demand by taking advantage of more diverse supplies and load patterns;

- 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 4-2. Transmission lines with higher voltage ratings are designed to carry the largest volume of energy over longer distances, connecting high-demand areas in Wisconsin with generation resources located in other parts of the state and in other states in the MISO region.

Figure 4-2 Existing High-Voltage Transmission Lines in Wisconsin



Historical Transmission Costs

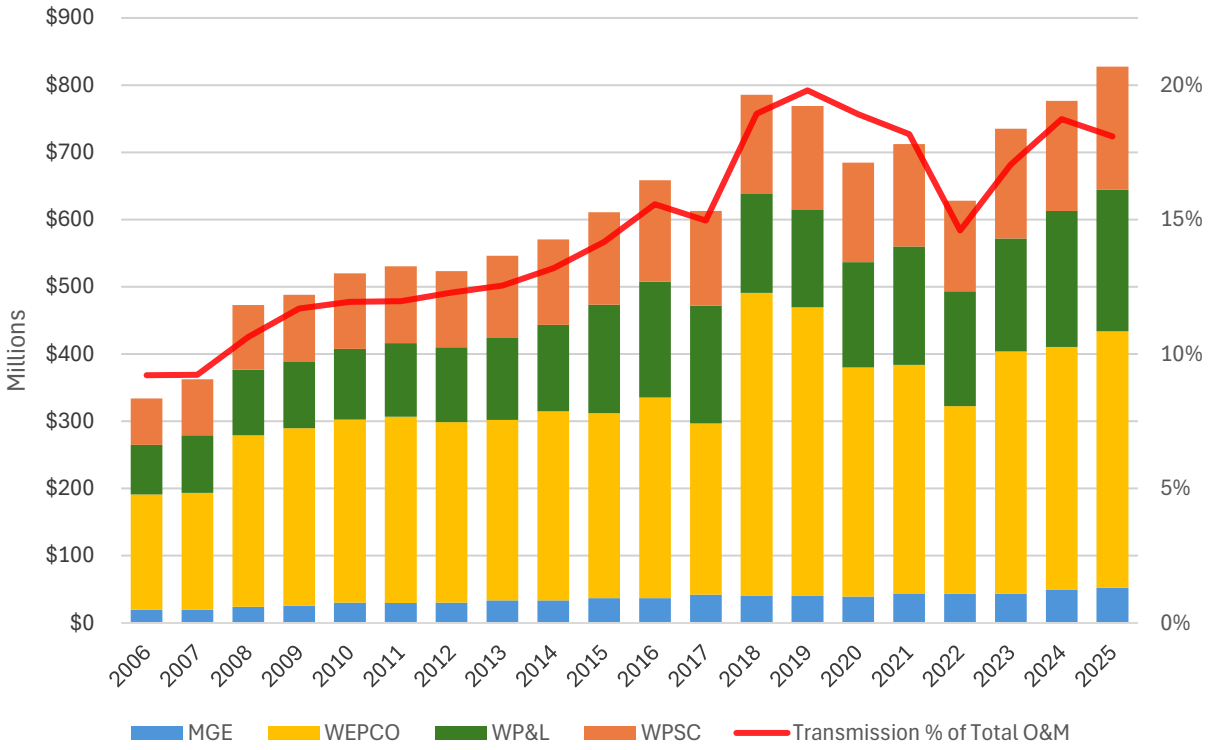
Transmission development and operation occurs collaboratively between MISO and individual providers within the region. Most Wisconsin electric providers do not own or operate their own high voltage transmission lines and associated infrastructure. In Wisconsin, such assets are predominantly owned by the American Transmission Company LLC (ATC), the transmission company formed in 2001 and jointly owned by a conglomerate of Wisconsin utilities which builds and operates all transmission infrastructure in the territory of participating providers and participates in MISO planning and operations along with individual providers. NSPW operates transmission independently of ATC because NSPW utilizes the transmission network owned by its parent company. DPC also operates its own transmission system.

Three main regulatory bodies are involved in the recovery process of transmission costs: FERC, MISO, and the Commission. Federal law assigns the highest authority to FERC in interstate transmission regulation. FERC has delegated the power to coordinate transmission services to regional transmission organizations and operators such as MISO and allows MISO to recover transmission costs according to approved FERC tariffs.

Under these rate structures, MISO facilitates payment for transmission services by Wisconsin electrical providers to ATC. Individual Wisconsin electric providers pay rates to MISO to cover transmission-related construction and operations expenses within their territory. MISO then distributes the revenue from electric providers to the appropriate transmission owners for their services. MISO also collects a charge from electric providers and transmission owners to cover the costs of its own planning and operations activities. The Commission reviews the costs regulated Wisconsin electric providers incur from MISO for these transmission services and approves recovery of costs through customer rates.

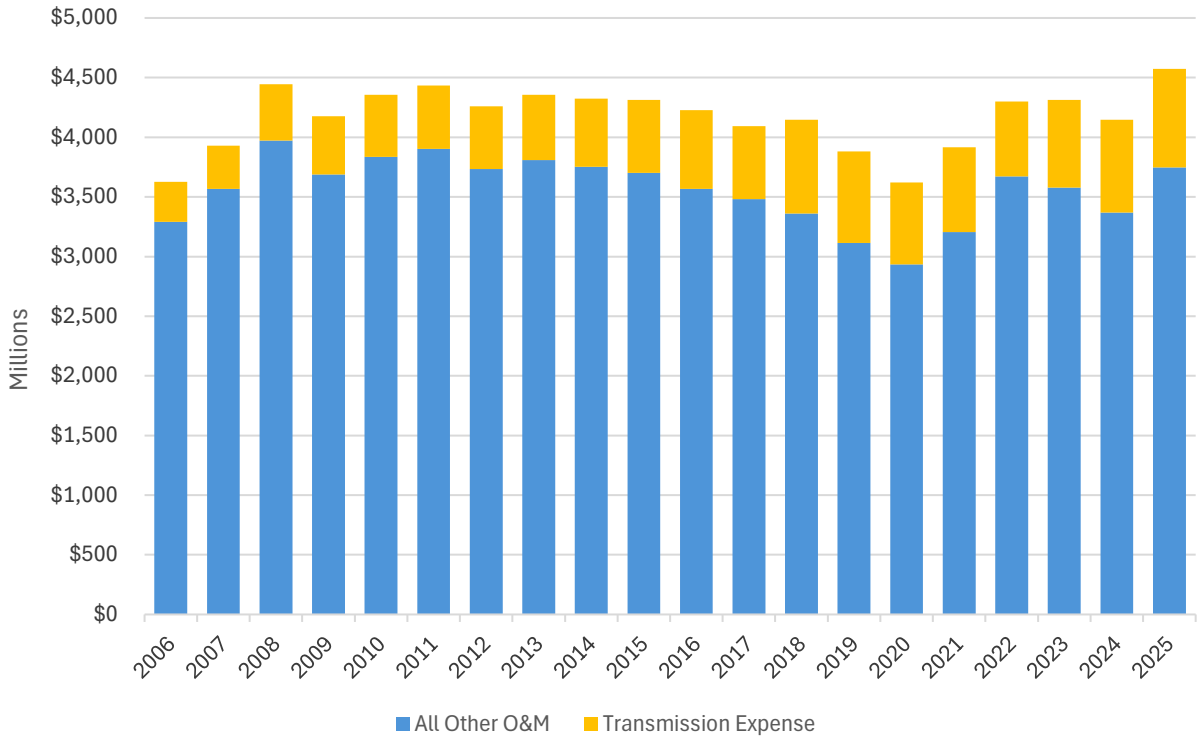
Figure 4-3 shows the transmission expenses reported by MGE, WEPCO, WP&L, and WPSC from 2006 through 2025. As an owner of its own transmission infrastructure, NSPW does not pay the same transmission service charges and, as such, is not included in Figure 4-3. Combined transmission expenses for MGE, WEPCO, WP&L and WPSC increased from $334.1 million in 2006 to $785.6 million in 2018. Combined transmission expenses subsequently decreased to $628.0 million in 2022, and have since increased again to $827.6 million in 2025.

Figure 4-3 Transmission Expenses MGE, WEPCO, WPL, WPSC 2006-2025



Transmission accounted for an increasing proportion of those electric providers' total Operations and Maintenance (O&M) expenses from 2006-2019. This proportion briefly decreased from 2019 to 2022, but has since increased again to a fluctuating range near the high of the period in more recent years. However, as shown in Figure 4-4, the total O&M expenses paid by customers have remained comparatively stable, ranging from approximately $3.9 to $4.6 billion each year between 2007 and 2025, except for a low of $3.6 billion in 2020 due to a decline in fuel costs associated with lower customer demand during the COVID-19 pandemic. Total O&M expenses have remained nominally stable overall despite recent inflationary pressures, though increased somewhat for 2025. Increases in transmission expenses have been offset by decreases in other O&M expenses due to a variety of factors, including reduced fuel costs associated with the increased deployment of renewable generation, the decline in natural gas fuel prices during the 2010s, and decreases in the energy market prices providers must pay for purchased power.

Figure 4-4 Operating Expenses MGE, WEPCO, WPL, WPSC 2006-2025



Regional Transmission Planning

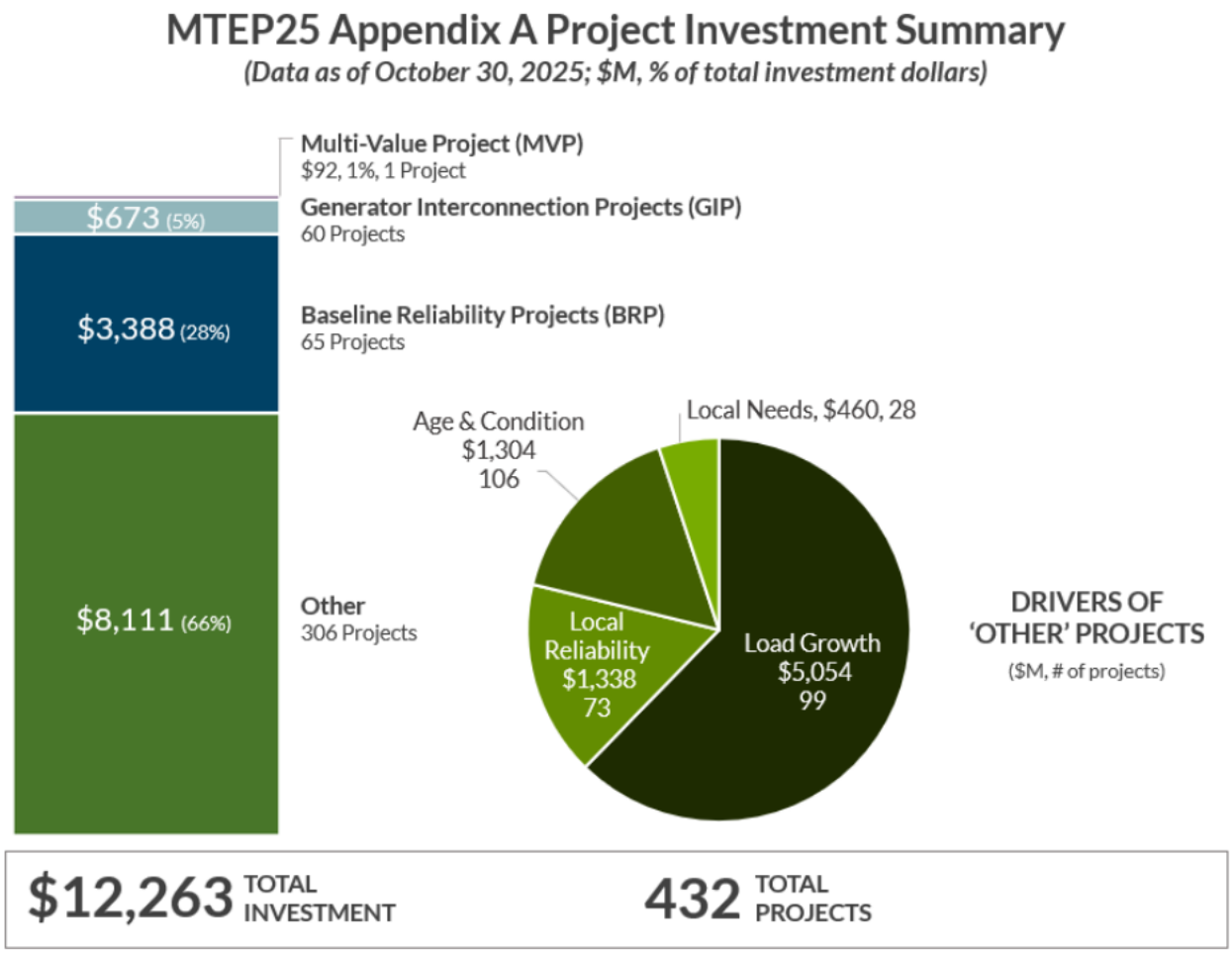
Increased transmission costs in Wisconsin over the past 17 years reflect increased transmission infrastructure development and construction costs. The annual MTEP process serves as a primary foundation for reviewing transmission needs and identifying and developing transmission infrastructure. MTEP focuses on identifying infrastructure sufficient to provide adequate energy delivery throughout the MISO region, meet national standards for maintaining service reliability, facilitate competitive regional energy markets, and support the policy goals of member states. Transmission projects identified and pursued through the MTEP process include:

- Baseline reliability projects, which resolve North American Electric Reliability Corporation (NERC) standards to ensure the regional grid functions reliably;
- Generation interconnection projects (GIPs) to support the addition of new generation facilities in specific locations;
- Market efficiency projects (MEPs) to reduce transmission costs by reducing congestion on the transmission grid;
- "Other" projects that resolve specific, typically local issues like:
  - Local reliability projects to address localized transmission capacity needs within transmission owner service areas;

- Age and condition updates to replace or enhance existing transmission infrastructure; and
- Load growth projects to update the transmission system to meet increased demand at specific locations

On the MISO region-wide basis, total costs from MTEP approved projects have steadily increased from $1 billion annually in 2010 to more than $3 billion each year since 2021. In the most recently completed planning cycle, MISO approved 432 MTEP25 projects totaling over $12 billion in costs across the entire regional footprint. As shown in Figure 4-5, load growth projects accounted for the largest share of approved projects region-wide, followed by baseline reliability projects.

Figure 4-5 MISO MTEP25 Snapshot (Footprint-wide)



Shares of MTEP-approved costs are allocated to Wisconsin and other individual states for projects located partially or entirely within their borders. As shown in Table 4-1, $1,839 million in costs for 73 approved MTEP25 projects are expected to be allocated to Wisconsin, with approximately $854 million in costs allocated to load growth driven projects.

Table 4-1 MTEP25 Projects in Wisconsin[94]

Types of Projects	Estimated Costs	Number of Planned Projects
Baseline Reliability Projects	$545,905,600	5
Generator Interconnection Projects	$128,271,456	20
Other[1]	$1,164,856,000	48
Age and Condition	$168,206,000	20
Load Growth	$854,658,000	14
Other Local Needs	$23,800,000	5
Reliability	$118,192,000	9
Total	$1,839,033,056	73

A key contributor to transmission cost increases throughout the past decade has been the implementation of MISO's MVP portfolio, a set of large-scale transmission projects across the MISO footprint. The first group of projects was approved by MISO in 2011 to alleviate congestion caused by rapid growth in wind generation. The MVP projects had a total estimated cost of $5.1 billion, with costs for each individual project incorporated into annual MTEP portfolios and recovered through provider expenses once each project is put in service. Unlike other MTEP projects, the cost of each MVP is shared over the entire region that MISO has determined to benefit from the project. Transmission owners who have built an MVP provide MISO with financial information regarding the project's cost. MISO then uses the information from all the MVP owners to calculate the MVP Usage Rate (MUR) charged to affected utilities to recover project costs.

MISO is currently in the process of planning additional groups of large-scale regional transmission projects through its LRTP process. Similar to providers' resource planning approaches (see Chapter 2), MISO and its stakeholders assess transmission needs under multiple scenarios that encompass a range of potential future economic, policy, and technology conditions. MISO reports that identified LRTP projects are primarily meant to address system reliability needs throughout the MISO region in light of plans across multiple states and utilities to retire existing resources and add a substantial amount of new resources.

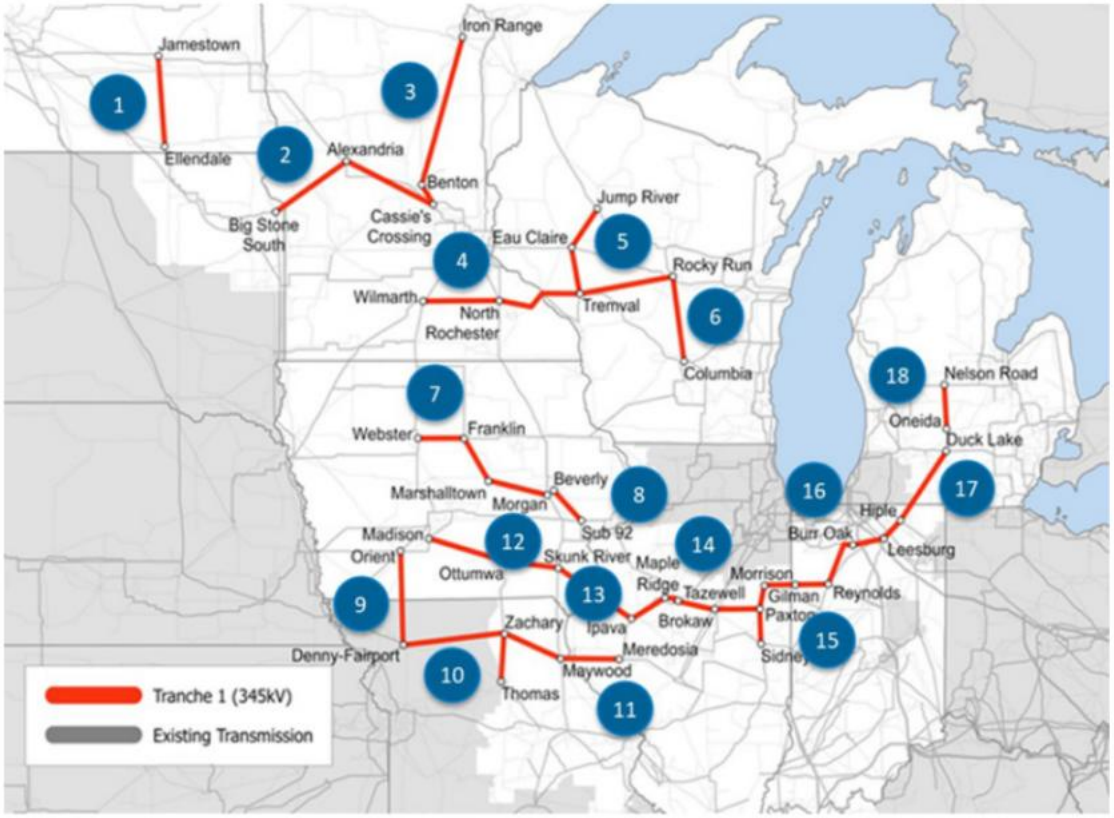
To date, MISO has approved two "tranches" of LRTP projects, each with projects in Wisconsin.

MISO approved LRTP "Tranche 1" projects shown in Figure 4-6 in July 2022 as an addendum to MTEP21. "Tranche 2.1" was approved in December 2024 as part of MTEP24 and builds on the foundation of Tranche 1. Planning is currently underway for additional

[94] The "Other" category includes Age and Condition, Load Growth, Other Local Needs, and Reliability Projects, which are italicized in this Table to distinguish these as sub-categories.

LRTP projects, with one set of solutions meant to address needs in the MISO Midwest (North/Central) sub-region (including Wisconsin) and another meant to address needs in the South sub-region of MISO.

Figure 4-6 LRTP Tranche 1 Transmission Portfolio



MISO reports that Tranche 1 represents a portfolio of least-regrets transmission projects aimed to ensure a reliable, resilient, and cost-effective transmission system as the region's generation resource mix continues to evolve. Total region-wide costs for the approved Tranche 1 projects was estimated at $10.3 billion. Projects approved by MISO require affected transmission owner(s), selected developer(s), or other designated entities to design, plan, and seek any required state or federal regulatory approvals. Under state law, projects sited in Wisconsin will be required to receive Commission approval. The transmission line review process involves rigorous reporting and analysis, as well as opportunities for public participation, as described for construction cases (Certificate of Authority [CA] or Certificate of Public Convenience and Necessity [CPCN]) in Chapter 2. As shown in Figure 4-7, LRTP Tranche 1 projects four, five, and six from Figure 4-6, are to be sited partially or completely in Wisconsin, and have been approved by the Commission under dockets 1515-CE-103, 5-CE-158, and 5-CE-157, respectively.

Figure 4-7 LRTP Tranche 1 Projects in Wisconsin

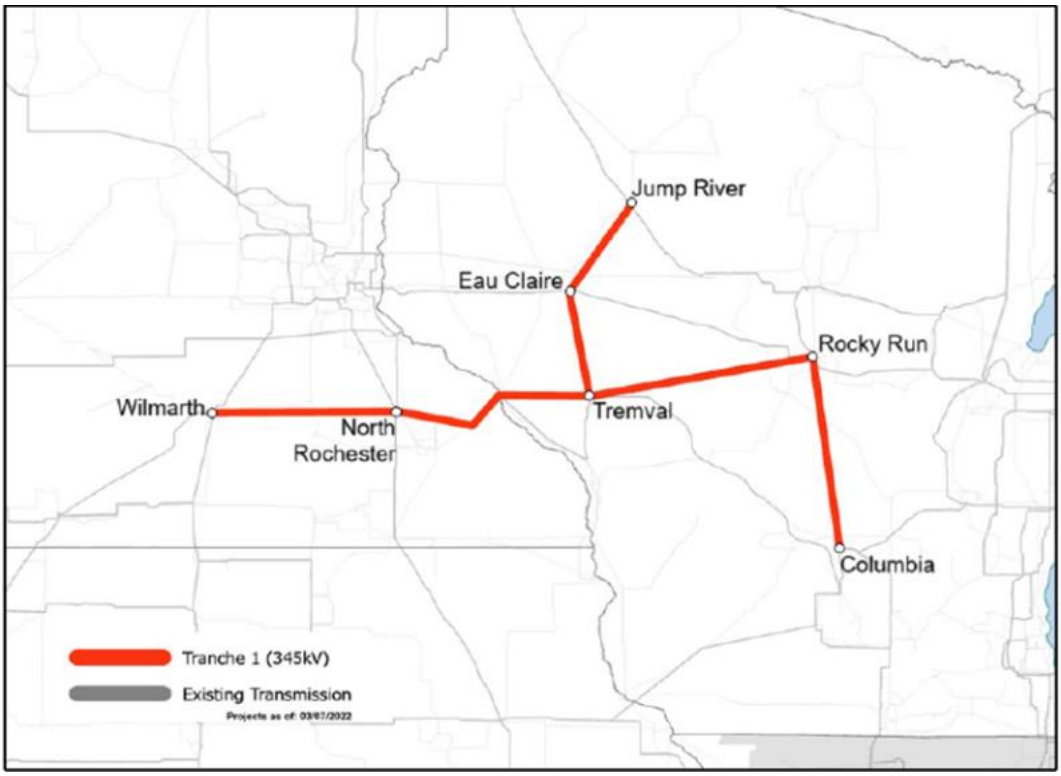
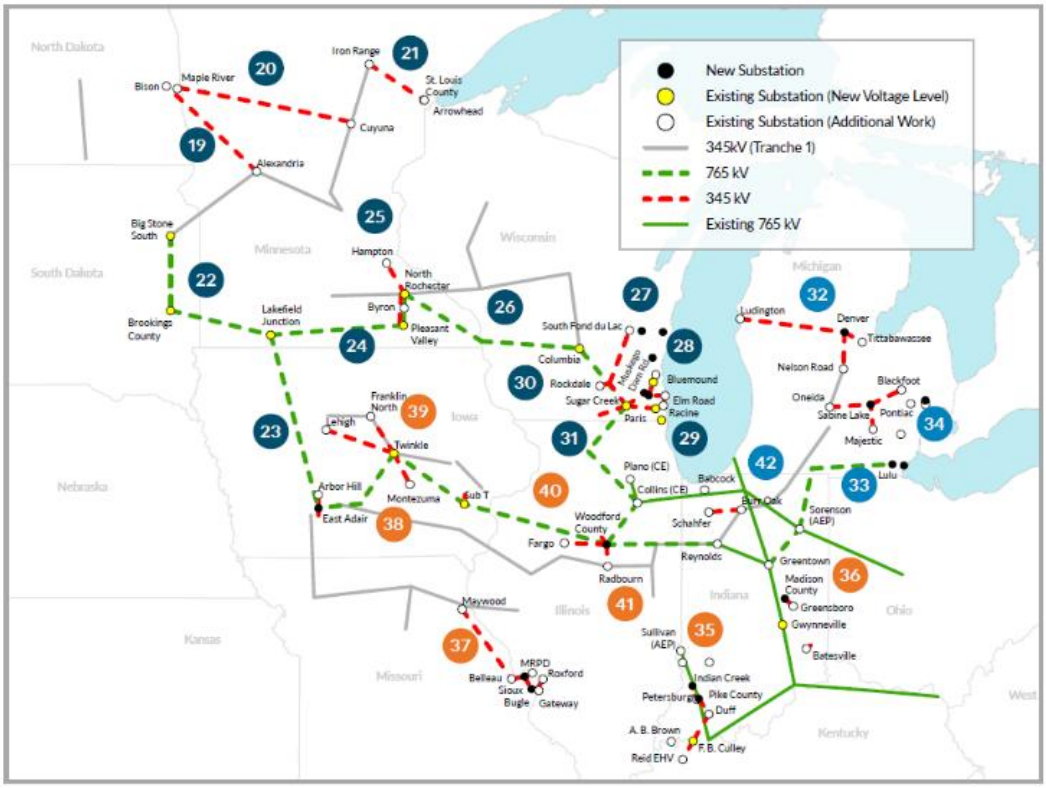


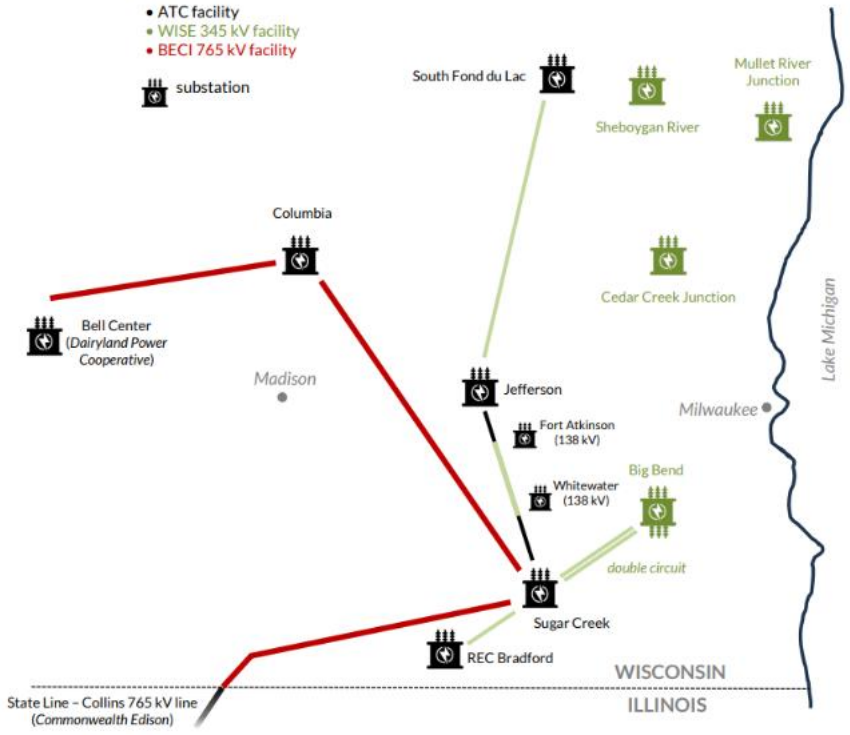
Figure 4-8 MISO LRTP Tranche 2.1



MISO reports that Tranche 2.1 represents a portfolio of least-regrets transmission projects aimed at providing reliability, transfer ability, and economic value throughout the MISO footprint. Total region-wide costs for the approved Tranche 2.1 projects were estimated at $21.9 billion. As shown in Figure 4-9, LRTP Tranche 2.1 projects 26, 27, 28, 29, 30, and 31 from Figure 4-7, are to be sited partially or completely in Wisconsin.

Per the MISO Tariff, LRTP projects are subject to MISO's Competitive Transmission Process if they are not subject to state or local right-of-first-refusal laws, or the majority of a project does not consist of updates or upgrades to existing transmission facilities. The Wisconsin Southeast or "WISE" (LRTP 2.1 Project 28) as well as Bell Center–Columbia–Sugar Creek–IL/WI Border or "BECI" (LRTP 2.1 Projects 26, 30, and 31) projects were subject to this process. The WISE project consists of new 345 kV transmission lines and new substations. The BECI project consists of new 765 kV transmission lines. Both projects are shown in Figure 4-9 below.

Figure 4-9 LRTP Tranche 2.1 Projects in Wisconsin



MISO approved the WISE and BECI LRTP projects assuming targeted in-service dates by June 1, 2033 and June 1, 2034, respectively. Both projects are expected to require a CPCN from the Commission before construction can commence.

Throughout the LRTP analysis process, the Commission has participated in MISO's public stakeholder processes that discuss the rationale for these projects and have worked with the OMS in reviewing the drivers and needs for these projects. This engagement will continue as MISO pursues analysis for all future LRTPs.[3]

LRTP projects allocate costs, similar to MVPs, to all users importing and exporting energy from MISO through the MUR. There are two sub-regions of the MISO footprint, a MISO Midwest (North/Central) sub-region that includes 11 states, including Wisconsin, and a MISO South sub-region that includes MISO's territory in the Southern states of Arkansas, Louisiana, Mississippi, and Texas. MISO allocates costs for LRTP projects in each sub-region only to customers in that sub-region, with exceptions for projects that provide demonstrated benefits to all of MISO. According to this method, the cost of the LRTP Tranche 1 and 2.1 projects would be shared amongst utilities in the Midwest sub-region using an MUR charge.

MISO calculates the MUR for each year of the project's life by dividing the annual revenue requirement of the projects by the total energy use of all the utilities located in the benefited region. MISO then charges each utility this rate based on their total energy usage. The Commission's preliminarily estimate found that Wisconsin electric providers could pay about $379.29 million for the Tranche 2.1 projects in the first year of service using MISO's forecasted energy use for Wisconsin electrical providers and the MUR (based on 2024 values), if the projects are approved for siting in each respective state. The costs allocated to Wisconsin electric providers would amount to 14.16 percent of the total charges MISO collects annually for these projects. Like other transmission expenses, the Commission will review regulated providers' recovery of those costs in future rate reviews.

In addition to delegating power to coordinate transmission services to regional transmission owners and operators, FERC may issue Orders that impact transmission processes for MISO and other transmission providers. In 2024, FERC issued Order No. 1920 which requires transmission providers, including MISO, to adopt long-term regional and scenario-based planning. MISO's LRTP processes and cost allocation methods may already align with the requirements of Order No. 1920, however, it is possible that the Order will necessitate changes to how MISO conducts long-term planning in the future. In addition to this Order, FERC issued an Advanced Notice of Proposed Rulemaking in 2024 on the Implementation on Dynamic Line Ratings (DLR) under FERC Docket No. RM24-6. DLRs are a prominent category of grid-enhancing technology. FERC's intention is for DLRs to improve overall grid performance and transmission efficiency, and as this issue progresses at FERC, there may be subsequent changes to MISO's processes.

Chapter 5 – Customer Rates and Bills

Through its regulatory authority over customer rates the Commission works to advance the goal of supporting an affordable electric supply. Rate regulation seeks to balance affordability for customers while setting the rates based on costs, allowing providers an opportunity to recover their reasonable costs and earn a fair profit. Under Commission regulation, many electric providers also work to develop new and innovative rates and programs to meet customers' evolving needs and to serve specific types of customers cost-effectively.

Utility Cost Drivers

One of the first steps in the rate setting process is for electric providers to propose a revenue requirement; the total amount of money a utility needs to recover through customer rates to provide adequate and reliable service. Historical costs and forecasts of future growth in customer energy use and future costs of providing service are the basis of the revenue requirement development. The revenue requirement also includes a return on equity (ROE) on the assets used to provide service, such as generation plants, which each provider uses to pay interest on money it borrows and to provide a return to investors. The Commission 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.)

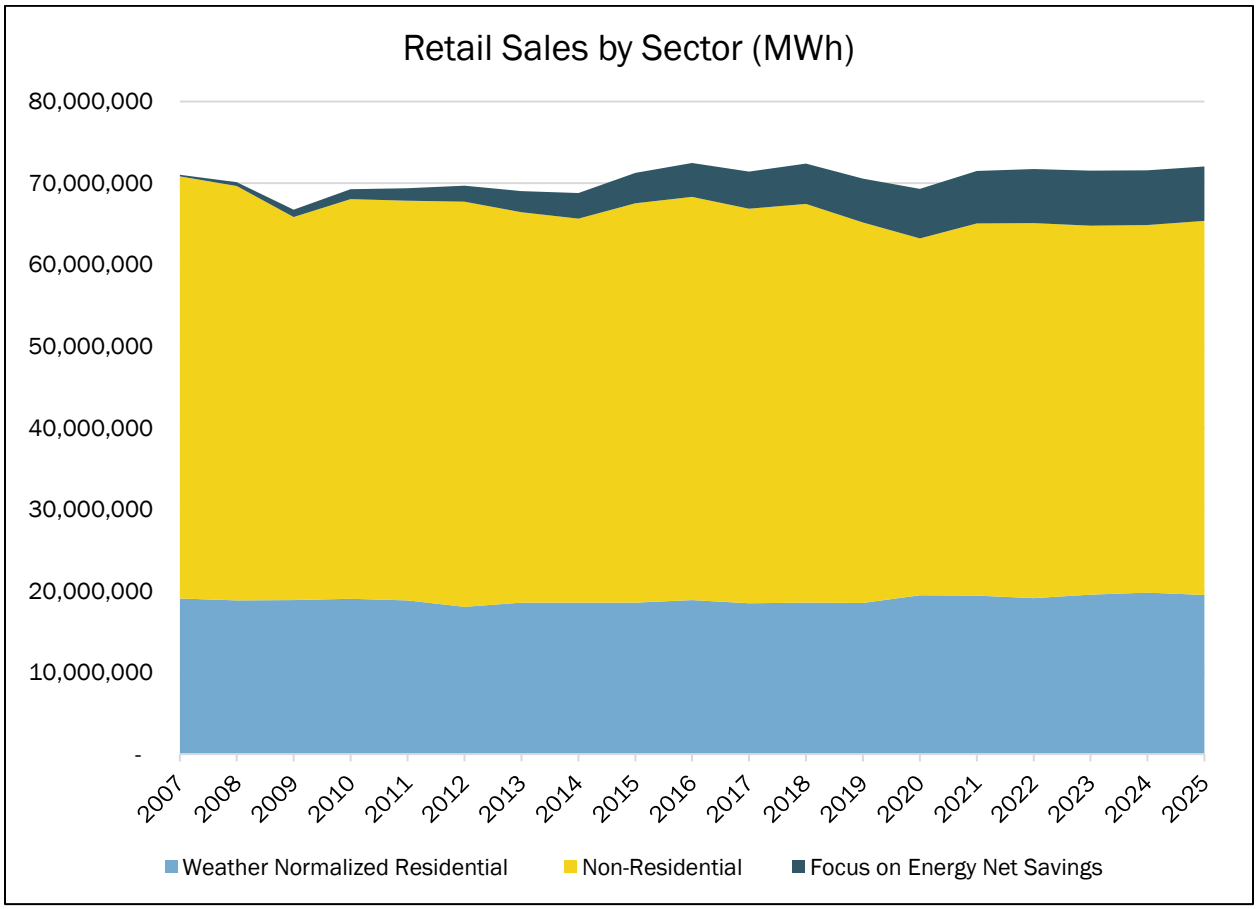
Two key trends are influencing revenue requirement levels for providers across Wisconsin. First, customer sales growth has remained limited throughout the past decade. Second, due to considerable forecast load growth (predominantly associated with new data center projects), electric providers are planning significant investments to meet anticipated growth in electric supply needs. (See Chapters 1 and 2.)

Trends in Customer Sales

In 2008 and 2009, Wisconsin electricity sales fell in response to a recession, and did not reach pre-2008 levels through 2025. As shown in Figure 5-1 and Table 5-1, a post-recession rebound in sales was followed by a period of limited growth between 2010 and 2018 and year over year declines in 2019 and 2020, resulting in a long-term trend of decreasing energy use overall. The onset of the COVID-19 pandemic contributed to a 3 percent decrease in electric sales in 2020. After a rebound in 2021 as customer use increased and economic conditions improved, annual growth rates have declined minimally through 2024.

The growth in energy efficiency statewide is a key reason that sales have not returned to pre-2008 levels. After incorporating total net energy savings recorded by Wisconsin's statewide energy efficiency program, Focus, since 2007, Figure 5-1 and Table 5-1 show that, in the absence of those reductions in energy use, annual growth rates would have been higher in each of the past 17 years, with total efficiency savings increasing throughout the period. This reduction in sales ultimately contributes toward reductions in utility spending plans, supporting affordability. Notably, using Focus net energy savings is a conservative estimate of energy efficiency impacts; many customers may also be taking additional energy-efficient actions outside of the program that would further increase net energy savings.

Figure 5-1 Retail Sales of Electricity, by Sector (MWh)[95]



[95] 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.

Table 5-1 Annual Growth Rates for Retail Electricity Sales (%)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Average Growth
Residential	-4.3%	2.9%	0.0%	0.0%	1.7%	-2.2%	0.5%	-0.1%	4.9%	-0.2%	-1.5%	2.1%	1.3%	-1.4%	0.3%
Non-Residential	1.4%	-3.7%	-1.7%	4.0%	1.0%	-2.1%	1.0%	-4.6%	-6.2%	4.3%	0.8%	-1.6%	-0.4%	1.8%	-0.4%
Total	-0.2%	-1.9%	-1.2%	2.9%	1.2%	-2.1%	0.8%	-3.3%	-3.0%	2.9%	0.1%	-0.5%	0.1%	0.8%	-0.2%
Total w/o Focus on Energy	0.5%	-1.0%	-0.3%	3.6%	1.7%	-1.5%	1.4%	-2.6%	-1.8%	3.2%	0.3%	-0.3%	0.0%	0.7%	0.3%

Usage per customer provides another measure of the effects of energy efficiency on overall sales. Weather-normalized average electricity use per customer for residential customers declined 7 percent from 2007 through 2019, before increasing nearly 5 percent in 2020, likely due to people spending more time at home during the COVID-19 pandemic. From 2020 to 2022, usage dropped over 6.5 percent. Usage has since increased in 2023, 2024, and 2025. (See Appendix D, Figure D-2 for illustration.)

As non-residential customers tend to be a more widely varying population, average energy intensity in dollars per unit of energy is commonly used in place of weather-normalized average electricity use per customer. Average energy intensity in dollars per unit of energy increased more than 110 percent from 2007 through 2025. (See Appendix D, Figures D-1 for illustration.) The effects of these per-customer trends have been partially offset by an increase in the number of total customers served, but not at sufficient levels for total sales to reach their pre-2008 levels.

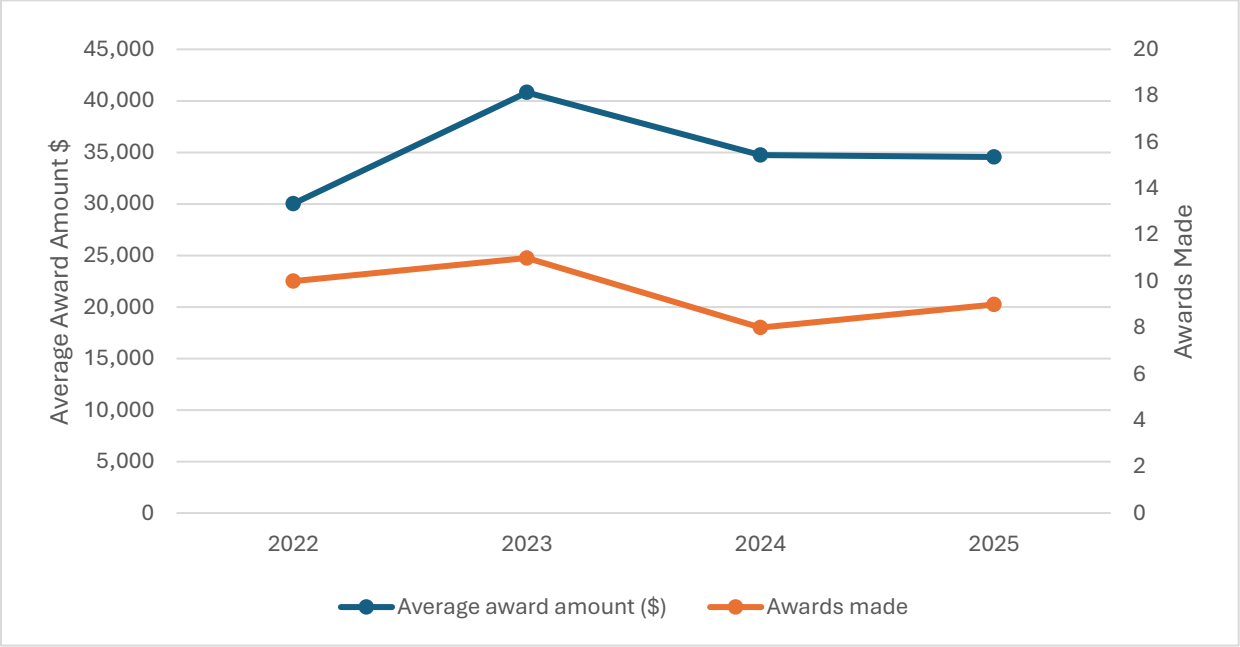
Public Participation

The Commission encourages public participation in its cases because public input is essential to reach the most fair and reasonable decision possible.[96] The Commission continues to see substantial public engagement in generic investigations, construction cases, and rate or tariff cases. How an individual or organization participates in a proceeding depends on their interest in the issues and the type of case. A simplified and more common way to participate in a case is as a member of the public. Any person or organization can follow a case by tracking the filings in the case on the Commission's Case Management System and, at the time and in the manner requested by the Commission, provide their opinion to the PSC by attending a public hearing, or submitting a written comment for the record.

[96] See also the Commission Public Participation webpage: https://psc.wi.gov/Pages/CommissionActions/PublicParticipation.aspx

Alternatively, any person or organization that meets certain criteria may participate in a case as an intervenor. Those who have substantial interests that might be affected by a case can request to become a party through "intervention." Intervenors may qualify for compensation for some costs incurred while participating. Between 2022 and 2025 the Commission made 38 awards for intervenor compensation. Figure 5-2 shows the number of individual awards and average amount per year. The amount for any intervenor compensation award can range greatly depending on the specifics of a case and the intervenor's needs, with award ranges from $8,000 to $104,790, and an average award amount of $35,028, across the last four years.

Figure 5-2 Intervenor Compensation Awards and Average $ Amount, 2022-2025



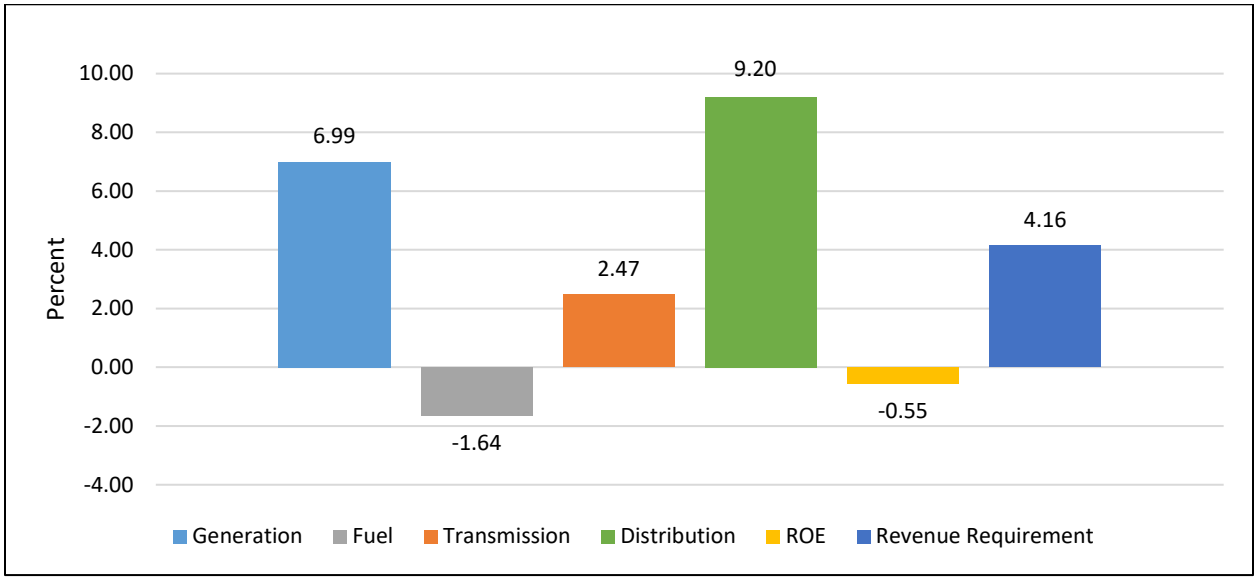
Revenue Requirements of Investor-Owned Utilities with Generation

Wisconsin's five largest IOUs,[97] who serve nearly 90 percent of the state's electric customers, provide most of the electric supply through utility-owned generation. The majority of the revenue requirements for each of these "Major IOUs" comes from generation and distribution infrastructure investments.

As shown in Figure 5-3, total revenue requirements for the Major IOUs increased 4.16 percent per year between 2015 and 2024. Of the revenue requirement components, the Commission has direct control over generation, ROE, and distribution infrastructure for large projects. Fuel costs and transmission rates are mostly outside the Commission's control and represent pass-through expenses.

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

Figure 5-3 Ten-year Annual Growth Rate of Revenue Requirements Components—Major IOUs (%)



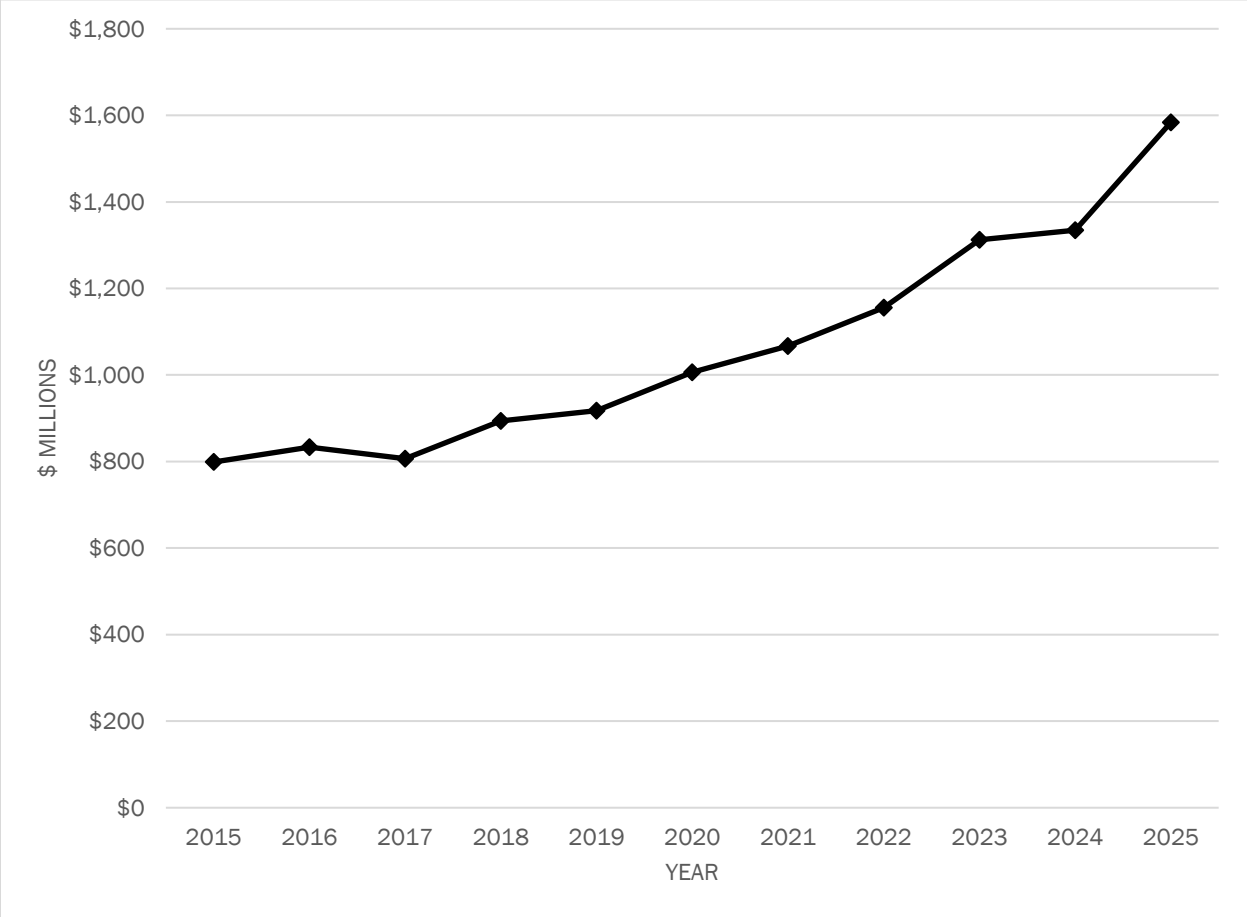
The increase in total revenue requirement between 2015 and 2025 was driven primarily by increased costs for generation resources and distribution system infrastructure. Total impacts from the investments in generation and distribution on the revenue requirement are reflected in the amount of annual depreciation value from historical investments authorized by the Commission in rate proceedings. Transmission costs also increased, as analyzed further in Chapter 4. These increases were partially offset by fuel costs and decreases in ROE for IOU assets. Fuel costs began to increase due to increased natural gas prices during 2022 and due to changes in generation mix and market conditions. In 2023 through 2025, natural gas prices reverted to the pre-2022 trend.

ROE is a metric that drives a utility's profitability. Ongoing expenses such as operations and maintenance and debt costs are passed through to customers. ROE, which is a return on the capital owned by the utility, serves as an authorized profit margin for the utility, in addition to ongoing expenses. ROE is set for each utility, for typically 2 years, in a rate case proceeding. When setting an ROE, the Commission considers the requested ROE from the utility, any ROE recommendations by intervening parties, as well as an ROE recommendation produced by Commission staff. Minor changes to ROE can have a large effect on the revenue the utility is authorized to collect and the electricity rates customers pay.

In Wisconsin, ROE has generally remained flat or trended down over the last 10 years. However, as shown in Figure 5-4, a decrease in ROE does not necessarily result in a decrease in earnings because a utility's earnings reflect the total return on each utility's authorized rate base, as well as any cost saving efficiencies the utility is able to capture.

Similar to nationwide utility trends, total growth in net income for Wisconsin IOUs is a result of increasing costs of, and the rapid growth in, utility infrastructure investment.

Figure 5-4 Ten-year Annual Total Net Income —Major IOUs ($)



Earnings Sharing Mechanism (ESM)

While earnings have increased for Wisconsin's major IOUs, the PSC has routinely directed utilities to implement an Earning Sharing Mechanism (ESM) as part of its determinations in rate case proceedings.

In simple terms, an ESM requires earnings in excess of a utility's authorized return to be credited back to its customers. In setting just and reasonable rates, the Commission has imposed this mechanism to protect customers from bearing the costs of excess overearnings by a utility. During the same timeframe of 2015 to 2025, the Commission-imposed ESMs has resulted in over $260 million in utility revenues being returned to customers.

Effects of Tax Reform and Federal Funding on Investor-Owned Utilities

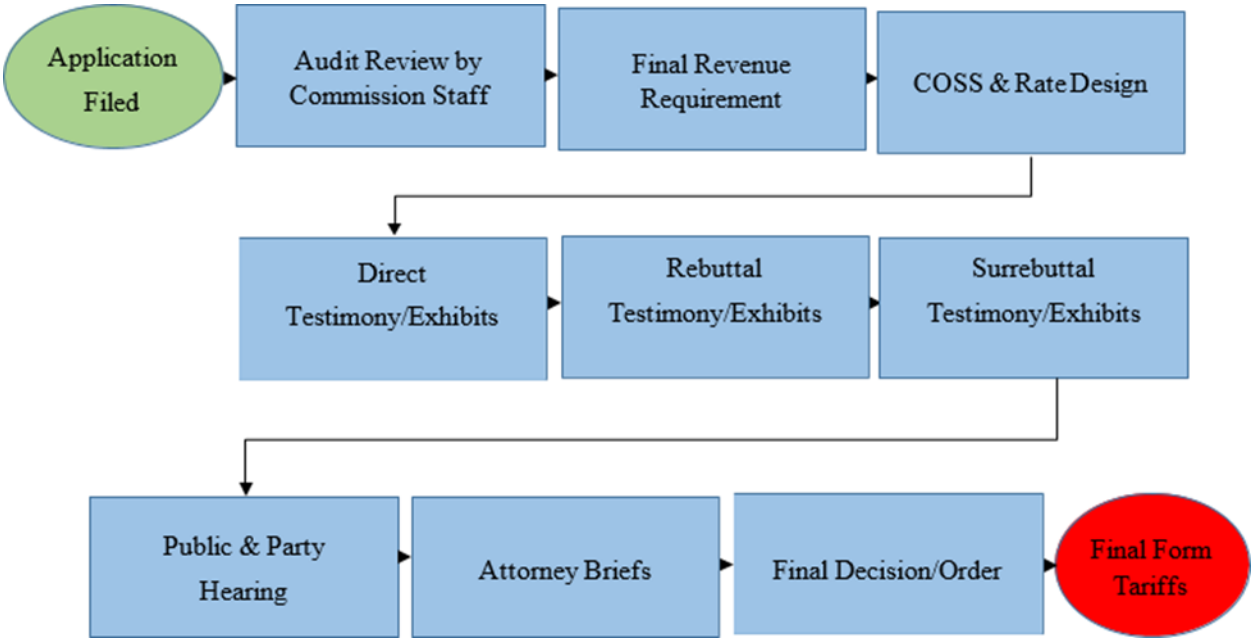
The Infrastructure Investment and Jobs Act (IIJA), signed into law on November 15, 2021, includes approximately $65 billion in investments for clean energy projects. The IRA, signed into law on August 16, 2022, directed nearly $400 billion in federal funding to increase clean energy. This funding includes provisions that provide direct benefits to end-use customers as well as tax credits and grants for larger clean energy projects.

The House of Representatives Bill 1 of the 119th Congress, signed into law on July 4, 2025, terminates several IRA clean energy credits and accelerates deadlines for existing funding. These accelerated deadlines will affect any unobligated funding associated with the IRA.[98]

Determining Customer Rates

Customer rates are established by each electric provider to generate sufficient revenue to recover their costs. Figure 5-5 summarizes the rate case process[99] that is followed by all electric providers regulated by the Commission, including all investor-owned and municipal electric utilities.[100]

Figure 5-5Rate Case Process



[98] Source: https://blogs.law.columbia.edu/climatechange/2025/05/13/ira-programs-at-risk-under-the-budget-reconciliation-bill/

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

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

An electric utility must file an application with the Commission, and have it approved, before it can increase customer rates. 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 the 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 will be needed to cover its expenses and return on investment in that year and subsequent years. The provider then proposes customer rates to allocate that revenue requirement among its customers.

As the first step in application review, the Commission audits the utility's revenue requirement by reviewing the application's forecasts and proposals and requesting additional information as needed. This 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, the Commission may make adjustments to the proposed revenue requirement to more accurately reflect projected costs. Finally, a final revenue requirement is established that will be used to determine rates.

The final revenue requirement is used when reviewing the utility's proposed rate design. Rate design analysis begins with a cost-of-service study (COSS) that seeks to charge actual costs to customers by estimating the allocation of utility costs among different customer classes, such as residential, commercial, industrial, and agricultural classes.[101]

Utilities may submit one or more COSS models in their application, and the Commission may design one or more additional models of their own. The COSS models guide alternative rate designs, which can be proposed by the utility, the Commission, and other parties, that attempt 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. A rate case proceeding 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;

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

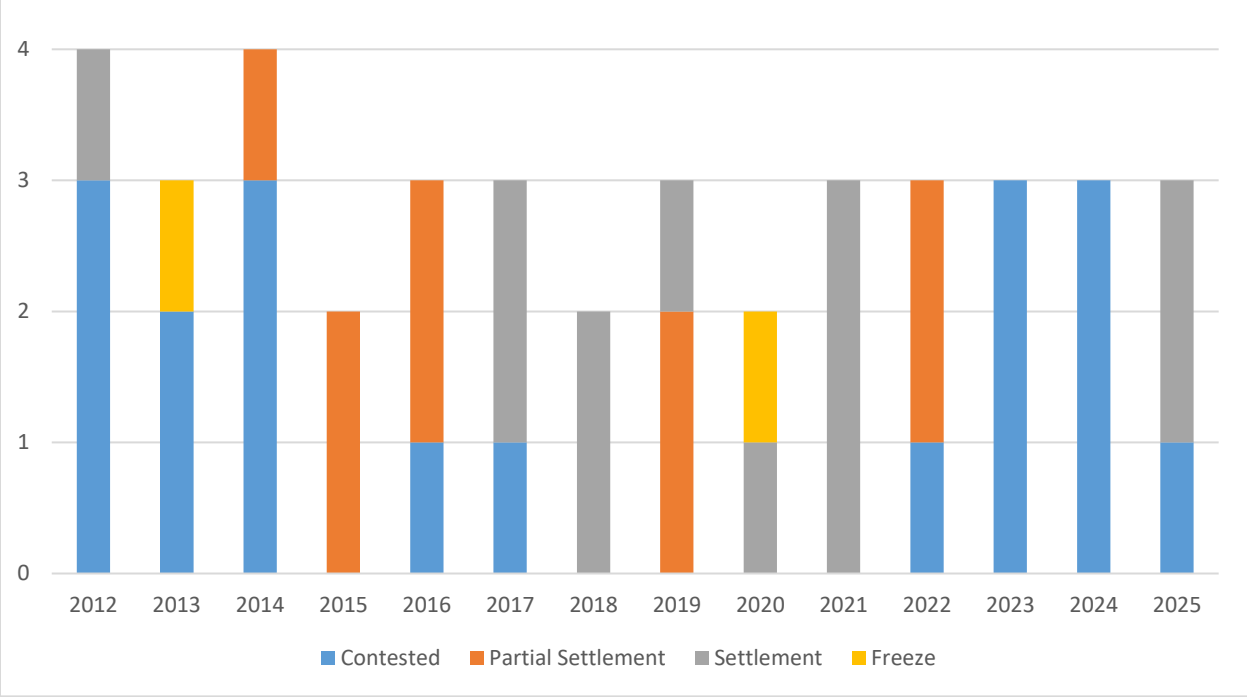
- Opportunities for rebuttal and surrebuttal testimony to initial evidence, which may be submitted by the utility and the Commission as well as by other interested parties;
- At least one public and party hearing to receive testimony from all interested parties, including members of the public; and
- Opportunities for 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, the Commission, 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 determine whether to approve the proposed settlement agreement. 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 the requirement that any rates resulting from the settlement agreement are just and reasonable.

As shown in Figure 5-6, a trend away from fully litigated IOU rate case proceedings and towards partial or full settlement agreements had already begun in the early 2010s, and that trend accelerated after the passage of the 2018 settlement legislation. The trend slowed with 2023 and 2024, which saw only contested IOU rate case proceedings, but rose once more in 2025 with the presence of two settlement agreements.

Figure 5-6 Resolution of Investor-Owned Utility Rate Cases, Application Years 2012-2025



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 generally designed to reflect the minimum cost of service utilities must cover to serve customers regardless of energy usage level. 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 municipal 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. Under Wisconsin Act 141 (Act 141), all customers contribute to low-income assistance via their bills. Some fees will appear as line items like Commitment to Community fees or Act 141 fees. In other cases, this contribution will be embedded into bills. (More information on programs targeting affordability issues can be found in Chapter 6.) Rarely, elements may be eliminated. Notably, as of October 1, 2025, residential electric and natural gas bills are exempt from state sales tax, removing that component which was previously included in residential bills.

Current Rates and Bills

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

Residential Customers

Electric providers typically bill residential customers almost entirely through customer and energy charges. Tables 5-2 and 5-3 summarize residential rates for IOUs and municipal

utilities, respectively, based on the Commission-approved tariffs in place during 2025. For municipal utilities, the median customer charge was $10.50 per month, and the median energy charge was 10.77 cents per kWh. IOUs had a median customer charge of $13.00 per month and a median energy charge of 13.78 cents per kWh. On average, IOUs charged higher rates compared to municipal utilities. Both tables also demonstrate that rates can vary based on the cost profiles of 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.[102]

Table 5-2 Wisconsin Electric IOU Bill Components for Residential Customers, 2025

Summary Statistics	Energy (cents/kWh)*	Customer Charge ($/month)
Minimum	9.10	$8.50
25th Percentile	12.12	$11.00
Median	13.78	$13.00
Average	13.89	$13.04
75th Percentile	15.11	$15.00
Maximum	18.41	$17.92

**Note: For MGE and NSPW, the cents/kWh value is based on a weighted average of their seasonal rates.*

Table 5-3 Wisconsin Municipal Electric Utility Bill Components for Residential Customers, 2025

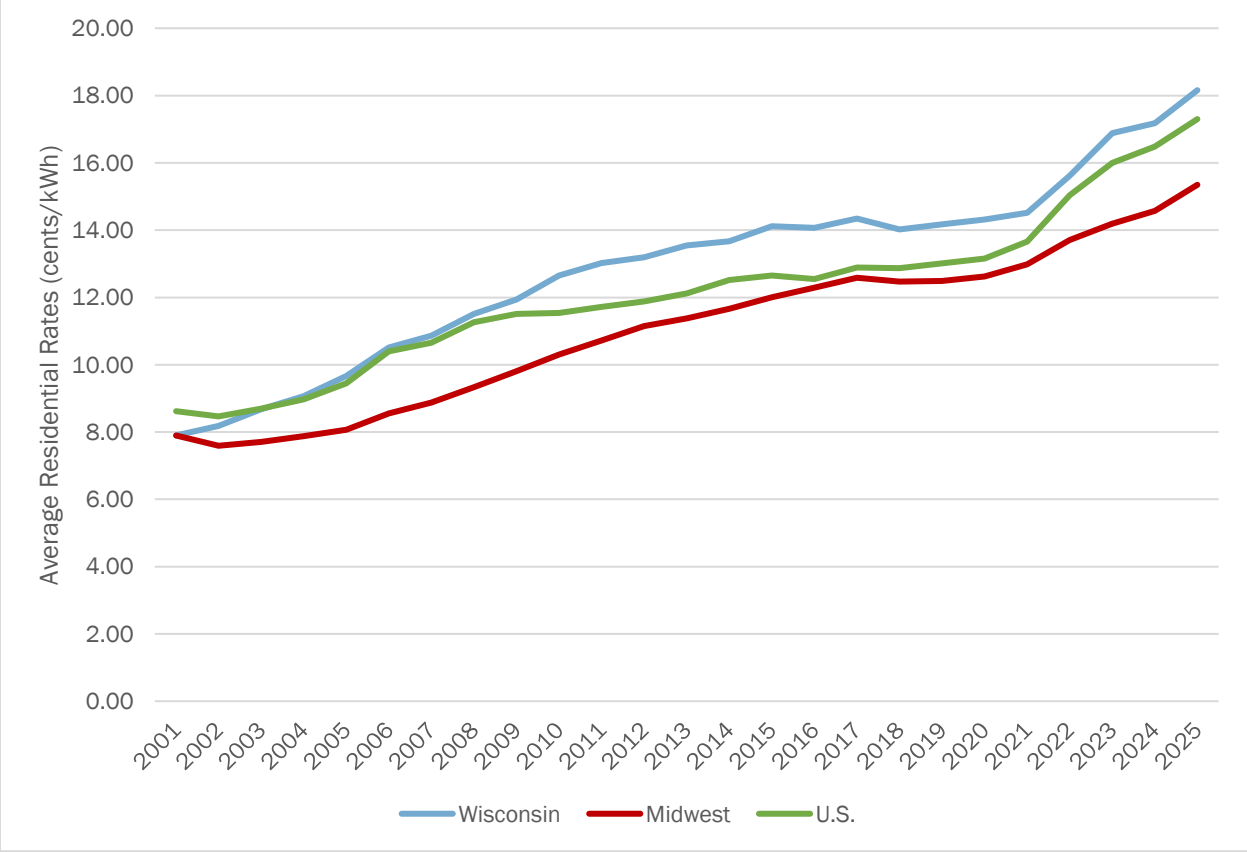
Summary Statistics	Energy (cents/kWh)	Customer Charge ($/month)*
Minimum	7.00	$5.00
25th Percentile	9.85	$5.00
Median	10.77	$10.50
Average	10.89	$10.60
75th Percentile	11.90	$13.00
Maximum	17.25	$17.00

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

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

National data collected by the EIA enables a general comparison of Wisconsin rate levels to other states and regions, though comparisons between states should be made cautiously due to differences in energy market conditions and regulatory structures. As shown in Figure 5-7 below, based on an overall, sales-weighted average of all electric utilities within each state, Wisconsin's average 2025 residential energy charges were approximately 18 cents per kWh, the Midwest average was approximately 15 cents per kWh, and the National average was approximately 17 cents per kWh.[103] Appendix D, Table D-1 provides more detailed comparisons, including charges for each individual Midwest state.

Figure 5-7 Average Residential Electricity Rates, 1990-2025[104]



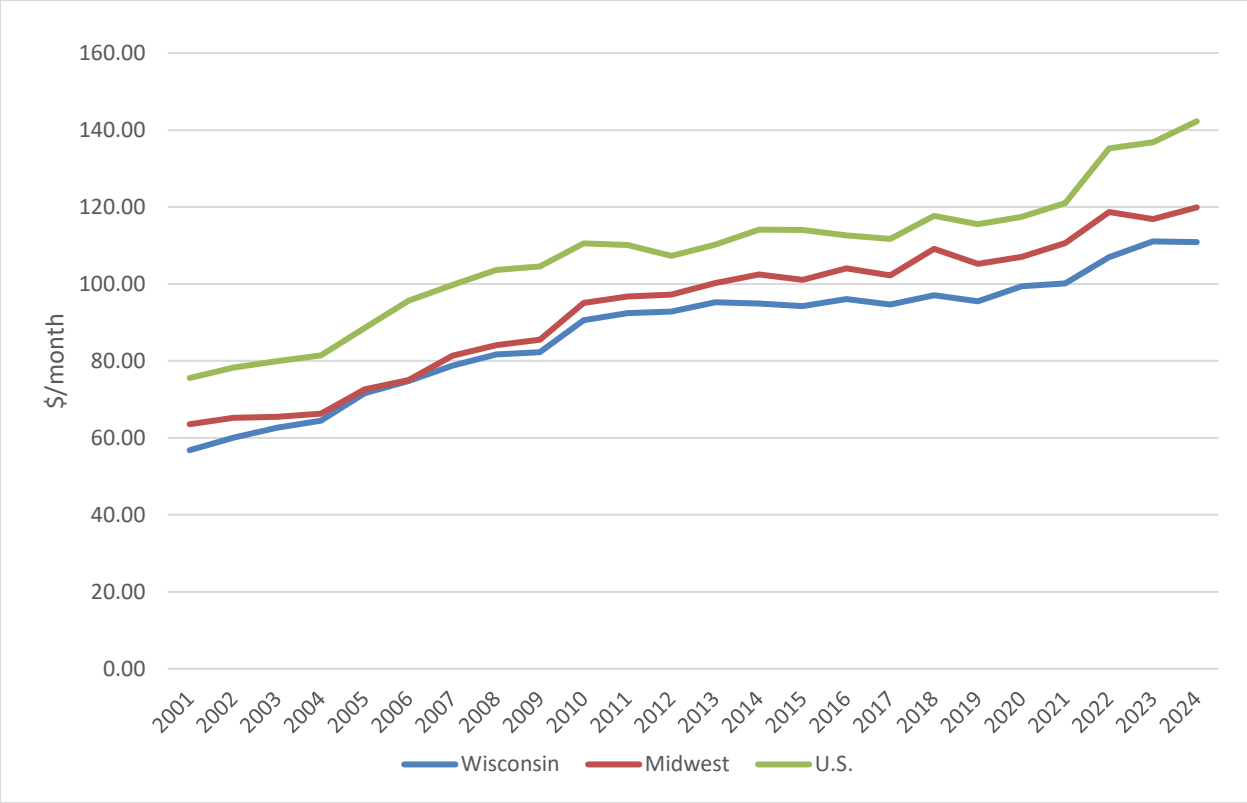
Although customer rate levels are higher, EIA data demonstrates that average monthly electric bills in Wisconsin have remained consistently lower than other states during the past decade. Wisconsin's average 2024 bill of $110.87 compares to Midwest average bills

[103] For this analysis, Midwest states include Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio, and Wisconsin.

[104] U.S. Energy Information Administration, Electricity Sales, Revenue, and Average Prices (Table 5A). Issued October 7, 2021. Accessed March 22, 2022, at: https://www.eia.gov/electricity/sales_revenue_price/.

of $119.90 and national average bills of $142.26. (See Appendix D, Figure D-3 for more detailed comparisons of average bills by census region.)

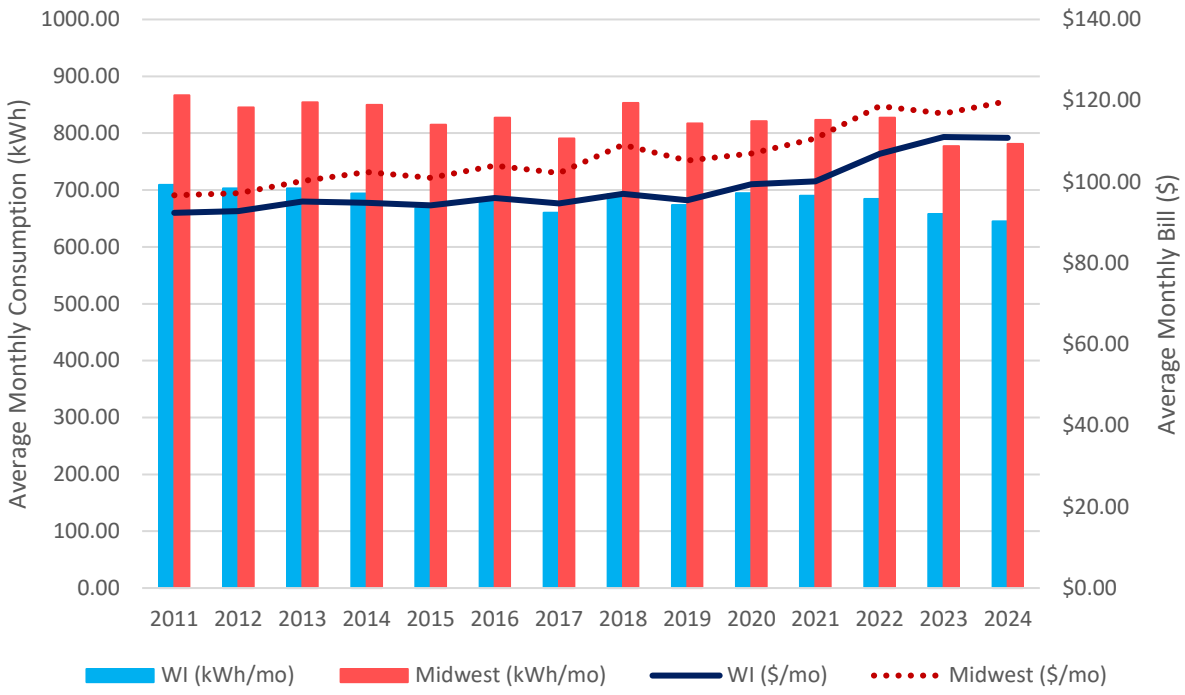
Figure 5-8 Historical Comparison of Average Monthly Residential Electric Bills, 2001-2024[105]



Wisconsin's lower bills reflect significantly lower average levels of electricity use. As shown in Figure 5-9, Wisconsin customers used an average of 645 kWh per month in 2024, compared to 781 kWh per month across other Midwest states. This usage difference has been present throughout the 2010s and early-to-mid 2020s and is, in part, attributable to the success of the statewide Focus on Energy program which has operated in Wisconsin for 25 years.

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

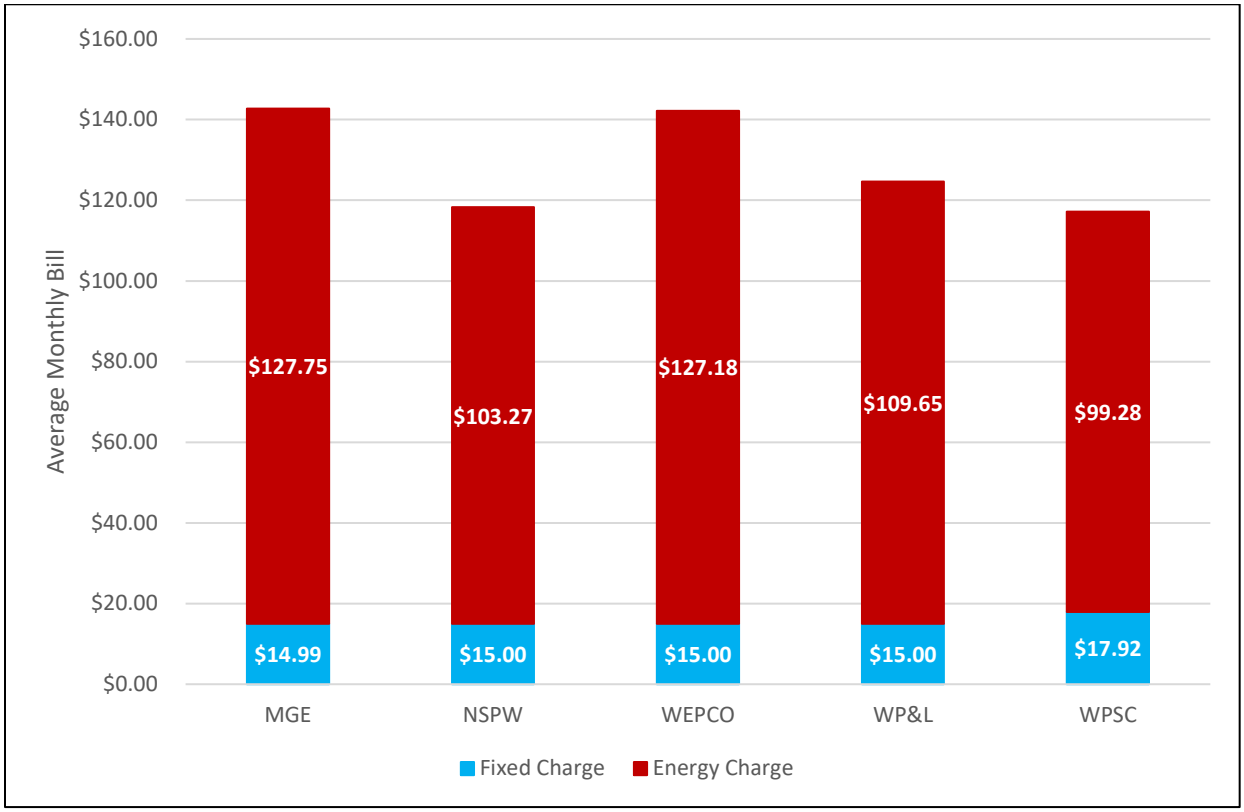
Figure 5-9 Monthly Residential Electricity Costs and Consumption in Wisconsin and the Midwest, 2011-2024



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 2025 ranged from $51.84 to $126.78 per month.[106] Figure 5-10 illustrates total 2025 residential bills at average usage levels for Wisconsin's five largest IOUs.

[106] 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 .

Figure 5-10 2025 Monthly Residential Electricity Bills (Fixed and Energy Charges Only) for Wisconsin's Largest IOUs, at Average Levels of Energy Use



Non-Residential Customers

Based on national EIA data, Wisconsin's average 2024 energy rate for commercial customers of 13.06 cents per kWh falls slightly below the national average of 13.41 cents per kWh and above the Midwest regional average of 11.54 cents per kWh (additional data can be found in Appendix D, Table D-2). Wisconsin's average 2025 energy rate for industrial customers of 8.92 cents per kWh exceeds the national average of 8.62 cents per kWh and the Midwest regional average of 8.51 cents per kWh (Appendix D, Table D-3). However, drawing clear conclusions from rate and bill comparisons for non-residential customers is generally more difficult than for residential customers given the variations between non-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 5-4, municipal Cp-1 customers paid average energy charges of approximately 8 cents per kWh, average customer charges of approximately $54 per month, and demand charges of approximately $8 per kW in 2025. (More details on the analysis can be found in Appendix D, Figures D-6 and D-7 and Table D-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.

Table 5-4 Municipal Utility Bill Components for Cp-1 Customers, 2024

Summary	Energy Charge ($/kWh)	Distribution Demand ($/kW)	Billable Demand ($/kW)	Customer Charge ($/month)*
Minimum	$0.0393	$0.00	$5.25	$20.00
25th Percentile	$0.0716	$1.25	$7.00	$50.00
Median	$0.0836	$1.50	$8.00	$50.00
Average	$0.0831	$1.51	$7.96	$54.21
75th Percentile	$0.0929	$1.75	$8.88	$58.75
Maximum	$0.1280	$3.00	$12.00	$125.00

**Note: Summary statistics include data from 68 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, including TOU rates and real-time pricing options for commercial and industrial customers.

Residential Time-of-Use Rates

A total of 76 electric providers in Wisconsin offer a 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 5-11, 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 designed to provide power primarily during peak hours, and the greater availability of low-cost wind resources in the overnight hours.[107] 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.

[107] 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 5-11 Illustrative Example of Time Varying Price of Electricity on an Average Summer Day in Wisconsin



All utilities with residential 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 5-5, approximately 38,000 customers of investor-owned and municipal electric utilities, or 1.49 percent of all residential customers, are currently enrolled in TOU rates. Total TOU enrollment has increased by approximately 7,000 customers since 2018.

Table 5-5 Enrollment in Standard and TOU Rates

Residential Rate Class	Total Enrollment	Percent of Total
Standard Rate	2,516,200	98.51%
TOU Rate	38,118	1.49%

Several utilities have three-tier TOU rates, which add an additional on-peak shoulder period surrounding the highest-peak period. Three-tier TOU rates function as a typical TOU rate does, where rates vary based on the cost to serve customers in each period. Ideally, the additional period allows utilities to more accurately capture those costs. MGE, WPSC, and WP&L, all of which are IOUs, have implemented three-tier TOU rates thus far. Additionally, the cities of Oconomowoc, Kaukauna, and Menasha, as municipal electric

utilities, have recently received Commission approval for optional three-tier residential time-of-day tariffs.

The increasing use of new technologies in future years could help increase customers' ability to control their energy use and enhance the benefits of enrolling in TOU rates accordingly. 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 in Chapter 3 for more information on the use of smart thermostats to control demand.) If EV use increases in the future, the use of charging equipment that allows customers to control charging time for vehicles could provide similar benefits. (See further discussion on EVs in the Electric Vehicle section in Chapter 3.)

Real-Time Pricing for Commercial and Industrial Customers

A total of 38 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 incentivize 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 400 kW of demand.

Incremental load enrollees are provided with 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 5-6, 122 commercial and industrial customers were enrolled in real-time pricing rates in 2025, an enrollment rate of 0.03 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 5-6 Enrollment in Incremental Load and Real-Time Pricing Rates

Industrial	Total Enrollment	Percent of Total
Standard Rate	352,265	99.96%
Incremental Load (NLMP/EDR)	4	0.00%
Real-Time Pricing (RTMP)	122	0.03%

Chapter 6 – Energy Affordability

Energy affordability refers to whether the energy costs paid by customers are affordable in the context of other household or business necessities. Discussions on affordability often refer to determining the energy burden of customers, with energy burden defined as the ratio between annual energy costs and annual income. By paying the same rates as all customers, but with more limited financial resources, low-income customers often face a higher energy burden: they must pay a larger percentage of their total income for the same amount of service. Other indicators of whether energy bills are affordable can include the amount of accounts in arrears, the uptake of energy assistance programs, and the number of customers receiving disconnection notices and disconnections of service.

The Commission has increased its efforts in recent years to assess energy burden and other affordability indicators, and to review and expand the options available to help customers address their affordability challenges.

Energy Burden

In February 2021, the Commission requested that all IOUs with at least 15,000 customers, including MGE, NSPW, WEPCO, WP&L, and WPS, provide detailed energy burden analysis on electricity, natural gas, and water costs in their annual reports to the Commission, beginning with the 2020 annual reports submitted in spring 2021.

The Commission initially directed that submissions should provide energy burden data by assessing bills as a percentage of income by county, but identified limitations in using county-level data to fully assess geographic variation, since median calculations do not capture the significant differences in income and energy use that may be present across different municipalities and neighborhoods within a single county. The Commission subsequently directed that the energy burden analysis provided by these utilities be done at the census tract level. A census tract is a statistical subdivision of a county that has approximately 4,000 inhabitants and is a commonly seen level of tracking energy burden and other socioeconomic characteristics.[108] In 2022 and 2023, utilities began to incorporate reporting at that more granular level, but data was reported with different characteristics and variables, making comparisons between years and between utilities challenging. The Commission has provided the utilities with a template energy burden reporting table and guidance on data sources to use in analysis and reporting for the 2024 annual reports and those going forward.

[108] Census tracts can vary in population size, with census.gov stating that a tract can range between 1,200 and 8,000 inhabitants with 4,000 as the "optimum size". https://www.census.gov/glossary/?term=Census+tract.

In 2023, the Commission approved funding in its State Energy Program Annual Plan to hire a consultant to conduct an Energy Burden Action Study to research data sources and provide a basis for consistent and accessible energy burden metrics and reporting.[109] The goal of that work was to develop an actionable plan for short and long-term deployment of energy burden metrics for consideration in Commission programs and processes.

The Commission hired Vermont Energy Investment Corporation (VEIC) to conduct the study. In 2024, VEIC completed two documents produced through this work, which are available on the PSC website. The Energy Burden Metrics Report[110] identified options for Wisconsin to define, calculate, and track energy burden and other affordability metrics. The Energy Burden Action Plan[111] built off the analysis in the Metrics Report, identifying some Commission processes that could be informed by the proposed energy burden metrics. The Action Plan also included short- and long-term recommendations on actions the Commission could take to improve data and reporting, while recognizing the costs and efforts needed to implement recommendations. The Commission rapidly implemented short-term recommendations by updating the template energy burden reporting table to collect clear and consistent data, and increasing its collaboration with DOA's Division of Energy, Housing, and Community Resources (DEHCR), the state agency that administers Wisconsin's Home Energy Assistance Program (WHEAP), which collects data on households that receive energy assistance and levels of energy burden. This collaboration with DEHCR resulted in a memorandum of understanding (MOU) and data sharing agreement between the agencies, allowing data from both utilities and energy assistance recipients to be compared at generalized levels, including census tracts.

While energy burden data provided by the energy providers is improving in consistency and accuracy, and the Commission and DEHCR are working on a tool to allow for sharing and exploring combined data sets, there are existing tools that allow federal and state agencies, as well as organizations or members of the public to use to get a high-level understanding of energy burden using data from the American Census Survey (ACS). The online tool that is specific to evaluating energy burden is the Low-Income Energy Affordability Data (LEAD) tool[112] which can provide information at the national, state, county, city, or census tract level. Using this tool at different levels of geographic granularity demonstrates the effect on reported energy burdens. The tool also allows a user to filter by sources of heating fuel, which has an appreciable effect on overall energy burden levels in Wisconsin in light of differing costs for different fuel types. When exploring energy burden levels for customers served by regulated Wisconsin utilities, a user can deselect fuel types such as bottled gas, fuel oil, coal, or wood from the LEAD tool display.

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[109] Final Decision approving Project Year 2023 State Energy Program Annual Plan. (PSC REF# 464921.)
[110] https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=525810.
[111] Microsoft Word - WI PSC EBAS - Energy Burden Action Plan - Final_2-18-2025.docx.
[112] https://www.energy.gov/scep/slsc/lead-tool (available/accessed January 2026).

It is important to note that the LEAD tool is for informational purposes and does not provide year-to-year changes as it uses five-year running average data from the ACS.

Figure 6-1 shows a county-wide evaluation of energy burden across Wisconsin from the LEAD tool using utility gas and electricity data, while Figure 6-2 shows a census-tract level evaluation of energy burden in parts of southeast Wisconsin. The increased granularity of census tract level reporting shows census tracts that are over three times the energy burden levels seen when looking at county level data for parts of southeastern Wisconsin. Similar results are seen in other areas of the state when increasing the granularity of data.

Figure 6-1 Wisconsin County-Level Evaluation of Energy Burden Levels using Area Median Income (LEAD Tool, January 2026)

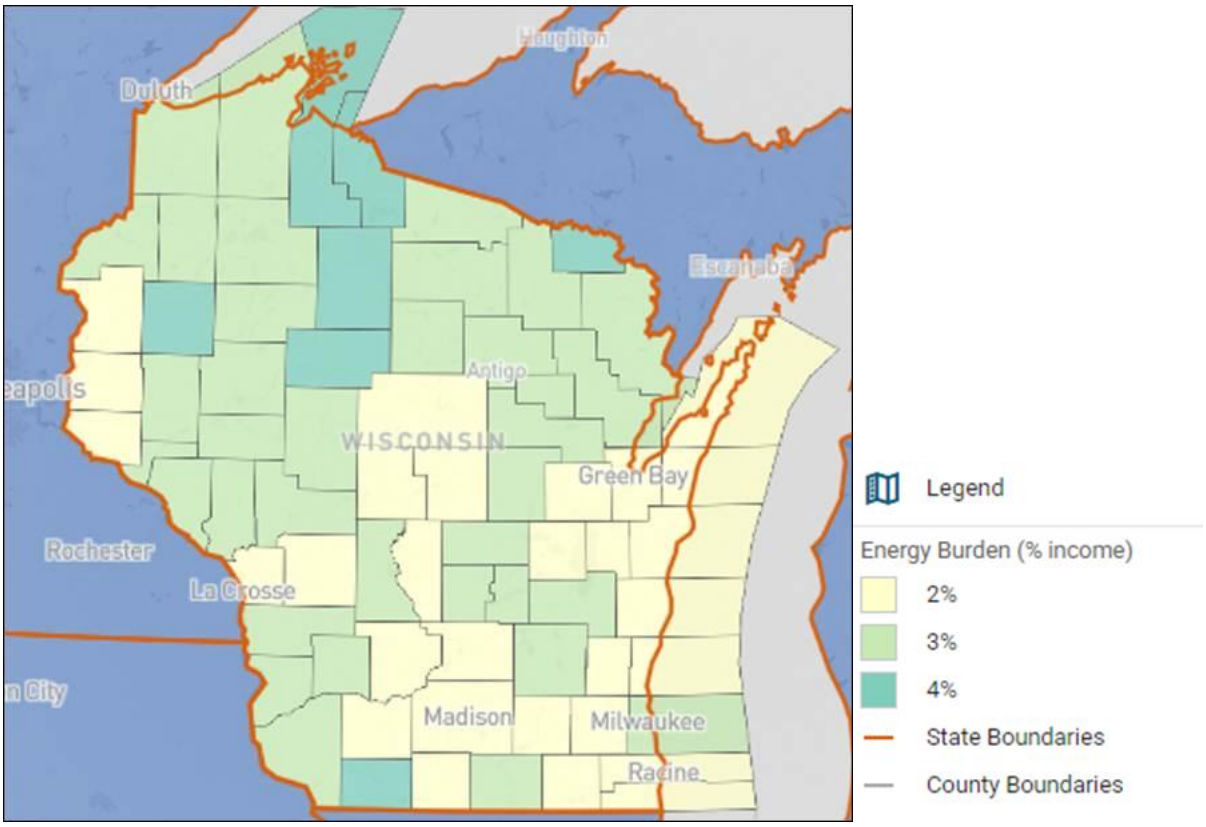
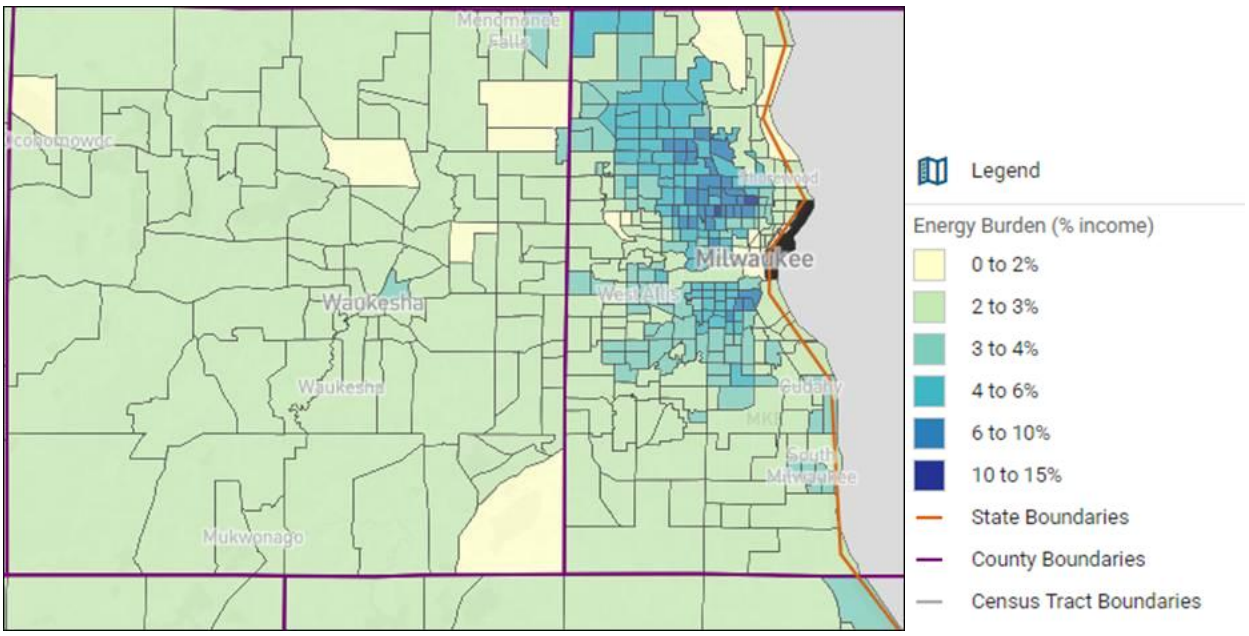


Figure 6- 2 Southeastern Wisconsin Energy Burden at Census-Tract Level using Area Median Income (LEAD Tool, January, 2026)



Average energy burden can be visualized graphically using LEAD census tract data, as seen in Figures 6-3 through 6-5. Each point represents a census tract in Wisconsin, with average annual household income plotted on the x-axis and average annual energy spending on the y-axis. A dashed trendline indicates that average spending generally increases with household income. The solid trendline describes an energy burden cutoff, calculated at either three percent for electric or utility gas spending or six percent for combined utility gas and electric spending.[113]

[113] www.energy.gov/scep/low-income-energy-affordability-data-lead-tool

Figure 6-3 Energy Burden Plots with Affordability Trendline – Electricity and Utility Gas – 6 % Energy Burden (LEAD Data, January 2026)

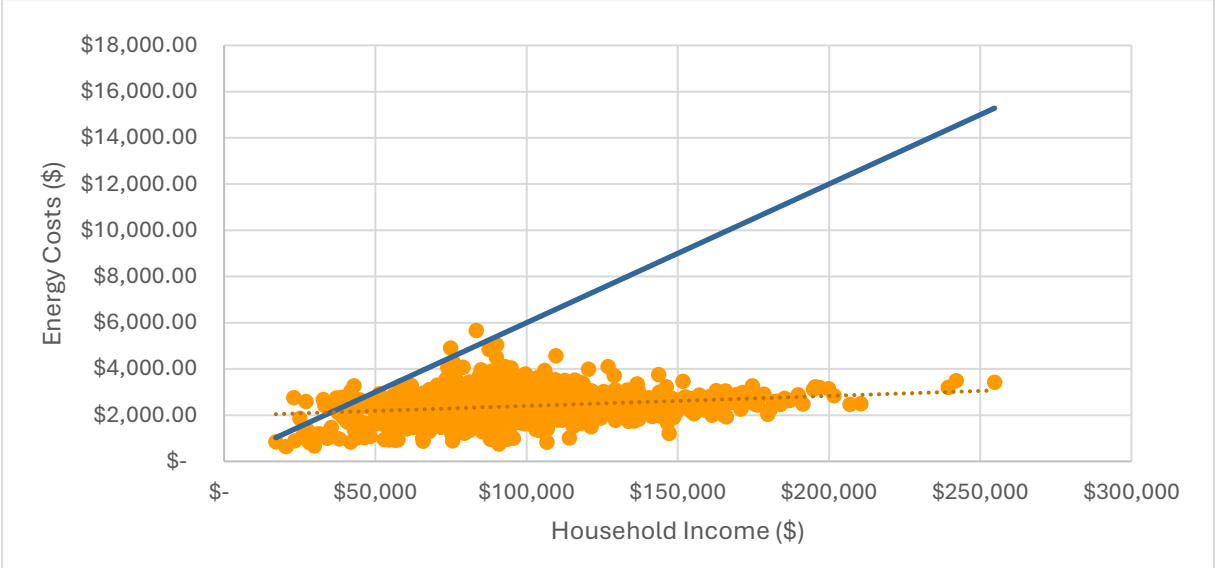


Figure 6-4 Energy Burden Plots with Affordability Trendline – Electricity Costs and 3 % Energy Burden Target (LEAD Data, January 2026)

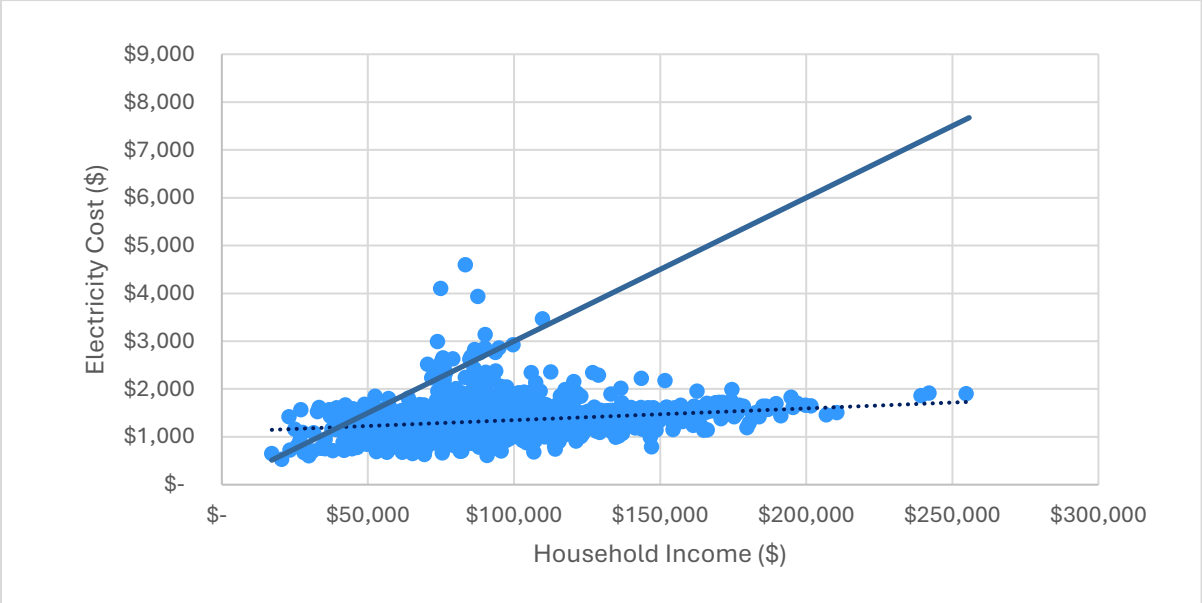
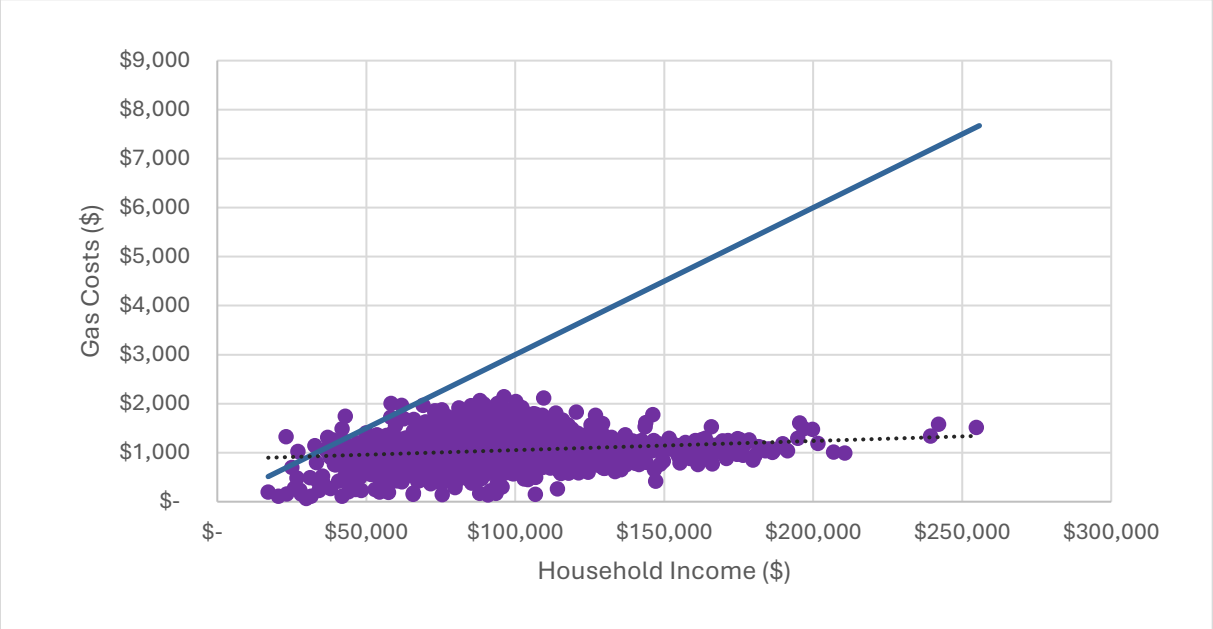


Figure 6-5 Energy Burden Plots with Affordability Trendline – Gas Costs and 3% Energy Burden Target (LEAD Data, January 2026)



While many census tracts fall below the three or six percent energy burden targets, some Wisconsin census tracts face costs that place them above the solid line, indicating that customers in those tracts face energy burdens that could be considered unaffordable. Table 6-1 describes the number and percentage of Wisconsin census tracts which fall above that affordability level. The percentages are calculated relative to the total of 1,542 census tracts in Wisconsin as of the 2020 census.

Table 6-1 Census Tracts Above Affordability Threshold (LEAD Data, January 2026)

	Count	Percent
Census Tracts with Electricity Burden greater than 3%:	80	5.2%
Census Tracts with Gas Burden greater than 3%:	10	0.6%
Census Tracts with Electricity and Gas Burden greater than 6%	25	1.6%

In addition to geographic analysis, the LEAD tool provides users the ability to investigate energy burden levels for different ranges of income level in each geographic area. As of January 2026, the LEAD tool provided an estimate for annual area median income (AMI) in Wisconsin of $97,605. Figure 6-6 shows that in Wisconsin at the county level, the LEAD tool indicates that households at 0-30 percent of AMI experience energy burden levels on average up to 14 percent, compared to households at 80-100 percent of AMI, who on average have energy burden levels of 2 percent.

Figure 6-6 County-Level Energy Burden for Ranges of Area Median Income (LEAD Tool, January, 2026)

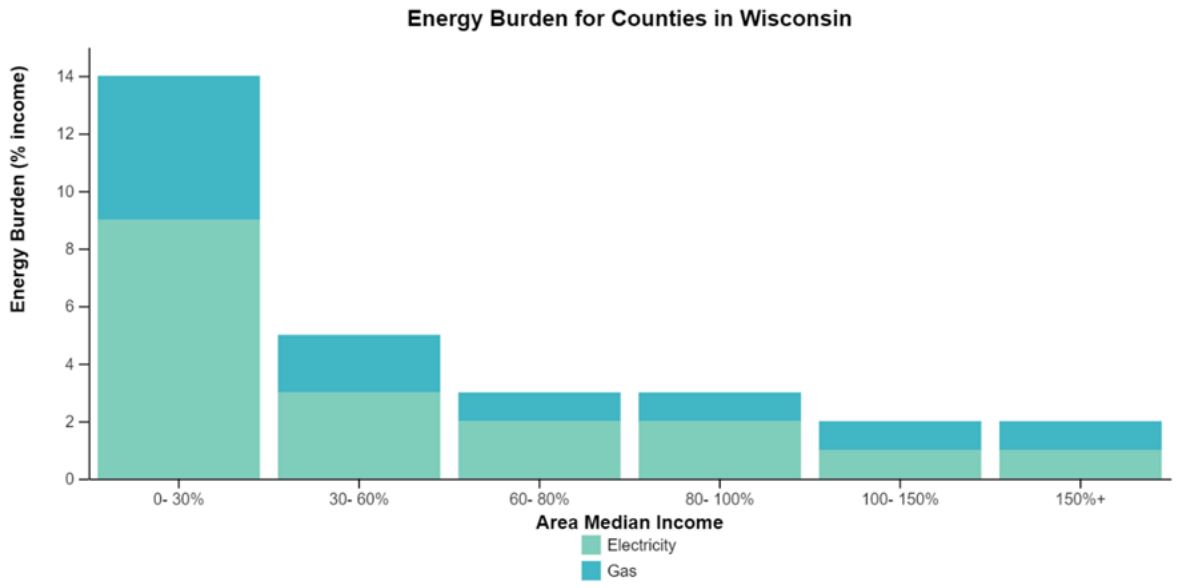


Table 6-2 compares Wisconsin's average energy burden of annual electricity and gas costs at various income levels to the average energy burdens in the U.S. and other Midwest states. The table, composed of weighted average LEAD data, again shows the disparity between the calculation of all incomes statewide, households below 60 percent of AMI, and households below 200 percent of the Federal Poverty Line (FPL). By this analysis, Wisconsin's lowest income households face a lower average energy burden than comparable Midwestern states and the national average, but still exceed the 6 percent threshold above which energy bills may be considered unaffordable.

Table 6-2 State Comparison of Electricity and Gas Burden (LEAD Data, January 2026)

State	All Incomes	< 60% AMI[114]	<200% FPL
Illinois	2.40%	9.46%	11.02%
Iowa	2.59%	8.60%	9.32%
Michigan	2.66%	9.92%	10.64%
Minnesota	2.05%	6.78%	8.51%
Wisconsin	2.27%	7.30%	8.29%
United States	2.16%	8.33%	8.86%

[114] LEAD uses AMI data based on the 2022 income limits established by HUD.

Going forward, the Commission will continue to examine ways of evaluating energy burden using utility-specific data collected through annual reports, ACS data, and data shared through the MOU with DEHCR on WHEAP participation and impacts.

Additional Commission Data on Affordability

In addition to energy burden, the Commission receives data on other indicators of affordability such as the amount of arrears (defined as charges left unpaid by customers), the number of customers with arrears, the number of customers receiving disconnection notices and the number of disconnections of service, which in many cases occurs due to bill nonpayment. Utilities provide this information as part of their annual reports to the Commission. The Commission also collects information in the annual reports from the investor-owned utilities on any utility-specific low-income affordability programs that are available to eligible customers.

Prior to disconnecting service for nonpayment, utility providers must send customers a disconnection notice at least 10 calendar days prior to the day of the proposed disconnection. The notice must include the reason(s) for disconnection, a way to contact the utility to either pay the account balance, establish a payment arrangement, or inform the utility if there is a threat to health or safety, and inform the customer they may appeal to the Commission if they have a dispute regarding the disconnection. A disconnection would occur if customers do not contact the utility or Commission staff to resolve the pending disconnection by the means provided in the disconnection notice within the timeframe provided in the disconnection notice. As Figures 6-7 and 6-8 indicate, actual disconnections occur in response to a small fraction of the disconnection notices received. Disconnections increased between 2021-2025 as Wisconsin's COVID-related disconnection moratorium was lifted and utilities returned to pre-COVID bill collections practices.

Figure 6-7 Total Disconnection Notices and Disconnections, Residential Electric Customers 2021–2025 (Annual Report Data)

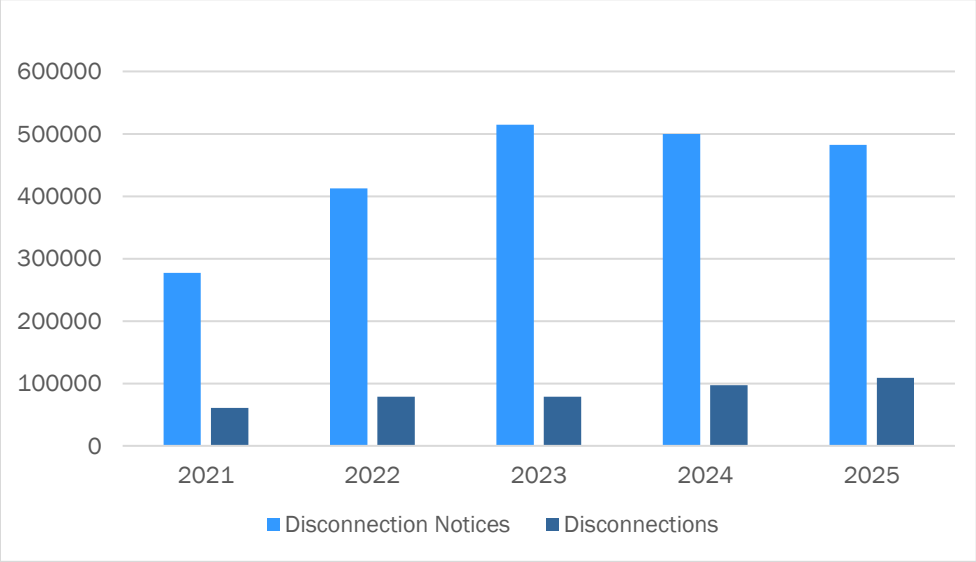
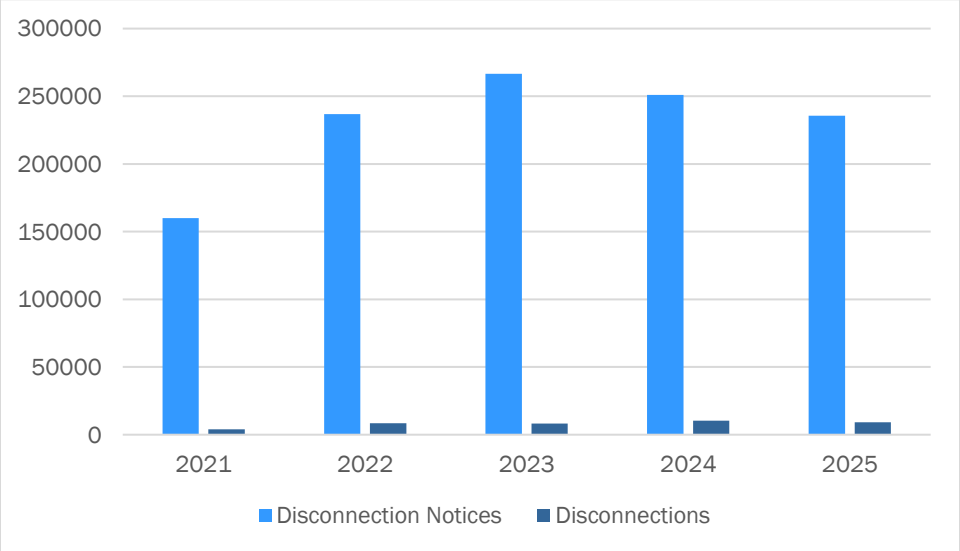


Figure 6-8 Total Disconnection Notices and Disconnections, Residential Natural Gas Customers 2021–2025 (Annual Report Data)



As shown in Figures 6-9 and 6-10, the data gathered under the annual reports demonstrated that the number of residential customer accounts with arrears has been relatively stable from 2021 through 2025, for electric service as well as natural gas. The increase in financial assistance available to qualifying customers, Commission ordered and utility initiated Deferred Payment Arrangements and Arrearage Management Programs, and expanded communication efforts regarding financial resources may have contributed to the decrease in the number of customers with arrears after 2022 and the decrease in total arrears that occurred in 2024 and 2025.

Figure 6-9 Number of Residential Customers with Arrears, 2021–2025 (Annual Report Data)

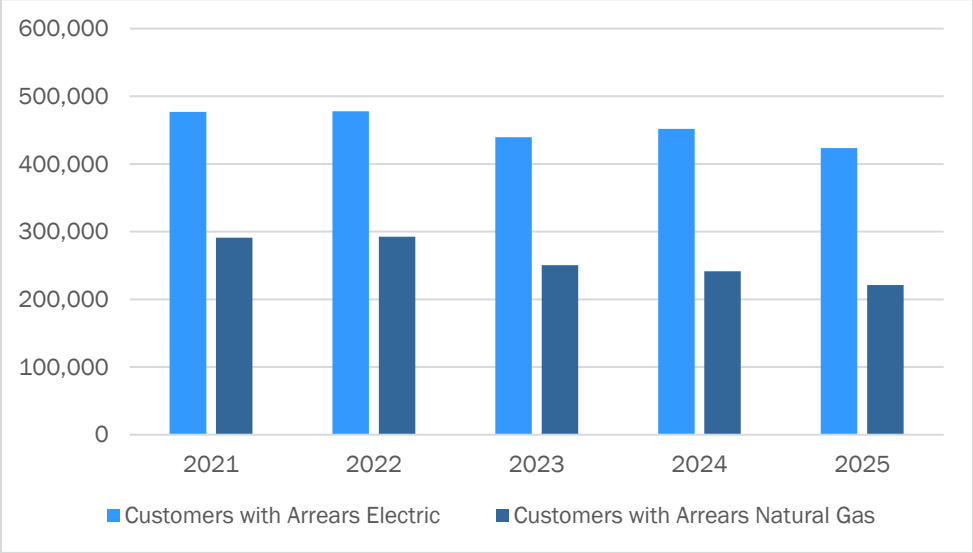


Figure 6-10 Year-End Residential Arrears Comparison by Year, 2021–2025 (Annual Report Data)

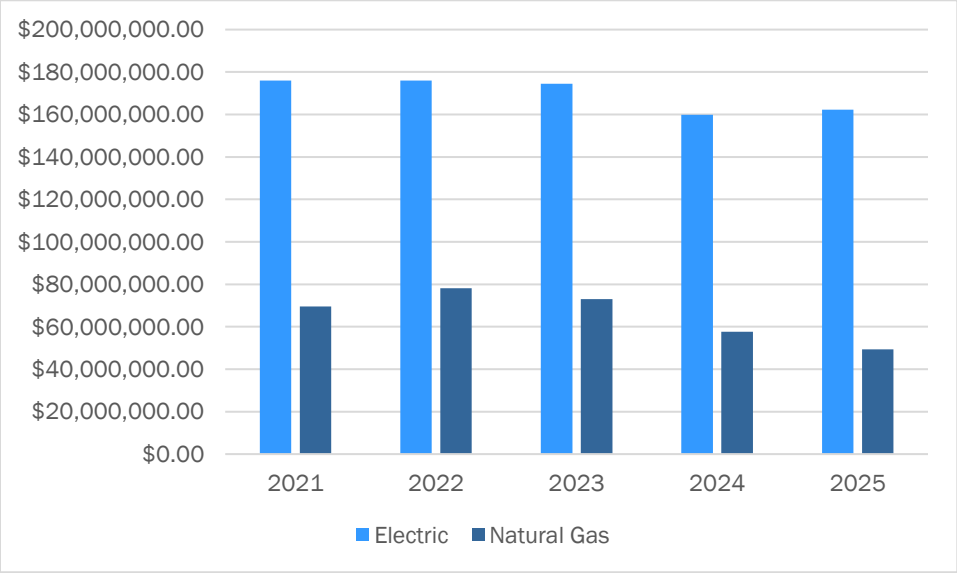


Table 6-3 displays the disconnection rate for each investor-owned utility. The rates in the table compare the number of disconnections at each utility to the number of residential customers served, separated by gas and electric operations and calculated from utility annual report data. The average disconnection rate for electric investor-owned utilities, weighted for the number of utility customers, has risen, up from 2.77 percent in 2021 to 4.79 percent in 2025. For much of 2021, in response to the COVID-19 pandemic, utilities

were under a temporary requirement[115] to file a disconnection plan with the Commission prior to seeking to disconnect service for nonpayment. This temporary requirement was lifted by the Commission in October 2022, and utilities were able to follow their standard disconnection procedures for non-payment. The lower numbers of disconnections in 2021 for some utilities may be due to this requirement.

Table 6-3 Disconnection Rates – Investor-Owned Utilities (Annual Report Data)

Disconnection Rates – Investor-Owned Utilities					
Utility Name - Type	***2021***	***2022***	***2023***	***2024***	***2025***
Consolidated Water Power Company - Electric	0.00%	5.48%	0.00%	11.43%	1.45%
Madison Gas And Electric Company - Electric	0.01%	0.68%	1.12%	2.24%	1.61%
Northern States Power Company (WIS) - Electric	0.80%	0.99%	3.00%	5.57%	8.12%
Superior Water Light and Power Company - Electric	2.98%	3.98%	4.19%	3.64%	4.60%
Wisconsin Electric Power Company - Electric	2.69%	3.84%	4.70%	5.21%	5.44%
Wisconsin Power And Light Company - Electric	5.25%	5.22%	3.10%	3.34%	3.45%
Wisconsin Public Service Corporation - Electric	2.47%	3.61%	2.98%	3.12%	3.23%
Madison Gas And Electric Company - Gas	0.01%	0.63%	1.02%	2.04%	0.78%
Northern States Power Company (WIS) - Gas	0.06%	0.11%	0.07%	0.15%	0.28%
Superior Water Light And Power Company - Gas	0.20%	0.34%	0.34%	0.22%	0.58%
Wisconsin Electric Power Company - Gas	0.01%	0.12%	0.11%	0.15%	0.14%
Wisconsin Gas LLC - Gas	0.14%	0.54%	0.50%	0.67%	0.50%
Wisconsin Power And Light Company - Gas	0.62%	0.64%	0.47%	0.35%	0.40%
Wisconsin Public Service Corporation - Gas	0.49%	0.67%	0.56%	0.34%	0.64%
Electric Weighted Average	2.77%	3.58%	3.69%	4.31%	4.67%
Gas Weighted Average	0.20%	0.44%	0.43%	0.54%	0.44%

Figures 6-11 and 6-12 display the individual trends in disconnection rate by utility over time. Trends varied by utility, with some utilities experiencing a flat or declining trend in disconnection rates, others an increasing rate.

[115] See Supplemental Order on Residential Disconnection – Fourth PSC REF#: 408377.

Figure 6-11 Trends in Electric Disconnection Rates for IOUs (Annual Report Data)

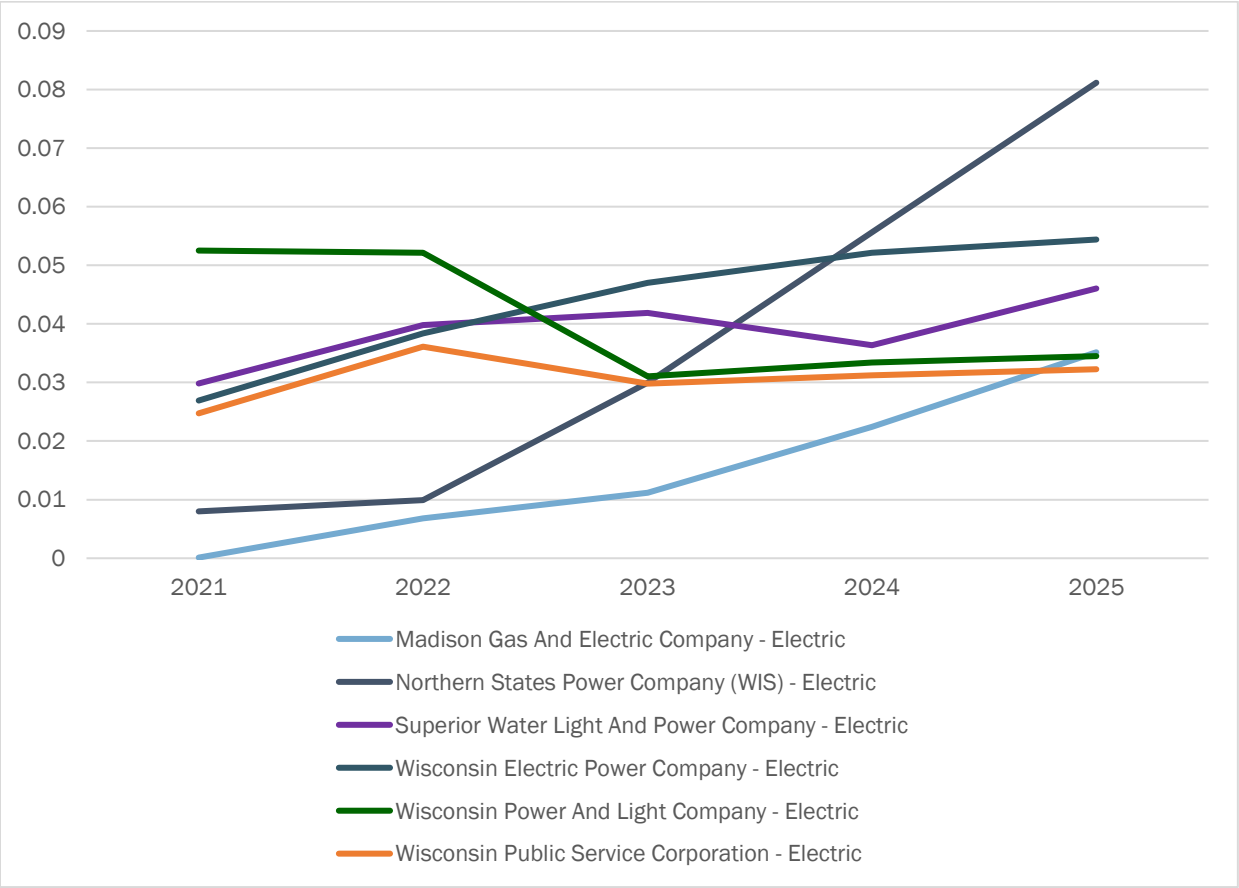
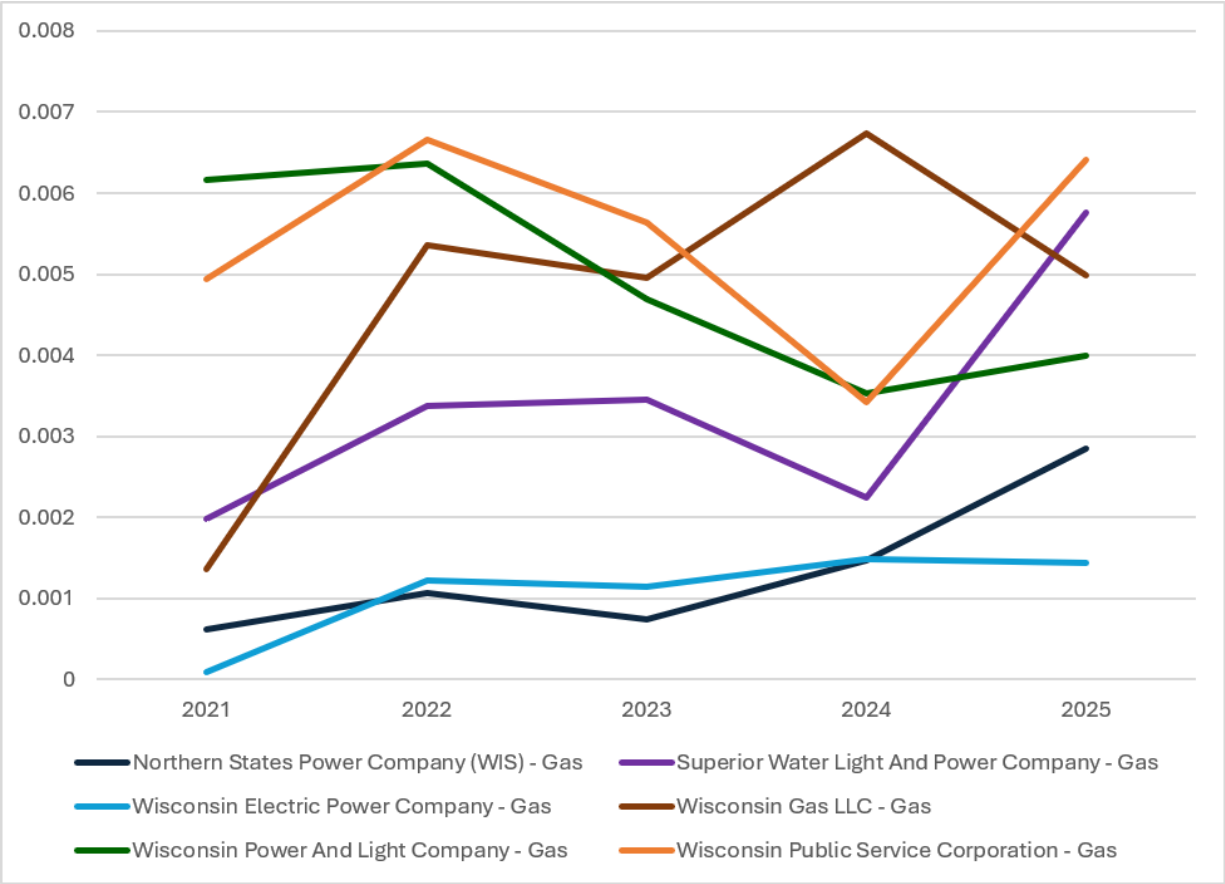


Figure 6-12 Trends in Natural Gas Disconnection Rates for IOUs (Annual Report Data)



Understanding trends in arrears, disconnections, and disconnection rates can help the Commission understand the impact and effectiveness of policies and programs related to customer arrears and disconnections. The Commission will continue to look at ways of collecting data to evaluate energy affordability for households in Wisconsin. Through a recently executed MOU and data sharing agreement with DOA-DEHCR, the Commission will be able to evaluate utility data with other agency data on energy assistance, which may provide new insights into how households are able to leverage existing programs and where gaps in affordability continue.

Assisting Customers with Affordability Challenges

Wisconsin electric providers, the Wisconsin DOA, and the Commission help all customers facing affordability challenges, including low-income customers, to manage their energy burden through multiple types of programs.

Bill Payment Programs

The Commission requires regulated electric utilities in Wisconsin to offer DPAs to residential customers who are unable to pay their bill in full.[116] 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. Regulated utilities are also required to offer residential customers budget billing options which help balance the seasonal spikes in usage and bills most customers experience by evenly distributing costs over a twelve-month period.[117]

The state's largest IOUs offer additional low-income assistance programs, many of which are designed as AMPs that forgive portions of participants' overdue utility bills under certain conditions. Some utilities provide additional programs that complement their AMPs or DPA offerings.

- In July 2025, the Commission approved MGE's Back on Track program, an AMP that provides low-income customers that have received energy assistance forgiveness for one twelfth of their arrears each month that a customer pays their bill.
- MGE also offers the Customer Service Plus (CS+) program, designed to complement its Back on Track program by providing customers with relatively lower arrears amounts or those that have experienced unusual circumstances causing them to fall behind on payments an additional assistance contribution if the customer commits to and completes a predefined number of payments, even if those payments are not in full based on the current amount due.
- In NSPW's 2025 rate case, the Commission approved the Residential Arrears Assistance Program (RAAP), which provides a one-time bill credit to WHEAP customers in arrears once per year. This is approved as a pilot program through December 2027, and NSPW will provide annual reports on metrics to evaluate the program's performance.
- WP&L offers an AMP to assist low-income customers who have received energy assistance funds by forgiving an initial percentage of arrears forgiveness on their past due balance and an additional one twelfth of their arrears forgiven each month that a participating customer pays their bill.
- WP&L also offers a Hometown Care Energy Fund, which provides financial assistance of up to $500 to qualifying customers to help pay their energy bills.
- WEPCO's, WG's, and WPSC's Low Income Forgiveness Tool (LIFT) program requires participants to pay 50 percent of their budget billing installment each month. If the amount is paid, one twelfth of their arrears is forgiven each month.
- In December 2025, SWL&P requested revisions to their AMP and the Commission is actively considering the proposed changes to that program in docket 5820-TU-100.

[116] See Wis. Admin. Code ch. PSC 113.0404
[117] See Wis. Admin. Code ch. PSC 113.0406(5)

SWL&P's AMP would assist customers with more than $200 in arrears who receive WHEAP benefits by forgiving one twelfth of their arrears balance each month that a participating customer pays their bill.

Electric providers and Commission Consumer Affairs staff also refer customers facing affordability challenges to multiple governmental and community assistance programs. Households with incomes of less than 60 percent of the state median income[118] are eligible for WHEAP, which is funded by federal energy assistance through the Low-Income Home Energy Assistance Program (LIHEAP) and by Wisconsin's Public Benefits (PB) Program. LIHEAP is a block grant funded by the federal government that focuses primarily on heating assistance for low-income households. Wisconsin's PB program was created in 1999 and operates a low-income fund into which electric providers in the state contribute an amount primarily generated by a fee added to customers' electric bills. The PB program provides benefits for non-heating electric use to customers of participating utilities. Wisconsin's investor-owned utilities are required by law to participate in the PB program, while municipal utilities have the option of participating in the state program or operating their own Commitment to Community program. The money in this fund is divided between the energy assistance program and the Weatherization Assistance Program (WAP).

Program administration of WHEAP is done by DOA-DEHCR, and program elements including eligibility requirements and policies are set out in a WHEAP manual for each program year. DEHCR may modify programs or policies within the manual as needed and communicate changes with interested parties. Households may be eligible for both regular energy assistance benefits and crisis assistance to help pay their energy bills, depending on the household's situation and the availability of funds. WHEAP also provides some assistance with HVAC repair and replacement services for low-income households. Eligible WHEAP households will receive assistance as long as funds are available; once funds are depleted for a year, households may not receive benefits.[119] The amount of energy assistance received by a household depends on a variety of factors, including size of the household, income, and energy costs.

The regular benefits energy assistance is a one-time payment during the heating season (October 1-May 15). The funding pays a portion of energy costs, but it is not intended to cover the entire energy costs of a residence. In most cases, the energy assistance benefit is paid directly to the household's energy supplier, but some households are able to receive payment directly based on specific criteria. Crisis assistance may be available to

[118] For the 2025-2026 program year, examples of incomes that may be eligible for the WHEAP program based on 60 percent of Wisconsin's median income are an annual income of $50,243 for a household of 2, or $73,888 for a household of 4. (Source: https://energyandhousing.wi.gov/Pages/AgencyResources/energy-assistance.aspx).

[119] The program's benefit calculator is programmed to ensure the program does not run out of funds and to date the program has never run out of funds in Wisconsin.

households year-round. Crisis assistance may be available for households that have no heat, have received a disconnection or past due notice, or are nearly out of fuel and are unable to purchase more. Crisis assistance is discretionary and is dependent upon funds available and the household's situation. Households are limited in the amount of crisis they can receive annually and must have provided at least $25 to the energy provider within the last three months to be eligible. WHEAP agencies provide a 24-hour crisis phone number to help with emergencies after business hours.

Data from DOA-DEHCR is available statewide as well as for specific energy providers. Figure 6-13 shows the amounts of paid applications for LIHEAP and PB program funds between 2019 and 2025 program years. There are always more paid PB (non-heat electric) applications than paid LIHEAP (heat) applications as some applicants are not eligible for a heat benefit due to living in government subsidized housing that includes heat or for other reasons, but those households remain eligible for the non-heat electric payment. The data shows a high number of applications paid out in 2020 during the peak of the Covid-19 pandemic, with a trend of declining applications and payments since that time.
Figure 6-14 shows the average regular energy assistance payments made to recipients of LIHEAP and PB programs between 2019 and 2025. This data includes some payments made through American Rescue Plan Act (ARPA) funds that were available for the years indicated. Figure 6-15 shows the overall regular assistance expenditures for the LIHEAP and PB programs between 2019 and 2025. These data sets do not include the additional funds used for crisis payments. While concerns have been expressed about the status of continued funding for LIHEAP, the program has been fully funded for 2026. An appropriations package signed into law in February 2026 provides nationwide funding for LIHEAP of $4.05 billion, approximately $20 million more than the program's 2025 budget. Wisconsin's allocation for PY 2026 is $112,832,158, up from $112,382,499 in PY 2025.

Figure 6-13 LIHEAP and PB Paid Application Trends, 2019-2025 Program Years (DOA-DEHCR Data)

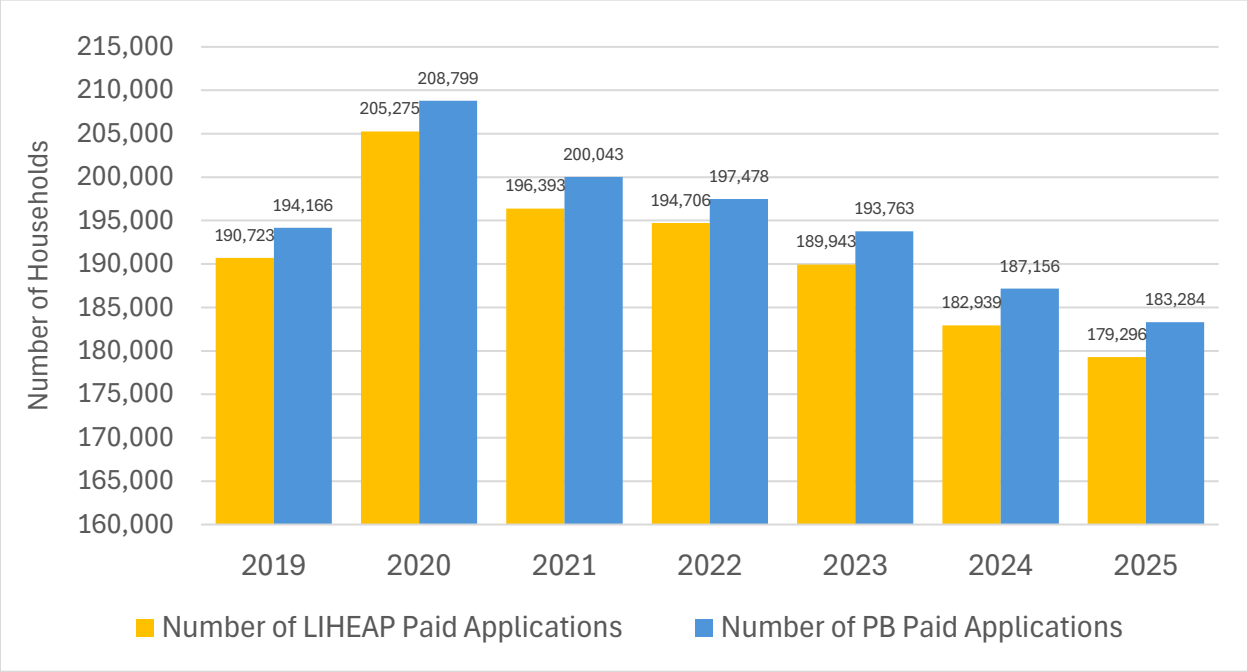


Figure 6-14 WHEAP (LIHEAP and PB) Average Benefit Payments, 2019-2025 Program Years (DOA-DEHCR Data)

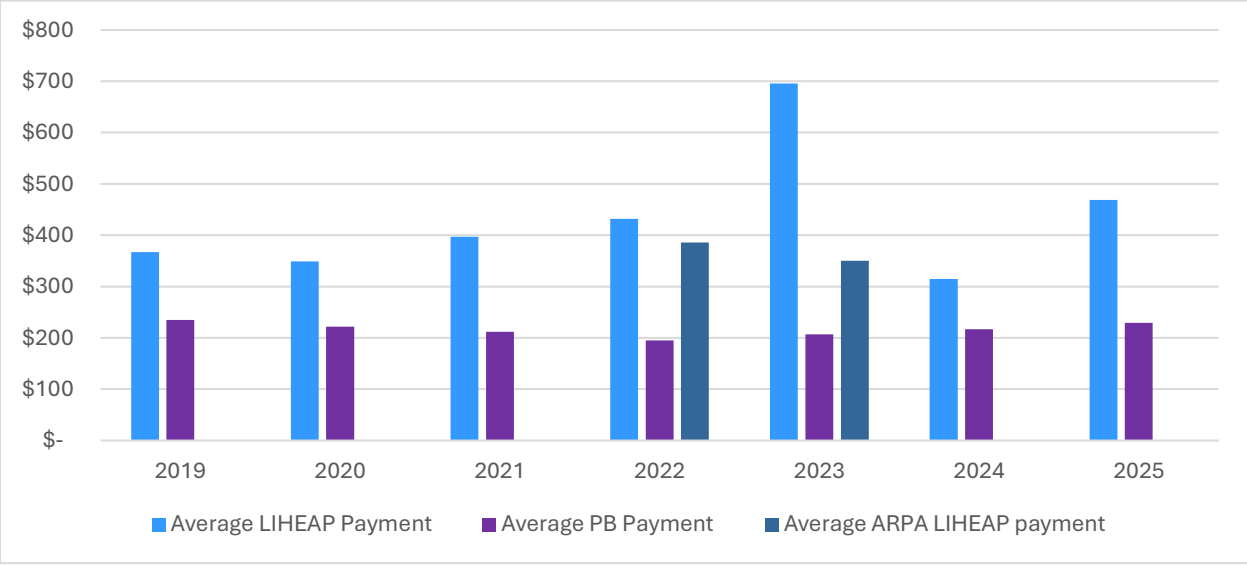
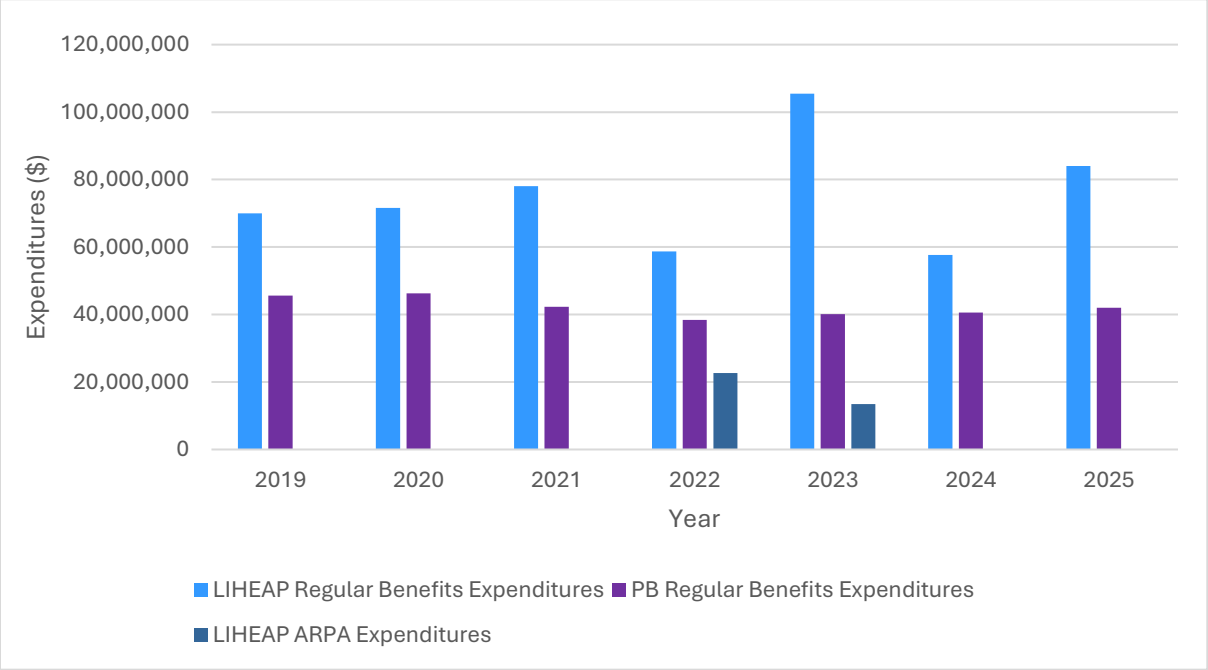


Figure 6-15 WHEAP (LIHEAP and PB) Expenditures, 2019-2025 Program Years (DOA-DEHCR Data)



In addition to the regular energy assistance payment data, which refers to payments made during the heating season in Wisconsin, DOA-DEHCR also keeps track of crisis assistance payment trends. As stated above, crisis assistance payments can be made at any time of year given available funding and household eligibility is met.

Figure 6-16 WHEAP (LIHEAP and PB) Average Crisis Assistance Payments, 2019-2025 Program Years (DOA-DEHCR Data)

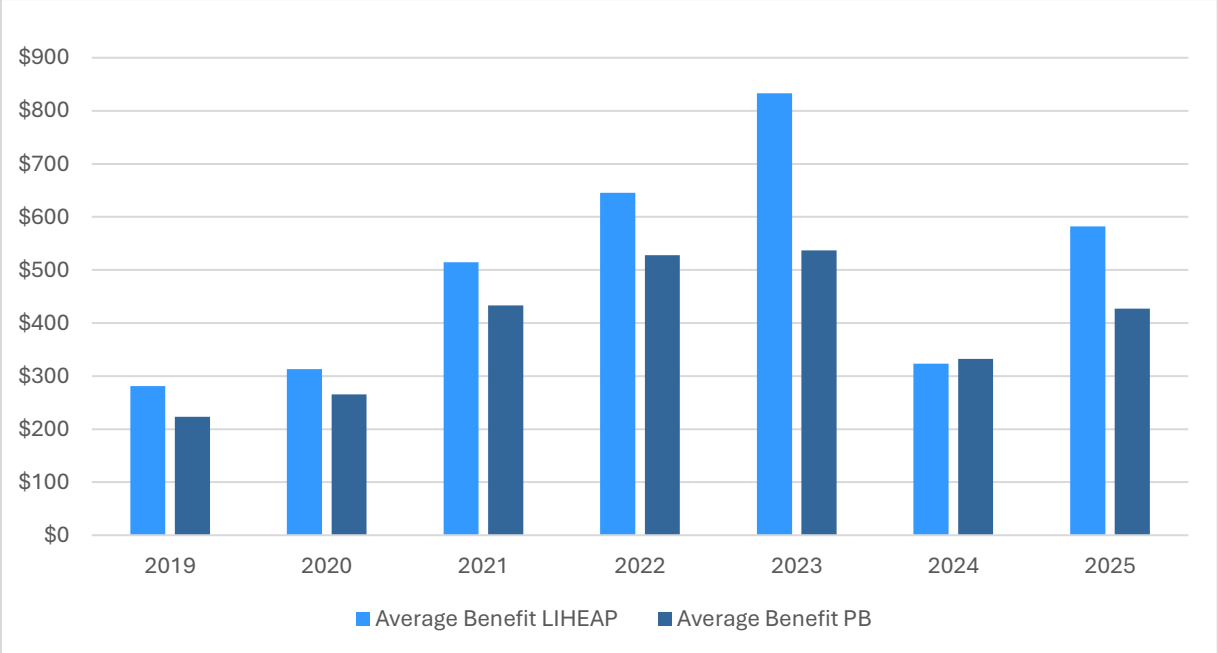
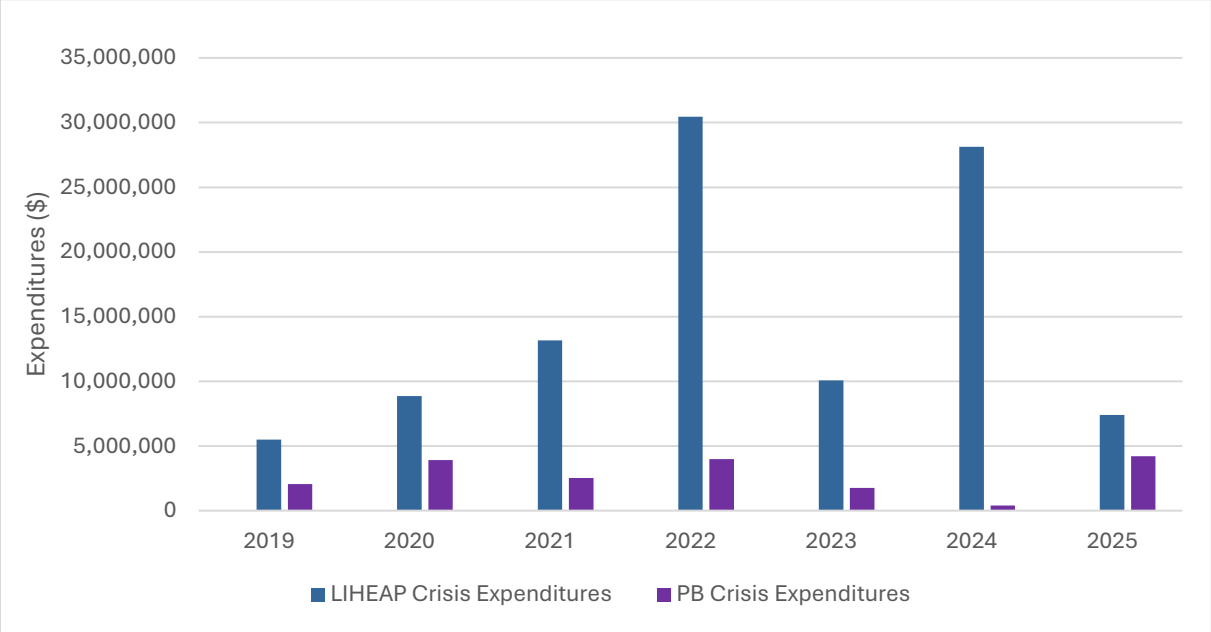


Figure 6-17 WHEAP (LIHEAP and PB) Crisis Assistance Expenditures, 2019-2025 Program Years (DOA-DEHCR Data)



Many electric providers also financially support the Keep Wisconsin Warm/Cool Fund (KWW/CF), a statewide, non-profit effort that provides preventative services and financial assistance in response to energy emergencies. Heat for Heroes assists veterans facing service disconnections or other energy challenges. Customers also may be able to find assistance through a variety of other local non-profits throughout Wisconsin, such as the Aging and Disability Resource Centers, the Salvation Army, and local churches.

Energy Efficiency Programs

One reason customers may experience a higher energy burden is because they live in residences with less energy-efficient lighting, appliances, and heating and cooling systems. As discussed in earlier chapters, energy efficiency programs can reduce energy peaks which save all customers money by reducing the need for additional generation resources. Energy efficiency programs can also help low-income households reduce their energy bills. Focus on Energy, Wisconsin's statewide energy efficiency and renewable resource program, offers multiple program options that can benefit income-qualified customers (customers at 80 percent AMI or below). (See Chapter 3 for more information.) Weatherization programming can also help low-income customers reduce their energy bills. DEHCR administers the state's low-income Weatherization Assistance Program (WAP) and households that are eligible for WHEAP (60 percent of state median income (SMI)) may be eligible for free energy efficiency improvements to their homes through this program. In addition, four Wisconsin electric providers—NSPW, WEPCO, WP&L, and WPSC—operate additional voluntary energy efficiency programs that provide enhanced financial support to low-income customers.

In response to public and stakeholder interest in exploring opportunities to expand Focus' support for low-income customers, the Commission reviewed low-income offerings as part of its general updates of Focus policies and goals in the Quadrennial Planning Process in docket 5-FE-104, *Quadrennial Planning Process IV*. In its Final Decision in that docket, the Commission requested a review of options and approaches for a benefits adder to be applied to the cost-effectiveness analysis of Focus' programs and offerings targeting customers below 60 percent of statewide median income. Developing cost-effectiveness approaches that recognize the higher cost-to-serve low-income customers as well as the additional benefits associated with serving these customers is one way that regulators can encourage energy efficiency programs to engage with this population. The Commission subsequently determined[120] that the application of a 20 percent adder to the net benefits quantified in Focus' primary cost-effectiveness test for those programs and offerings targeting customers earning at or below 60 percent of statewide median income is reasonable and in the public interest. Further review of the appropriate application of the approved low-income benefits adder is included among the issues in the scope of *Quadrennial Planning Process V*.[121]

Also, in the Final Decision in docket 5-FE-104, the Commission required the Program Administrator to develop a framework to identify communities with low Focus participation and recommend program interventions and KPIs to address service discrepancies, emphasizing underserved customers with the highest energy burdens. To meet this direction, the Focus administrator along with VEIC developed a data-driven framework that compares historic Focus participation data with publicly available demographic and socioeconomic geospatial data, including the LEAD tool and ACS data. The evaluation resulted in the identification of Communities of Focus, which represent those census tracts in Wisconsin where households and communities face disproportionate barriers to Focus participation and would benefit from enhanced service. More information on the process used can be found in the Final Decision[122] approving the approach used to identify the Communities of Focus, as well as the Commission's approval of the framework used to assess underserved customers and future refinements of the framework including incorporating energy burden data from investor-owned utilities filed in the annual reports.

Notably, Wisconsin was allocated $149 million in funding under the IRA's HER programs, which offer multiple options for energy efficiency and electrification rebates for projects serving low- and moderate-income households. Wisconsin's implementation of the IRA HER program funds reserved the majority of total rebate funding for low-income households and offers higher maximum rebates to those households to help address the financial barriers to participation they may face. Wisconsin launched the HOMES Program

[120] Order 5-FE-104, issued December 21, 2023 (PSC REF#: 487366)
[121] Order 5-FE-105, issued February 24, 2026 (PSC REF#: 580871)
[122] Order 5-FE-104, issued August 21, 2024 (PSC REF#: 514798)

in August 2024[123] and the HEAR Program in December 2024.[124] As of October 2025, the full HEAR program is operational and includes rebates for retail purchases and installations of energy-efficient appliances. As of May 2026, 523 low-income households have participated in the HOMES program ($4.1 million of rebates) and 811 low-income households have participated in the HEAR program ($4.5 million of rebates). The percentage of rebate funds going to low-income households is 81 percent on average, which is above the target set in the Commission's Final Decision[125] of reserving 60 percent of funds for low-income households.

Affordability Investigation Dockets

Bill affordability has been a major concern for the public and intervenors in rate cases over the last several years. In response to these concerns, the Commission directed staff to open investigation dockets[126] related to bill affordability for four of the largest Wisconsin utilities. The Commission has a history of opening investigation dockets to allow for more flexible review of topics than in contested rate or tariff cases, allowing groups to intervene and provide information in a non-contested case setting. In each docket, utilities, stakeholders, and the Commission worked collaboratively to discuss options to address bill affordability issues and propose program elements that could address affordability challenges. The Commission used several facilitation exercises to encourage participants to discuss and reach areas of agreement where possible, while documenting those items with some group interest but no clear agreement on a program policy.

In the dockets for the WEC utilities, a report[127] was provided that summarized the process and discussions, with some consensus-based suggestions for modifications to the LIFT program. These areas of consensus included:

- Meaningfully connecting LIFT participants to energy efficiency programs.
- Including participation in other income-qualified programs such as the Keep Wisconsin Warm/Cool Fund, Heat for Heroes, and the utilities' RAP as criteria for potential LIFT eligibility.
- Allowing LIFT participants in good standing (making timely minimum required payments) that continue to participate in energy assistance programs such as WHEAP or the ones above to auto-enroll in a second year of LIFT.

[123] Home Efficiency Rebates program August 2024
[124] Home Electrification and Appliance Rebate program December 2024
[125] PSC REF#: 505286 Order 9716-FG-2023, Issued June 13, 2024.
[126] Dockets 5-UI-121 (WEPCO) and 6690-UI-101 (WPSC) were opened in 2023. Dockets 6680-UI-100 (WP&L) and 3270-UI-101 (MGE) were opened in 2024.
[127] PSC REF#: 570116

- Exploring a new pilot program that could utilize the ability of local community benefit organizations, in collaboration with the WEC utilities, to reach out to new customers that are auto-enrolled in a program such as LIFT to ensure customers are set up for success with an understanding of the benefits and requirements of program enrollment.
- Exploring a new pilot program that could be geotargeted to areas of high energy burden that would establish minimum required payments that address customer energy burden more specifically than the current approach of requiring 50 percent of a customer's budget bill.

In the MGE and WP&L dockets, topics that had been raised in the investigation dockets informed affordability-related terms of the settlements that were reached between each utility and participating intervenors and approved by the Commission in settlement discussions in the 2025 rate cases for each of those utilities. As part of the WP&L settlement[128], the utility is developing a Customer Affordability Pilot Program to provide bill credits to recipients of energy assistance in specifically burdened census tracts. The WP&L settlement also includes the TOU Rate Automatic Switch Program, which will automatically enroll income-qualified customers that stand to reduce their annual bills by $90 in the TOU program.

As part of the MGE settlement[129], the utility will provide $500,000 to targeted low- to moderate-income customers in 2026 and 2027 on programs that could include providing increased outreach to LMI customers, funding for insulation or smart thermostats, or energy assessments. MGE worked collaboratively with participating intervenors to develop incentives to improve participation in existing programs such as WHEAP, Focus, and MGE Connect that can reduce customer costs, thereby reducing disconnection notices and uncollectible bill balances for LMI customers. Financial incentives will be provided to customers that newly enroll in programs as well as the community-benefit organization that promotes the programs and assists customers with enrollment.

[128] PSC REF#: 571102
[129] PSC REF#: 571099

Appendix A (Chapter 1)

Table A-1 Assessment of Electric Demand and Supply Conditions, Monthly Non-Coincident Peak Demands, MW

Year	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	11,094	10,449	10,524	9,199	9,536	11,824	13,929	12,644	11,224	10,063	9,917	10,327
2020	9,979	9,945	9,115	8,340	10,951	12,748	13,698	13,669	10,259	9,060	9,463	9,964
2021	9,850	10,446	9,273	8,839	10,811	13,599	13,817	13,499	11,050	9,667	9,825	10,429
2022	10,506	10,060	9,355	9,063	11,645	14,429	13,398	12,858	12,472	9,092	10,308	10,511
2023	10,161	10,019	9,280	9,166	11,120	12,404	13,496	14,873	13,008	10,877	9,895	9,817
2024	10,359	9,292	9,137	9,024	9,272	13,241	13,746	14,516	11,859	9,317	9,184	10,494
2025	10,745	10,333	9,214	9,148	10,096	14,126	14,103	13,685	11,627	11,127	9,363	10,383
Future												
2026	10,886	10,290	9,938	9,445	11,188	13,453	14,234	13,870	12,297	9,833	10,047	10,958
2027	11,180	10,683	10,466	9,862	11,612	13,669	14,760	14,442	13,026	10,646	11,052	11,980
2028	12,510	12,131	12,014	11,669	13,492	16,025	17,086	16,686	15,420	12,882	13,050	14,189
2029	14,413	13,889	13,841	13,246	14,937	17,495	18,559	18,156	16,828	14,302	14,450	15,403
2030	15,643	15,127	15,035	14,447	16,171	18,630	19,694	19,296	17,780	15,256	15,410	16,200
2031	16,432	15,910	15,639	15,047	16,797	18,787	19,852	19,458	17,879	15,345	15,499	16,273
2032	16,466	15,935	15,668	15,075	16,830	18,814	19,883	19,489	17,907	15,378	15,537	16,317

Table A-2 Seasonal Wisconsin Aggregated Supply and Demand[130]

Report Line MISO Description	Summer Capacity						
Capacity (MW)	2026	2027	2028	2029	2030	2031	2032
High Certainty Resources (Existing Resource)	12,588	11,648	11,896	10,929	11,217	10,881	10,852
Low Certainty Resources (Existing Resource)	0	1,317	710	1,655	985	985	985
Behind the Meter (Existing Resource)	328	353	380	410	388	387	387
DRR plus Registered DSM (Existing Resource)	638	636	679	682	719	719	719
New Capacity DPP Signed GIA (New Resource)	84	410	1,765	2,845	3,181	3,406	3,488
New Capacity DPP GIA Phase (New Resource)	0	15	16	56	85	85	85
New Capacity DPP Phase 3 (New Resource)	0	94	164	286	537	779	779
New Capacity DPP Phase 2 (New Resource)	0	0	13	13	24	224	224
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	0	171	284	514	514
New Capacity Not in Interconnection Queue (New Resource)	0	139	563	976	2,868	4,159	5,700
New BTMG / New DR (New Resource)	18	39	63	79	96	104	111
RZ Internal Transfer-In (ZRC)	1,943	2,011	2,098	2,123	2,156	2,207	2,215
RZ Internal Transfer-Out (ZRC)	1,174	1,117	1,272	1,390	1,517	1,605	2,051
External Resource Imports (Existing Resource)	122	24	18	18	18	18	18
Total Committed Net Capacity (MW) Included DPP Signed GIA	14,531	15,337	16,462	17,473	17,389	17,240	16,854
Total Potential Net Capacity (MW)	14,547	15,554	17,077	18,809	20,999	22,821	23,982
Summer Demand							
Non-Coincident Peak gross of DR	12,189	12,790	15,013	16,845	17,738	17,854	17,884
Full Responsibility Transaction	174	174	174	80	55	55	0

[130] Data was compiled from Wisconsin's 5 largest investor-owned utilities assuming MISO's current accreditation method for *all* planning years. The accreditation method does not change to Direct Loss of Load starting in planning year 2028.

Coincident LSE Peak with Zonal Peak gross of DR	9,391	9,801	11,644	12,884	13,728	13,833	13,852
Coincident LSE Peak to MISO Peak gross of DR	11,827	12,424	14,636	16,460	17,345	17,460	17,489
Summer Reserve Requirements							
Planning Reserve Margin Requirement (MW)	12,710	13,782	16,439	18,608	19,557	19,669	19,641
Resources above Planning Reserve Requirement	1,598	1,772	638	201	1,442	3,151	4,342

Fall Capacity							
Report Line MISO Description Capacity (MW)	2026	2027	2028	2029	2030	2031	2032
High Certainty Resources (Existing Resource)	11,961	11,146	11,541	10,538	10,675	10,284	10,242
Low Certainty Resources (Existing Resource)	0	1,227	551	1,532	1,022	1,022	1,022
Behind the Meter (Existing Resource)	267	296	321	348	325	325	324
DRR plus Registered DSM (Existing Resource)	519	519	562	565	565	564	564
New Capacity DPP Signed GIA (New Resource)	80	414	2,086	2,551	2,648	2,831	2,778
New Capacity DPP GIA Phase (New Resource)	0	18	20	59	80	80	80
New Capacity DPP Phase 3 (New Resource)	0	94	172	321	571	648	648
New Capacity DPP Phase 2 (New Resource)	0	0	13	20	20	220	220
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	0	285	272	462	462
New Capacity Not in Interconnection Queue (New Resource)	0	203	553	992	3,283	4,668	5,838
New BTMG / New DR (New Resource)	18	39	62	79	96	104	111
RZ Internal Transfer-In (ZRC)	1,912	1,966	2,026	2,020	2,038	2,065	2,063
RZ Internal Transfer-Out (ZRC)	991	1,094	1,204	1,276	1,348	1,391	1,818
External Resource Imports (Existing Resource)	128	29	22	22	22	22	22
Total Committed Net Capacity (MW) Included DPP Signed GIA	13,877	14,552	16,079	16,489	16,156	15,932	15,408
Total Potential Net Capacity (MW)	13,893	14,841	16,708	18,006	20,219	21,855	22,508

Fall Demand							
Non-Coincident Peak gross of DR	10,595	11,632	13,580	15,119	16,085	16,137	16,164
Full Responsibility Transaction	178	178	178	80	55	55	0
Coincident LSE Peak with Zonal Peak gross of DR	7,941	8,758	10,439	11,620	12,278	12,306	12,322
Coincident LSE Peak to MISO Peak gross of DR	10,044	11,070	13,004	14,533	15,485	15,537	15,563
Fall Reserve Requirements							
Planning Reserve Margin Requirement (MW)	11,408	12,755	15,186	17,112	18,166	18,196	18,162
Resources above Planning Reserve Requirement	2,484	2,086	1,522	895	2,053	3,659	4,345

Report Line MISO Description	Winter Capacity						
Capacity (MW)	2026	2027	2028	2029	2030	2031	2032
High Certainty Resources (Existing Resource)	11,291	10,261	10,492	9,042	9,620	9,339	9,279
Low Certainty Resources (Existing Resource)	0	955	754	1,722	1,004	1,004	1,004
Behind the Meter (Existing Resource)	127	129	131	72	73	73	73
DRR plus Registered DSM (Existing Resource)	621	618	659	661	661	661	661
New Capacity DPP Signed GIA (New Resource)	62	375	1,462	1,924	2,030	2,044	2,027
New Capacity DPP GIA Phase (New Resource)	0	17	138	49	73	73	73
New Capacity DPP Phase 3 (New Resource)	0	94	162	300	462	442	442
New Capacity DPP Phase 2 (New Resource)	0	0	13	13	203	213	213
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	0	174	366	366	366
New Capacity Not in Interconnection Queue (New Resource)	0	277	603	859	2,980	4,212	5,386
New BTMG / New DR (New Resource)	2	4	6	8	10	10	11
RZ Internal Transfer-In (ZRC)	1,876	1,894	1,861	1,864	1,865	1,883	1,884
RZ Internal Transfer-Out (ZRC)	1,054	1,005	1,017	1,025	1,066	1,091	1,464
External Resource Imports (Existing Resource)	147	36	36	36	36	36	36

Total Committed Net Capacity (MW) Included DPP Signed GIA	13,070	13,300	14,669	14,470	14,421	14,146	13,698
Total Potential Net Capacity (MW)	13,071	13,640	15,283	15,653	18,271	19,218	19,945
Winter Demand							
Non-Coincident Peak gross of DR	9,313	10,797	12,551	14,042	14,730	14,780	14,804
Full Responsibility Transaction	190	190	190	64	44	0	0
Coincident LSE Peak with Zonal Peak gross of DR	7,027	8,252	9,721	10,786	11,258	11,295	11,306
Coincident LSE Peak to MISO Peak gross of DR	8,987	10,466	12,214	13,587	14,378	14,428	14,453
Winter Reserve Requirements							
Planning Reserve Margin Requirement (MW)	10,911	12,754	14,934	16,545	17,465	17,457	17,488
Resources above Planning Reserve Requirement	2,160	886	350	-892	806	1,761	2,458

Spring Capacity							
Report Line MISO Description Capacity (MW)	2026	2027	2028	2029	2030	2031	2032
High Certainty Resources (Existing Resource)	12,707	11,339	11,857	10,567	11,286	11,005	10,946
Low Certainty Resources (Existing Resource)	0	1,300	717	1,689	1,004	1,004	1,004
Behind the Meter (Existing Resource)	335	368	396	375	381	380	380
DRR plus Registered DSM (Existing Resource)	587	598	644	649	649	648	648
New Capacity DPP Signed GIA (New Resource)	265	1,244	2,528	3,025	3,309	3,347	3,347
New Capacity DPP GIA Phase (New Resource)	0	20	155	81	81	81	81
New Capacity DPP Phase 3 (New Resource)	0	94	168	552	735	735	735
New Capacity DPP Phase 2 (New Resource)	0	0	13	22	212	222	222
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	0	290	502	502	502
New Capacity Not in Interconnection Queue (New Resource)	43	376	573	1,820	4,115	5,933	6,083
New BTMG / New DR (New Resource)	21	39	62	78	96	103	110
RZ Internal Transfer-In (ZRC)	1,892	2,041	2,029	2,115	2,143	2,148	2,148

RZ Internal Transfer-Out (ZRC)	1,112	1,255	1,316	1,500	1,580	2,025	2,068
External Resource Imports (Existing Resource)	123	20	20	20	20	20	20
Total Committed Net Capacity (MW) Included DPP Signed GIA	14,842	15,709	17,174	17,142	17,416	16,731	16,629
Total Potential Net Capacity (MW)	14,861	16,167	17,827	19,733	22,904	24,054	24,110
Spring Demand							
Non-Coincident Peak gross of DR	9,883	11,889	13,318	14,660	15,224	15,256	15,278
Full Responsibility Transaction	151	151	151	64	44	0	0
Coincident LSE Peak with Zonal Peak gross of DR	7,634	9,368	10,535	11,524	11,799	11,819	11,829
Coincident LSE Peak to MISO Peak gross of DR	9,505	11,500	12,921	14,220	14,805	14,836	14,858
Spring Reserve Requirements							
Planning Reserve Margin Requirement (MW)	11,915	14,737	16,941	18,954	19,660	19,599	19,628
Resources above Planning Reserve Requirement	2,946	1,430	887	779	3,244	4,455	4,482

Figure A-1 Predominant Fossil Fuel Source in 2025 – Coal, Fuel Oil, Natural Gas

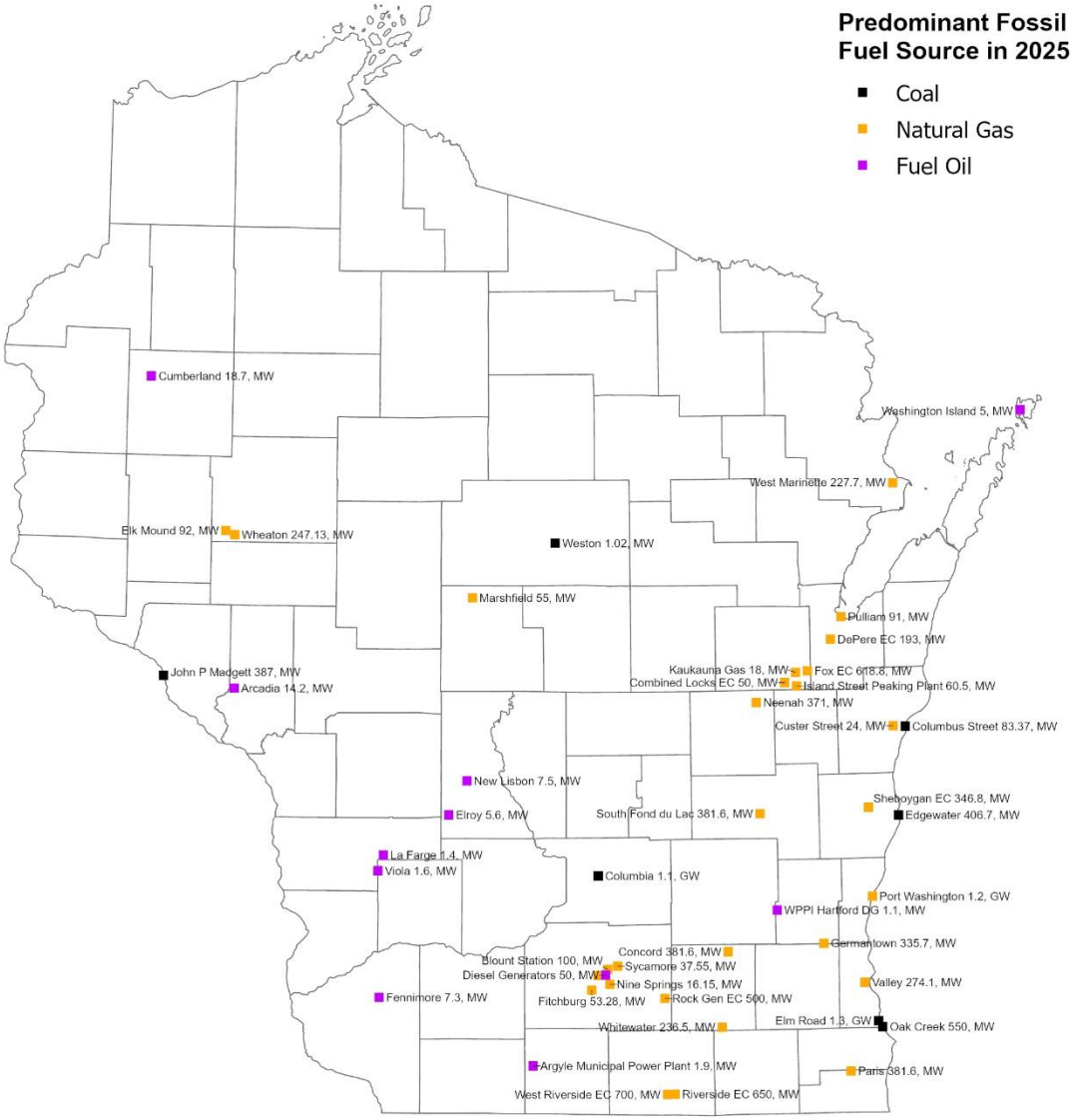


Figure A-2 Predominant Fossil Fuel Source in 2025 – Coal

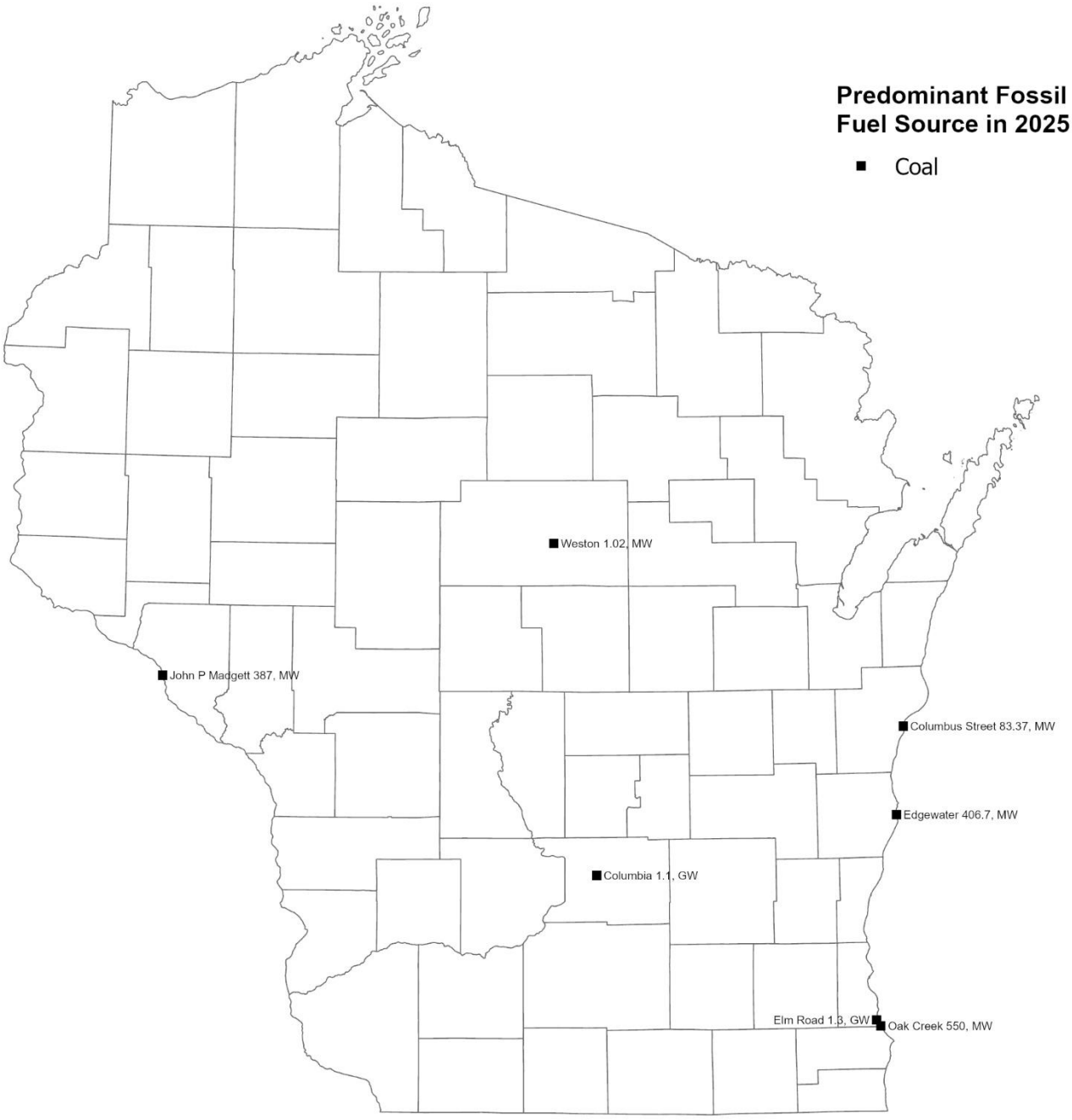


Figure A-3 Predominant Fossil Fuel Source in 2025 – Natural Gas

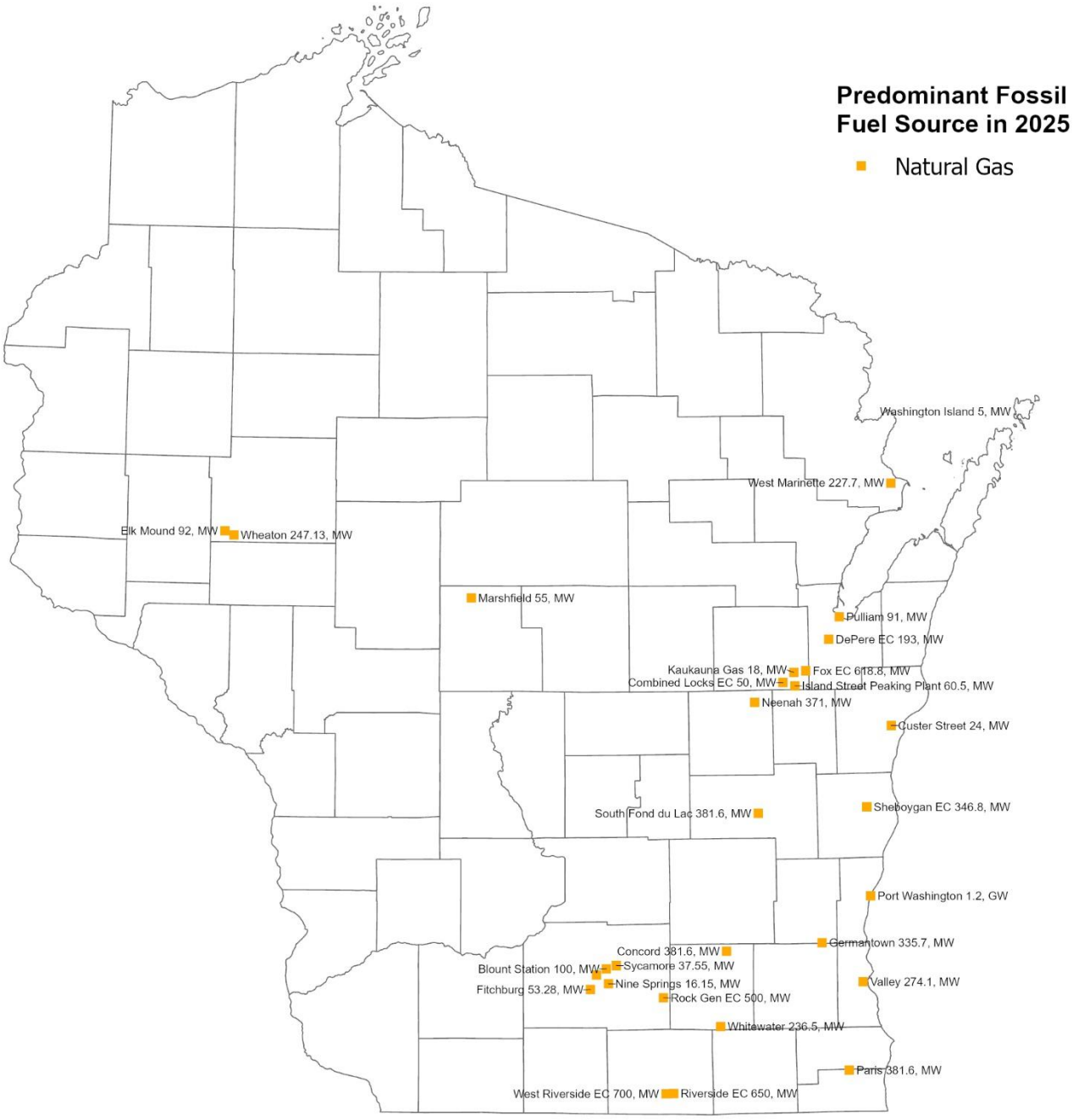


Figure A-4 Wisconsin Non-Emitting Resource Generation Facilities, 2025

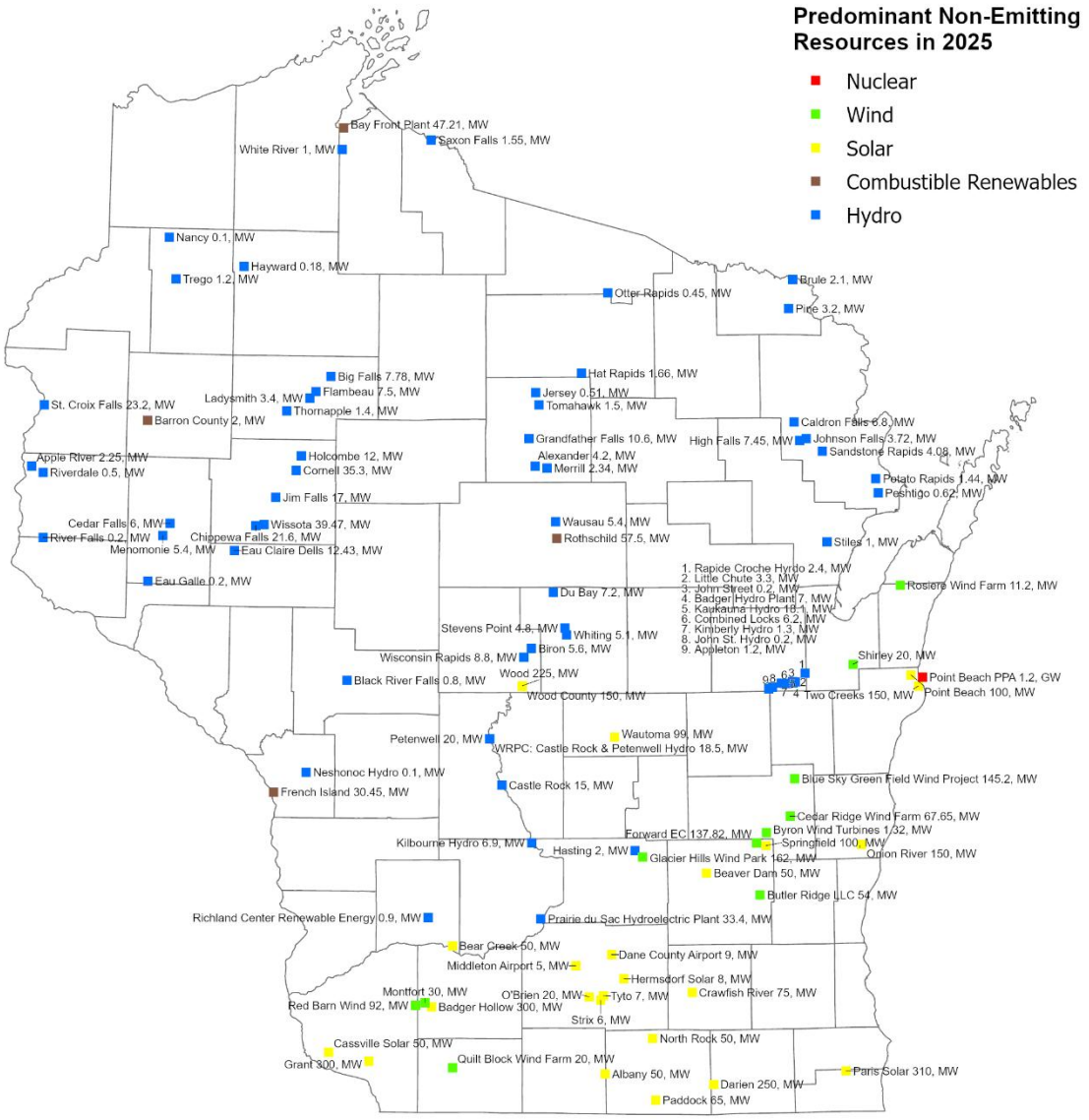


Figure A-5 Predominant Renewable Fuel Source in 2025 – Solar

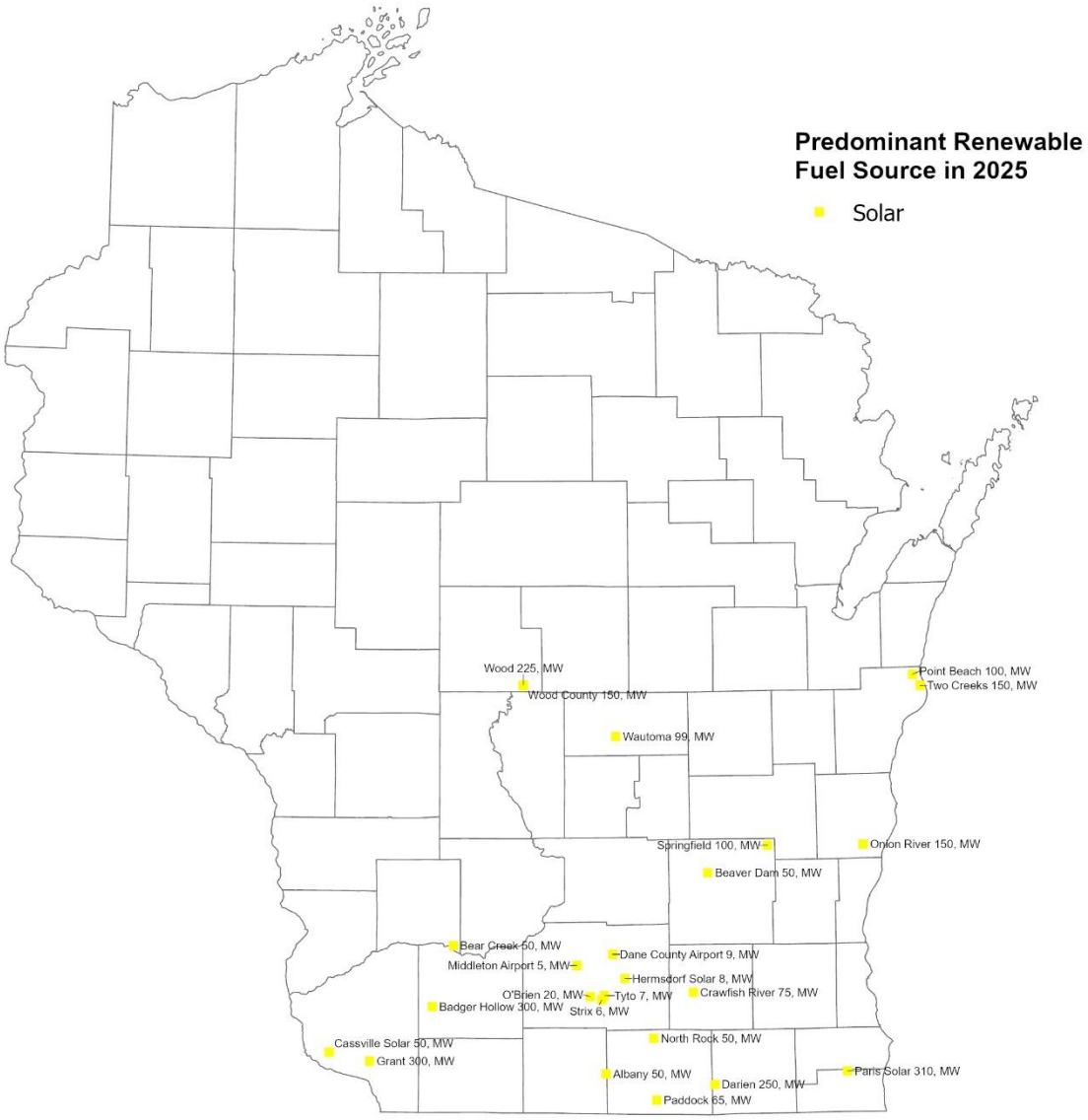


Figure A-6 Predominant Renewable Fuel Source in 2025 – Wind

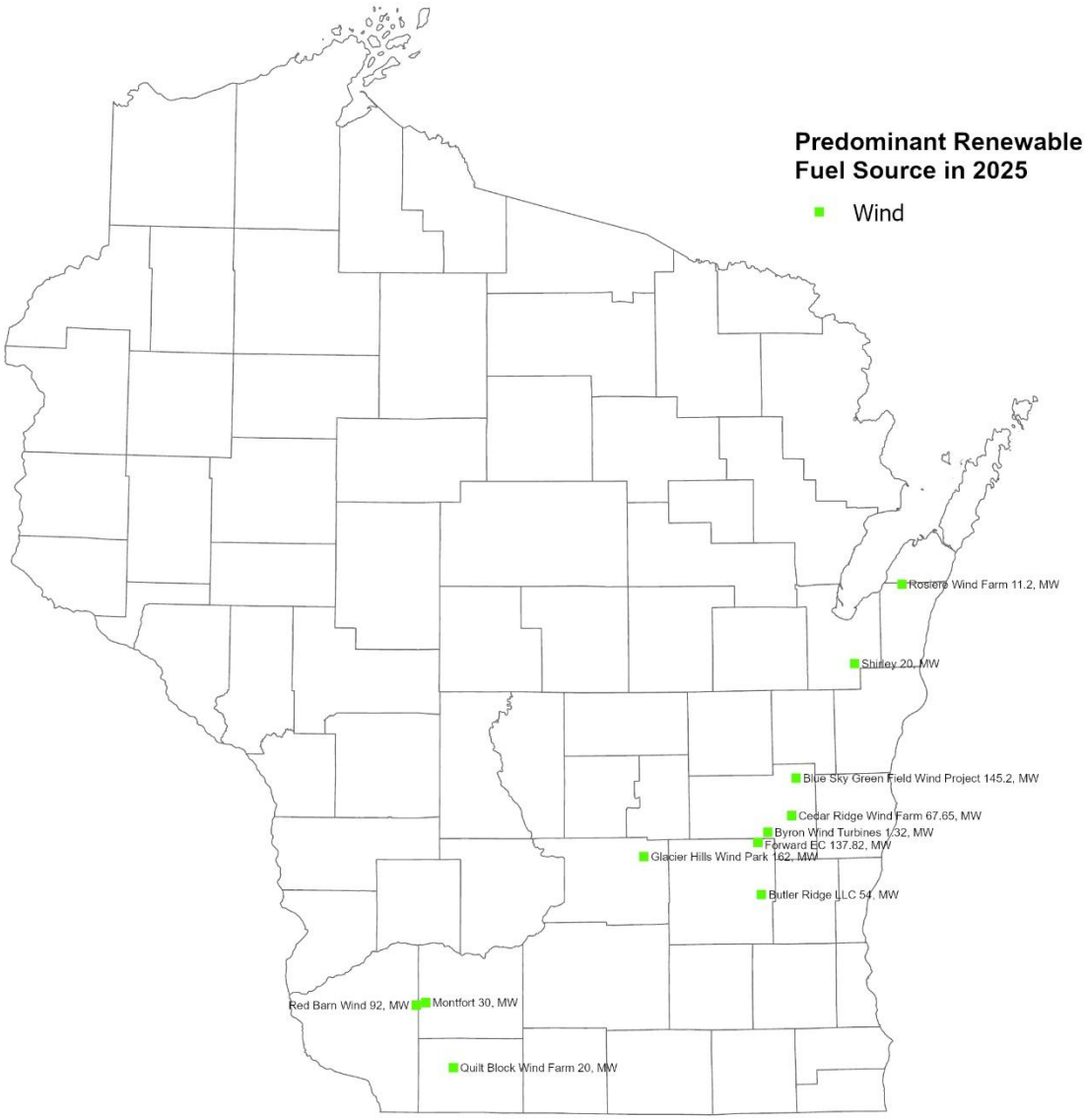


Figure A-7 Wisconsin Hydro Generating Facilities – 2025

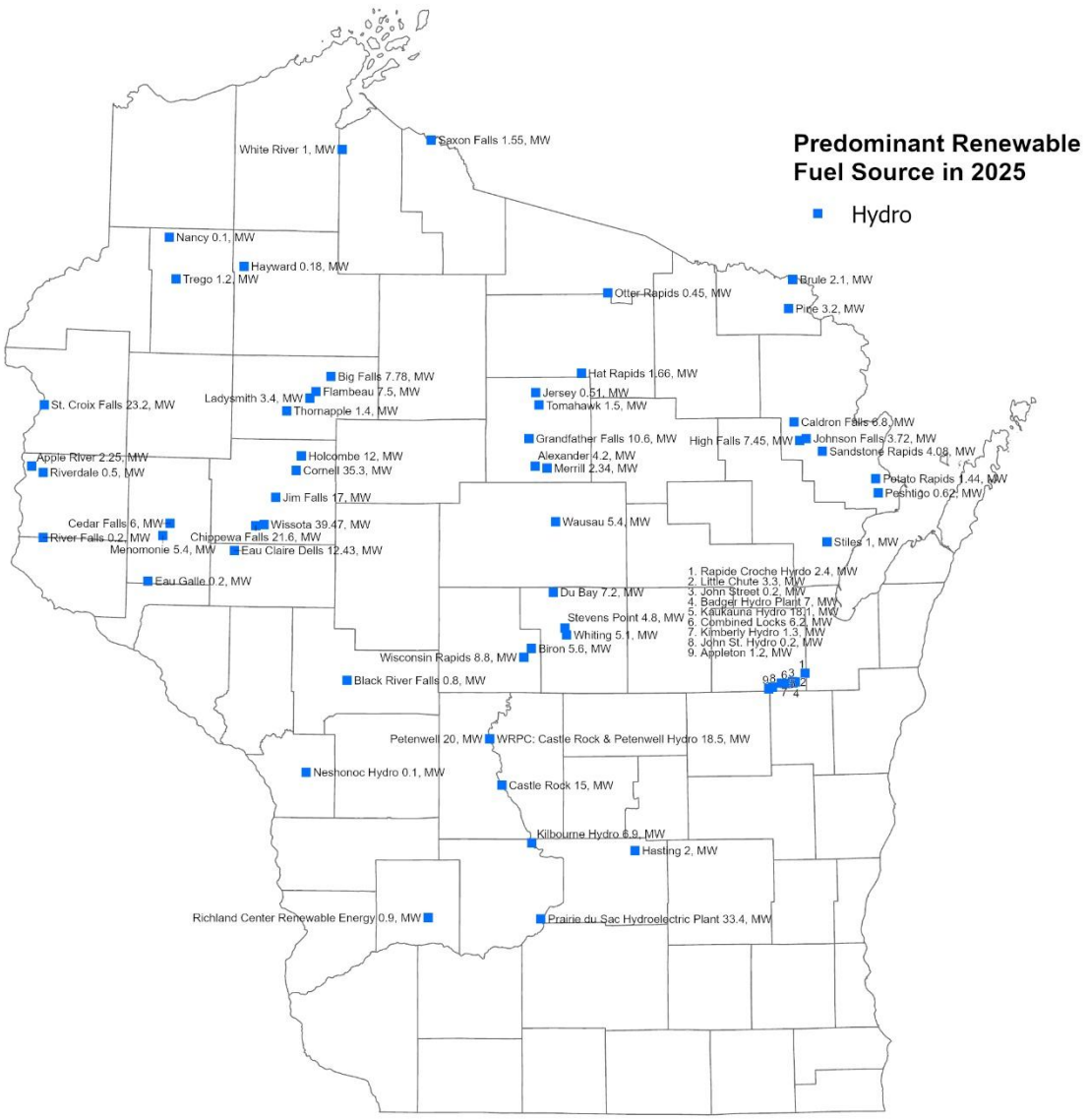


Figure A-8 Wisconsin Combustible Renewables Facilities - 2025



Figure A-9 Wisconsin Nuclear Generating Facilities – 2025

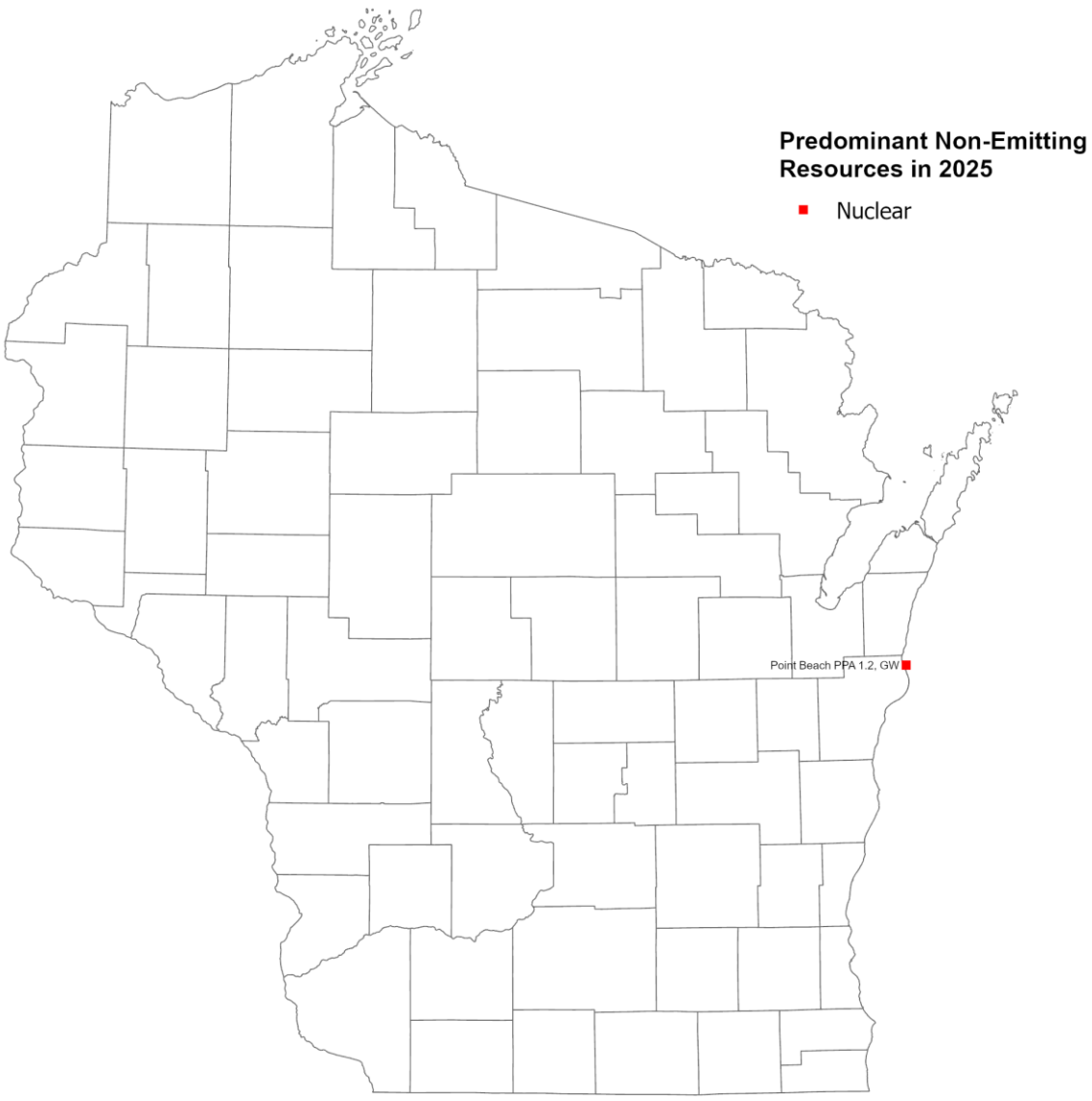


Table A-3 Coal Generation Units Total CO2 Emissions, 2023 and 2024

Unit Name	2023 (MMTon)	2024 (MMTon)	2025 (MMTon)
Elm Road #1 (WEPCO)	2.26	3.06	2.57
Elm Road #2 (WEPCO)	2.64	2.23	2.69
Oak Creek #5 (WEPCO)	0.69	0.25	Retired
Oak Creek #6 (WEPCO)	0.85	0.15	Retired
Oak Creek #7 (WEPCO)	1.31	1.00	1.28
Oak Creek #8 (WEPCO)	1.11	1.09	1.11
Columbia Energy Center #1 (WPS)	0.63	0.70	0.94
Columbia Energy Center #2 (WPS)	0.63	0.73	0.91
Weston #3 (WPS)	0.54	0.71	1.00
Weston #4 (WPS)	1.78	2.14	2.33
Columbia Energy Center #1 (MGE)	0.45	0.44	0.44
Columbia Energy Center #2 (MGE)	0.42	0.45	0.44
Elm Road #1 (MGE)	0.22	0.30	0.24
Elm Road #2 (MGE)	0.26	0.22	0.24
Columbia Energy Center #1 (WPL)	1.23	1.43	1.74
Columbia Energy Center #2 (WPL)	1.20	1.47	1.64
Edgewater #5 (WPL)	2.06	2.25	2.09
John P Madgett #1 (DPC)	1.54	1.34	1.50
Weston #4 (DPC)	0.66	0.68	0.77
Boswell Energy Center (WPPI)	0.58	0.61	0.77
Columbus Street #9 (MPU)	-	-	-

Table A-4 Coal Generation Units CO2 Emissions Rate, 2023 and 2024

Unit Name	2023 (lb/kWh)	2024 (lb/kWh)	2025 (lb/kWh)
Elm Road #1 (WEPCO)	1.98	1.90	1.87
Elm Road #2 (WEPCO)	1.92	1.80	1.87
Oak Creek #5 (WEPCO)	2.51	2.52	Retired
Oak Creek #6 (WEPCO)	2.53	2.52	Retired
Oak Creek #7 (WEPCO)	2.37	2.41	2.50
Oak Creek #8 (WEPCO)	2.40	2.46	2.51
Columbia Energy Center #1 (WPS)	2.42	2.42	2.38
Columbia Energy Center #2 (WPS)	2.36	2.38	2.37
Weston #3 (WPS)	2.03	2.13	2.04
Weston #4 (WPS)	1.89	1.91	1.91
Columbia Energy Center #1 (MGE)	2.41	2.41	2.37
Columbia Energy Center #2 (MGE)	2.36	2.37	2.37
Elm Road #1 (MGE)	1.97	1.89	1.90
Elm Road #2 (MGE)	1.92	1.79	1.90
Columbia Energy Center #1 (WPL)	2.40	2.41	2.37
Columbia Energy Center #2 (WPL)	2.35	2.37	2.36
Edgewater #5 (WPL)	2.34	2.37	2.31
John P Madgett #1 (DPC)	2.71	3.03	2.58
Weston #4 (DPC)	1.88	1.90	1.73
Boswell Energy Center (WPPI)	2.21	2.24	2.21
Columbus Street #9 (MPU)	2.68	2.65	NA

Table A-5 Gas Generation Units by Total CO2 Emissions, 2023 and 2024

Unit Name	2023 (MMTon)	2024 (MMTon)	2025 (MMTon)
Wheaton #1 (NSP)	0.0060	0.0043	0.0015
Wheaton #2 (NSP)	0.0080	0.0055	0.0030
Wheaton #3 (NSP)	0.0072	0.0031	0.0016
Wheaton #4 (NSP)	0.0062	0.0042	0.0016
Concord #1 (WEPCO)	0.0279	0.0382	0.0396
Concord #2 (WEPCO)	0.0300	0.0336	0.0402
Concord #3 (WEPCO)	0.0163	0.0239	0.0369
Concord #4 (WEPCO)	0.0145	0.0312	0.0337
Germantown #5 (WEPCO)	0.0098	0.0203	0.0218
Paris #1 (WEPCO)	0.0394	0.0512	0.0373
Paris #2 (WEPCO)	0.0284	0.0313	0.0366
Paris #3 (WEPCO)	0.0232	0.0316	0.0383
Paris #4 (WEPCO)	0.0270	0.0507	0.0468
Port Washington #1 (WEPCO)	1.6024	1.4039	1.3644
Port Washington #2 (WEPCO)	1.5481	1.4033	1.3370
Rothschild (WEPCO)	0.0364	0.0270	0.0476
Valley #1 (WEPCO)	0.2639	0.2884	0.2195
Valley #2 (WEPCO)	0.1535	0.1486	0.2301
West Riverside (WEPCO)	0.1380	0.4014	0.4465
Weston RICE #1 (WEPCO)	0.0026	0.0056	0.0089
Weston RICE #2 (WEPCO)	0.0037	0.0058	0.0101
Weston RICE #3 (WEPCO)	0.0033	0.0057	0.0091
Weston RICE #4 (WEPCO)	0.0031	0.0057	0.0091
Weston RICE #5 (WEPCO)	0.0038	0.0056	0.0097
Weston RICE #6 (WEPCO)	0.0037	0.0055	0.0095
Weston RICE #7 (WEPCO)	0.0039	0.0056	0.0097
Whitewater (WEPCO)	0.1422	0.1603	0.1552
DePere Energy Center (WPS)	0.0885	0.0862	0.1122
Fox Energy Center (WPS)	1.6179	1.6664	1.3491
Pulliam 31 (WPS)	0.0708	0.0378	0.0735
West Marinette 31 (WPS)	0.0112	0	0.0061
West Marinette 32 (WPS)	0.0124	0.0018	0.0099
West Marinette 33 (WPS)	0.0510	0.0203	0.0492
Weston RICE #1 (WPS)	0.0026	0.0056	0.0089
Weston RICE #2 (WPS)	0.0038	0.0058	0.0101
Weston RICE #3 (WPS)	0.0034	0.0057	0.0091
Weston RICE #4 (WPS)	0.0031	0.0056	0.0091
Weston RICE #5 (WPS)	0.0038	0.0056	0.0097
Weston RICE #6 (WPS)	0.0037	0.0055	0.0095

Unit Name	2023 (MMTon)	2024 (MMTon)	2025 (MMTon)
Weston RICE #7 (WPS)	0.0039	0.0056	0.0097
Whitewater (WPS)	0.1422	0.1603	0.1552
Blount Station (MGE)	0.0124	0.0436	0.0423
Fitchburg - 2 units (MGE)	2.31E-05	1.9E-05	0.0002
Sycamore - 2 units (MGE)	0.0004	2.58E-05	0.0000
Nine Springs (MGE)	5.31E-05	8.33E-05	0.0001
M34/Marinette (MGE)	0.0616	0.0332	0.0637
West Campus (MGE)	0.2127	0.1756	0.1935
West Riverside (MGE)	0.0215	0.1003	0.1120
Neenah (WPL)	0.1766	0.2159	0.1424
Neenah (WPL)	0.1877	0.2309	0.1501
Riverside Energy Center #1 (WPL)	0.6610	0.6218	0.6074
Riverside Energy Center #2 (WPL)	0.6490	0.6234	0.6125
Sheboygan Energy Center #1 (WPL)	0.1902	0.2106	0.1363
Sheboygan Energy Center #2 (WPL)	0.1394	0.1830	0.1424
South Fond du Lac #2 (WPL)	0.0067	0.0028	0.0087
South Fond du Lac #3 (WPL)	0.0055	0.0023	0.0093
West Riverside #1 (WPL)	0.5797	0.5698	0.8047
West Riverside #2 (WPL)	0.6485	0.5775	0.8097
Elk Mound #1 (DPC)	0.0108	0.0074	0.0270
Elk Mound #2 (DPC)	0.0133	0.0101	0.0249
RockGen #1 (DPC)	0.1140	0.0986	0.1084
RockGen #2 (DPC)	0.1105	0.0479	0.1017
RockGen #3 (DPC)	0.1247	0.1049	0.1183
South Fond du Lac #1 (WPPI)	0.0016	0.0034	0.0100
South Fond du Lac #2 (WPPI)	0.0062	0.0020	0.0097
Island Street Peaking Plant (WPPI)	0.0057	0.0074	0.0131
Custer Street (MPU)	0.0025	0.0041	NA
M-1 (GLU)	0.0054	0.0024	0.0113

Table A-6 Gas Generation Units CO2 Emissions Rate, 2023 and 2024

Unit Name	2023 (lb/kWh)	2024 (lb/kWh)	2025 (lb/kWh)
Wheaton #1 (NSP)	1.96	2.03	2.45
Wheaton #2 (NSP)	1.85	1.92	1.86
Wheaton #3 (NSP)	1.97	2.34	2.12
Wheaton #4 (NSP)	1.95	1.97	1.94
Concord #1 (WEPCO)	1.63	1.61	1.65
Concord #2 (WEPCO)	1.64	1.61	1.62
Concord #3 (WEPCO)	1.61	1.58	1.62
Concord #4 (WEPCO)	1.65	1.58	1.63
Germantown #5 (WEPCO)	1.92	1.67	1.67
Paris #1 (WEPCO)	1.65	1.61	1.64
Paris #2 (WEPCO)	1.61	1.61	1.63
Paris #3 (WEPCO)	1.58	1.58	1.62
Paris #4 (WEPCO)	1.64	1.59	1.63
Port Washington #1 (WEPCO)	0.82	0.82	0.82
Port Washington #2 (WEPCO)	0.82	0.82	0.82
Rothschild (WEPCO)	0.56	0.39	0.64
Valley #1 (WEPCO)	2.27	2.2	2.61
Valley #2 (WEPCO)	2.8	2.4	2.75
West Riverside (WEPCO)	0.81	0.81	0.82
Weston RICE #1 (WEPCO)	1.11	1.01	1.00
Weston RICE #2 (WEPCO)	1.08	1.01	1.01
Weston RICE #3 (WEPCO)	1.09	1.02	1.01
Weston RICE #4 (WEPCO)	1.1	1.02	1.01
Weston RICE #5 (WEPCO)	1.07	1.01	1.01
Weston RICE #6 (WEPCO)	1.08	1.02	1.01
Weston RICE #7 (WEPCO)	1.1	1.01	1.00
Whitewater (WEPCO)	0.97	0.96	0.96
DePere Energy Center (WPS)	1.35	1.35	1.35
Fox Energy Center (WPS)	0.82	0.82	0.82
Pulliam 31 (WPS)	1.45	1.47	1.46
West Marinette 31 (WPS)	1.83	0	1.82
West Marinette 32 (WPS)	1.82	1.83	1.82
West Marinette 33 (WPS)	1.47	1.5	1.50
Weston RICE #1 (WPS)	1.09	0.99	0.99
Weston RICE #2 (WPS)	1.07	0.99	1.00
Weston RICE #3 (WPS)	1.08	1	1.00
Weston RICE #4 (WPS)	1.08	0.99	1.00
Weston RICE #5 (WPS)	1.06	0.99	1.00
Weston RICE #6 (WPS)	1.06	1	1.00

Unit Name	2023 (lb/kWh)	2024 (lb/kWh)	2025 (lb/kWh)
Weston RICE #7 (WPS)	1.09	0.99	0.99
Whitewater (WPS)	0.97	0.96	0.96
Blount Station (MGE)	2.86	1.97	1.59
Fitchburg - 2 units (MGE)	2.99	2.99	2.99
Sycamore - 2 units (MGE)	3.32	2.99	2.99
Nine Springs (MGE)	1.83	2.24	2.01
M34/Marinette (MGE)	1.62	1.6	1.59
West Campus (MGE)	1.31	1.35	1.38
West Riverside (MGE)	0.41	0.81	0.82
Neenah (WPL)	1.32	1.34	1.34
Neenah (WPL)	1.31	1.32	1.33
Riverside Energy Center #1 (WPL)	1.30	1.31	1.30
Riverside Energy Center #2 (WPL)	1.32	1.33	1.31
Sheboygan Energy Center #1 (WPL)	1.33	1.36	1.36
Sheboygan Energy Center #2 (WPL)	1.32	1.34	1.36
South Fond du Lac #2 (WPL)	1.88	2.15	2.04
South Fond du Lac #3 (WPL)	1.86	1.92	2.04
West Riverside #1 (WPL)	1.25	1.27	1.29
West Riverside #2 (WPL)	1.26	1.28	1.30
Elk Mound #1 (DPC)	1.53	1.56	1.36
Elk Mound #2 (DPC)	1.56	1.50	1.33
RockGen #1 (DPC)	1.41	1.37	1.48
RockGen #2 (DPC)	1.43	1.38	1.47
RockGen #3 (DPC)	1.41	1.37	1.48
South Fond du Lac #1 (WPPI)	2.15	2.21	2.08
South Fond du Lac #2 (WPPI)	1.91	2.15	2.08
Island Street Peaking Plant (WPPI)	1.57	1.49	1.43
Custer Street (MPU)	2.39	1.84	NA
M-1 (GLU)	1.34	1.34	1.30

Appendix B (Chapter 2)

Table B-1 ***Total Annual Emissions Forecast for Wisconsin Electric Providers, 2024-2032, Million Metric Tons***

Utility	2024	2026	2028	2030	2032
WEC (WEPCO & WPSC)	35.7	17.9	18.9	N/A	N/A
WPL	8.4	8.8	9.31	4.49	4.49
Dairyland	3.426	3.702	2.267	1.773	1.004
MGE	2.085	1.9	N/A	N/A	NA
WPPI	3.97	2.27	2.01	2	2.06
NSPW	4.1	1.8	1.1	0.5	0.6
MPU	0.16	0.246	0.275	0.271	0.271

Figure B-1 ***Total Annual Emissions Forecast for Madison Gas and Electric***

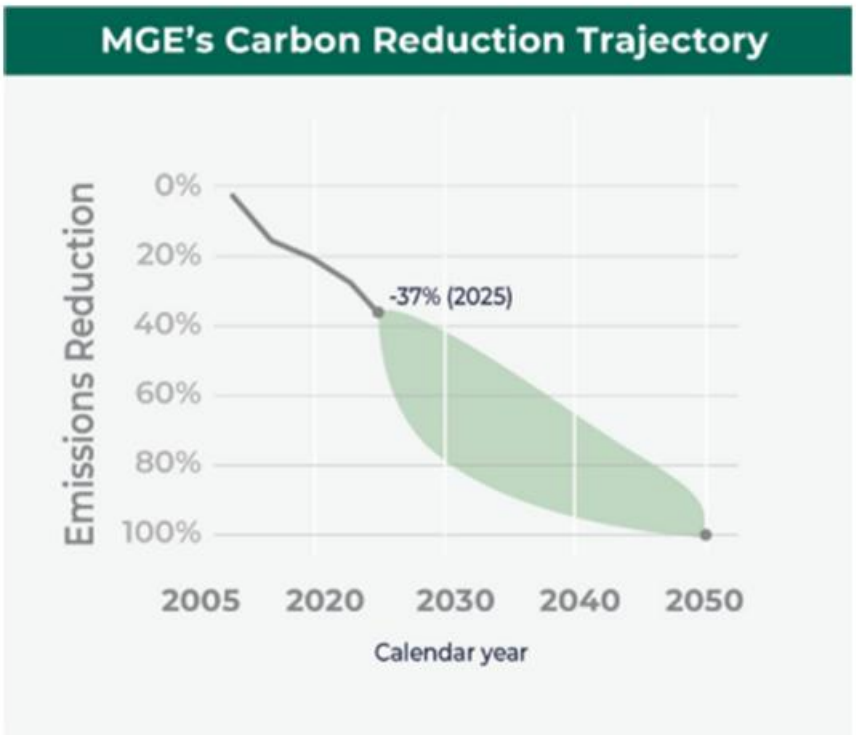


Table B-2 Annual Unit Selection for Baseline Scenario, MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	1,200	600	0	0	0	600	0
2035	1,200	1,200	0	0	0	1,200	0
2036	1,200	1,200	0	0	0	600	0
2037	1,200	1,200	0	0	0	0	0
2038	1,200	600	0	0	0	0	0
2039	0	0	0	0	1,200	1,200	0
2040	0	0	0	0	1,200	1,200	0
2041	0	1,200	0	0	600	1,200	0
2042	1,200	0	0	0	1,800	0	0
2043	0	1,800	0	0	1,200	0	0
2044	1,800	1,200	0	0	1,800	0	0
Total	9,000	9,000	0	0	7,800	6,000	0

Table B-3 Annual Unit Selection for High Gas Price (4.04 $/MMBTU), MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	1,200	1,200	0	0	0	0	0
2035	1,200	1,200	0	0	600	1,200	0
2036	1,200	600	0	0	0	600	0
2037	1,200	0	0	0	0	1,200	0
2038	1,200	600	0	0	0	0	0
2039	0	1,200	0	0	600	600	0
2040	0	0	0	0	1,200	1,200	0
2041	0	1,200	0	0	600	1,200	0
2042	1,200	0	0	0	1,800	0	0
2043	600	1,200	0	0	1,800	0	0
2044	1,200	1,800	0	0	1,200	0	0
Total	9,000	9,000	0	0	7,800	6,000	0

Table B-4 Annual Unit Selection for Low Gas Price (2.43 $/MMBTU), MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	1,200	600	0	0	0	600	0
2035	1,200	1,200	0	0	0	1,200	0
2036	1,200	1,200	0	0	0	600	0
2037	1,200	1,200	0	0	0	0	0
2038	1,200	600	0	0	0	0	0
2039	0	0	0	0	1,200	1,200	0
2040	0	0	0	0	1,200	1,200	0
2041	0	1,200	0	0	600	1,200	0
2042	1,200	0	0	0	1,800	0	0
20413	0	1,800	0	0	1,200	0	0
2044	1,800	1,200	0	0	1,800	0	0
Total	9,000	9,000	0	0	7,800	6,000	0

Table B-5 Annual Unit Selection for Solar Capacity Accreditation Sensitivity, MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	1,200	1,200	0	0	0	0	0
2035	1,200	1,200	0	0	0	1,200	0
2036	1,200	1,200	0	0	0	0	0
2037	1,200	600	0	0	0	600	0
2038	1,200	0	0	0	0	600	0
2039	0	600	0	0	0	1,200	0
2040	0	600	0	0	0	1,200	0
2041	0	600	0	1,200	600	1,200	0
2042	1,800	0	0	0	0	0	0
2043	0	1,200	0	1,200	1,200	0	0
2044	1,200	1,800	0	1,200	0	0	0
Total	9,000	9,000	0	3,600	1,800	6,000	0

Table B-6 Annual Unit Selection for Net Zero by 2050, MW

Year\ Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	NEW NUCLEAR	NEW FLEX
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	1,800	0	0	0	0	0	0	0	0
2029	3,000	0	0	0	0	0	0	0	0
2030	2,400	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	1,200
2032	0	0	0	0	0	0	0	0	600
2033	0	0	0	0	0	0	0	0	600
2034	0	0	0	0	1,200	0	0	0	600
2035	0	0	0	0	0	0	0	0	1,200
2036	0	0	0	0	0	0	0	600	0
2037	0	0	0	0	0	0	0	1,200	0
2038	0	0	0	0	0	600	0	1,200	0
2039	0	0	0	0	0	0	0	1,800	0
2040	0	0	0	0	0	0	0	1,800	0
2041	0	0	0	0	0	0	0	2,400	0
2042	0	0	0	0	0	600	0	1,200	0
2043	0	0	0	0	600	1,200	0	600	0
2044	0	0	0	0	2,400	1,200	0	1,200	600
Total	7,200	0	0	0	4,200	3,600	0	12,000	4,800

Table B-7 Annual Unit Selection for Nuclear Sensitivity

Year\ Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	NEW NUCLEAR
2025	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0
2034	1,200	600	0	0	0	600	0	0
2035	1,200	1,200	0	0	0	1,200	0	0
2036	1,200	1,200	0	0	0	600	0	0
2037	1,200	1,200	0	0	0	0	0	0
2038	1,200	600	0	0	0	0	0	0
2039	0	0	0	0	1,200	1,200	0	0
2040	0	0	0	0	1,200	1,200	0	0
2041	0	1,200	0	0	600	1,200	0	0
2042	1,800	0	0	0	0	0	0	0
2043	600	1,200	0	0	1,200	0	0	0
2044	600	1,800	0	0	1,200	0	0	600
Total	9,000	9,000	0	0	5,400	6,000	0	600

Table B-8 New Additions and Transfers of Utility-Owned or Leased Generation Capacity by Wisconsin ElectricProviders 2025 through 2032

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/Leaser	Source	PSC Status and Docket Number
2025	200	Paris Solar[131]	New	WEPCO/WPSC/MGE	Solar	9801-CE-100, approved; 5-BS-254, approved
2025	110	Paris Solar BESS[132]	New	WEPCO/WPSC/MGE	Battery Storage	9801-CE-100, approved; 5-BS-254, approved
2025	250	Darien Solar[133]	New	WEPCO WPSC/MGE	Solar	9806-CE-100, approved; 5-BS-255, approved
2025	6	Strix Solar	New	MGE	Solar	
2025	255	Wheaton replacement	New	NSPW	NaturalGas	4220-CE-185, approved
2026	100	Neenah Generating Station upgrades	Existing	WP&L	Natural Gas	6680-CE-185, approved
2026	100	Sheboygan Falls Generating Station upgrades	Existing	WP&L	Natural Gas	6680-CE-186, approved
2026	7	Blount Battery Storage	New	MGE	Battery Storage	
2026	7	Huiskamp Battery Storage	New	MGE	Battery Storage	
2026	7	West Middleton Battery Storage	New	MGE	Battery Storage	
2027	75	Darien Solar Storage[134]	New	WEPCO / MGE	Battery Storage	9806-CE-100 approved; 5-BS-255, approved
2027	300	Koshkonong Solar[135]	New	WEPCO/WPSC/MGE	Solar	9811-CE-100, approved; 5-BS-258, approved

[131] Ownership shares are 150 MW to WEPCO, 30 MW to WPSC, and 20 MW to MGE.
[132] Ownership shares are 82.5 MW to WEPCO, 16.5 MW to WPSC, and 11 MW to MGE.
[133] Ownership shares are 187.5 MW to WEPCO, 37.5 MW to WPSC, and 25 MW to MGE.
[134] Ownership shares are 67.5 MW to WEPCO and 7.5 MW to MGE.
[135] Ownership shares are 225 MW to WEPCO, 45 MW to WPSC, and 30 MW to MGE.

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/Leaser	Source	PSC Status and Docket Number
2027	165	Koshkonong Solar Storage[136]	New	WEPCO/WPSC/MGE	Battery Storage	9811-CE-100, approved; 5-BS-258, approved
2027	300	High Noon Solar[137]	New	WEPCO/WPSC/MGE	Solar	9814-CE-100, approved; 5-BS-276 approved
2027	165	High Noon Solar Storage[138]	New	WEPCO/WPSC/MGE	Battery Storage	9814-CE-100, approved; 5-BS-276, approved
2027	20	Sunnyside Solar	New	MGE	Solar	
2027	40	Sunnyside Battery Storage	New	MGE	Battery Storage	
2027	18	Columbia Energy Dome[139]	New	WP&L / WPSC / MGE	Long Duration Energy Storage	5-CE-156, approved
2027	149	Badger State Solar	New	DPC	Solar	9800-CE-100, approved
2025	99	Edgewater Battery Storage	New	WP&L	Battery Storage	6680-CE-184, approved
2027	6.5	Six Mile Solar	New	MGE	Solar	
2027	6.5	Pine Hill Solar	New	MGE	Solar	
2027	8	Nine Springs Solar	New	MGE	Solar	
2027	130	Paris Reciprocating Internal Combustion Engine (RICE)	New	WEPCO	Natural Gas	6630-CE-316, approved
2028	1,138	Oak Creek Combustion Turbines (CTs)	New	WEPCO	Natural Gas	6630-CE-317, approved
2028	150	Dawn Harvest Solar[140]	New	WEPCO / WPSC / MGE	Solar	9809-CE-100, approved; 5-BS-281, pending

[136] Ownership shares are 123.75 MW to WEPCO, 24.75 MW to WPSC, and 16.5 MW to MGE.
[137] Ownership shares are 225 MW to WEPCO, 45 MW to WPSC, and 30 MW to MGE.
[138] Ownership shares are 123.75 MW to WEPCO, 24.75 MW to WPSC, and 16.5 MW to MGE.
[139] Ownership shares are 9.6 MW to WP&L, 5.0 MW to WPSC, and 3.4 MW to MGE.
[140] Ownership shares are proposed as 120 MW to WEPCO, 15 MW to WPSC, and 15 MW to MGE.

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/Leaser	Source	PSC Status and Docket Number
2028	50	Dawn Harvest Battery Storage	New	WEPCO	Battery Storage	9809-CE-100, approved; 5-BS-281, pending
2028	150	Saratoga Solar[141]	New	WEPCO / WPSC / MGE	Solar	9816-CE-100, approved; 5-BS-280, approved
2028	50	Saratoga Battery Storage[142]	New	WEPCO / WPSC / MGE	Battery Storage	9816-CE-100, approved; 5-BS-280, approved
2028	98.4	Good Oak Solar[143]	New	WEPCO / WPSC / MGE	Solar	5-CE-159
2028	67	Gristmill Solar[144]	New	WEPCO / WPSC / MGE	Solar	5-CE-159
2028	14	Port Washington Generating Station upgrades	Existing	WEPCO	Natural Gas	6630-CE-318
2028	156	Riverside Generation Station upgrades	Existing	WP&L	Natural Gas	
2028	300	Elk Creek Solar	New	NSPW	Solar	9819-CE-100, approved; 4220-BS-101, approved
2028	77	Elk Creek Battery Storage	New	NSPW	Battery Storage	9819-CE-100, approved; 4220-BS-101, approved
2028	112	Badger Hollow Wind[145]	New	WEPCO / WPSC / MGE	Wind	9827-CE-100, approved; 5-BS-282, approved
2028	67	Whitetail Wind[146]	New	WEPCO / WPSC / MGE	Wind	5-BS-282, approved
2029	300	Ten Mile Creek Solar	New	NSPW	Solar	4220-CE-190, pending
2029	300	Ten Mile Creek Battery Storage	New	NSPW	Battery Storage	4220-CE-190, pending

[141] Ownership shares are proposed as 120 MW to WEPCO, 15 MW to WPSC, and 15 MW to MGE.
[142] Ownership shares are proposed as 40 MW to WEPCO, 5 MW to WPSC, and 5 MW to MGE.
[143] Ownership shares are proposed as 78.8 MW to WEPCO, 9.8 MW to WPSC, and 9.8 MW to MGE.
[144] Ownership shares are proposed as 53.6 MW to WEPCO, 6.7 MW to WPSC, and 6.7 MW to MGE.
[145] Ownership shares are 89.6 MW to WEPCO, 11.2 MW to WPSC, and 11.2 MW to MGE.
[146] Ownership shares are 53.6 MW to WEPCO, 6.7 MW to WPSC, and 6.7 MW to MGE.

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/Leaser	Source	PSC Status and Docket Number
2029	180	Whitewater Solar[147]	New	WEPCO / WPSC	Solar	9828-CE-100, approved; 5-BS-287, pending
2029	225	Emerald Bluffs Solar[148]	New	WEPCO/ MGE	Solar	9830-CE-100, pending; 5-BS-288, pending
2029	100	Fox Solar[149]	New	WEPCO / MGE	Solar	9833-CE-100, pending; 5-BS-290, pending
2029	100	Sinnissippi Solar	New	WEPCO	Solar	9823-CE-100, pending; 6630-BS-102, pending
2029	150	Superior Solar[150]	New	WEPCO / MGE	Solar	5-BS-292, pending
2029	45	Generic Solar 2029	New	MGE	Solar	
2029	200	Ursa Solar[151]	New	WEPCO / WPSC / MGE	Solar	9818-CE-100, approved; 5-BS-280, approved
2029	550	Generic BESS 2029	New	WEPCO	Battery Storage	
2029	270	Foundry Ridge CTs	New	WEPCO	Natural Gas	9835-CE-100, pending; 6630-BS-103, pending
2029	1,125	Red Oak Ridge CTs	New	WEPCO	Natural Gas	9837-CE-100, pending; 6630-BS-104, pending
2029	153	Bent Tree North (MN)	New	WP&L	Wind	6680-CE-189
2029	277	Columbia Wind	New	WP&L	Wind	9836-CE-100
2029	140	Wind Project 2	New	WP&L	Wind	
2030	180	Dawn Break Solar[152]	New	WEPCO / MGE	Solar	9825-CE-100, pending; 5-BS-289, pending

[147] Ownership shares are proposed as 90 MW to WEPCO, 90 MW to WPSC.
[148] Ownership shares are proposed as 202.5 MW to WEPCO and 22.5 MW to MGE.
[149] Ownership shares are proposed as 90 MW to WEPCO, 10 MW to MGE.
[150] Ownership shares are proposed as 135 MW to WEPCO, 15 MW to MGE.
[151] Ownership shares are 160 MW to WEPCO, 20 MW to WPSC, and 20 MW to MGE.
[152] Ownership shares are proposed as 162 MW to WEPCO, 18 MW to MGE.

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/Leaser	Source	PSC Status and Docket Number
2030	180	Dawn Break Battery Storage[153]	New	WEPCO / MGE	Battery Storage	9825-CE-100, pending; 5-BS-289, pending
2030	200	Akron Solar[154]	New	WEPCO / MGE	Solar	9832-CE-100, pending; 5-BS-291, pending
2030	1,500	WEPCO Solar TBD 2030	New	WEPCO	Solar	
2030	206	WPSC Solar TBD 2030	New	WPSC	Solar	
2030	100	WP&L Solar TBD 2030	New	WP&L	Solar	
2030	750	WEPCO Gas TBD 2030	New	WEPCO	Natural Gas	
2030	551	WEPCO Wind TBD 2030	New	WEPCO	Wind	
2030	69	WPSC Wind TBD 2030	New	WPSC	Wind	
2031	300	WEPCO Solar TBD 2031	New	WEPCO	Solar	
2031	38	WPSC Solar TBD 2031	New	WPSC	Solar	
2031	28	WEPCO Gas TBD 2031	New	WEPCO	Natural Gas	
2031	28	WPSC Gas TBD 2031	New	WPSC	Natural Gas	
2032	50	MGE Wind 2032	New	MGE	Wind	
2032	1,138	WEPCO Gas TBD 2032	New	WEPCO	Natural Gas	

PSC Approval Process

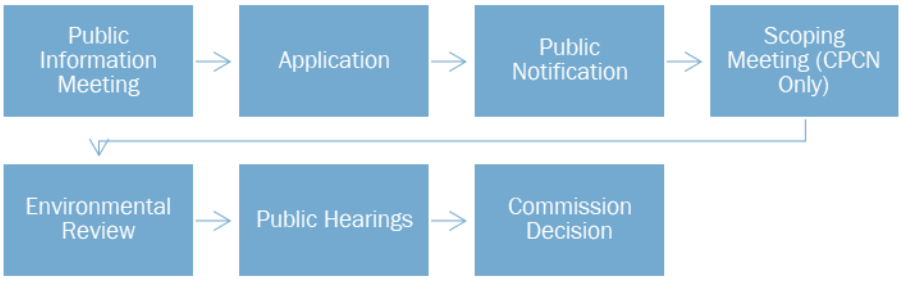
There are two kinds of certificates that Wisconsin utilities or independent developers must obtain prior to constructing large electric or natural gas projects. The nature of the proposed project determines which certification is applicable to a specific proposal. A CPCN is required for proposed electric generation facilities of 100 or more MW and proposed high-voltage electric transmission lines of 100 kV or more. A CA is required for

[153] Ownership shares are proposed as 162 MW to WEPCO, 18 MW to MGE.
[154] Ownership shares are proposed as 180 MW to WEPCO, 20 MW to MGE.

any construction project less than 100 MW that meets the review threshold based on size and cost of the project.[155]

As shown in Figure 2-1 and described below, there are numerous steps in the approval process for a construction case (there are additional protocols for wind siting projects.

Figure B-2 Steps in a Construction Case



Before filing its application with the PSC, a developer, utility, or transmission company that wants to build a new construction project might host a public information meeting. The public can attend these meetings to learn about the preliminary design of a proposed project and give input directly to the applicant. After the public information meeting, the developer, utility, or transmission company officially kicks off the construction case when it files an application. This is when the PSC opens a docket for the construction case. Generally, an application includes information about the need, cost, size, and location of the proposed project. Applications for proposed power plants of 100 or more MW and proposed high-voltage electric transmission lines of 345 kV or more, must include information for two or more sites or routes, detailed engineering plans, plant costs (public utilities only), and a review of potential environmental and community impacts. Non-utility power plant applicants are exempt from a "needs" test and from demonstrating how their engineering specifications are better than available alternatives. Upon receiving the application, the PSC notifies the public. The PSC sends a public notification letter to all property owners on or near the potential sites, as well as local government officials, local libraries, the media, and other agencies and interested persons. This letter briefly describes the project; includes a map; identifies the level of environmental review the project will require; lists places where copies of the application are available for review; and gives contact information for comments and questions.

The Commission often hosts project scoping meetings when an Environmental Impact Statement (EIS) is required for the proposed project to give the public a chance to learn about the proposed project, ask questions, and talk directly with the utility, Department of

[155] CPCN process, including public participation opportunities, also applies to transmission dockets.

Natural Resources (DNR) staff, or Commission staff. Meetings may be held multiple times during the construction case. The Commission completes an environmental review of the application, resulting in a Commission determination to prepare an Environmental Assessment (EA), prepare a more extensive EIS, or take no further review. These documents are posted in the case file on the PSC website. The Commission provides opportunities for the public to comment at various stages of its review and notifies the public when it is accepting such comments and how to file them. As a result of this process the Commission may propose changes in project design or site location to protect the environment or an affected community. DNR will also review an application for air, solid waste, water quality, and water discharge permits. When an application requires a permit from DNR, the Commission and DNR cooperate in the environmental review process. The Commission holds public hearings on the application (and any final EIS) depending on the size and cost of the project and sends a Notice of Hearing to parties to the case, and landowners in the project area. At the hearings the Commission will receive "for the record" testimony and exhibits from parties to the case and comments from members of the public. The Commission also accepts written comments from the public. After the hearing, the Commissioners review the record before making a decision. In an Open Meeting, the Commissioners will discuss the issues presented and vote either to approve or deny the proposal or approve the proposal with modifications or conditions. Following the Open Meeting, the Commission issues a written order and posts it to the online docket page.

As described above, this process provides numerous opportunities for public participation, including opportunities for the public to subscribe to and follow the case online and to provide comments during open comment periods and for the official record. Certain individuals and organizations may also apply for party status as intervenors, which provides authority to file testimony and exhibits and appear at hearings and be available for cross-examinations and to ask questions to other parties. Intervenors may be eligible to apply for and receive intervenor compensation. Additionally, all Commission meetings are available to attend in person on watch live or recorded on the Commission's YouTube Channel.[156]

[156] https://www.youtube.com/@PSCWI

Appendix C (Chapter 3)

Table C-1 Dispatched Demand Response Capacity (MW) as a Proportion of Total Demand Response Program Capacity (MW) by Provider

Utility with Interruptible Load Control Program	2022	2023	2024	2025
DPC	5.10/5.40 (94%)	0.00/5.20 (0%)	0.00/10.40 (0%)	0.00/14.80 (0%)
MGE	0.00/8.47 (0%)	0.00/7.07 (0%)	0.00/7.35 (0%)	0.00/6.52 (0%)
NSP	63.00/63.00 (100%)	65.00/65.00 (100%)	65.50/65.50 (100%)	64.07/64.07 (100%)
WPL	125.00/125.00 (100%)	80.00/80.00 (100%)	131.00/131.00 (100%)	103.00/103.00 (100%)
WPPI	0.00/48.30 (0%)	0.00/38.30 (0%)	0.00/45.40 (0%)	0.00/48.30 (0%)
WEPCO	0.00/132.26 (0%)	0.00/124.57 (0%)	0.00/112.87 (0%)	0.00/113.93 (0%)
WPS	0.00/181.17 (0%)	0.00/168.89 (0%)	0.00/159.74 (0%)	0.00/205.61 (0%)
Total	193.10/563.61 (34%)	145.00/489.03 (30%)	196.50/532.25 (37%)	167.07/556.23 (30%)
Utility with Direct Load Control Program	**Year**			
	2022	**2023**	**2024**	**2025**
DPC	12.05/12.05 (100%)	14.10/14.10 (100%)	84.15/84.15 (100%)	87.16/87.16 (100%)
MGE	2.56/20.70 (12%)	3.95/20.89 (18%)	5.03/21.97 (23%)	5.11/22.23 (30%)
NSP	17.70/17.70 (100%)	16.70/17.00 (98%)	17.93/17.93 (100%)	18.60/18.60 (100%)
WPL	0.00/5.70 (0%)	0.00/10.00 (0%)	0.00/13.00 (0%)	0.00/17.00 (0%)
SWLP	0.00/.22 (0%)	0.00/.17 (0%)	0.00/.15 (0%)	0.00/.16 (0%)
Total	32.31/55.93 (56%)	34.75/58.21 (60%)	107.11/137.19 (78%)	110.87/145.15 (76%)

*Note: There were instances where utilities reported dispatched MW as greater than total program capacity. In these instances, total program capacity was adjusted to match dispatched capacity.

Table C-2 Summary of Demand Response Activity by Provider

Utility	Summary	2022	2023	2024	2025
DPC	DR Capacity	17.45	19.30	94.55	101.96
	DR Dispatched	17.15	14.10	84.15	87.16
	DR Customers	12,101	14,201	94,652	100,688
MGE	DR Capacity	29.17	27.96	29.32	28.75
	DR Dispatched	2.56	3.95	5.03	5.11
	DR Customers	3,568	5,509	7,009	7,309
NSPW	DR Capacity	80.70	82.00	83.43	82.67
	DR Dispatched	80.70	81.70	83.43	82.67
	DR Customers	22,130	22,363	22,614	23,076
SWLP	DR Capacity	0.22	0.17	0.15	0.16
	DR Dispatched	0.00	0.00	0.00	0.00
	DR Customers	165	164	157	158
WPL	DR Capacity	130.70	90.00	144.00	120.00
	DR Dispatched	125.00	80.00	131.00	103.00
	DR Customers	5,500	10,000	13,566	17,203
WPPI	DR Capacity	48.30	38.30	45.40	48.30
	DR Dispatched	0.00	0.00	0.00	0.00
	DR Customers	11	11	10	10

WEPCO	DR Capacity	132.26	124.57	112.87	113.93
	DR Dispatched	0.00	0.00	0.00	0.00
	DR Customers	83	82	78	75
WPSC	DR Capacity	181.17	168.89	159.74	205.61
	DR Dispatched	0.00	0.00	0.00	0.00
	DR Customers	46	45	45	45

Table C-3 Demand Response Capacity (All Types) by Program

DR Program	DR Type	2022 Enrollments	2022 Capacity	2023 Enrollments	2023 Capacity	2024 Enrollments	2024 Capacity	2025 Enrollments	2025 Capacity
DPC									
Daily EV Charging	Direct Load Control	100	0.05	200	0.10	250	0.15	286	0.16
Daily Thermal Storage	Direct Load Control	12,000	12.00	14,000	14.00	14,000	14.00	14,000	14.00
Registered DLC	Direct Load Control	0	0.00	0	0.00	57,000	30.00	63,000	33.00
Unregistered DLC	Direct Load Control	0	0.00	0	0.00	23,400	40.00	23,400	40.00
Registered Bulk Interruptible	Interruptible Load	1	5.40	1	5.20	2	10.40	2	14.80
MGE									
CP-1 C&I High Load Factor Direct Control Interruptible Service for Transmission Voltage	Direct Load Control	1	11.26	1	11.18	1	11.18	1	11.18
MGE Connect	Direct Load Control	3,559	2.56	5,500	3.95	7,000	5.03	7,300	5.11
IS-4 Electric Interruptible Service	Direct Load Control	4	6.88	4	5.76	4	5.76	4	5.94
IS-3 Electric Interruptible Service	Interruptible Load	4	8.47	4	7.07	4	7.35	4	6.52
NSP									
AC Rewards	Direct Load Control	1,410	1.70	1,913	2.10	2452	2.93	2,809	3.17
Saver's Switch (Commercial)	Direct Load Control	1,090	5.70	970	6.20	951	6.20	950	6.20

Saver's Switch (Residential AC)	Direct Load Control	17,975	10.00	16,090	8.10	15,842	8.20	15,942	8.61
Saver's Switch (Residential Water Heaters)	Direct Load Control	1,384	0.30	3,120	0.60	3,097	0.60	3,107	0.62
Electric Rate Savings (commercial)	Interruptible Load	271	63.00	270	65.00	272	65.50	268	64.07
SWLP									
Controlled Space Heating	Direct Load Control	118	0.21	117	0.16	113	0.14	113	0.15
Controlled Water Heating	Direct Load Control	47	0.01	47	0.01	45	0.01	45	0.01
WPPI									
Interruptible Load	Interruptible Load	11	48.30	11	38.30	10	45.40	10	48.30
WPL									
Smart Hours	Direct Load Control	5,500	5.70	10,000	10.00	13,566	13.00	17,203	17.00
C&I Interruptible	Interruptible Load	121	125.00	117	80.00	117	131.00	117	103.00
WEPCO									
Curtailable Service	Interruptible Load	47	25.50	47	22.60	46	23.40	43	21.56
General Primary Combined Firm and Non-Firm Service	Interruptible Load	24	66.13	24	62.89	23	57.20	23	58.69
Real Time Pricing Rider	Interruptible Load	1	39.10	1	37.77	1	31.42	1	32.84
Seasonal Curtailable	Interruptible Load	11	1.53	10	1.32	8	0.86	8	0.84
WPS									

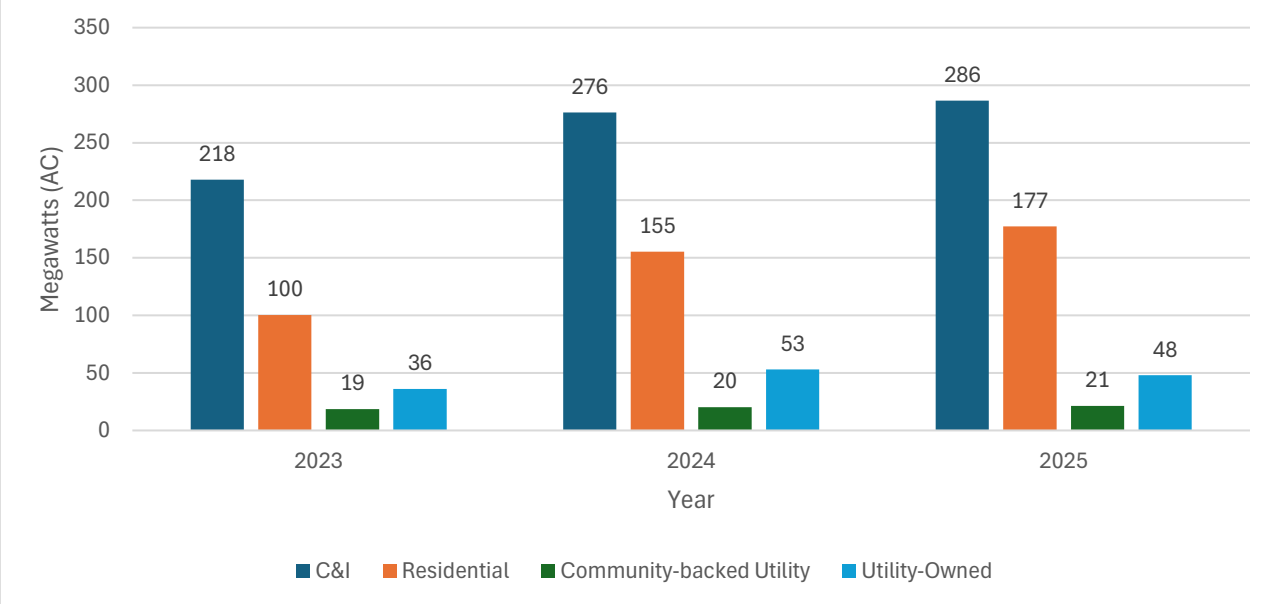
General Primary Interruptible	Interruptible Load	38	135.52	38	128.46	38	115.68	38	161.70
Real Time Market Pricing	Interruptible Load	8	45.65	7	40.42	7	44.05	7	43.91

Figure C-1 Renewable DER Installations by Customer Class, 2023-2025



**Note: These include DERs that are renewable resources only and do not include resources representing only demand response. Utility DERs are included for additional context.*

Figure C-2 Renewable DER Capacity in MW-AC by Customer Class, 2023-2025



**Note: These include DERs that are renewable resources only and do not include resources representing only demand response. Utility DERs are included for additional context.*

Appendix D (Chapter 5)

Figure D-1 Energy Intensity – Non-Residential Sales ($ of GDP/MWh)

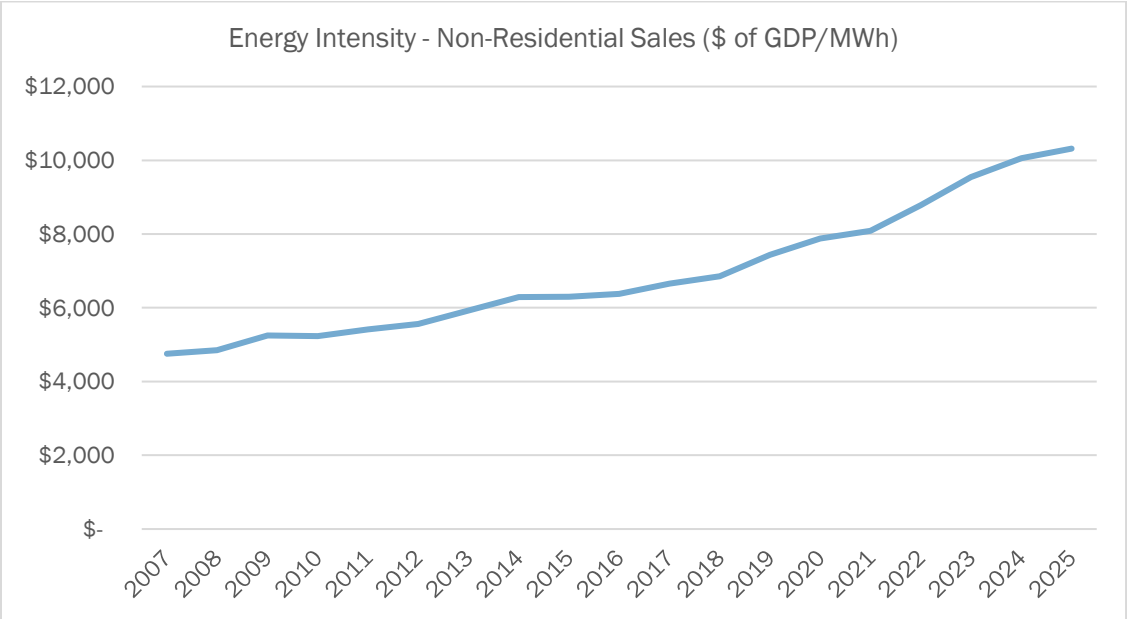


Figure D-2 Weather-Normalized Annual Use, per Residential Customer (kWh)

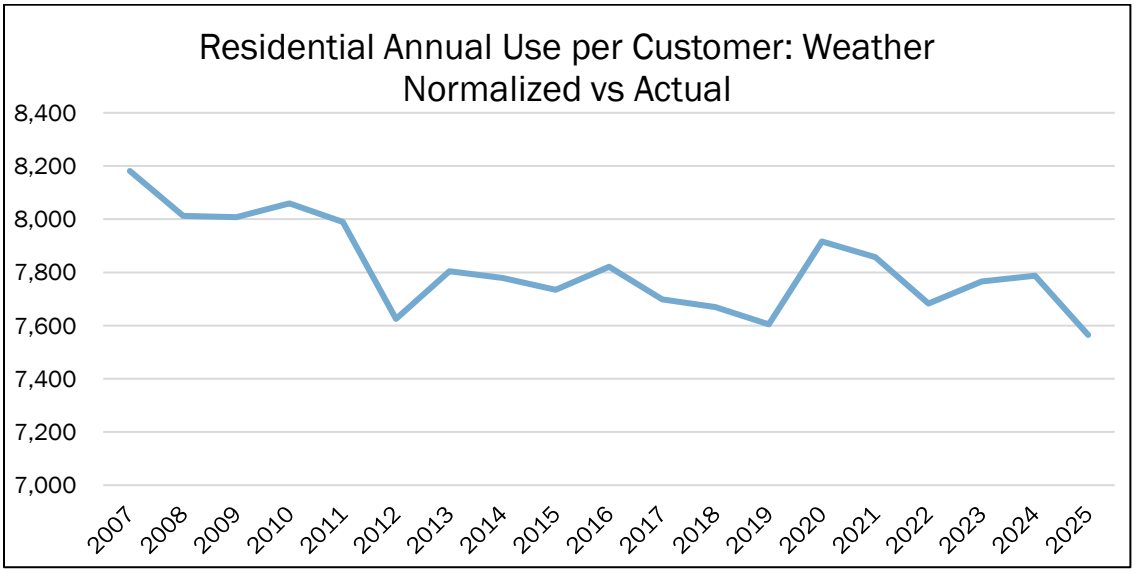


Table D-1 Residential Average Rates in the Midwest and U.S. (cents/kWh)

State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Illinois	12.50	12.54	12.95	12.77	13.03	13.04	13.18	15.65	15.71	15.87	17.69
Indiana	11.57	11.79	12.29	12.26	12.58	12.83	13.37	14.59	14.94	14.77	16.23
Iowa	11.63	11.94	12.34	12.24	12.46	12.46	12.73	13.15	13.31	13.40	13.72
Kansas	12.34	13.06	13.31	13.35	12.71	12.85	12.98	13.99	13.38	14.15	14.56
Michigan	14.42	15.22	15.40	15.45	15.74	16.26	17.54	17.86	18.84	19.30	20.01
Minnesota	12.12	12.67	13.04	13.14	13.04	13.17	13.50	14.25	14.73	15.45	15.82
Missouri	11.21	11.21	11.63	11.34	11.14	11.22	11.41	11.74	12.58	12.91	13.49
Nebraska	10.60	10.84	10.97	10.70	10.77	10.80	10.75	10.79	11.20	11.53	12.34
North Dakota	9.62	10.16	10.29	10.25	10.30	10.44	10.85	10.92	11.01	11.51	11.81
South Dakota	11.08	11.47	11.77	11.59	11.55	11.75	12.22	12.09	12.32	12.86	13.38
Ohio	12.80	12.47	12.63	12.56	12.38	12.29	12.77	13.85	15.38	15.99	16.96
Wisconsin	14.11	14.07	14.35	14.02	14.18	14.32	14.52	15.62	16.88	17.18	18.16
Midwest	12.00	12.29	12.58	12.47	12.49	12.62	12.99	13.71	14.19	14.58	15.35
U.S. Total	12.65	12.55	12.89	12.87	13.01	13.15	13.66	15.04	16.00	16.48	17.30

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

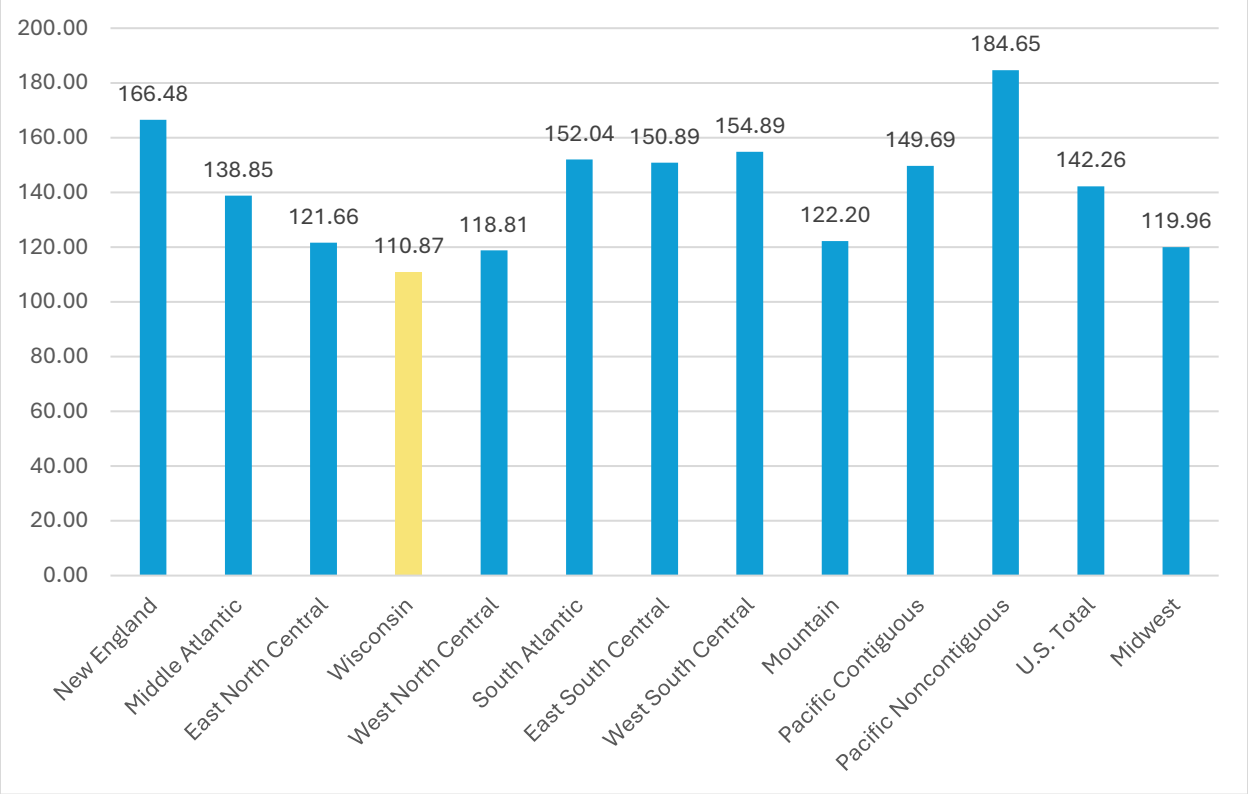
State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Illinois	9.02	9.02	9.09	9.12	9.08	9.15	9.65	11.32	11.24	11.81	13.07
Indiana	9.78	10.01	10.54	10.60	11.03	11.21	11.58	12.86	12.55	12.44	13.88
Iowa	8.92	9.17	9.46	9.68	9.99	9.96	10.17	10.55	10.33	10.22	11.05
Kansas	10.10	10.47	10.59	10.66	10.29	10.40	10.52	11.51	10.85	11.19	11.35
Michigan	10.55	10.64	11.00	11.15	11.39	11.71	12.31	12.55	13.40	14.01	14.48
Minnesota	9.44	9.86	10.48	10.38	10.34	10.43	11.22	12.30	12.39	12.15	12.27
Missouri	9.16	9.26	9.47	9.40	9.07	8.93	9.17	9.55	10.14	10.26	10.63
Nebraska	8.67	8.80	8.85	8.83	8.85	8.89	8.81	8.82	8.76	8.39	8.79

State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North Dakota	8.83	9.15	9.19	9.10	9.01	9.02	9.17	8.45	7.38	7.19	7.40
South Dakota	9.16	9.58	9.74	9.62	9.59	9.65	10.15	10.21	10.16	10.55	10.89
Ohio	10.07	9.97	10.05	10.11	9.72	9.53	9.75	10.39	10.75	10.66	11.60
Wisconsin	10.89	10.77	10.87	10.67	10.72	10.75	10.95	11.85	12.76	12.63	13.06
Midwest	9.55	9.73	9.94	9.94	9.92	9.97	10.29	10.86	10.89	10.96	11.54
U.S. Total	10.64	10.43	10.66	10.67	10.68	10.59	11.22	12.41	12.59	12.75	13.41

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

State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Illinois	6.67	6.51	6.47	6.80	6.52	6.70	7.30	8.57	8.20	8.83	10.14
Indiana	6.86	6.97	7.54	7.38	7.36	6.98	7.39	8.65	8.24	8.15	8.89
Iowa	5.90	6.05	6.21	6.45	6.60	6.43	6.63	7.06	6.91	6.80	7.20
Kansas	7.61	7.49	7.54	7.60	7.35	7.30	7.38	8.30	7.64	7.73	8.03
Michigan	7.02	6.91	7.19	7.10	7.07	7.24	7.69	8.33	8.16	8.26	8.59
Minnesota	7.02	7.37	7.37	7.52	7.53	7.67	8.29	9.25	9.20	9.15	9.32
Missouri	6.44	7.12	7.33	7.22	7.11	6.84	7.11	7.67	7.90	7.87	8.38
Nebraska	7.59	7.69	7.66	7.60	7.65	7.38	7.26	7.21	7.63	7.66	8.00
North Dakota	8.07	7.98	7.63	7.98	7.94	7.26	7.37	7.28	7.37	7.25	7.50
South Dakota	7.37	7.57	7.84	7.77	7.81	7.79	8.02	8.04	8.01	8.28	8.68
Ohio	7.02	6.98	6.92	7.01	6.55	6.16	6.55	7.45	7.03	7.10	8.52
Wisconsin	7.58	7.49	7.49	7.33	7.31	7.29	7.63	8.49	8.68	8.54	8.92
Midwest	7.10	7.18	7.27	7.31	7.23	7.09	7.39	8.03	7.91	7.97	8.51
U.S. Total	6.91	6.76	6.88	6.92	6.81	6.67	7.18	8.32	8.04	8.13	8.62

Figure D-3 Average Monthly Residential Bills by Census Division (2024 EIA Data)[157]



[157] U.S. Energy Information Administration. 2022 Average Monthly Bill – Residential. https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf. Accessed February 15, 2024.

Figure D-4 2025 Distribution of Monthly Residential Electricity Bills for Municipal Utilities[158]

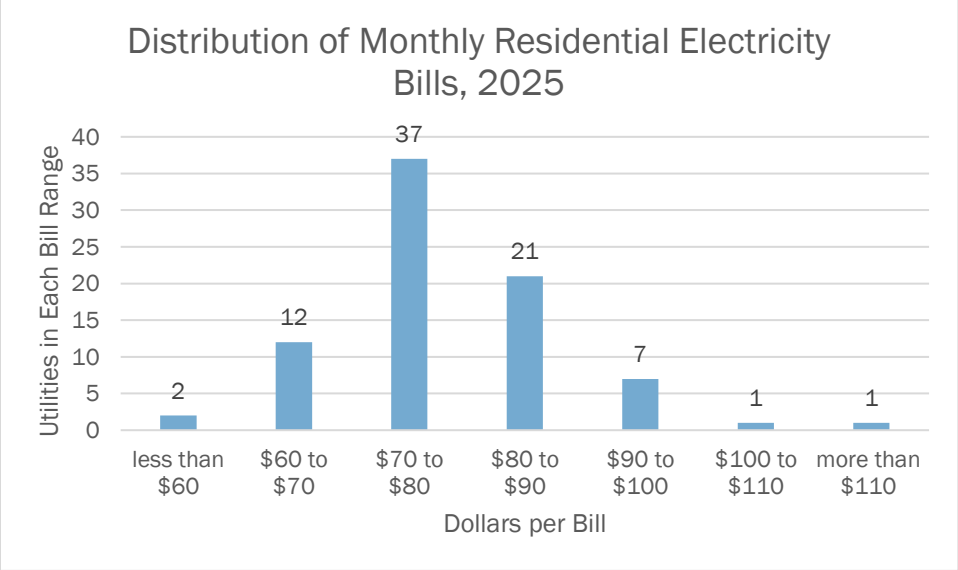
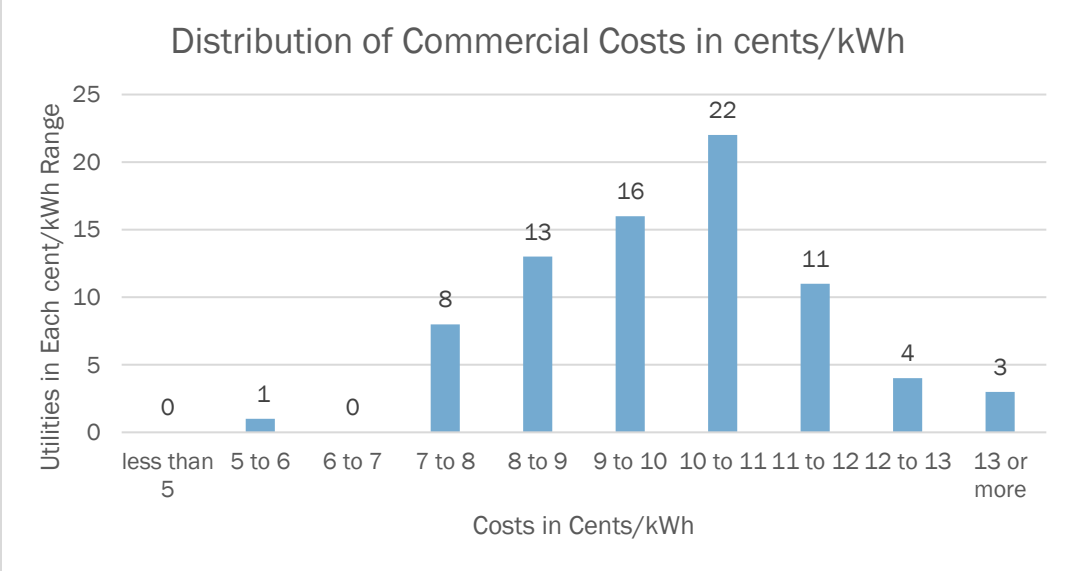
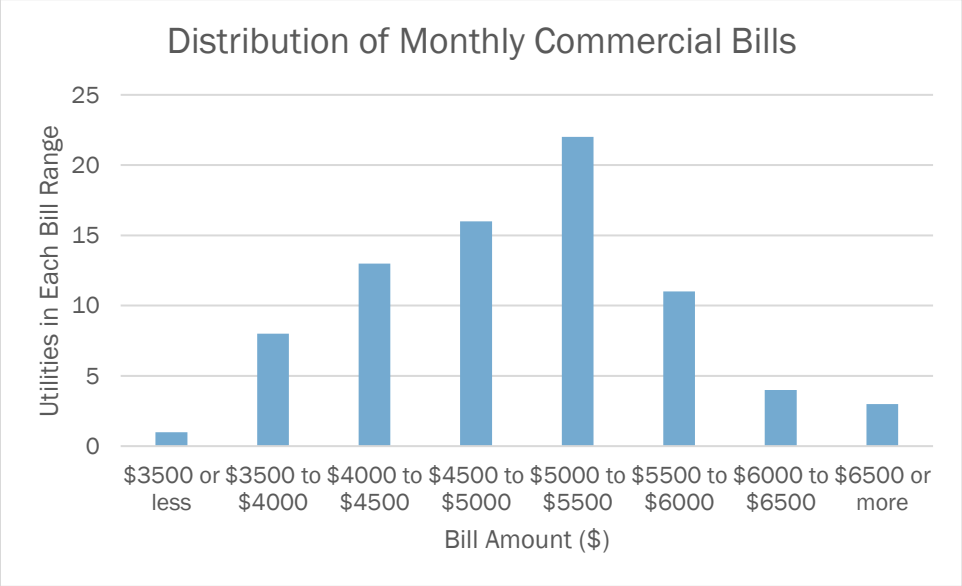


Figure D-5 2025 Distribution of Commercial (CP-1) Costs in Cents/kWh for Municipal Utilities[159]



[158] Source: Major utility tariffs filed with the Commission, https://apps.psc.wi.gov/RATES/tariffs/default.aspx.
[159] Source: Major utility tariffs filed with the Commission, https://apps.psc.wi.gov/RATES/tariffs/default.aspx.

Figure D-6 Distribution of Monthly Commercial (CP-1) Bills for Municipal Utilities[160]



The monthly costs summarized in Figure C-5 and Figure C-6 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-6 (only one utility has a threshold below 100 kW and two others do not have a CP-1 schedule in their effective tariff).

[160] Source: Major utility tariffs filed with the Commission, https://apps.psc.wi.gov/RATES/tariffs/default.aspx.

Table D-4 2025 Estimated Monthly Bill Data for Municipal Utility Cp-1 Customers

Summary	Total Cost (cents/kWh)*	Estimated Bill ($/month)*
Minimum	5.42	$2,710.00
25th Percentile	8.805	$4,402.50
Median	10.07	$5,035.00
Average	9.98	$4,991.66
75th Percentile	10.95	$5,475.00
Maximum	13.7	$6,850.00

*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.

Abbreviations, Acronyms, and Initialisms

Abbreviations, Acronyms, and Initialisms	Definition
§	Section
AC	Alternating current
ACS	American Census Survey
AFC	Alternative Fuel Corridors
AMI	area median income
AMP	Arrearage Management Program
ATC	American Transmission Company LLC
CA	Certificate of Authority
Cadmus	Cadmus Group
ch.	Chapter
Commission	Public Service Commission of Wisconsin
CO2	Carbon Dioxide
COSS	cost-of-service study
CPCN	Certificate of Public Convenience and Necessity
CY	calendar year
DC	Direct current
DEHCR	Division of Energy, Housing, and Community Resources
DER	Distributed Energy Resources
DLR	Dynamic Line Rating
DNR	Department of Natural Resources
DOA	Wisconsin Department of Administration
DOE	U.S. Department of Energy
DPA	Deferred Payment Agreement
DPC	Dairyland Power Cooperative
DRR	Demand response resources
EA	Environmental Assessment
EDR	Economic Development Rider
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EGEAS	Electric Generation Expansion Analysis System
EPA	U.S. Environmental Protection Agency
ESM	Earning Sharing Mechanism
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
Focus	Focus on Energy
FPL	Federal Poverty Line
fps	Feet per second
FRT	Full Responsibility Transaction
GIP	Generator Interconnection Project
GW	Gigawatt

Abbreviations, Acronyms, and Initialisms	Definition
HEAR	Home Electrification and Appliance Rebates
HER	Home Energy Rebate
Hz	Hertz
HILF	High impact, low frequency
HOMES	Home Efficiency Rebates
ICAP	Installed Capacity
ICE	Improved Customer Experience
IEEE	Institute of Electric and Electronic Engineers
IMM	Independent market monitor
IOU	Investor-owned utility
IPL	Interstate Power and Light Company
IPP	Independent Power Producer
IRA	Inflation Reduction Act
IRP	Integrated Resource Planning
ITC	Investment Tax Credit
KPI	Key Performance Indicators
kV	kilovolt
kW	Kilowatt
kWh	Kilowatt hour
KWWF	Keep Wisconsin Warm/Cool Fund
LEAD	Low-Income Energy Affordability Data
LICMARP	Low Income Case Management Arrearage Reduction Program
LIFT	Low Income Forgiveness Tool
LIHEAP	Low-Income Home Energy Assistance Program
LMI	low-and-moderate income
LMP	Locational Marginal Pricing
LMR	Load Modifying Resources
LRTP	Long Term Transmission Planning
LSE	Load Serving Entity
LTRA	Long-Term Resource Assessment
MEP	Market Efficiency Project
MGE	Madison Gas and Electric Company
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British thermal units
MOU	memorandum of understanding
MPU	Manitowoc Public Utilities
MTEP	MISO Transmission Expansion Plan
MUR	MVP Usage Rate
MVP	Multi Value Project
MW	megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standards
NARUC	National Association of Regulatory Utility Commissioners
NEM	net-energy-metering
NERC	North American Electric Reliability Corporation

Abbreviations, Acronyms, and Initialisms	Definition
NEVI	National Electric Vehicle Infrastructure (
NLMP	New Load Market Pricing
NRC	Nuclear Regulatory Commission
NSPM	Northern States Power Company-Minnesota
NSPW	Northern States Power Company-Wisconsin
NWE	Northwestern Wisconsin Electric Company
NZ2050	Net Zero 2050
O&M	Operations and Maintenance
OBBB	One, Big, Beautiful Bill
OEI	Office of Energy Innovation
OMS	Organization of MISO States
PB	Public Benefits
PCAC	Power cost adjustment clause
PPA	Purchased power agreements
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PV	photovoltaic
PY	Planning Year
Quad V	Quadrennium V
RAP	Regulatory Assistance Project
RER	Renewable Energy Rider
RIIA	Renewable Integration Impact Assessment
RLIP	Revised Low Income Program
ROE	return on equity
ROW	Right-of-way
RPS	Renewable Portfolio Standard
RTMP	Real Time Market Pricing
RTO	Regional Transmission Organization
SAC	Seasonal Accredited Capacity
SAFER2	Statewide Assistance for Energy Resilience and Reliability
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SEA	Strategic Energy Assessment
SMI	state median income
SWL&P	Superior Water, Light and Power Company
TCJA	Tax Cuts and Jobs Act
TOU	Time-of-Use
TRC	Total Resource Cost
UCAP	Unforced Capacity
VEIC	Vermont Energy Investment Corporation
WAP	Weatherization Assistance Program
WEC	Wisconsin Energy Corporation
WEM	Wisconsin Emergency Management
WEPCO	Wisconsin Electric Power Company

Abbreviations, Acronyms, and Initialisms	Definition
WEVI	Wisconsin Electric Vehicle Infrastructure35
WG	Wisconsin Gas LLC
WHEAP	Wisconsin's Home Energy Assistance Program
Wis. Admin. Code	Wisconsin Administrative Code
WisDOT	Wisconsin Department of Transportation
Wis. Stat.	Wisconsin Statutes
WP&L	Wisconsin Power and Light Company
WPPI	WPPI Energy
WPSC	Wisconsin Public Service Corporation

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5-ES-113 Strategic Energy Assessment 2026-2032

Summary of SEA Tables

This document contains all data tables included in the SEA 2026-2032.

The purpose of this document is to make data presented in the SEA available in an excel format.

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Table 1-1 Utility Reported Expected Maximum Annual Peak Demand, with Percent Change from Previous Year

Year	Maximum Monthly Peak Load (MW)	Percent change from the previous year (%)
2021	13846	
2022	14429	4.21%
2023	14873	3.08%
2024	14516	-2.40%
2025	14126	-2.69%
2026	14234	0.77%
2027	14760	3.69%
2028	17086	15.76%
2029	18559	8.62%
2030	19694	6.12%
2031	19852	0.81%
2032	19883	0.16%

Table 1-2 Wisconsin Aggregated Supply and Demand, MW

Year[1]	Season	2025	2026
Projected Net Capacity (MW)[2]	Summer	14240.97	14546.99
Forecasted Peak Demand (MW)[3]	Summer	11644.03	11827.42
WI Utilities' Initial PRMR (MW)	Summer	12709.58	12949.42
Resources above Initial PRMR (MW)	Summer	1531.396	1597.567
MISO PRM (%)	Summer	7.90%	7.90%
Projected Net Capacity (MW)	Fall	13910.16	13892.91
Forecasted Peak Demand (MW)	Fall	9948.161	10044.29
WI Utilities' Initial PRMR (MW)	Fall	11585.55	11408.41
Resources above Initial PRMR (MW)	Fall	2324.612	2484.496
MISO PRM (%)	Fall	14.90%	11.60%
Projected Net Capacity (MW)	Winter	12847.42	13071.13
Forecasted Peak Demand (MW)	Winter	8556.075	8986.94
WI Utilities' Initial PRMR (MW)	Winter	10265.37	10910.91
Resources above Initial PRMR (MW)	Winter	2582.053	2160.221
MISO PRM (%)	Winter	18.40%	18.90%
Projected Net Capacity (MW)	Spring	13879.42	14860.73
Forecasted Peak Demand (MW)	Spring	9083.537	9504.601
WI Utilities' Initial PRMR (MW)	Spring	11524.51	11914.52
Resources above Initial PRMR (MW)	Spring	2354.91	2946.216
MISO PRM (%)	Spring	25.30%	23.40%

[1] MISO Planning Years run from June 1 to May 31. Listed years represent the first calendar year in the planning year (i.e. PY 2025 is June 1 2025-May 31, 2026).

[2] Net capacity numbers include projected future generation reported by utilities and projected net imports and exports; whether and when the resource additions are implemented may vary based on factors including federal and state regulatory approvals and construction timelines.

[3] Defined by MISO as coincident Load Serving Entity (LSE) peak to MISO peak gross of demand response net Full Responsibility Transaction (FRT).

Table 1-3 Carbon Dioxide Reduction Goals of Wisconsin Electric Providers		
Provider	**2030 CO2 Reduction Goal**	**2050 CO2 Reduction Goal**
Northern States Power Company-Wisconsin (Xcel Energy, Inc.)	80%	100%
Madison Gas and Electric Company	NA	100%
Wisconsin Electric Power Company	NA	100%
Wisconsin Power and Light Company (Alliant)	50%	100%
Wisconsin Public Service Corporation	NA	100%
Dairyland Power Cooperative	50%	NA

Table 2-1 Planned Utility-Owned or Leased Generation Capacity Retirement through 2032				
Year	**Name**	**Capacity (MW)**	**Fuel**	**Owner/Leaser**
2025	Wheaton 1, 2, 3, 4, 6	56, 68, 56, 61, 70	Natural Gas and Fuel Oil	NSPW
2027	Rosiere Wind Farm	11	Wind	MGE
2027	Oak Creek 7, 8	318, 324	Coal	WEPCO
2030	French Island 3, 4	157 (total)	Natural Gas	NSPW

Table 2-2 Planned Utility-Owned or Leased Generation Fuel Switch Retrofits through 2032					
Switch Year	**Name**	**Capacity (MW)**	**Existing Fuel**	**Proposed Fuel**	**Owner/Leaser**
2029	Elm Road 1, 2[1]	650, 650	Coal	Natural Gas	WEPCO
2030	Columbia 1, 2[2]	566, 565	Coal	Natural Gas	WP&L, WPSC, MGE
2030	Edgewater 5[3]	406	Coal	Natural Gas	WP&L
2030	Weston 4	595	Coal	Natural Gas	WPSC

[1]MGE announces its intent to convert Elm Road Generating Station from Coal to Natural Gas; https://www.mge.com/about-mge/electric-system/coal-fired-generation

[2] Wisconsin energy companies announce plan to continue operations at Columbia Energy Center, commit to exploring conversion to natural gas. https://www.alliantenergy.com/news/news-center/2024/05/052324-generationupdate

[3]Alliant Energy announces its intent to convert Edgewater 5 to natural gas. https://www.alliantenergy.com/news/news-center/2024/05/052324-generationupdate

Table 2-3 Seasonal Wisconsin Aggregated Supply and Demand, MW							
Summer	**2026[1]**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Projected Net Capacity[2]	14547	15554	17077	18809	20999	22821	23982
Expected Forecasted Peak Demand[3]	11827	12424	14636	16460	17345	17460	17489
WI LSE's Initial PRMR (MW)[4]	12949	13782	16439	18608	19557	19669	19641
Resources above Initial PRMR (MW)	1598	1772	638	201	1442	3151	4342
MISO PRM (%)[5]	7.90%	9.40%	11.00%	12.50%	12.40%	12.30%	12.30%
Fall	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Projected Net Capacity	13893	14841	16708	18006	20219	21855	22508
Expected Forecasted Peak Demand	10044	11070	13004	14533	15485	15537	15563
WI LSE's Initial PRMR (MW)	11408	12755	15186	17112	18166	18196	18162
Resources above Initial PRMR (MW)	2484	2086	1522	895	2053	3659	4345
MISO PRM (%)	11.60%	13.40%	15.20%	17.10%	16.90%	16.70%	16.70%
Winter	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Projected Net Capacity	13071	13640	15283	15653	18271	19218	19945
Expected Forecasted Peak Demand	8987	10466	12214	13587	14378	14428	14453
WI LSE's Initial PRMR (MW)	10911	12754	14934	16545	17465	17457	17488
Resources above Initial PRMR (MW)	2160	886	350	-892	806	1761	2458
MISO PRM (%)	18.90%	19.70%	20.40%	21.20%	21.10%	21.00%	21.00%
Spring	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Projected Net Capacity	14861	16167	17827	19733	22904	24054	24110
Expected Forecasted Peak Demand	9505	11500	12921	14220	14805	14836	14858
WI LSE's Initial PRMR (MW)	11915	14737	16941	18954	19660	19599	19628
Resources above Initial PRMR (MW)	2946	1430	887	779	3244	4455	4482
MISO PRM (%)	23.40%	26.50%	29.60%	32.70%	32.40%	32.10%	32.10%

[1] MISO Planning Years (PY) run from June 1 to May 31. Listed years represent the correspond to the calendar year in which a season falls in (i.e. PY 2024-25 is Summer 2024, Fall 2024, Winter 2024, and Spring 2025).

[2] 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.

[3] Defined by MISO as coincident LSE peak to MISO peak gross of demand response net FRT.

[4] Initial PRMR is calculated as described in Section 3.1 of MISO's Business Practice Manual 11: Resource Adequacy.

[5] The PRM values are retrieved from MISO's estimated outyear PRM values available in MISO's 2026-2027 Loss of Load Expectation Study Final Report; https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf.

Table 2-4 Projected Carbon Dioxide Reductions from Owned Generation in 2026 and 2032 by Utility					
Utility	**2005 CO2 Emissions (Million metric tons)**	**2026 CO2 Emissions (Million metric tons)**	**2026 CO2 Reduction (% from 2005)**	**2032 CO2 Emissions (Million Metric tons)**	**2032 CO2 Reduction (% from 2005)**
Northern States Power Company - Wisconsin (Xcel Energy)	4.1	1.8	56%	0.6	85%
Wisconsin Electric Company	35.7	17.9	50%	N/A	N/A
WPPI	3.97	2.27	43%	2.06	48%
Wisconsin Power and Light Company (Alliant)	8.8	8.8	0%	4.49	49%
Madison Gas and Electric Company	3.55	1.9	46%	N/A	N/A
Dairyland Power Cooperative	4.43	3.7	16%	1	77%
Manitowoc Public Utilities	0.463	0.246	47%	0.27	41%
All Providers	57.46	34.72	40%	8.42	61%

Table 2-5 Resource Planning Responses: November 2025				
Provider	**Response**			**Additional Responses/Notes**
DPC	PSC REF#: 567612			PSC REF#: 567613
GLU	PSC REF#: 567954			
MPC	PSC REF#: 568377			
NSPW	PSC REF#: 567939	PSC REF#: 567940	PSC REF#: 567943	
MGE	PSC REF#: 570772			
WEPCO	PSC REF#: 567851	PSC REF#: 567852	PSC REF#: 567881	Same information as WPSC filing
WP&L	PSC REF#: 569483			
WPSC	PSC REF#: 567884	PSC REF#: 567885	PSC REF#: 567889	Same information as WEPCO filing
WPPI	PSC REF#: 567945			

Table 2-6 Primary Resource Planning Models Used by Wisconsin Electric Providers

Provider	Response
DPC	EnCompass
NSPW	EnCompass
MGE	EGEAS
WEPCO	PLEXOS
WP&L	AURORA
WPSC	PLEXOS

Table 3-1 Focus on Energy Quad IV KPI Achievements

KPI	Description	KPI Target Thresholds	Verified Results
Customer Satisfaction	Maintain high customer satisfaction at the portfolio level	50% of bonus >= 9.0 75% of bonus >= 9.1 100% of bonus >= 9.2	Participation-weighted average satisfaction across the portfolio was 9.4 in CY 2024
MMBtu Achievement	Achieve a minimum of 40% of the Quadrennium IV gross lifecycle MMBtu goal by the end of 2024	40% of Quadrennium IV lifecycle MMBtu goal	Total gross lifecycle MMBtu savings across the portfolio was 55,978,211 in CY 2024, which was 83% of the Quadrennium IV goal.
Income Qualified Applications	Increase the number of applications received by the income qualified program by 6% by 2024 over an average baseline from Quadrennium III	50% of bonus at >= 6% 75% of bonus at >= 7% 100% of bonus at >= 8%	952 income qualified applications were received by the program in CY 2024, which was a decrease of 40% over the Quadrennium III average.
Rural Incentive Spend	Ensure that incentives paid to rural customers are proportational to the percentage of rural customers in the state	50% of bonus >= 31% 75% of bonus >= 32% 100% of bonus >= 33%	Rural incentives accounted for 33% of all incentives disbursed in 2024.

Table 3-2 2025 Solar DER Snapshot by Category

Category	Number of Installations	Capacity (MW-AC)
Residential	22,989	161.68
Commercial and Industrial	2690	156.31
Utility-backed Community Projects	14	21.02
Utility-owned	46	29.9
Total	25,739	368.91

Table 3-3 2025 Solar Plus Storage DER Snapshot by Customer Category

Category	Number of Installations	Capacity (MW-AC)
Residential	475	6.6
Commercial and Industrial	37	6.16
Utility-owned	1	0.01
Total	513	12.77

Table 4-1 MTEP25 Projects in Wisconsin [1]		
Types of Projects	**Estimated Costs**	**Number of Planned Projects**
Baseline Reliability Projects	$545,905,600	5
Generator Interconnection Projects	$128,271,456	20
Other	$1,164,856,000	48
Age and Condition	$168,206,000	20
Load Growth	$854,658,000	14
Other Local Needs	$23,800,000	5
Reliability	$118,192,000	9
Total	$1,839,033,056	73

[1] The “Other” category includes Age and Condition, Load Growth, Other Local Needs, and Reliability Projects, which are italicized in this Table to distinguish these as sub-categories.

Table 5-1 Annual Growth Rates for Retail Electricity Sales (%)															
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Average Growth**
Residential	-4.30%	2.90%	0.00%	0.00%	1.70%	-2.20%	0.50%	-0.10%	4.90%	-0.20%	-1.50%	2.10%	1.30%	-1.40%	0.30%
Non-Residential	1.40%	-3.70%	-1.70%	4.00%	1.00%	-2.10%	1.00%	-4.60%	-6.20%	4.30%	0.80%	-1.60%	-0.40%	1.80%	-0.40%
Total	-0.20%	-1.90%	-1.20%	2.90%	1.20%	-2.10%	0.80%	-3.30%	-3.00%	2.90%	0.10%	-0.50%	0.10%	0.80%	-0.20%
Total w/o Focus on Energy	0.50%	-1.00%	-0.30%	3.60%	1.70%	-1.50%	1.40%	-2.60%	-1.80%	3.20%	0.30%	-0.30%	0.00%	0.70%	0.30%

Table 5-2 Wisconsin Electric IOU Bill Components for Residential Customers, 2025		
Summary Statistics	**Energy (cents/kWh)***	**Customer Charge ($/month)**
Minimum	9.1	$8.50
25th Percentile	12.12	$11.00
Median	13.78	$13.00
Average	13.89	$13.04
75th Percentile	15.11	$15.00
Maximum	18.41	$17.92

*Note: For MGE and NSPW, the cents/kWh value is based on a weighted average of their seasonal rates.

Table 5-3 Wisconsin Municipal Electric Utility Bill Components for Residential Customers, 2025		
Summary Statistics	**Energy (cents/kWh)**	**Customer Charge ($/month)***
Minimum	7.00	$5.00
25th Percentile	9.85	$5.00
Median	10.77	$10.50
Average	10.89	$10.60
75th Percentile	11.90	$13.00
Maximum	17.25	$17.00

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

Table 5-4 Municipal Utility Bill Components for Cp-1 Customers, 2024				
Summary	Energy Charge ($/kWh)	Distribution Demand ($/kW)	Billable Demand ($/kWh)	Customer Charge ($/month)*
Minimum	$0.04	$0.00	$5.25	$20.00
25th Percentile	$0.07	$1.25	$7.00	$50.00
Median	$0.08	$1.50	$8.00	$50.00
Average	$0.08	$1.51	$7.96	$54.21
75th Percentile	$0.09	$1.75	$8.88	$58.75
Maximum	$0.13	$3.00	$12.00	$125.00

*Note: Summary statistics include data from 68 municipal utilities that offer Cp-1 rates with a flat energy charge.

Table 5-5 Enrollment in Standard and TOU Rates		
Residential Rate Class	**Total Enrollment**	**Percent of Total**
Standard Rate	2,516,200	98.51%
TOU Rate	38,118	1.49%

Table 5-6 Enrollment in Incremental Load and Real-Time Pricing Rates		
Industrial	**Total Enrollment**	**Percent of Total**
Standard Rate	352265	99.96%
Incremental Load (NLMP/EDR)	4	0.00%
Real-Time Pricing (RTMP)	122	0.03%

Table 6-1 Census Tracts Above Affordability Threshold (LEAD Data, January 2026)

	Count	Percent
Percent of Census Tracts with Electricity Burden greater than 3%:	80	5.24%
Percent of Census Tracts with Gas Burden greater than 3%:	10	0.66%
Percent of Census Tract with Electricity and Gas Burden greater than 6%	25	1.64%

Table 6-2 State Comparison of Electricity and Gas Burden (LEAD Data, January 2026)

State	All Incomes	< 60% AMI[1]	<200% FPL
Illinois	2.40%	9.46%	11.02%
Iowa	2.59%	8.60%	9.32%
Michigan	2.66%	9.92%	10.64%
Minnesota	2.05%	6.78%	8.51%
Wisconsin	2.27%	7.30%	8.29%
United States	2.16%	8.33%	8.86%

[1] LEAD uses AMI data based on the 2022 income limits established by HUD.

Table 6-3 Disconnection Rates - Investor-Owned Utilities (Annual Report Data)

Utility Name - Type	2021	2022	2023	2024	2025
Consolidated Water Power Company - Electric	0.00%	5.48%	0.00%	11.43%	1.45%
Madison Gas And Electric Company - Electric	0.01%	0.68%	1.12%	2.24%	1.61%
Madison Gas And Electric Company - Gas	0.01%	0.63%	1.02%	2.04%	0.78%
Northern States Power Company (WIS) - Electric	0.80%	0.99%	3.00%	5.57%	8.12%
Northern States Power Company (WIS) - Gas	0.06%	0.11%	0.07%	0.15%	0.28%
Superior Water Light And Power Company - Electric	2.98%	3.98%	4.19%	3.64%	4.60%
Superior Water Light And Power Company - Gas	0.20%	0.34%	0.34%	0.22%	0.58%
Wisconsin Electric Power Company - Electric	2.69%	3.84%	4.70%	5.21%	5.44%
Wisconsin Electric Power Company - Gas	0.01%	0.12%	0.11%	0.15%	0.14%
Wisconsin Gas LLC - Gas	0.14%	0.54%	0.50%	0.67%	0.50%
Wisconsin Power And Light Company - Electric	5.25%	5.22%	3.10%	3.34%	3.45%
Wisconsin Power And Light Company - Gas	0.62%	0.64%	0.47%	0.35%	0.40%
Wisconsin Public Service Corporation - Electric	2.47%	3.61%	2.98%	3.12%	3.23%
Wisconsin Public Service Corporation - Gas	0.49%	0.67%	0.56%	0.34%	0.64%
Weighted Average Electric	2.77%	3.58%	3.69%	4.31%	4.67%
Weighted Average Gas	0.20%	0.44%	0.43%	0.54%	0.44%

Table A-1 Assessment of Electric Demand and Supply Conditions, Monthly Non-Coincident Peak Demands, MW

Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2003	10739	10498	10291	9602	9048	12725	13319	13694	11937	10136	10450	11302
2004	10924	10384	10091	9400	10273	12486	12958	12437	12161	9902	10557	11478
2005	11127	10678	10433	9610	10000	14020	13832	14323	13224	11912	10833	11581
2006	10622	10556	10174	9550	11527	12559	15006	14507	11060	10320	10909	11553
2007	10958	11419	10682	9946	11343	13834	14163	14461	13693	12033	11091	11503
2008	11249	11167	10437	9899	9583	12283	13256	12883	13111	10216	10279	11438
2009	11273	10681	10246	9209	9606	13694	11051	12260	10846	9454	9944	11075
2010	10671	10226	9611	9030	12490	12495	13069	14098	11662	9608	10170	11101
2011	10552	10645	9824	9311	10668	13601	14870	13553	13092	9624	9955	10520
2012	10614	10020	9779	9005	10394	13974	15105	13439	12927	9681	10186	10475
2013	10685	10182	9720	9171	10221	11937	14347	14162	13428	9647	9814	10897
2014	11299	10656	10272	9150	10117	11793	13290	12270	11255	9339	10403	10514
2015	11107	10710	10153	9072	9871	11243	12860	13308	13065	9207	9694	9986
2016	10755	10139	9659	9049	10190	12500	13730	13851	13030	9695	9574	10900
2017	10842	10245	9720	9166	10047	13143	13230	12474	13123	10178	9972	10804
2018	10977	10414	9674	9375	12739	14143	13655	13373	13118	10357	10155	10220
2019	11094	10449	10524	9199	9536	11824	13929	12644	11224	10063	9917	10327
2020	9979	9945	9115	8340	10951	12748	13698	13669	10259	9060	9463	9964
2021	9850	10446	9273	8839	10811	13599	13817	13499	11050	9667	9825	10429
2022	10506	10060	9355	9063	11645	14429	13398	12858	12472	9092	10308	10511
2023	10162	10020	9283	9167	11120	12404	13497	14874	13009	10879	9895	9815
2024	10360	9292	9139	9025	9273	13242	13746	14517	11859	9318	9185	10494
2025	10746	10333	9216	9149	10098	14125	14103	13686	11628	9654	10009	10490
Future												
2026	10749	10326	10066	9370	11024	13041	14228	13873	12266	9810	10062	10931
2027	11182	10761	10580	9869	11594	13566	14757	14442	13008	10637	11072	11954
2028	12500	12199	12120	11671	13482	15915	17075	16685	15397	12893	13085	14184
2029	14445	14011	14006	13318	15000	17471	18637	18256	16909	14410	14593	15504
2030	15774	15345	15287	14611	16325	18706	19876	19487	17935	15427	15598	16331
2031	16594	16155	15904	15214	16926	18845	20004	19617	18003	15493	15662	16383
2032	16609	16159	15910	15214	16932	18845	20010	19620	18000	15494	15670	16395

Table A-2 Seasonal Wisconsin Aggregated Supply and Demand [1]

Summer Capacity							
Report Line MISO Description Capacity (MW)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
High Certainty Resources (Existing Resource)	12588	11648	11896	10929	11217	10881	10852
Low Certainty Resources (Existing Resource)	0	1317	710	1655	985	985	985
Behind the Meter (Existing Resource)	328	353	380	410	388	387	387
DRR plus Registered DSM (Existing Resource)	638	636	679	682	719	719	719
New Capacity DPP Signed GIA (New Resource)	84	410	1765	2845	3181	3406	3488
New Capacity DPP GIA Phase (New Resource)	0	15	16	56	85	85	85
New Capacity DPP Phase 3 (New Resource)	0	94	164	286	537	779	779
New Capacity DPP Phase 2 (New Resource)	0	0	13	13	24	224	224
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	0	171	284	514	514
New Capacity Not in Interconnection Queue (New Resource)	0	139	563	976	2868	4159	5700
New BTMG / New DR (New Resource)	18	39	63	79	96	104	111
RZ Internal Transfer-In (ZRC)	1943	2011	2098	2123	2156	2207	2215
RZ Internal Transfer-Out (ZRC)	1174	1117	1272	1390	1517	1605	2051
External Resource Imports (Existing Resource)	122	24	18	18	18	18	18
Total Committed Net Capacity (MW) Included DPP Signed GIA	14531	15337	16462	17473	17389	17240	16854
Total Potential Net Capacity (MW)	14547	15554	17077	18809	20999	22821	23982
Summer Demand							
Non-Coincident Peak gross of DR	12189	12790	15013	16845	17738	17854	17884
Full Responsibility Transaction	174	174	174	80	55	55	0
Coincident LSE Peak with Zonal Peak gross of DR	9391	9801	11644	12884	13728	13833	13852
Coincident LSE Peak to MISO Peak gross of DR	11827	12424	14636	16460	17345	17460	17489
Summer Reserve Requirements							
Planning Reserve Margin Requirement (MW)	12710	13782	16439	18608	19557	19669	19641
Resources above Planning Reserve Requirement	1598	1772	638	201	1442	3151	4342
Fall Capacity							
Report Line MISO Description Capacity (MW)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
High Certainty Resources (Existing Resource)	11961	11146	11541	10538	10675	10284	10242
Low Certainty Resources (Existing Resource)	0	1227	551	1532	1022	1022	1022
Behind the Meter (Existing Resource)	267	296	321	348	325	325	324
DRR plus Registered DSM (Existing Resource)	519	519	562	565	565	564	564

Table A-2 Seasonal Wisconsin Aggregated Supply and Demand [1]

New Capacity DPP Signed GIA (New Resource)	80	414	2086	2551	2648	2831	2778
New Capacity DPP GIA Phase (New Resource)	0	18	20	59	80	80	80
New Capacity DPP Phase 3 (New Resource)	0	94	172	321	571	648	648
New Capacity DPP Phase 2 (New Resource)	0	0	13	20	20	220	220
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	0	285	272	462	462
New Capacity Not in Interconnection Queue (New Resource)	0	203	553	992	3283	4668	5838
New BTMG / New DR (New Resource)	18	39	62	79	96	104	111
RZ Internal Transfer-In (ZRC)	1912	1966	2026	2020	2038	2065	2063
RZ Internal Transfer-Out (ZRC)	991	1094	1204	1276	1348	1391	1818
External Resource Imports (Existing Resource)	128	29	22	22	22	22	22
Total Committed Net Capacity (MW) Included DPP Signed GIA	13877	14552	16079	16489	16156	15932	15408
Total Potential Net Capacity (MW)	13893	14841	16708	18006	20219	21855	22508
Fall Demand							
Non-Coincident Peak gross of DR	10595	11632	13580	15119	16085	16137	16164
Full Responsibility Transaction	178	178	178	80	55	55	0
Coincident LSE Peak with Zonal Peak gross of DR	7941	8758	10439	11620	12278	12306	12322
Coincident LSE Peak to MISO Peak gross of DR	10044	11070	13004	14533	15485	15537	15563
Fall Reserve Requirements							
Planning Reserve Margin Requirement (MW)	11408	12755	15186	17112	18166	18196	18162
Resources above Planning Reserve Requirement	2484	2086	1522	895	2053	3659	4345
Winter Capacity							
Report Line MISO Description Capacity (MW)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
High Certainty Resources (Existing Resource)	11291	10261	10492	9042	9620	9339	9279
Low Certainty Resources (Existing Resource)	0	955	754	1722	1004	1004	1004
Behind the Meter (Existing Resource)	127	129	131	72	73	73	73
DRR plus Registered DSM (Existing Resource)	621	618	659	661	661	661	661
New Capacity DPP Signed GIA (New Resource)	62	375	1462	1924	2030	2044	2027
New Capacity DPP GIA Phase (New Resource)	0	17	138	49	73	73	73
New Capacity DPP Phase 3 (New Resource)	0	94	162	300	462	442	442
New Capacity DPP Phase 2 (New Resource)	0	0	13	13	203	213	213
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	0	174	366	366	366
New Capacity Not in Interconnection Queue (New Resource)	0	277	603	859	2980	4212	5386

Table A-2 Seasonal Wisconsin Aggregated Supply and Demand [1]

New BTMG / New DR (New Resource)	2	4	6	8	10	10	11
RZ Internal Transfer-In (ZRC)	1876	1894	1861	1864	1865	1883	1884
RZ Internal Transfer-Out (ZRC)	1054	1005	1017	1025	1066	1091	1464
External Resource Imports (Existing Resource)	147	36	36	36	36	36	36
Total Committed Net Capacity (MW) Included DPP Signed GIA	13070	13300	14669	14470	14421	14146	13698
Total Potential Net Capacity (MW)	13071	13640	15283	15653	18271	19218	19945
Winter Demand							
Non-Coincident Peak gross of DR	9313	10797	12551	14042	14730	14780	14804
Full Responsibility Transaction	190	190	190	64	44	0	0
Coincident LSE Peak with Zonal Peak gross of DR	7027	8252	9721	10786	11258	11295	11306
Coincident LSE Peak to MISO Peak gross of DR	8987	10466	12214	13587	14378	14428	14453
Winter Reserve Requirements							
Planning Reserve Margin Requirement (MW)	10911	12754	14934	16545	17465	17457	17488
Resources above Planning Reserve Requirement	2160	886	350	-892	806	1761	2458
Spring Capacity							
Report Line MISO Description Capacity (MW)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
High Certainty Resources (Existing Resource)	12707	11339	11857	10567	11286	11005	10946
Low Certainty Resources (Existing Resource)	0	1300	717	1689	1004	1004	1004
Behind the Meter (Existing Resource)	335	368	396	375	381	380	380
DRR plus Registered DSM (Existing Resource)	587	598	644	649	649	648	648
New Capacity DPP Signed GIA (New Resource)	265	1244	2528	3025	3309	3347	3347
New Capacity DPP GIA Phase (New Resource)	0	20	155	81	81	81	81
New Capacity DPP Phase 3 (New Resource)	0	94	168	552	735	735	735
New Capacity DPP Phase 2 (New Resource)	0	0	13	22	212	222	222
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	0	290	502	502	502
New Capacity Not in Interconnection Queue (New Resource)	43	376	573	1820	4115	5933	6083
New BTMG / New DR (New Resource)	21	39	62	78	96	103	110
RZ Internal Transfer-In (ZRC)	1892	2041	2029	2115	2143	2148	2148
RZ Internal Transfer-Out (ZRC)	1112	1255	1316	1500	1580	2025	2068
External Resource Imports (Existing Resource)	123	20	20	20	20	20	20
Total Committed Net Capacity (MW) Included DPP Signed GIA	14842	15709	17174	17142	17416	16731	16629
Total Potential Net Capacity (MW)	14861	16167	17827	19733	22904	24054	24110

Table A-2 Seasonal Wisconsin Aggregated Supply and Demand [1]

Spring Demand							
Non-Coincident Peak gross of DR	9883	11889	13318	14660	15224	15256	15278
Full Responsibility Transaction	151	151	151	64	44	0	0
Coincident LSE Peak with Zonal Peak gross of DR	7634	9368	10535	11524	11799	11819	11829
Coincident LSE Peak to MISO Peak gross of DR	9505	11500	12921	14220	14805	14836	14858
Spring Reserve Requirements							
Planning Reserve Margin Requirement (MW)	11915	14737	16941	18954	19660	19599	19628
Resources above Planning Reserve Requirement	2946	1430	887	779	3244	4455	4482

[1] Data was compiled from Wisconsin's 5 largest investor-owned utilities assuming MISO's current accreditation method for all planning years. The accreditation method does not change to Direct Loss of Load starting in planning year 2028.

Table A-3 Coal Generation Units Total CO2 Emissions, 2023 and 2024

Unit Name	2023 (MMTon)	2024 (MMTon)	2025 (MMTon)
Elm Road #1 (WEPCO)	2.26	3.06	2.57
Elm Road #2 (WEPCO)	2.64	2.23	2.69
Oak Creek #5 (WEPCO)	0.69	0.25	Retired
Oak Creek #6 (WEPCO)	0.85	0.15	Retired
Oak Creek #7 (WEPCO)	1.31	1.00	1.28
Oak Creek #8 (WEPCO)	1.11	1.09	1.11
Columbia Energy Center #1 (WPS)	0.63	0.70	0.94
Columbia Energy Center #2 (WPS)	0.63	0.73	0.91
Weston #3 (WPS)	0.54	0.71	1.00
Weston #4 (WPS)	1.78	2.14	2.33
Columbia Energy Center #1 (MGE)	0.45	0.44	0.44
Columbia Energy Center #2 (MGE)	0.42	0.45	0.44
Elm Road #1 (MGE)	0.22	0.30	0.24
Elm Road #2 (MGE)	0.26	0.22	0.24
Columbia Energy Center #1 (WPL)	1.23	1.43	1.74
Columbia Energy Center #2 (WPL)	1.20	1.46	1.64
Edgewater #5 (WPL)	2.06	2.25	2.09
Jogn P Madgett #1 (DPC)	1.54	1.34	1.50
Weston #4 (DPC)	0.66	0.68	0.77
Boswell Energy Center (WPPI)	0.58	0.61	0.77
Columbus Street #9 (MPU)	-	-	-

Table A-4 Coal Generation Units CO2 Emissions Rate, 2023-2025

Unit Name	2023 (lb/kWh)	2024 (lb/kWh)	2025 (lb/kWh)
Elm Road #1 (WEPCO)	1.98	1.90	1.87
Elm Road #2 (WEPCO)	1.92	1.80	1.87
Oak Creek #5 (WEPCO)	2.51	2.52	Retired
Oak Creek #6 (WEPCO)	2.53	2.52	Retired
Oak Creek #7 (WEPCO)	2.37	2.41	2.50
Oak Creek #8 (WEPCO)	2.40	2.46	2.51
Columbia Energy Center #1 (WPS)	2.42	2.42	2.38
Columbia Energy Center #2 (WPS)	2.36	2.38	2.37
Weston #3 (WPS)	2.03	2.13	2.04
Weston #4 (WPS)	1.89	1.91	1.91
Columbia Energy Center #1 (MGE)	2.41	2.41	2.37
Columbia Energy Center #2 (MGE)	2.36	2.37	2.37
Elm Road #1 (MGE)	1.97	1.89	1.90
Elm Road #2 (MGE)	1.92	1.79	1.90
Columbia Energy Center #1 (WPL)	2.40	2.41	2.37
Columbia Energy Center #2 (WPL)	2.35	2.37	2.36
Edgewater #5 (WPL)	2.34	2.37	2.31
Jogn P Madgett #1 (DPC)	2.71	3.03	2.58
Weston #4 (DPC)	1.88	1.90	1.73
Boswell Energy Center (WPPI)	2.21	2.24	2.21
Columbus Street #9 (MPU)	2.68	2.65	N/A

Table A-5 Gas Generation Units by Total CO2 Emissions, 2023-2025

Unit Name	2023 (MMTon)	2024 (MMTon)	2025 (MMTon)
Wheaton #1 (NSP)	0.0060	0.0043	0.0015
Wheaton #2 (NSP)	0.0080	0.0055	0.0030
Wheaton #3 (NSP)	0.0072	0.0031	0.0016
Wheaton #4 (NSP)	0.0063	0.0042	0.0016
Concord #1 (WEPCO)	0.0279	0.0382	0.0396
Concord #2 (WEPCO)	0.0300	0.0336	0.0402
Concord #3 (WEPCO)	0.0163	0.0239	0.0369
Concord #4 (WEPCO)	0.0145	0.0312	0.0337
Germantown #5 (WEPCO)	0.0098	0.0203	0.0218
Paris #1 (WEPCO)	0.0394	0.0513	0.0373
Paris #2 (WEPCO)	0.0284	0.0313	0.0366
Paris #3 (WEPCO)	0.0232	0.0316	0.0383
Paris #4 (WEPCO)	0.0270	0.0507	0.0468
Port Washington #1 (WEPCO)	1.6029	1.4043	1.3644
Port Washington #2 (WEPCO)	1.5485	1.4037	1.3370
Rothschild (WEPCO)	0.0364	0.0270	0.0476
Valley #1 (WEPCO)	0.2639	0.2885	0.2195
Valley #2 (WEPCO)	0.1536	0.1487	0.2301
West Riverside (WEPCO)	0.1381	0.4015	0.4465
Weston RICE #1 (WEPCO)	0.0026	0.0056	0.0089
Weston RICE #2 (WEPCO)	0.0037	0.0058	0.0101
Weston RICE #3 (WEPCO)	0.0034	0.0057	0.0091
Weston RICE #4 (WEPCO)	0.0031	0.0057	0.0091
Weston RICE #5 (WEPCO)	0.0038	0.0056	0.0097
Weston RICE #6 (WEPCO)	0.0037	0.0055	0.0095
Weston RICE #7 (WEPCO)	0.0039	0.0056	0.0097
Whitewater (WEPCO)	0.1422	0.1604	0.1552
DePere Energy Center (WPS)	0.0885	0.0863	0.1122
Fox Energy Center (WPS)	1.6183	1.6669	1.3491
Pulliam 31 (WPS)	0.0709	0.0378	0.0735
West Marinette 31 (WPS)	0.0112	0.0000	0.0061
West Marinette 32 (WPS)	0.0125	0.0018	0.0099
West Marinette 33 (WPS)	0.0510	0.0203	0.0492
Weston RICE #1 (WPS)	0.0026	0.0056	0.0089
Weston RICE #2 (WPS)	0.0038	0.0058	0.0101
Weston RICE #3 (WPS)	0.0034	0.0057	0.0091
Weston RICE #4 (WPS)	0.0031	0.0056	0.0091
Weston RICE #5 (WPS)	0.0038	0.0056	0.0097
Weston RICE #6 (WPS)	0.0037	0.0055	0.0095
Weston RICE #7 (WPS)	0.0039	0.0056	0.0097
Whitewater (WPS)	0.1422	0.1604	0.1552
Blount Station (MGE)	0.0124	0.0436	0.0423
Fitchburg - 2 units (MGE)	0.0000	0.0000	0.0002
Sycamore - 2 units (MGE)	0.0003	0.0000	0.0000
Nine Springs (MGE)	0.0001	0.0001	0.0001

Table A-5 Gas Generation Units by Total CO2 Emissions, 2023-2025

M34 / Marinette (MGE)	0.0616	0.0332	0.0637
West Campus (MGE)	0.2127	0.1756	0.1935
West Riverside (MGE)	0.0215	0.1003	0.1120
Neenah #1 (WPL)	0.1766	0.2160	0.1424
Neenah #2 (WPL)	0.1878	0.2310	0.1501
Riverside Energy Center #1 (WPL)	0.6612	0.6219	0.6074
Riverside Energy Center #2 (WPL)	0.6492	0.6236	0.6125
Sheboygan Energy Center #1 (WPL)	0.1902	0.2106	0.1363
Sheboygan Energy Center #2 (WPL)	0.1394	0.1831	0.1424
South Fond du Lac #2 (WPL)	0.0067	0.0028	0.0087
South Fond du Lac #3 (WPL)	0.0055	0.0023	0.0093
West Riverside #1 (WPL)	0.5799	0.5699	0.8047
West Riverside #2 (WPL)	0.6487	0.5777	0.8097
Elk Mound #1 (DPC)	0.0108	0.0074	0.0270
Elk Mound #2 (DPC)	0.0133	0.0101	0.0249
Rock Gen #1 (DPC)	0.1140	0.0986	0.1084
Rock Gen #2 (DPC)	0.1105	0.0479	0.1017
Rock Gen #3 (DPC)	0.1247	0.1049	0.1183
South Fond du Lac #1 (WPPI)	0.0016	0.0034	0.0100
South Fond du Lac #2 (WPPI)	0.0062	0.0020	0.0097
Island Street Peaking Plant (WPPI)	0.0057	0.0074	0.0131
Custer Street (MPU)	0.0025	0.0041	N/A
M-1 (GLU)	0.0054	0.0024	0.0113

Table A-6 Gas Generation Units CO2 Emissions Rate 2023-2025

Unit Name	2023 (lb/kWh)	2024 (lb/kWh)	2025 (lb/kWh)
Wheaton #1 (NSP)	1.96	2.03	2.45
Wheaton #2 (NSP)	1.85	1.92	1.86
Wheaton #3 (NSP)	1.97	2.34	2.12
Wheaton #4 (NSP)	1.95	1.97	1.94
Concord #1 (WEPCO)	1.63	1.61	1.65
Concord #2 (WEPCO)	1.64	1.61	1.62
Concord #3 (WEPCO)	1.61	1.58	1.62
Concord #4 (WEPCO)	1.65	1.58	1.63
Germantown #5 (WEPCO)	1.92	1.67	1.67
Paris #1 (WEPCO)	1.65	1.61	1.64
Paris #2 (WEPCO)	1.61	1.61	1.63
Paris #3 (WEPCO)	1.58	1.58	1.62
Paris #4 (WEPCO)	1.64	1.59	1.63
Port Washington #1 (WEPCO)	0.82	0.82	0.82
Port Washington #2 (WEPCO)	0.82	0.82	0.82
Rothschild (WEPCO)	0.56	0.39	0.64
Valley #1 (WEPCO)	2.27	2.20	2.61
Valley #2 (WEPCO)	2.80	2.40	2.75
West Riverside (WEPCO)	0.81	0.81	0.82
Weston RICE #1 (WEPCO)	1.11	1.01	1.00
Weston RICE #2 (WEPCO)	1.08	1.01	1.01
Weston RICE #3 (WEPCO)	1.09	1.02	1.01
Weston RICE #4 (WEPCO)	1.10	1.02	1.01
Weston RICE #5 (WEPCO)	1.07	1.01	1.01
Weston RICE #6 (WEPCO)	1.08	1.02	1.01
Weston RICE #7 (WEPCO)	1.10	1.01	1.00
Whitewater (WEPCO)	0.97	0.96	0.96
DePere Energy Center (WPS)	1.35	1.35	1.35
Fox Energy Center (WPS)	0.82	0.82	0.82
Pulliam 31 (WPS)	1.45	1.47	1.46
West Marinette 31 (WPS)	1.83	0.00	1.82
West Marinette 32 (WPS)	1.82	1.83	1.82
West Marinette 33 (WPS)	1.47	1.50	1.50
Weston RICE #1 (WPS)	1.09	0.99	0.99
Weston RICE #2 (WPS)	1.07	0.99	1.00
Weston RICE #3 (WPS)	1.08	1.00	1.00
Weston RICE #4 (WPS)	1.08	0.99	1.00
Weston RICE #5 (WPS)	1.06	0.99	1.00
Weston RICE #6 (WPS)	1.06	1.00	1.00
Weston RICE #7 (WPS)	1.09	0.99	0.99
Whitewater (WPS)	0.97	0.96	0.96
Blount Station (MGE)	2.86	1.97	1.59
Fitchburg - 2 units (MGE)	2.99	2.99	2.99
Sycamore - 2 units (MGE)	3.32	2.99	2.99
Nine Springs (MGE)	1.83	2.24	2.01

Table A-6 Gas Generation Units CO2 Emissions Rate 2023-2025

M34 / Marinette (MGE)	1.62	1.60	1.59
West Campus (MGE)	1.31	1.35	1.38
West Riverside (MGE)	0.41	0.81	0.82
Neenah #1 (WPL)	1.32	1.34	1.34
Neenah #2 (WPL)	1.31	1.32	1.33
Riverside Energy Center #1 (WPL)	1.30	1.31	1.30
Riverside Energy Center #2 (WPL)	1.32	1.33	1.31
Sheboygan Energy Center #1 (WPL)	1.33	1.36	1.36
Sheboygan Energy Center #2 (WPL)	1.32	1.34	1.36
South Fond du Lac #2 (WPL)	1.88	2.15	2.04
South Fond du Lac #3 (WPL)	1.86	1.92	2.04
West Riverside #1 (WPL)	1.25	1.27	1.29
West Riverside #2 (WPL)	1.26	1.28	1.30
Elk Mound #1 (DPC)	1.53	1.56	1.36
Elk Mound #2 (DPC)	1.56	1.50	1.33
Rock Gen #1 (DPC)	1.41	1.37	1.48
Rock Gen #2 (DPC)	1.43	1.38	1.47
Rock Gen #3 (DPC)	1.41	1.37	1.48
South Fond du Lac #1 (WPPI)	2.15	2.21	2.08
South Fond du Lac #2 (WPPI)	1.91	2.15	2.08
Island Street Peaking Plant (WPPI)	1.57	1.49	1.43
Custer Street (MPU)	2.39	1.84	N/A
M-1 (GLU)	1.34	1.34	1.30

Table B-1 Total Annual Emissions Forecast for Wisconsin Electric Providers, 2024-2032, Million Metric Tons

Utility	2024	2026	2028	2030	2032
WEC (WEPCO & WPSC)	35.7	17.9	18.9	N/A	N/A
WPL	8.4	8.8	9.31	4.49	4.49
Dairyland	3.426	3.702	2.267	1.773	1.004
MGE	2.085	1.9	N/A	N/A	NA
WPPI	3.97	2.27	2.01	2	2.06
NSPW	4.1	1.8	1.1	0.5	0.6
MPU	0.16	0.246	0.275	0.271	0.271

Table B-2 Annual Unit Selection for Baseline Scenario, MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	1200	600	0	0	0	600	0
2035	1200	1200	0	0	0	1200	0
2036	1200	1200	0	0	0	600	0
2037	1200	1200	0	0	0	0	0
2038	1200	600	0	0	0	0	0
2039	0	0	0	0	1200	1200	0
2040	0	0	0	0	1200	1200	0
2041	0	1200	0	0	600	1200	0
2042	1200	0	0	0	1800	0	0
2043	0	1800	0	0	1200	0	0
2044	1800	1200	0	0	1800	0	0
Total	9000	9000	0	0	7800	6000	0

Table B-3 Annual Unit Selection for High Gas Price (4.04 $/MMBTU), MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	1200	1200	0	0	0	0	0
2035	1200	1200	0	0	600	1200	0
2036	1200	600	0	0	0	600	0
2037	1200	0	0	0	0	1200	0
2038	1200	600	0	0	0	0	0
2039	0	1200	0	0	600	600	0
2040	0	0	0	0	1200	1200	0
2041	0	1200	0	0	600	1200	0
2042	1200	0	0	0	1800	0	0
2043	600	1200	0	0	1800	0	0
2044	1200	1800	0	0	1200	0	0
Total	9000	9000	0	0	7800	6000	0

Table B-4 Annual Unit Selection for Low Gas Price (2.43 $/MMBTU), MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	1200	600	0	0	0	600	0
2035	1200	1200	0	0	0	1200	0
2036	1200	1200	0	0	0	600	0
2037	1200	1200	0	0	0	0	0
2038	1200	600	0	0	0	0	0
2039	0	0	0	0	1200	1200	0
2040	0	0	0	0	1200	1200	0
2041	0	1200	0	0	600	1200	0
2042	1200	0	0	0	1800	0	0
20413	0	1800	0	0	1200	0	0
2044	1800	1200	0	0	1800	0	0
Total	9000	9000	0	0	7800	6000	0

Table B-5 Annual Unit Selection for Solar Capacity Accreditation Sensitivity, MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	1200	1200	0	0	0	0	0
2035	1200	1200	0	0	0	1200	0
2036	1200	1200	0	0	0	0	0
2037	1200	600	0	0	0	600	0
2038	1200	0	0	0	0	600	0
2039	0	600	0	0	0	1200	0
2040	0	600	0	0	0	1200	0
2041	0	600	0	1200	600	1200	0
2042	1800	0	0	0	0	0	0
2043	0	1200	0	1200	1200	0	0
2044	1200	1800	0	1200	0	0	0
Total	9000	9000	0	3600	1800	6000	0

Table B-6 Annual Unit Selection for Net Zero by 2050, MW

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	NEW NUCLEAR	NEW FLEX
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	1800	0	0	0	0	0	0	0	0
2029	3000	0	0	0	0	0	0	0	0
2030	2400	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	1200
2032	0	0	0	0	0	0	0	0	600
2033	0	0	0	0	0	0	0	0	600
2034	0	0	0	0	1200	0	0	0	600
2035	0	0	0	0	0	0	0	0	1200
2036	0	0	0	0	0	0	0	600	0
2037	0	0	0	0	0	0	0	1200	0
2038	0	0	0	0	0	600	0	1200	0
2039	0	0	0	0	0	0	0	1800	0
2040	0	0	0	0	0	0	0	1800	0
2041	0	0	0	0	0	0	0	2400	0
2042	0	0	0	0	0	600	0	1200	0
2043	0	0	0	0	600	1200	0	600	0
2044	0	0	0	0	2400	1200	0	1200	600
Total	7200	0	0	0	4200	3600	0	12000	4800

Table B-7 Annual Unit Selection for Nuclear Sensitivity

Year\ Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	NEW NUCLEAR
2025	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0
2034	1200	600	0	0	0	600	0	0
2035	1200	1200	0	0	0	1200	0	0
2036	1200	1200	0	0	0	600	0	0
2037	1200	1200	0	0	0	0	0	0
2038	1200	600	0	0	0	0	0	0
2039	0	0	0	0	1200	1200	0	0
2040	0	0	0	0	1200	1200	0	0
2041	0	1200	0	0	600	1200	0	0
2042	1800	0	0	0	0	0	0	0
2043	600	1200	0	0	1200	0	0	0
2044	600	1800	0	0	1200	0	0	600
Total	9000	9000	0	0	5400	6000	0	600

Table B-8 New Additions and Transfers of Utility-Owned or Leased Generation Capacity by Wisconsin Electric Providers 2025 through 2032

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/Leaser	Source	PSC Status and Docket Number
2025	200	Paris Solar[1]	New	WEPCO/WPSC/MGE	Solar	9801-CE-100, approved; 5-BS-254, approved
2025	110	Paris Solar BESS[2]	New	WEPCO/WPSC/MGE	Battery Storage	9801-CE-100, approved; 5-BS-254, approved
2025	250	Darien Solar[3]	New	WEPCO WPSC/MGE	Solar	9806-CE-100, approved; 5-BS-255, approved
2025	6	Strix Solar	New	MGE	Solar	
2025	255	Wheaton replacement	New	NSPW	Natural Gas	4220-CE-185, approved
2026	100	Neenah Generating Station upgrades	Existing	WP&L	Natural Gas	6680-CE-185, approved
2026	100	Sheboygan Falls Generating Station upgrades	Existing	WP&L	Natural Gas	6680-CE-186, approved
2026	7	Blount Battery Storage	New	MGE	Battery Storage	
2026	7	Huiskamp Battery Storage	New	MGE	Battery Storage	
2026	7	West Middleton Battery Storage	New	MGE	Battery Storage	
2027	75	Darien Solar Storage[4]	New	WEPCO / MGE	Battery Storage	9806-CE-100 approved; 5-BS-255, approved
2027	300	Koshkonong Solar[5]	New	WEPCO/WPSC/MGE	Solar	9811-CE-100, approved; 5- BS-258, approved
2027	165	Koshkonong Solar Storage[6]	New	WEPCO/WPSC/MGE	Battery Storage	9811-CE-100, approved; 5-BS-258, approved
2027	300	High Noon Solar[7]	New	WEPCO/WPSC/MGE	Solar	9814-CE-100, approved; 5-BS-276 approved
2027	165	High Noon Solar Storage[8]	New	WEPCO/WPSC/MGE	Battery Storage	9814-CE-100, approved; 5-BS-276, approved
2027	20	Sunnyside Solar	New	MGE	Solar	
2027	40	Sunnyside Battery Storage	New	MGE	Battery Storage	
2027	18	Columbia Energy Dome[9]	New	WP&L / WPSC / MGE	Long Duration Energy Storage	5-CE-156, approved
2027	149	Badger State Solar	New	DPC	Solar	9800-CE-100, approved
2025	99	Edgewater Battery Storage	New	WP&L	Battery Storage	6680-CE-184, approved
2027	6.5	Six Mile Solar	New	MGE	Solar	
2027	6.5	Pine Hill Solar	New	MGE	Solar	
2027	8	Nine Springs Solar	New	MGE	Solar	
2027	130	Paris Reciprocating Internal Combustion Engine (RICE)	New	WEPCO	Natural Gas	6630-CE-316, approved
2028	1,138	Oak Creek Combustion Turbines (CTs)	New	WEPCO	Natural Gas	6630-CE-317, approved
2028	150	Dawn Harvest Solar[10]	New	WEPCO / WPSC / MGE	Solar	9809-CE-100, approved; 5-BS-281, pending
2028	50	Dawn Harvest Battery Storage	New	WEPCO	Battery Storage	9809-CE-100, approved; 5-BS-281, pending
2028	150	Saratoga Solar[11]	New	WEPCO / WPSC / MGE	Solar	9816-CE-100, approved; 5-BS-280, approved
2028	50	Saratoga Battery Storage[12]	New	WEPCO / WPSC / MGE	Battery Storage	9816-CE-100, approved; 5-BS-280, approved
2028	98.4	Good Oak Solar[13]	New	WEPCO / WPSC / MGE	Solar	5-CE-159
2028	67	Gristmill Solar[14]	New	WEPCO / WPSC / MGE	Solar	5-CE-159
2028	14	Port Washington Generating Station upgrades	Existing	WEPCO	Natural Gas	6630-CE-318
2028	156	Riverside Generation Station upgrades	Existing	WP&L	Natural Gas	

Table B-8 New Additions and Transfers of Utility-Owned or Leased Generation Capacity by Wisconsin Electric Providers 2025 through 2032

2028	300	Elk Creek Solar	New	NSPW	Solar	9819-CE-100, approved; 4220-BS-101, approved
2028	77	Elk Creek Battery Storage	New	NSPW	Battery Storage	9819-CE-100, approved; 4220-BS-101, approved
2028	112	Badger Hollow Wind[15]	New	WEPCO / WPSC / MGE	Wind	9827-CE-100, approved; 5-BS-282, approved
2028	67	Whitetail Wind[16]	New	WEPCO / WPSC / MGE	Wind	5-BS-282, approved
2029	300	Ten Mile Creek Solar	New	NSPW	Solar	4220-CE-190, pending
2029	300	Ten Mile Creek Battery Storage	New	NSPW	Battery Storage	4220-CE-190, pending
2029	180	Whitewater Solar[17]	New	WEPCO / WPSC	Solar	9828-CE-100, approved; 5-BS-287, pending
2029	225	Emerald Bluffs Solar[18]	New	WEPCO/ MGE	Solar	9830-CE-100, pending; 5-BS-288, pending
2029	100	Fox Solar[19]	New	WEPCO / MGE	Solar	9833-CE-100, pending; 5-BS-290, pending
2029	100	Sinnissippi Solar	New	WEPCO	Solar	9823-CE-100, pending; 6630-BS-102, pending
2029	150	Superior Solar[20]	New	WEPCO / MGE	Solar	5-BS-292, pending
2029	45	Generic Solar 2029	New	MGE	Solar	
2029	200	Ursa Solar[21]	New	WEPCO / WPSC / MGE	Solar	9818-CE-100, approved; 5-BS-280, approved
2029	550	Generic BESS 2029	New	WEPCO	Battery Storage	
2029	270	Foundry Ridge CTs	New	WEPCO	Natural Gas	9835-CE-100, pending; 6630-BS-103, pending
2029	1,125	Red Oak Ridge CTs	New	WEPCO	Natural Gas	9837-CE-100, pending; 6630-BS-104, pending
2029	153	Bent Tree North (MN)	New	WP&L	Wind	6680-CE-189
2029	277	Columbus Wind	New	WP&L	Wind	9836-CE-100
2029	140	Wind Project 2	New	WP&L	Wind	
2030	180	Dawn Break Solar[22]	New	WEPCO / MGE	Solar	9825-CE-100, pending; 5-BS-289, pending
2030	180	Dawn Break Battery Storage[23]	New	WEPCO / MGE	Battery Storage	9825-CE-100, pending; 5-BS-289, pending
2030	200	Akron Solar[24]	New	WEPCO / MGE	Solar	9832-CE-100, pending; 5-BS-291, pending
2030	1,500	WEPCO Solar TBD 2030	New	WEPCO	Solar	
2030	206	WPSC Solar TBD 2030	New	WPSC	Solar	
2030	100	WP&L Solar TBD 2030	New	WP&L	Solar	
2030	750	WEPCO Gas TBD 2030	New	WEPCO	Natural Gas	
2030	551	WEPCO Wind TBD 2030	New	WEPCO	Wind	
2030	69	WPSC Wind TBD 2030	New	WPSC	Wind	
2031	300	WEPCO Solar TBD 2031	New	WEPCO	Solar	
2031	38	WPSC Solar TBD 2031	New	WPSC	Solar	
2031	28	WEPCO Gas TBD 2031	New	WEPCO	Natural Gas	
2031	28	WPSC Gas TBD 2031	New	WPSC	Natural Gas	
2032	50	MGE Wind 2032	New	MGE	Wind	
2032	1,138	WEPCO Gas TBD 2032	New	WEPCO	Natural Gas	

[1] Ownership shares are 150 MW to WEPCO, 30 MW to WPSC, and 20 MW to MGE.
[2] Ownership shares are 82.5 MW to WEPCO, 16.5 MW to WPSC, and 11 MW to MGE.
[3] Ownership shares are 187.5 MW to WEPCO, 37.5 MW to WPSC, and 25 MW to MGE.
[4] Ownership shares are 67.5 MW to WEPCO and 7.5 MW to MGE.
[5] Ownership shares are 225 MW to WEPCO, 45 MW to WPSC, and 30 MW to MGE.
[6] Ownership shares are 123.75 MW to WEPCO, 24.75 MW to WPSC, and 16.5 MW to MGE.
[7] Ownership shares are 225 MW to WEPCO, 45 MW to WPSC, and 30 MW to MGE.
[8] Ownership shares are 123.75 MW to WEPCO, 24.75 MW to WPSC, and 16.5 MW to MGE.
[9] Ownership shares are 9.6 MW to WP&L, 5.0 MW to WPSC, and 3.4 MW to MGE.
[10] Ownership shares are proposed as 120 MW to WEPCO, 15 MW to WPSC, and 15 MW to MGE.
[11] Ownership shares are proposed as 120 MW to WEPCO, 15 MW to WPSC, and 15 MW to MGE.
[12] Ownership shares are proposed as 40 MW to WEPCO, 5 MW to WPSC, and 5 MW to MGE.
[13] Ownership shares are proposed as 78.8 MW to WEPCO, 9.8 MW to WPSC, and 9.8 MW to MGE.

Table B-8 New Additions and Transfers of Utility-Owned or Leased Generation Capacity by Wisconsin Electric Providers 2025 through 2032

[14] Ownership shares are proposed as 53.6 MW to WEPCO, 6.7 MW to WPSC, and 6.7 MW to MGE.
[15] Ownership shares are 89.6 MW to WEPCO, 11.2 MW to WPSC, and 11.2 MW to MGE.
[16] Ownership shares are 53.6 MW to WEPCO, 6.7 MW to WPSC, and 6.7 MW to MGE.
[17] Ownership shares are proposed as 90 MW to WEPCO, 90 MW to WPSC.
[18] Ownership shares are proposed as 202.5 MW to WEPCO and 22.5 MW to MGE.
[19] Ownership shares are proposed as 90 MW to WEPCO, 10 MW to MGE.
[20] Ownership shares are proposed as 135 MW to WEPCO, 15 MW to MGE.
[21] Ownership shares are 160 MW to WEPCO, 20 MW to WPSC, and 20 MW to MGE.
[22] Ownership shares are proposed as 162 MW to WEPCO, 18 MW to MGE.
[23] Ownership shares are proposed as 162 MW to WEPCO, 18 MW to MGE.
[24] Ownership shares are proposed as 180 MW to WEPCO, 20 MW to MGE.

Table C-1 Dispatched Demand Response Capacity (MW) as a Proportional of Total Demand Response Program Capacity (MW) by Provider

Utility with Interruptible Load Control Program	Year			
	2022	2023	2024	2025
DPC	5.10/5.40 (94%)	0.00/5.20 (0%)	0.00/10.40 (0%)	0.00/14.80 (0%)
MGE	0.00/8.47 (0%)	0.00/7.07 (0%)	0.00/7.35 (0%)	0.00/6.52 (0%)
NSP	63.00/63.00 (100%)	65.00/65.00 (100%)	65.50/65.50 (100%)	64.07/64.07 (100%)
WPL	125.00/125.00 (100%)	80.00/80.00 (100%)	131.00/131.00 (100%)	103.00/103.00 (100%)
WPPI	0.00/48.30 (0%)	0.00/38.30 (0%)	0.00/45.40 (0%)	0.00/48.30 (0%)
WEPCO	0.00/132.26 (0%)	0.00/124.57 (0%)	0.00/112.87 (0%)	0.00/113.93 (0%)
WPS	0.00/181.17 (0%)	0.00/168.89 (0%)	0.00/159.74 (0%)	0.00/205.61 (0%)
Total	193.10/563.61 (34%)	145.00/489.03 (30%)	196.50/532.25 (37%)	167.07/556.23 (30%)
Utility with Direct Load Control Program	**Year**			
	2022	**2023**	**2024**	**2025**
DPC	12.05/12.05 (100%)	14.10/14.10 (100%)	84.15/84.15 (100%)	87.16/87.16 (100%)
MGE	2.56/20.70 (12%)	3.95/20.89 (18%)	5.03/21.97 (23%)	5.11/22.23 (30%)
NSP	17.70/17.70 (100%)	16.70/17.00 (98%)	17.93/17.93 (100%)	18.60/18.60 (100%)
WPL	0.00/5.70 (0%)	0.00/10.00 (0%)	0.00/13.00 (0%)	0.00/17.00 (0%)
SWLP	0.00/.22 (0%)	0.00/.17 (0%)	0.00/.15 (0%)	0.00/.16 (0%)
Total	32.31/55.93 (56%)	34.75/58.21 (60%)	107.11/137.19 (78%)	110.87/145.15 (76%)

Note: There were instances where utilities reported dispatched MW as greater than total program capacity. In these instances, total program capacity was adjusted to match dispatched capacity.

Table C-2 Summary of Demand Response Activity Provider

Utility	Summary	2022	2023	2024	2025
DPC	DR Capacity	17.45	19.3	94.55	101.96
	DR Dispatched	17.15	14.1	84.15	87.16
	DR Customers	12101	14201	94652	100688
MGE	DR Capacity	29.17	27.96	29.32	28.75
	DR Dispatched	2.56	3.95	5.03	5.11
	DR Customers	3568	5509	7009	7309
NSPW	DR Capacity	80.7	82	83.43	82.67
	DR Dispatched	80.7	81.7	83.43	82.67
	DR Customers	22130	22363	22614	23076
SWLP	DR Capacity	0.22	0.17	0.15	0.16
	DR Dispatched	0	0	0	0
	DR Customers	165	164	157	158
WPL	DR Capacity	130.7	90	144	120
	DR Dispatched	125	80	131	103
	DR Customers	5500	10000	13566	17203
WPPI	DR Capacity	48.3	38.3	45.4	48.3
	DR Dispatched	0	0	0	0
	DR Customers	11	11	10	10
WEPCO	DR Capacity	132.26	124.57	112.87	113.93
	DR Dispatched	0	0	0	0
	DR Customers	83	82	78	75
WPSC	DR Capacity	181.17	168.89	159.74	205.61
	DR Dispatched	0	0	0	0
	DR Customers	46	45	45	45

Table C-3 Demand Response Capacity (All Types) by Program

DR Program	DR Type	2022 Enrollments	Capacity	2023 Enrollments	Capacity	2024 Enrollments	Capacity	2025 Enrollments	Capacity
DPC									
Daily EV Charging	Direct Load Control	100	0.05	200	0.1	250	0.15	286	0.16
Daily Thermal Storage	Direct Load Control	12000	12	14000	14	14000	14	14000	14
Registered DLC	Direct Load Control	0	0	0	0	57000	30	63000	33
Unregistered DLC	Direct Load Control	0	0	0	0	23400	40	23400	40
Registered Bulk Interruptible	Interruptible Load	1	5.4	1	5.2	2	10.4	2	14.8
MGE									
CP-1 C&I High Load Factor Direct Control Interruptible Service for Transmission Voltage	Direct Load Control	1	11.26	1	11.18	1	11.18	1	11.18
MGE Connect	Direct Load Control	3559	2.56	5500	3.95	7000	5.03	7300	5.11
IS-4 Electric Interruptible Service	Direct Load Control	4	6.88	4	5.76	4	5.76	4	5.94
IS-3 Electric Interruptible Service	Interruptible Load	4	8.47	4	7.07	4	7.35	4	6.52
NSP									
AC Rewards	Direct Load Control	1410	1.7	1913	2.1	2452	2.93	2809	3.17
Saver's Switch (Commercial)	Direct Load Control	1090	5.7	970	6.2	951	6.2	950	6.2
Saver's Switch (Residential AC)	Direct Load Control	17975	10	16090	8.1	15842	8.2	15942	8.61
Saver's Switch (Residential Water Heaters)	Direct Load Control	1384	0.3	3120	0.6	3097	0.6	3107	0.62
Electric Rate Savings (commercial)	Interruptible Load	271	63	270	65	272	65.5	268	64.07
SWLP									
Controlled Space Heating	Direct Load Control	118	0.21	117	0.16	113	0.14	113	0.15
Controlled Water Heating	Direct Load Control	47	0.01	47	0.01	45	0.01	45	0.01
WPPI									

Interruptible Load	Interruptible Load	11	48.3	11	38.3	10	45.4	10	48.3
WPL									
Smart Hours	Direct Load Control	5500	5.7	10000	10	13566	13	17203	17
C&I Interruptible	Interruptible Load	121	125	117	80	117	131	117	103
WEPCO									
Curtailable Service	Interruptible Load	47	25.5	47	22.6	46	23.4	43	21.56
General Primary Combined Firm and Non-Firm Service	Interruptible Load	24	66.13	24	62.89	23	57.2	23	58.69
Real Time Pricing Rider	Interruptible Load	1	39.1	1	37.77	1	31.42	1	32.84
Seasonal Curtailable	Interruptible Load	11	1.53	10	1.32	8	0.86	8	0.84
WPS									
General Primary Interruptible	Interruptible Load	38	135.52	38	128.46	38	115.68	38	161.7
Real Time Market Pricing	Interruptible Load	8	45.65	7	40.42	7	44.05	7	43.91

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

State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Illinois	12.50	12.54	12.95	12.77	13.03	13.04	13.18	15.65	15.71	15.87	17.69
Indiana	11.57	11.79	12.29	12.26	12.58	12.83	13.37	14.59	14.94	14.77	16.23
Iowa	11.63	11.94	12.34	12.24	12.46	12.46	12.73	13.15	13.31	13.40	13.72
Kansas	12.34	13.06	13.31	13.35	12.71	12.85	12.98	13.99	13.38	14.15	14.56
Michigan	14.42	15.22	15.40	15.45	15.74	16.26	17.54	17.86	18.84	19.30	20.01
Minnesota	12.12	12.67	13.04	13.14	13.04	13.17	13.50	14.25	14.73	15.45	15.82
Missouri	11.21	11.21	11.63	11.34	11.14	11.22	11.41	11.74	12.58	12.91	13.49
Nebraska	10.60	10.84	10.97	10.70	10.77	10.80	10.75	10.79	11.20	11.53	12.34
North Dakota	9.62	10.16	10.29	10.25	10.30	10.44	10.85	10.92	11.01	11.51	11.81
South Dakota	11.08	11.47	11.77	11.59	11.55	11.75	12.22	12.09	12.32	12.86	13.38
Ohio	12.80	12.47	12.63	12.56	12.38	12.29	12.77	13.85	15.38	15.99	16.96
Wisconsin	14.11	14.07	14.35	14.02	14.18	14.32	14.52	15.62	16.88	17.18	18.16
Midwest	12.00	12.29	12.58	12.47	12.49	12.62	12.99	13.71	14.19	14.58	15.35
U.S. Total	12.65	12.55	12.89	12.87	13.01	13.15	13.66	15.04	16.00	16.48	17.30

Table D-2 Commerical Average Rates in the Midwest and U.S. (cents/kWh)

State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Illinois	9.02	9.02	9.09	9.12	9.08	9.15	9.65	11.32	11.24	11.81	13.07
Indiana	9.78	10.01	10.54	10.60	11.03	11.21	11.58	12.86	12.55	12.44	13.88
Iowa	8.92	9.17	9.46	9.68	9.99	9.96	10.17	10.55	10.33	10.22	11.05
Kansas	10.10	10.47	10.59	10.66	10.29	10.40	10.52	11.51	10.85	11.19	11.35
Michigan	10.55	10.64	11.00	11.15	11.39	11.71	12.31	12.55	13.40	14.01	14.48
Minnesota	9.44	9.86	10.48	10.38	10.34	10.43	11.22	12.30	12.39	12.15	12.27
Missouri	9.16	9.26	9.47	9.40	9.07	8.93	9.17	9.55	10.14	10.26	10.63
Nebraska	8.67	8.80	8.85	8.83	8.85	8.89	8.81	8.82	8.76	8.39	8.79
North Dakota	8.83	9.15	9.19	9.10	9.01	9.02	9.17	8.45	7.38	7.19	7.40
South Dakota	9.16	9.58	9.74	9.62	9.59	9.65	10.15	10.21	10.16	10.55	10.89
Ohio	10.07	9.97	10.05	10.11	9.72	9.53	9.75	10.39	10.75	10.66	11.60
Wisconsin	10.89	10.77	10.87	10.67	10.72	10.75	10.95	11.85	12.76	12.63	13.06
Midwest	9.55	9.73	9.94	9.94	9.92	9.97	10.29	10.86	10.89	10.96	11.54
U.S. Total	10.64	10.43	10.66	10.67	10.68	10.59	11.22	12.41	12.59	12.75	13.41

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

State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Illinois	6.67	6.51	6.47	6.80	6.52	6.70	7.30	8.57	8.20	8.83	10.14
Indiana	6.86	6.97	7.54	7.38	7.36	6.98	7.39	8.65	8.24	8.15	8.89
Iowa	5.90	6.05	6.21	6.45	6.60	6.43	6.63	7.06	6.91	6.80	7.20
Kansas	7.61	7.49	7.54	7.60	7.35	7.30	7.38	8.30	7.64	7.73	8.03
Michigan	7.02	6.91	7.19	7.10	7.07	7.24	7.69	8.33	8.16	8.26	8.59
Minnesota	7.02	7.37	7.37	7.52	7.53	7.67	8.29	9.25	9.20	9.15	9.32
Missouri	6.44	7.12	7.33	7.22	7.11	6.84	7.11	7.67	7.90	7.87	8.38
Nebraska	7.59	7.69	7.66	7.60	7.65	7.38	7.26	7.21	7.63	7.66	8.00
North Dakota	8.07	7.98	7.63	7.98	7.94	7.26	7.37	7.28	7.37	7.25	7.50
South Dakota	7.37	7.57	7.84	7.77	7.81	7.79	8.02	8.04	8.01	8.28	8.68
Ohio	7.02	6.98	6.92	7.01	6.55	6.16	6.55	7.45	7.03	7.10	8.52
Wisconsin	7.58	7.49	7.49	7.33	7.31	7.29	7.63	8.49	8.68	8.54	8.92
Midwest	7.10	7.18	7.27	7.31	7.23	7.09	7.39	8.03	7.91	7.97	8.51
U.S. Total	6.91	6.76	6.88	6.92	6.81	6.67	7.18	8.32	8.04	8.13	8.62

Table D-4 2025 Estimated Monthly Bill Data for Municipal Utility Cp-1 Customers

Summary	Total Cost (cents/kWh)*	Estimated Bill ($/month)*
Minimum	5.42	$2,710.00
25th Percentile	8.805	$4,402.50
Median	10.07	$5,035.00
Average	9.98	$4,991.66
75th Percentile	10.95	$5,475.00
Maximum	13.7	$6,850.00

*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.

5-ES-113 Strategic Energy Assessment 2026-2032

Aggregation of data schedules submitted by electric service providers

For a select set of data schedules, this document provides an aggregation of individual electric service provider data submitted under docket 5-ES-113 SEA 2026-2032.

The purpose of this document is to provide a broader state-wide roll up of data in excel format.

Assessment of Electric Demand and Supply Conditions - Historic

Instructions

SEA data collection pursuant to Wis. Admin. Code § PSC 111.11(2)(a)1-6, PSC 111.13, PSC 111.21(1)(b)-(f), PSC 111.23(2)(a)-(b), and PSC 111.41.
IOUs should include wholesale requirements customers' data.
Data for 2025 should represent January 1, 2025 to September 30, 2025.
Data for forecast years (2026-2032) should be entered on Schedule 2.
2023 data from the previous SEA represented 9 months of actual data and 3 months of forecast data and must be revised to reflect 12 months of actual data.
All 2024 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals.
All 2025 data from the previous SEA represented a 12-month forecast and must be revised to reflect 9 months of actuals (January 1 to September 30).
Peak load is defined as the Wisconsin load the provider would have served before implementing PSC 111.11(2a), items 2 through 6.
For Direct Load Control and Interruptible Load, report values for what was implemented or scheduled.
For Additional demand and additional supply, add a brief description.
For owned capacity, and merchant plant capacity under contract, include capacity located in state or used for Wisconsin customers.

Wisconsin Peak Electric Demand (MW)	2023	2024	2025
Date of Peak Load	N/A	N/A	N/A
Peak Load MW, non-coincident	14,472.9	14,115.7	13,815.5
Direct Load Control Program	-2.8	-3.0	-1.0
Interruptible load	293.5	272.6	304.5
Capacity sales, including reserves	309.9	281.9	281.9
Capacity purchases, including reserves	-173.0	-148.0	-148.0
Transmission loss responsibility associated with purchases	0.0	0.0	0.0
Additional demand factor (type description here)	-11.0	-1.8	-7.8
Adjusted electric demand	11,252.4	10,936.1	10,919.9
Electric Power Supply (MW)			
Owned generating capacity[1]	14,895.5	15,064.2	15,478.3
Merchant power plant capacity under contract	1,766.5	1,797.5	1,818.2
Unit retirements	-141.2	493.5	0.0
New: owned or leased capacity additions	456.6	361.9	512.4
Capacity changes at existing units	0.0	0.0	0.0

Electric Power Supply (MW)			
Capacity purchases without reserves, system basis	403.6	387.3	341.0
Capacity purchases without reserves, unit basis	589.9	736.9	656.0
Transmission loss responsibility associated with purchases	0.0	0.0	0.0
Capacity sales without reserves, system basis	24.8	79.0	7.5
Capacity Sales without reserves, unit basis	412.0	588.5	552.7
Additional supply factor--scheduled outages	0.0	0.0	0.0
Additional supply factor (type description here)	-29.6	-38.8	-29.3
Electric Power Supply	17,454.1	17,996.2	18,135.9
Reserve Margin	55.1%	64.6%	66.1%
Resources Not Dispatched (MW)			
Direct Load Control Program	82.3	85.8	88.8
Interruptible load	474.7	438.7	507.8
Additional demand factors (type description here)	0.0	0.0	0.0
Transmission : Firm Interface Capacity Counted for Reserves (MW)			
Resources using MINN/WUMS interface	119.0	217.6	217.7
Resources using CE/WUMS interface	92.2	91.7	92.5
Resources using Upper Michigan\Wisconsin interface	22.0	36.8	37.6
Total	234.0	349.0	349.7

Assessment of Annual Energy Supply Conditions

Instructions

Include actual data through September 30, 2025

IOUs are to include wholesale requirements customers' data.

SEA data collection pursuant to Wis. Admin. Code. § PSC 111.07

2023 data from the previous SEA represented 9 months of actual data and 3 months of forecast data and must be revised to reflect 12 months of actual data.

All 2024 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals.

All 2025 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals (January 1 to December 31).

All 2026 through 2030 data from the previous SEA represent 12-month forecasts and must be reviewed and revised to reflect current forecasts for these years.

Nothing on this form is expected to be confidential

	History			Current Year	Forecast					
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Owned Generating Energy Output (MWh)										
Coal	22,731,453	23,044,826	25,001,525	24,367,959	24,157,647	23,462,694	19,559,539	13,743,677	2,184,804	2,184,842
Nuclear	1,907,362	1,893,878	2,114,131	2,219,627	2,042,938	2,275,133	2,179,008	2,269,600	2,191,133	2,191,133
Natural Gas	25,367,616	25,534,355	23,220,503	24,695,935	25,816,558	27,597,135	32,276,556	38,192,604	45,815,866	45,588,887
Wind	4,204,037	4,626,807	4,388,255	4,527,683	4,755,363	5,060,175	6,775,652	9,164,297	9,802,313	9,952,168
Renewable Biomass or Biogas	362,668	349,193	404,092	533,742	561,875	581,670	598,777	602,498	604,446	604,446
Hydroelectric	965,127	927,670	950,138	1,011,430	1,024,054	1,024,214	1,083,239	1,083,254	1,083,012	1,083,151
Solar PV	693,739	2,822,823	4,141,310	4,578,134	5,234,678	5,834,778	9,403,003	12,033,287	12,709,609	12,704,256
Fuel Oil	2,750	1,962	5,732	5,408	5,677	5,976	5,454	3,301	3,312	4,430
Battery Discharge	0	0	39,003	257,349	423,822	684,564	850,447	863,460	863,460	863,460
Subtotal	56,234,754	59,201,514	60,264,689	62,197,267	64,022,611	66,526,339	72,731,675	77,955,978	75,257,955	75,176,772
Merchant Power Plant Energy Output under Contract (MWh)										
Coal	-1,122	0	0	0	0	0	0	0	0	0
Nuclear	8,967,646	9,003,449	8,977,986	8,985,256	8,990,568	9,015,192	8,990,568	8,990,568	8,990,568	8,990,568
Natural Gas	1,151,940	1,268,495	975,621	1,418,091	1,539,594	1,407,470	1,437,535	1,428,051	1,488,025	1,480,422
Wind	3,818,617	3,929,769	3,748,251	4,342,229	6,138,936	6,261,628	6,199,280	6,195,532	5,955,505	5,962,511
Renewable Biomass or Biogas	399,450	405,476	375,275	329,113	334,885	309,958	295,843	295,843	295,843	295,843
Hydroelectric	750,827	757,898	678,520	732,357	467,557	300,066	300,524	259,285	259,027	259,113
Solar PV	563,186	591,381	551,805	970,084	1,631,566	1,969,911	2,177,624	2,381,921	2,398,845	2,398,444
Fuel Oil	0	0	0	0	0	0	0	0	0	0
Subtotal	15,650,544	15,956,468	15,307,457	16,777,130	19,103,106	19,264,224	19,401,373	19,551,200	19,387,814	19,386,902
Total Energy Output	71,885,296	75,157,982	75,572,147	78,974,397	83,125,717	85,790,563	92,133,049	97,507,178	94,645,769	94,563,674

Assessment of Electric Demand and Supply Conditions Monthly Peak Demand (MW)

Instructions

Include data through September 30, 2025

IOUs are to include wholesale requirements customers' data.

SEA data Collection pursuant to Wis. Admin. Code § PSC 111.11(2)

Peak load is the Wisconsin load the electric provider would have served before implementing § PSC 111.11(2a)2 through 6

2023 data from the previous SEA represented 9 months of actual data and 3 months of forecast data and must be revised to reflect 12 months of actual data.

All 2024 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals.

All 2025 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals (January 1 to December 31).

Green-highlighted cells reflect actuals.

Nothing on this form is expected to be confidential

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical:												
2023	10,028	9,890	9,155	9,050	10,999	12,286	13,385	14,753	12,882	10,739	9,771	9,687
2024	10,228	9,159	9,006	8,898	9,156	13,110	13,625	14,392	11,735	9,205	9,070	10,361
2025	10,622	10,205	9,077	9,019	9,980	14,007	13,969	13,552	11,501	11,018	9,233	10,247
Forecasted:												
2026	10,757	10,165	9,814	9,310	11,084	13,321	14,112	13,748	12,190	9,726	9,924	10,820
2027	11,051	10,555	10,337	9,736	11,498	13,544	14,638	14,317	12,905	10,529	10,930	11,846
2028	12,382	12,002	11,884	11,540	13,380	15,899	16,961	16,560	15,301	12,771	12,928	14,054
2029	14,286	13,761	13,711	13,116	14,825	17,369	18,433	18,029	16,709	14,192	14,326	15,267
2030	15,515	14,999	14,907	14,317	16,060	18,503	19,570	19,171	17,664	15,145	15,287	16,064
2031	16,304	15,781	15,509	14,918	16,684	18,661	19,728	19,333	17,760	15,233	15,376	16,137
2032	16,338	15,807	15,538	14,946	16,719	18,687	19,759	19,363	17,789	15,267	15,413	16,181

Assessment of Energy Conditions Monthly Energy (MWH)

Instructions

Include actual data through September 30, 2025

IOUs are to include wholesale requirements customers' data.

Data in this schedule is the Wisconsin load the electric provider would have served before implementing § PSC 111.11(2a)2 through 6.

SEA data collection pursuant to Wis. Admin. Code § PSC 111.07

2023 data from the previous SEA represented 9 months of actual data and 3 months of forecast data and must be revised to reflect 12 months of actual data.

All 2024 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals.

All 2025 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals (January 1 to December 31).

Green-highlighted cells reflect actuals.

Nothing on this form is expected to be confidential

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical:												
2023	6,078,282	5,452,178	5,806,738	5,313,494	5,540,465	6,169,255	6,751,282	6,831,382	5,867,185	5,631,642	5,493,140	5,751,040
2024	6,152,227	5,435,464	5,565,093	5,234,726	5,460,172	6,122,631	6,810,889	6,761,809	5,937,252	5,520,584	5,385,809	6,049,397
2025	6,419,531	5,680,459	5,653,971	5,341,953	5,434,673	6,325,078	7,318,654	6,771,095	5,937,219	5,772,332	5,534,503	6,244,722
Forecasted:												
2026	6,345,615	5,697,281	5,870,783	5,412,185	5,626,542	6,127,736	7,005,623	6,841,653	5,933,018	5,709,951	5,721,082	6,357,521
2027	6,560,439	5,882,425	6,122,653	5,653,469	5,879,071	6,379,279	7,241,742	7,129,641	6,269,922	6,127,799	6,170,214	6,828,722
2028	7,095,477	6,613,624	6,892,314	6,464,723	6,730,517	7,545,704	8,403,401	8,228,672	7,517,433	7,256,583	7,233,184	8,025,188
2029	8,218,232	7,515,200	7,820,029	7,364,578	7,576,146	8,313,563	9,174,548	9,000,462	8,160,158	7,908,182	7,875,856	8,490,478
2030	8,711,712	8,001,545	8,317,210	7,861,194	8,089,431	8,821,900	9,695,279	9,522,931	8,620,224	8,376,143	8,337,613	8,904,351
2031	9,120,210	8,381,731	8,661,633	8,196,177	8,432,534	8,891,648	9,767,579	9,596,589	8,721,503	8,474,612	8,433,134	9,124,847
2032	9,341,627	8,694,018	8,873,589	8,408,455	8,647,867	9,119,194	9,998,060	9,826,790	8,948,199	8,702,006	8,661,308	9,340,716

Unit Retirements, Upgrades, Fuel Switching

Instructions

Provide data for plants expected to be retired, upgraded, or switched to a different fuel by December 31, 2032. Add lines as needed to included all applicable plants.

Provide information on facilities with 10 MW or more in capacity. This includes facilities where the combined capacity of units to be retired or upgraded is 10 MW or more, even though individual units may have a smaller capacity rating.

SEA data collection pursuant to Wis. Admin. Code § PSC 111.21

Nothing on this form is expected to be confidential

	Name of Facility	Capacity Change	Unit #	Location	Primary Fuel Type	Nameplate Capacity (MW)	Expected Year	Expected CO2 (lbs/kWh)	Nameplate Added Capacity (MW)	Expected Nameplate Capacity (MW)	New Primary Fuel Type
Retirement	Wheaton 6	Retirement	6	Eau Claire, WI	Oil	70	2025	N/A	N/A	N/A	N/A
Retirement	Wheaton 4	Retirement	4	Eau Claire, WI	Natural Gas	61	2025	N/A	N/A	N/A	N/A
Retirement	Wheaton 3	Retirement	3	Eau Claire, WI	Natural Gas	56	2025	N/A	N/A	N/A	N/A
Retirement	Wheaton 2	Retirement	2	Eau Claire, WI	Natural Gas	68	2025	N/A	N/A	N/A	N/A
Retirement	Wheaton 1	Retirement	1	Eau Claire, WI	Natural Gas	56	2025	N/A	N/A	N/A	N/A
Retirement	French Island	Retirement	3&4	La Crosse, WI	Natural Gas	157	2030	N/A	N/A	N/A	N/A
Retirement	Rosiere Wind Farm	Retirement	nprised c	Kewaunee County, WI	Wind	11.2	2027	N/A			
Fuel Change	Weston	Fuel Change	4	Kronenwetter, WI	Coal	416.5	2030				Fuel Oil / Natural Gas
Retirement	Oak Creek	Retirement	7	Oak Creek, WI	Coal	317.6	2027				
Retirement	Oak Creek	Retirement	8	Oak Creek, WI	Coal	324	2027				
Upgrade	Port Washington	Upgrade	1	Port Washington, WI	Natural Gas	654	2027		7	661	
Upgrade	Port Washington	Upgrade	2	Port Washington, WI	Natural Gas	654	2027		7	661	
Fuel Change	Elm Road	Fuel Change	1	Oak Creek, WI	Coal	650	2029				Natural Gas
Fuel Change	Elm Road	Fuel Change	2	Oak Creek, WI	Coal	650	2029				Natural Gas
Upgrade	Riverside (AGP Upgrade)	Upgrade		1401 West B-R Townline Road, Beloit, WI 53511	Gas	529.9	2028	1.152	156	685.9	
Upgrade	Neenah 1 (AGP Upgrade)	Upgrade	1	200 County Road CB, Neenah, WI 52601	Gas	147.1	2026	1.181	50	197.1	
Upgrade	Neenah 2 (AGP Upgrade)	Upgrade	2	201 County Road CB, Neenah, WI 52601	Gas	148.7	2026	1.181	50	198.7	
Upgrade	Sheboygan 1 (AGP Upgrade)	Upgrade	1	N5787 Bridgewood Road, Sheboygan, WI 53085	Gas	149.7	2026	1.181	50	199.7	
Upgrade	Sheboygan 2 (AGP Upgrade)	Upgrade	2	N5787 Bridgewood Road, Sheboygan, WI 53085	Gas	148.1	2026	1.181	50	198.1	
Fuel Change	Columbia Unit 1	Fuel Change	1	W8375 Murray Road, Pardeeville WI (43.4858021,-89.4190171)	Coal	566	2030	1.142	0	303.6	Gas
Fuel Change	Columbia Unit 2	Fuel Change	2	W8375 Murray Road, Pardeeville WI (43.4858021,-89.4190171)	Coal	565	2030	1.145	0	302.9	Gas
Fuel Change	Edgewater 5	Fuel Change	5	3739 Lakeshore Drive, Sheboygan WI (43.7166971,-87.7089039)	Coal	405.4	2030	1.249	0	405.6	Gas

New Generating Facilities

Instructions:

Provide data for all new plants expected to commence construction and/or be placed in commercial operation prior to December 31, 2032

Do not enter existing facilities that are switching fuel here; use schedule 7.

SEA data collection pursuant to Wis. Admin. Code § PSC 111.21

In-service date refers to the year the unit or facility is expected to be commerically operational.

Review, revise and add data as appropriate.

Nothing on this form is expected to be confidential

** Some facilities have multiple owners and appear as multiple line items in the list below as a result*

Name of Facility*	Unit #	Cost ($/kW)	City	State	Primary Fuel Type	Summer Net-Rated Capacity MW	Winter Net-Rated Capacity MW	Expected Annual Generation (kWh)	Expected In-Service Year	CO2 (pounds per kWh)
Strix Solar			Fitchburg	WI	Solar	6	6	12,376,000	2025	0
Paris Solar-Battery Park			Paris	WI	Solar	20	20	38,532,000	2025	0
Darien Solar			Darrien	WI	Solar	25	25	47,925,000	2025	0
Koshkonong Solar Energy Center			Christiana and Deerfield	WI	Solar	30	30	61,262,000	2027	0
Koshkonong Solar Energy Center			Christiana and Deerfield	WI	Battery	16.5	16.5	See Note 1	2027	0
High Noon Solar			Leeds, Lowville, Arlington and Hampden	WI	Solar	30	30	61,881,000	2027	0
High Noon Battery			Leeds, Lowville, Arlington and Hampden	WI	Battery	16.5	16.5	See Note 1	2027	0
Sunnyside Solar			Fitchburg	WI	Solar	20	20	46,541,000	2027	0
Sunnyside Battery			Fitchburg	WI	Battery	40	40	See Note 1	2027	0
Columbia Energy Dome			Portage	WI	Battery	3.42	3.42	See Note 1	2027	0
Saratoga Solar			Saratoga	WI	Solar	15.05	15.05	30,267,000	2028	0
Saratoga Battery			Saratoga	WI	Battery	5.03	5.03	See Note 1	2028	0
Ursa Solar			Springvale and Courtland	WI	Solar	20	20	40,429,000	2027	0
Dawn Harvest Solar			Harmony and La Prairie	WI	Solar	15	15	30,631,000	2027	0
Good Oak Solar			Lewiston	WI	Solar	9.84	9.84	20,703,000	2028	0
Gristmill Solar			Columbus and Fountain Prairie	WI	Solar	6.7	6.7	13,958,000	2028	0
Badger Hollow Wind			Montfort	WI	Wind	11.16	11.16	30,693,000		0
Whitetail Wind			Livingston	WI	Wind	6.72	6.72	21,325,000	2027	0
Six Mile Solar			Waunakee	WI	Solar	6.5	6.5	13,407,000	2027	0
Pine Hill Solar			Cross Plains	WI	Solar	6.5	6.5	13,407,000	2027	0
Nine Springs Solar			Madison	WI	Solar	8	8	16,501,000	2027	0
Blount Battery			Madison	WI	Battery	7	7	See Note 1	2026 (see Note 2)	0
Huiskamp Battery			Madison	WI	Battery	7	7	See Note 1	2026 (see Note 2)	0
West Middleton Battery			Madison	WI	Battery	7	7	See Note 1	2026 (see Note 2)	0
Emerald Bluffs Solar			Lemonweir and Seven Mile Creek	WI	Solar	22.5	22.5	46,410,000	2029	0

Fox Solar			Morgan	WI	Solar	10	10	19,802,000	2029	0
Superior Solar			Marquette	MI	Solar	14.97	14.97	28,717,000	2029	0
Akron Solar			Rome and Saratoga	WI	Solar	20	20	41,254,000	2030	0
Dawn Break Solar			Oasis, Hancock, Plainfield, and Deerfield	WI	Solar	18	18	34,901,000	2030	0
Dawn Break Battery			Oasis, Hancock, Plainfield, and Deerfield	WI	Solar	18	18		2030	0
Generic Solar			TBD	TBD	Solar	45	45	92,821,000	2029	0
Generic Wind			TBD	TBD	Wind	50	50	149,855,000	2032	0
RockGen (See Note 3)			Cambridge	WI	Natural Gas	168	168	176,798,143	2028	XXX
Darien BESS	1	1,882	Town of Darien	WI	Battery	11	11	n/a	2027	n/a

Existing Generating Facilities

Instructions

Enter information in separate rows for all utility generating facilities. Consistent with PSC annual report requirements, record separate rows by unit for large plants and record small plants in a single-row aggregate, not by unit.

For plants equipped with combinations of diferent generating fuels, report information for each fuel in a separate row.

Only report data for plants that were in service for all, or a portion, of 2024. Include all facilities operating in 2024 even if Schedule 7 indicates they will be retired in future years.

New facilities that will not begin operating until future years do not need to be entered here and can be documented in Schedule 8.

Enter Latitude, Longitude in Decimal Degrees, with a comma separating the two values.

When applicable, information on capacity, generation and cost of plant should be consistent with the information reported for generating plant statistics in PSC annual reports.

When applicable, information on CO2 emissions should be consistent with that reported in other state and federal sources (such as WI DNR and EIA). Explain any complications or inconsistencies in the notes column.

If net peak demand for 60 minutes is not available, provide data that is available, and specify the period in the notes column.

** Some facilities have multiple owners and appear as multiple line items in the list below as a result*

Name of Facility*	Unit #	1st Year Commercial Operation	Street Address	City	State	Latitude, Longitude	Primary Fuel Type	Total Cost of Plant- 2023	Total Cost of Plant- 2024	Total Cost of Plant - 2025	Nameplate Capacity (MW)	Summer Net-Rated Capacity MW	Winter Net-Rated Capacity MW	Annual Net Generation, Exclusive of Plant Use (KWh) - 2023	Annual Net Generation, Exclusive of Plant Use (KWh) - 2024	Annual Net Generation, Exclusive of Plant Use (KWh) - 2025	Fuel Type Units (Coal-tons/Oil-barrel/Gas-mcf/etc.)	Quantity (units of Fuel Burned)- 2023	Quantity (units of Fuel Burned)- 2024	Quantity (units of Fuel Burned) - 2025	CO2 (pounds per kWh)- 2023	CO2 (pounds per kWh)- 2024	CO2 (pounds per kWh) - 2025	Net Peak Demand on Plant - MW (60 minutes)	Plant Hours Connected to Load- 2023	Plant Hours Connected to Load- 2024	Plant Hours Connected to Load - 2025	Net Continuous Plant Capability (MW)	Notes
Columbia	1	1975	W8375 Murray Rd	Pardeeville	WI	43.4864, -89.4203	Coal	$ 152,756,531.00	$ 159,599,253.00	$ 323,367,934.00	105.5	106	107	413,139,000	401,593,000	1,129,511,000	Tons	254,847	249,528	677,813	2.41	2.41	2.37	111	7,415	7,716	15,273	108	2025 PSCW Annual Report combined both Columbia Units 1 &2.
Columbia	2	1978	W8375 Murray Rd	Pardeeville	WI	43.4864, -89.4203	Coal	$ 152,756,531.00	$ 159,599,253.00		105.5	106	112	393,691,000	422,978,000		Tons	241,397	260,293		2.36	2.37		112	6,103	7,458		108	2025 PSCW Annual Report combined both Columbia Units 1 &2.
Elm Road	1	2010	10800 S Chicago Rd	Oak Creek	WI	42.8492, -87.8336	Coal	$ 100,743,058.00	$ 103,447,956.00	$ 208,472,859.00	53	53	53	251,271,000	354,646,000	620,762,000	Tons	120,407	155,353	287,547	1.97	1.89	1.9	54.4	5,712	7,883	13,160	53	2025 PSCW Annual Report combined both Elm Road Units 1 &2.
Elm Road	2	2011	10800 S Chicago Rd	Oak Creek	WI	42.8492, -87.8336	Coal	$ 100,743,058.00	$ 103,447,956.00		53	53	53	301,644,000	272,939,000		Tons	142,878	110,842		1.92	1.786		54.2	6,876	5,842		53	2025 PSCW Annual Report combined both Elm Road Units 1 &2.
Blount Station		1902	717 E Main St	Madison	WI	43.0789, -89.3744	Natural Gas	$ 92,531,713.00	$ 87,132,469.00	$ 90,059,704.00	100	96	96	9,564,000	48,772,000	58,590,000	MCF	208,240	743,810	882,424	2.86	1.97	1.59	99.2	985	3,140	3,846	95	
Fitchburg - 2 units		1973	5961 McKee Rd	Fitchburg	WI	43.0147, -89.4603	Natural Gas	$ 6,565,792.00	$ 7,036,546.00	$ 7,063,572.00	53.3	35.8	48	17,000	14,000	120,000	MCF	4,215	6,240	3,208	2.99*	2.99*	2.99*	33.6	16	20	11	50	CO2 estimate not to exceed 2.99 pounds per kWh
Sycamore - 2 units		1967	4102 Sycamore Ave	Madison	WI	43.1133, -89.3128	Natural Gas	$ 6,934,714.00	$ 6,934,714.00	$ 6,950,580.00	37.6	28.2	37	231,000	19,000	-1,000	MCF	6,686	3,728	3,384	3.32	2.99*	2.99*	16.3	29	15	13	30	CO2 estimate not to exceed 2.99 pounds per kWh
Nine Springs		1964	7300 South Towne Dr	Madison	WI	43.0386, -89.3586	Natural Gas	$ 3,624,090.00	$ 3,644,321.00	$ 3,642,947.00	16	11.4	16	64,000	82,000	89,000	MCF	1,020	1,610	1,630	1.83	2.24	2.01	21.9	5	31	7	13	
M34/Marinette		1999	W1830 West Cleveland Ave	Peshtigo	WI	45.0869, -87.6892	Natural Gas	$ 34,349,163.00	$ 34,873,578.00	$ 34,928,167.00	90	74	90	83,772,000	45,757,000	88,264,000	MCF	1,054,660	569,390	1,070,380	1.62	1.6	1.59	93	1,374	778	1450	90	
West Campus		2005	515 Walnut St	Madison	WI	43.0750, -89.4251	Natural Gas	$ 115,563,180.00	$ 118,441,675.00	$ 124,441,314.00	157	129	138	357,935,000	286,751,000	309,007,000	MCF	3,855,901	3,148,583	3,382,134	1.31	1.35	1.38	138.3	3,636	3,092	3,349	150	
Diesel Generators		1999	Various locations	Madison	WI	Various Locations	Fuel Oil	$ 36,179,189.00	$ 36,749,682.00	$ 37,546,987.00	61	61	61	544,000	489,000	862,000	Barrels	1,216	1,235	2,725	2.13	2.13	1.92	31.9	691	649	1,021	54	
West Riverside		2020	4201 S Walters Rd	Beloit	WI	42.5812, -89.0405	Natural Gas	$ 26,241,090.00	$ 53,983,775.00	$ 55,361,013.00	50	48	48	115,389,000	273,011,000	301,136,000	MCF	915,740	1,624,928	1,912,760	0.41	0.81	0.82	49.9	5,890	7,495	7,007		
Saratoga Wind Farm		2018	10439 Jade Ave	Lime Springs	IA	43.4488, -92.2807	Wind	$ 108,141,531.00	$ 107,835,471.00	$ 108,198,649.00	66	66	66	259,697,000	281,930,000	27,014,700	None	0	0	0	0	0	0	65.9	8,760	8,760	8,760		
Two Creeks Solar Park		2020	6011 Irish Rd	Two Rivers	WI	44.2495, -87.5453	Solar	$ 71,210,319.00	$ 71,238,414.00	$ 71,229,010.00	50	50	50	96,313,000	99,686,000	95,635,000	None	0	0	0	0	0	0	50.1	8,760	8,760	8,760		
Dane County PV:		2020	Various locations	Various locations	WI	Various locations	Solar	$ 70,404,847.00	$ 74,065,393.00	$ 28,974,707.00	58	52	52	73,791,000	84,226,000	93,591,000	None	0	0	0	0	0	0						
Middleton (Morey) Airport		2020	8300 Airport Rd	Middleton	WI	43.1162, -89.5324												0	0	0	0	0	0	5.3	3,703	3,773	8,760		
Dane County Airport		2020	6002 N Stoughton Rd	Madison	WI	43.1605, -89.3294												0	0	0	0	0	0	10	4,128	4,170	8,760		
O'Brien Solar Fields		2021	2652 South Seminole Hwy	Fitchburg	WI	42.9977, -89.4576												0	0	0	0	0	0	22.1	4,330	4,345	8,760		
Hermsdorf Solar Fields		2022	7004 Meier Rd	Madison	WI	44.1112, -89.0826												0	0	0	0	0	0	7.9	4,057	4,112	8,760		
Tyto Solar		2024	4896 Irish Ln	Fitchburg	WI	42.9886, -89.3771												0	0	0	0	0	0	5.9	226	3,992	8,760		
Strix Solar		2025	5101 Byrne Rd, Fitchburg, WI 53575	Fitchburg	WI	43.0188, -89.4604												0	0	0	0	0	0	6	-	-	8,208	6	
Forward Energy Center		2007	858 W Main St	Brownsville	WI	43.6161, -88.4969	Wind	$ 35,176,000.00	$ 34,363,058.00	$ 34,382,407.00	18	18	18	38,176,000	41,969,000	38,641,000	None	0	0	0	0	0	0	17.7	8,760	8,760	8,760	18	
Red Barn Wind		2023	389 Ebenezer Road	Montfort	WI	43.1022, -90.3440	Wind	$ 16,872,155.00	$ 16,717,139.00	$ 16,753,754.00	9	9	9	16,814,000	29,745,000	28,188,000	None	0	0	0	0	0	0	9.1	6,504	8,760	8,760	9	
Rosiere Wind Farm		1999	E2680 Eagle Rd	Casco	WI	44.6694, -87.6333	Wind	$ 14,228,994.00	$ 14,819,123.00	$ 14,884,208.00	11.2	11.2	11.2	14,984,000	13,389,000	11,988,000	None	0	0	0	0	0	0	12	4,838	4,882	8,760	11.2	
Top of Iowa 3		2008	570 410th St	Kensett	IA	43.3597, -93.3208	Wind	$ 61,111,993.00	$ 62,234,360.00	$ 62,438,937.00	29.7	29.7	29.7	40,525,000	43,900,00	39,924,000	None	0	0	0	0	0	0	27.8	8,760	8,760	8,760	29.7	
Badger Hollow Solar Park - Phase 1		2021	2625 Co Rd J	Cobb & Montfort	WI	42.9412, -90.3104	Solar	$ 77,861,745.00	$ 78,269,378.00	$ 79,838,088.00	50	50	50	87,136,000	98,406	101,738,000	None	0	0	0	0	0	0	50.3	8,760	8,760	8,760	50	
Badger Hollow Solar Park -Phase 2		2023	2625 Co Rd J	Cobb & Montfort	WI	42.9412, -90.3104	Solar	$ 84,873,177.00	$ 89,723,805.00	$ 88,633,122.00	50	50	50	637,000	99,285,000	102,734,000	None	0	0	0	0	0	0	50	240	8,760	8,760	50	
Paris Solar		2024	Various locations	Paris	WI	42.6598, -87.9927	Solar	-	-	$ 41,236,684.00	20	20	20	576,000	39,744,000	39,744,000	None	0	0	0	0	0	0	20.3	-	8,760	8,760	20	
Darien Solar		2025	14 E Bradford Town Hall Rd	Bradford	WI	42.6176, -88.7631	Solar	-	-	$ 50,833,580.00	25	25	25	-	-	41,951,000	None	0	0	0	0	0	0	25.1	-	-	7,272	25	