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PUBLIC SERVICE COMMISSION OF WISCONSIN

FINAL STRATEGIC ENERGY ASSESSMENT

2018-2024

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MADISON, WISCONSIN

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Strategic Energy Assessment 2024 – Final

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To The Reader

This is the tenth biennial Strategic Energy Assessment (SEA) issued by the Public Service Commission of Wisconsin (Commission), an independent state regulatory agency whose authority and responsibilities include oversight of electric service in Wisconsin. This SEA describes the availability, reliability, and sustainability of Wisconsin's electric energy capacity and supply.

Understanding the SEA – Key Tips and Processes

While the Commission is required to prepare this technical document for comments by parties involved in the electric industry, it also intends that the SEA be available to the general public having an interest in reliable, reasonably-priced electric energy. To assist the general public, definitions of key terms and acronyms used within the electric industry and this report are included in the appendix of this document.

The Commission is required to hold a public hearing before issuing the final SEA. A public hearing was held on June 19, 2018, and a copy of the notice providing information on the hearing is available for review on the Commission's website at: http://psc.wi.gov.

The Commission must also make an environmental assessment on the draft SEA before the final report is issued. The environmental assessment is available on the Commission's website.

Public comments have been used to prepare the final SEA. Questions regarding the final SEA or requests for additional copies of the final SEA may be directed to PSCSEA@wisconsin.gov. Questions from the legislature and the media may be directed to Matthew Spencer at Matthew2.Spencer@wisconsin.gov or (608) 267-3589.

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STRATEGIC ENERGY ASSESSMENT

2018-2024 Electricity Issues

Study Scope

The Public Service Commission of Wisconsin (Commission) is required by Wis. Stat. § 196.491(2) to prepare a biennial Strategic Energy Assessment (SEA) that evaluates the adequacy and reliability of Wisconsin's current and future electrical capacity and supply.

The SEA intends to assess, identify, and describe:

- Any plans for assuring that there is an adequate ability to transfer electric power into or out of Wisconsin in a reliable manner;
- The adequacy and reliability of purchased generation capacity and energy to serve the needs of the public;
- The extent to which the regional bulk-power market is contributing to the adequacy and reliability of the state's electrical supply;
- The projected demand for electric energy and the basis for determining the projected demand;
- All large electric generating facilities for which an electricity provider or merchant plant developer plans to commence construction within seven years;
- Existing and planned generation facilities that use renewable energy sources;
- All high-voltage transmission lines for which an electricity provider plans to commence construction within seven years;
- Whether sufficient electric capacity and energy will be available to the public at a reasonable price;
- Regional and national policy initiatives that may have direct and material impacts on Wisconsin's energy supply and delivery;
- The extent to which effective competition is contributing to a reliable, low-cost, and environmentally sound source of electricity for the public;
- The extent of Wisconsin's distributed energy resources in terms of technology, size and prevalence;
- Activities to discourage inefficient and excessive energy use;
- The ways in which electricity sales and investments impact customer rates and bills; and
- The rates and bills paid by Wisconsin ratepayers, and how these compare to neighboring states and the nation.

The SEA must also consider the public interest in economic development, public health and safety, protection of the environment, and diversification of energy supply sources.

Study Methodology and Limitation

Under statutory and administrative code requirements, every electricity provider and transmission owner must file specified historic and forecasted information. The draft SEA must be distributed to interested parties for comment. After hearing and receipt of written comments, the final SEA is issued. In addition, an Environmental Assessment, which includes a discussion of generic issues and environmental impacts, is to be issued 30 days prior to the public hearing.

The tenth SEA covers the years 2018 through 2024. During the data collection process, all Wisconsin-based investor-owned utilities, cooperatives, municipal electric utilities, and other electricity and transmission providers submitted historic and forecasted information regarding statewide demand, generation, out-of-state sales and purchases, transmission capacity, energy efficiency, and distributed energy resources. This information was analyzed and reviewed—along with other data—to create this document providing a broad look at the current and future state of Wisconsin's electrical system.

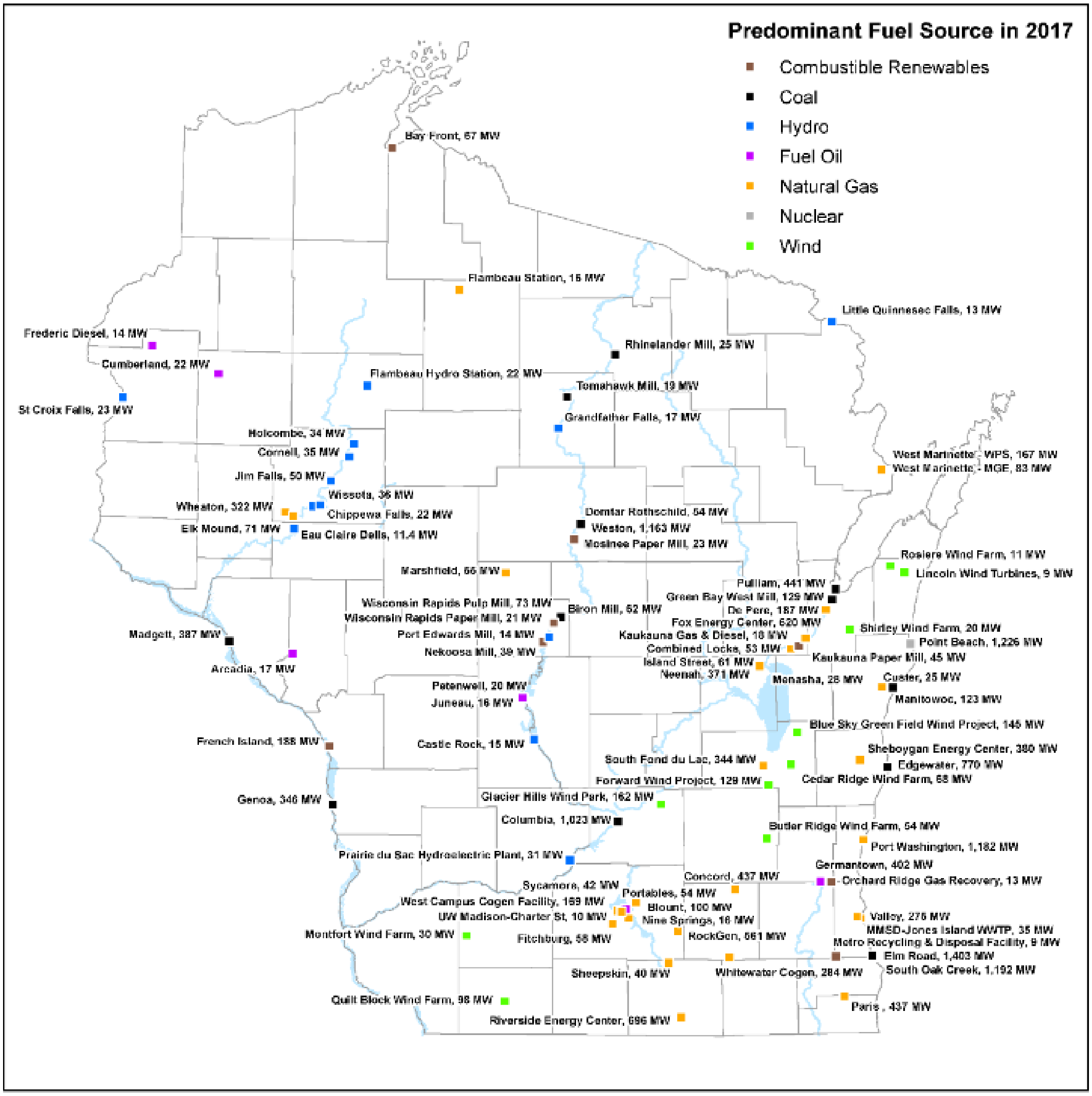
The SEA is an informational report that provides the public and stakeholders with information about relevant trends, facts, and issues affecting the state's electric industry. Under Wis. Stat. § 196.491(3)(dm), the SEA is not a prescriptive report, meaning that the ideas, facts, projects, and discussions contained in this report will not be used as the exclusive basis for ordering action by the Commission. Should a specific topic warrant further attention with the intent of Commission action, the Commission must take additional steps as authorized by law.

An electricity provider is defined for SEA purposes in Wisconsin Administrative Code as any entity that owns, operates, manages or controls; or who expects to own, operate, manage, or control; electric generation capacity greater than five megawatts (MW) in Wisconsin. Electricity providers also include entities that provide retail electric service or that self-generate electricity for internal use and sell any excess to a public utility.

The large entities submitting data for this SEA include: American Transmission Company LLC (ATC), Dairyland Power Cooperative (DPC), Great Lakes Utilities (GLU), Madison Gas and Electric Company (MGE), Manitowoc Public Utilities, Northern States Power-Wisconsin (NSPW) (d/b/a Xcel Energy (Xcel)), Superior Water, Light and Power Company (SWL&P), Wisconsin Electric Power Company (WEPCO) (d/b/a We Energies), Wisconsin Power and Light Company (WP&L) (d/b/a Alliant Energy), WPPI Energy (WPPI), and Wisconsin Public Service Corporation (WPSC). Smaller entities submitting data include all municipal utilities in Wisconsin with a Wis. Admin. Code ch. PSC 119 interconnection agreement for distributed generation resources.

DPC and WPPI provided data on behalf of their member cooperatives and municipal electricity providers. Large providers are required to include supply and demand data for any wholesale requirements that they have under contract, streamlining data reporting and reflecting current market activities. Figure 1 shows Wisconsin's existing generating facilities greater than nine MW.

Figure 1 Map of Electric Generation Facilities in Wisconsin (capacity greater than 9 MW)



EXECUTIVE SUMMARY

The Strategic Energy Assessment provides a unique opportunity for the Commission to address Wisconsin's electrical system at-large by looking at a wide range of issues.

This SEA incorporates some new elements, such as the Wisconsin perspective on the issues of grid modernization and cybersecurity, along with a discussion of the interconnected nature of electric sales, utility finances, electric rates, and the overall affordability of electric service. This SEA provides information on customer-owned generation, known as distributed energy resources (DER), building on data that made its debut in the previous SEA. The biggest changes to the SEA this year were mostly behind the scenes with a new online data collection system, and a data query tool providing public access to data filed for the SEA.

The following sections provide an overview of the contents of this report.

Adequacy and Reliability of Wisconsin's Electric Supply

- Data collected for the purposes of this SEA indicate that in general Wisconsin's planning reserve margins are expected to remain above the required planning reserve margin through 2024, although additional capacity may be necessary in 2019.
- Wisconsin exceeds the 7.8 percent planning reserve requirement[1] set by Midcontinent Independent System Operator, Inc. (MISO) for the 2017-2018 planning year.
- Electricity providers estimate increases in non-coincident demand peaks to be less than 0.5 percent annually for 2018-2024.
- Wisconsin's primary electric generation fuel source continues to be coal with approximately 51.4 percent of energy generated in Wisconsin from coal-fired facilities in 2016.
- The continued low cost of natural gas continues to change the generation mix proportions in the state.
- Wisconsin electric utilities estimate that they will retire approximately 2,100 MW of existing Wisconsin-based electric generation by 2024.
- Approximately 796 MW of new generation is expected to be added from 2018-2024.[2]

Transmission System Plans, Issues, and Developments

- The MISO reliability footprint consists of 15 states—including Wisconsin—and one Canadian Province. The Federal Energy Regulatory Commission's (FERC) Order 1000 requires coordination with neighboring regions, whether they are regional transmission organizations (RTO) or transmission planning regions. The Commission continues to work

[1] Unforced Capacity (UCAP) reserve margin requirement.
[2] This does not include 550 MW of anticipated capacity at the Nemadji Trail Energy Center proposed for 2025.

with MISO and other states to fully participate in this and other interregional processes and studies.

- The most recent MISO transmission expansion planning (MTEP) process contains 354 new projects totaling $2.7 billion in transmission facilities.
- On the 10-year planning horizon, MISO anticipates 6,129 miles of new or upgraded transmission lines.

Sales, Rates, and Affordability

- Since the last SEA, the rates section has been expanded to provide a broader context to Wisconsin's electric rates, such as what goes into rates, and how rates balance utility investment and sales when looking at the cost of electricity.
- Electricity sales in Wisconsin, and across the nation, are relatively flat. Contributors to flat sales may include energy efficiency and behind-the-meter peak shaving from distributed generation.
- Residential customers in Wisconsin with a median income pay a smaller percentage of their income on electricity costs than the national average, and fall in the middle of the range compared with neighboring Midwest states.

Energy Efficiency

- As of 2017, all of Wisconsin's investor-owned utilities (IOU) and municipal electric utilities participate in Focus on Energy (Focus), Wisconsin's energy efficiency program. The program also benefits from the participation of 13 electric cooperatives across the state.
- Focus offers energy efficiency support through multiple programs geared toward different customer types, from residential homeowners to farms, small businesses, and industrial facilities.
- In 2016, Focus created net economic benefits of $348 million and achieved $4.32 in benefits for every $1.00 in costs.

Renewable Resources

- Wisconsin's Renewable Portfolio Standard (RPS)[3] required that approximately 10 percent of all electricity sales in Wisconsin come from renewable resources by 2015. Sales of electricity from renewable resources surpassed 10 percent for the first time in 2013 and projections show this goal will continue to be met through at least 2024.

[3] Wis. Stat. § 196.378.

Grid Modernization

- Grid Modernization does not have a universal definition, but its core tenets revolve around the convergence of evolving customer needs and expectations, combined with the emergence of new technologies in the existing electric distribution system.
- In Wisconsin to date, grid modernization's focus is on ensuring the electric system continues to be safe and reliable, while being ready, as needed, to adapt quickly to changing technologies and customer desires and expectations.
- The Commission is working collaboratively with energy providers and stakeholders to identify areas of consensus on grid modernization projects particularly in the areas of safety and reliability, innovative rate design, advanced metering and customer information systems, and the interconnection of distributed energy resources.

Cyber and Physical Security

- To address the larger threat posed by breaches in cybersecurity, the Commission is working with the Wisconsin Department of Military Affairs and other state agencies to conduct large-scale, multi-state, and multi-disciplinary exercises to practice emergency responses to a wide-scale disruption of electric power and conventional communications systems.
- Wisconsin Emergency Management (WEM) led the State agencies in the November 2017 National GridEx IV exercise sponsored by the North American Electric Reliability Corporation (NERC) in a simulation exercise for large cyber/physical attacks on the critical infrastructure of the North America Bulk Electric System and other critical infrastructure sources. In May 2018, WEM followed up by conducting a similar Dark Sky exercise focused on Wisconsin electric and fuel systems. The full-scale exercise was based on the Wisconsin Threat and Hazard Identification and State Preparedness Report.

Distributed Energy Resources

- The Commission continues to collect information from utilities about Distributed Energy Resources (DER) in Wisconsin. This effort provides the Commission and other stakeholders with information about the amount of DER capacity and energy in the state. Wisconsin is currently working with the Organization of MISO States (OMS) on a MISO-wide survey to better understand the increasing rate of DER and its potential impact on the electrical grid system.
- Sixty-seven percent of the state's IOUs and 78 percent of the municipal electricity providers report at least one DER installation in their service territories.
- The growing numbers of DER installations speaks to the changing nature of Wisconsin's electrical system, but continues to represent less than 1 percent of total sales to customers in the state.

ADEQUACY AND RELIABILITY OF WISCONSIN'S ELECTRIC SUPPLY

This section of the SEA provides an assessment of Wisconsin's electric industry as required by Wis. Stat. § 196.491(2)(a). Specifically, the Commission is directed to evaluate the adequacy and reliability of the state's current and future electrical supply, including:

- The extent to which the regional bulk power market is contributing to the adequacy and reliability of the state's electrical supply;
- The adequacy and reliability of purchased generation capacity and energy to serve the needs of the public;
- The extent to which effective competition is contributing to a reliable, low cost, and environmentally sound source of electricity for the public; and
- Whether sufficient electric capacity and energy will be available to the public at a reasonable price.

This assessment is prepared with data filed by Wisconsin's electric service providers and other datasets, as appropriate.

Regional Bulk Power Market and Electric System Adequacy and Reliability

Forecasts indicate that in general Wisconsin will maintain an adequate and reliable electric supply with an acceptable planning reserve margin (PRM) through 2024. Current projections indicate that based on currently forecasted new and existing generation assets, Wisconsin's aggregate unforced capacity (UCAP) PRM will fall below MISO's current UCAP PRM of 7.8 percent for 2019. If these forecasts prove correct, Wisconsin's utilities may need to secure additional capacity, possibly in the form of a PPA.

MISO calculates the PRM to reduce the probability of losing load during peak conditions. This is usually expressed as a percent of capacity greater than the projected demand. Capacity includes both Wisconsin-based generation and generation owned or purchased by a Wisconsin utility but located outside of the state.

The PRM is an important component of the overall forecasted reliability of the electricity system in Wisconsin, as well as the obligations of the state's electricity providers to MISO. In docket 5-EI-141, the Commission set a planning guideline of 14.5 percent, Installed Capacity (ICAP) rating for a long-range PRM. The two PRM benchmarks, Wisconsin's and MISO's, are described below.

As part of its annual transmission expansion planning, MISO conducts an analysis of expected PRMs for its footprint based on loss of load expectations (LOLE). The LOLE is the result of an annual study for the next planning year with a goal to achieve a probability of losing firm load one day in 10 years, or 0.10 days per year as set by guidelines from North American Electric Reliability Corporation (NERC). Wisconsin is part of the greater MISO market and transmission planning effort. The nature of the bulk electric system is such that diversity of the footprint allows the sharing of resources to lower the PRM. MISO is divided into Local Resource Zones (LRZ) to provide balance across the footprint. Wisconsin is located in MISO's Zones One and Two.

The Commission currently requires that each electricity provider meet the planning reserve measurement process under Module E-1 of MISO's transmission tariff. For the 2017-2018 Planning Year, MISO requires a planning ICAP reserve margin of 15.8 percent and a planning Unforced Capacity (UCAP) reserve margin of 7.8 percent.

Table 1 shows that the 2017 Wisconsin PRM is 13.9 percent (UCAP). This indicates that Wisconsin is forecasted to maintain an adequate and reliable electric supply, even with the preliminary, projected growth in summer peak demand. As previously discussed, the PRM is expected to remain above the required reserve margin through 2024, although additional capacity may be necessary in 2019. These adequate PRMs are a result of a strong generation construction program beginning in the late 1990s, effective energy efficiency and conservation programs, and low-to-moderate demand and energy growth.

Table 1 Forecast Planning Reserve Margins from SEA (%)
Forecast Reserve in ICAP through 2014 and UCAP in 2016 and 2018[4, 5]

Planning Year	Final SEA 2000	Final SEA 2002	Final SEA 2004	Final SEA 2006	Final SEA 2008	Final SEA 2010	Final SEA 2012	Final SEA 2014	Final SEA 2016	Final SEA 2018
2001	18.0									
2002	17.4									
2003		19.1								
2004		20.9	18.3							
2005			17.4							
2006			15.0							
2007			16.1	18.2						
2008			12.8	18.9	30.9					
2009			10.0	16.4	16.3	11.7				
2010			11.0	17.5	18.7	24.1				
2011				17.2	20.9	26.1	6.6			
2012				17.4	18.5	25.8	7.3			
2013					14.4	24.9	21.9			
2014					11.0	20.1	15.8	20.5		
2015						18.7	15.8	18.9		
2016						15.1	13.0	17.3	16.9	
2017							11.6	15.3	13.9	
2018							13.3	13.7	13.7	12.0
2019								14.3	16.4	5.9
2020								13.8	15.5	8.2
2021									14.7	9.0
2022									13.6	9.2
2023										7.8
2024										6.4

Note: The SEA was expanded to cover seven years of forecast data in 2004; prior SEAs only examined two years. UCAP refers to the generator tested capacity multiplied by 1 - Equivalent Generator's Forced Outage Rate.

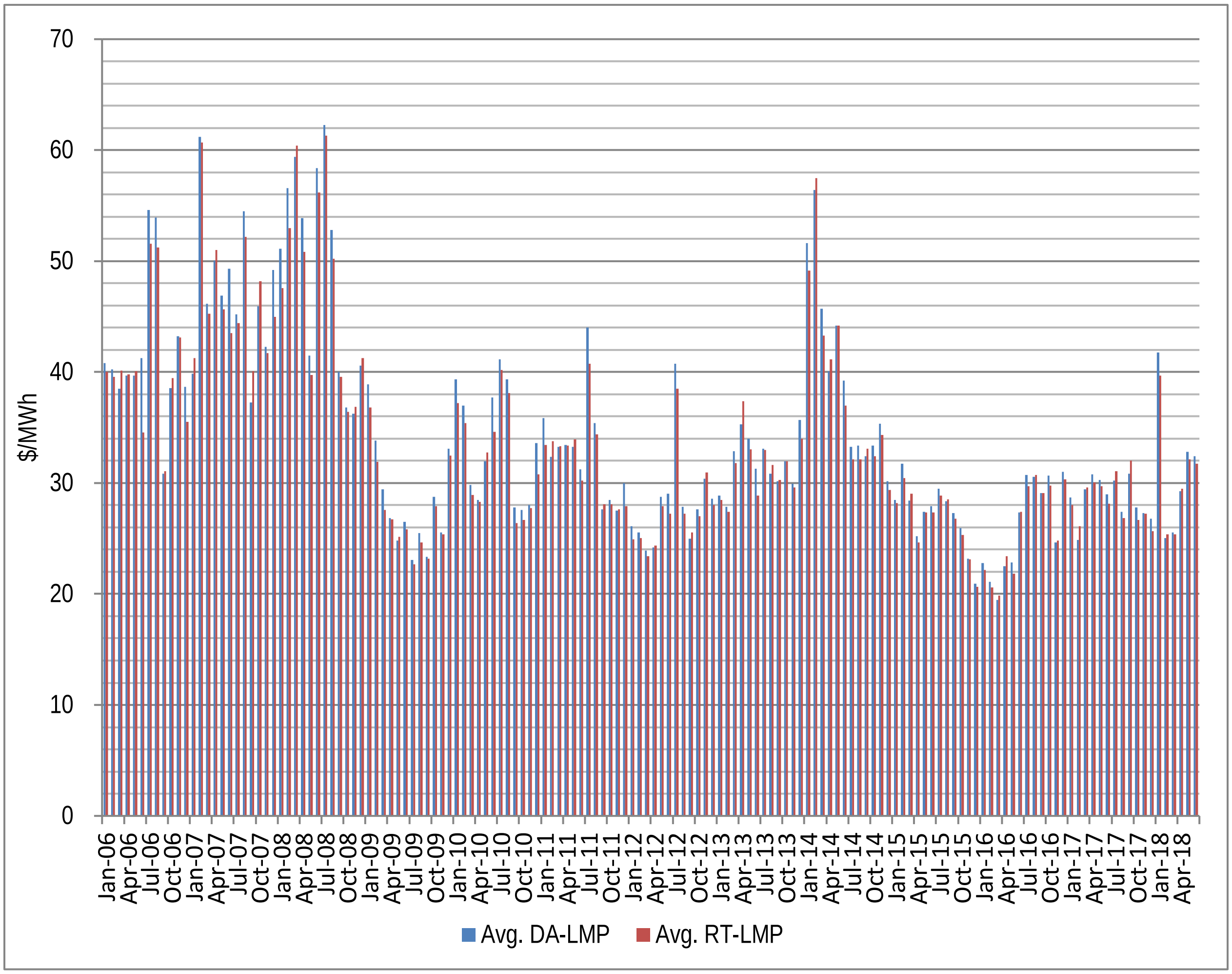
[4] The SEA was expanded to cover seven years of forecast data in 2004; prior SEAs examined two years.

[5] Source: Table 3 and previous SEA reports.

Effective Competition and Reliable, Low Cost, and Environmentally Sound Electricity Sources

While other sections of this SEA address reliability, this section focuses on statutory requirements related to low-cost and environmentally-sound electricity sources. The MISO wholesale energy market sets day-ahead and real-time prices for energy on a location-by-location basis throughout the area served by MISO participants. All of Wisconsin's electricity providers participate in MISO's wholesale energy market. For a broader view of the complete MISO market, Figure 2 displays wholesale energy market prices in MISO since the start of the market in 2006.

Figure 2 MISO System-Wide Average Monthly Day-Ahead and Real-Time Locational Marginal Pricing (LMP) ($/MWh)[6]



[6] Source: Commission staff, using data from the MISO portal.

A June 2018 report by MISO's independent market monitor (IMM), entitled *2017 State of the Market Report for the MISO Electricity Markets,*[7] provided evidence that MISO's wholesale energy markets were competitive, with market clearing prices nearly identical to the IMM's estimated reference-level marginal costs with a price-cost mark-up that was "effectively zero" in 2017[8]. The IMM also concluded that the marketplace experienced appropriate price convergence, with minor output withholding (only 0.11 percent of actual load) which is *de minimus*. Consequently, market power mitigation measures were applied infrequently.[9] These values, in conjunction with the average wholesale energy price during 2017 ($29.4.6/MWh) shows that the MISO wholesale energy market is competitive.

The final topic in this section is an assessment of whether competitive markets[10] are contributing to an environmentally sound source of electricity for the public. According to conventional economic theory, competitive markets will consider all direct economic costs and any indirect costs associated with externalities, such as pollutants, that have been regulated or monetized. In cases where legitimate externalities have not been factored in via allowances, taxes, non-compliance fines, or direct regulation, any non-private costs associated with such externalities are ignored. There may be some exceptions, for example, where the public may be willing to pay a premium for goods or services that are perceived to be environmentally superior.

Whenever new externalities are recognized by public policy, the resulting market clearing prices will be higher. For example, the effect of proposed environmental regulations may mean higher electricity prices in Wisconsin. Whether such price increases are attenuated to any extent by effective wholesale market competition is yet to be determined. The implementation and effects that might occur in the MISO wholesale energy markets are not yet known, pending the resolution of legal and administrative challenges. Conventional economic theory indicates that if such a policy were already generating a least-cost source of electricity, private business would have implemented such action already. Because public policy is the driver in this economic relationship, prices are expected to increase for electricity. Increases in the price of electricity may change consumption patterns and usage of electric energy. Dispatch of generator units will change accordingly, and preferred technologies will emerge. Basically, compliance costs will be incurred by all MISO market participants.

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[7] https://cdn.misoenergy.org/2017%20State%20of%20the%20Market%20Report242952.pdf .

[8] *Ibid.*

[9] *Ibid.*

[10] Wisconsin Stat. § 196.491(2)(a)12. does not specifically identify what "effective competition" means. Since Wisconsin does not have retail competition, the Commission considers the impacts of the wholesale energy market operated by MISO. This does not indicate that the Commission believes that all markets operated by MISO provide "effective competition."

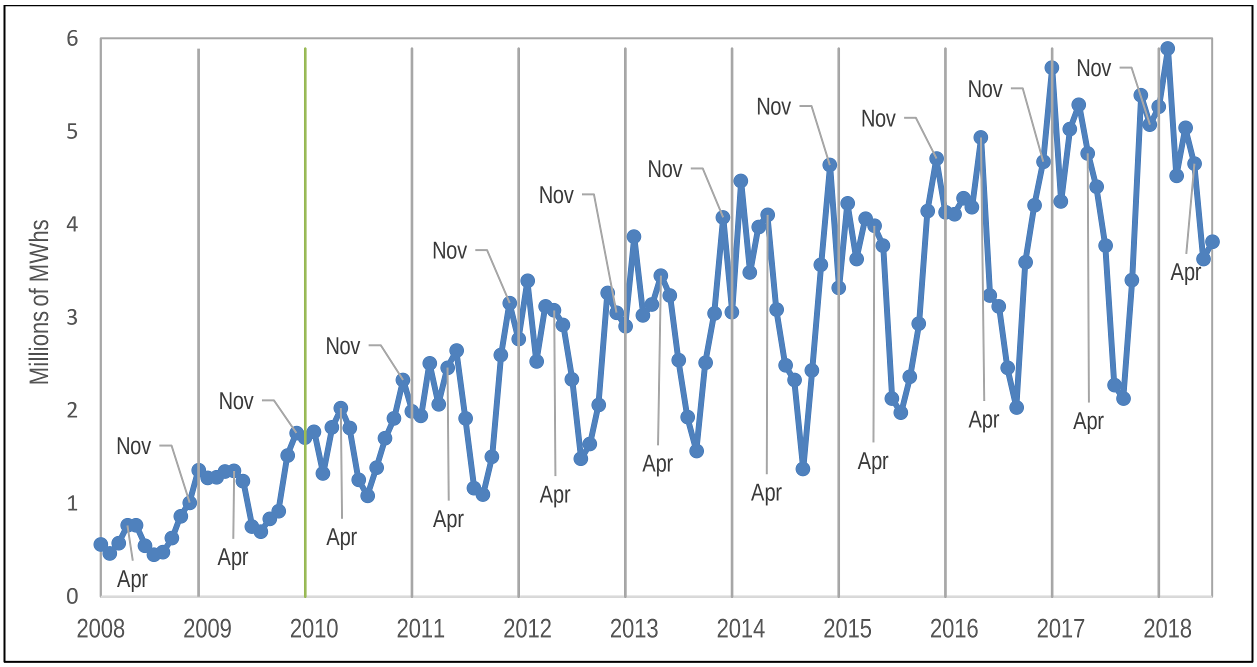
Assessment of Whether Sufficient Electric Capacity and Energy will be Available to the Public at a Reasonable Price

Load Serving Entities (LSE) anticipate new electric generation and purchases to assist in maintaining sufficient capacity through 2024. Regarding reasonable prices, the Commission reviews purchase power contracts for public utilities during rate and fuel cases.[11] The Commission also reviews and verifies that costs associated with new generation that will be rate-based pass an appropriate cost-effectiveness threshold.

The prior section noted the competitiveness of pricing in wholesale energy markets operated by MISO. According to the federal Energy Information Administration[12] the all-in, or levelized, cost of wind energy is $48/MWh, a lower cost resource than natural gas or nuclear generation. The presence of wind energy in the MISO footprint is growing (figure 3), as well as its variability due to changes in seasonal weather. Figure 4 shows the percentage of energy in the MISO footprint coming from wind resources.

The Commission's review process, along with the increasing amount of low-cost resources in the MISO footprint leads the Commission to conclude that capacity and energy will continue to be available at a reasonable price.

Figure 3 MISO Monthly Wind Generation in Millions MWh through June 2018[13]



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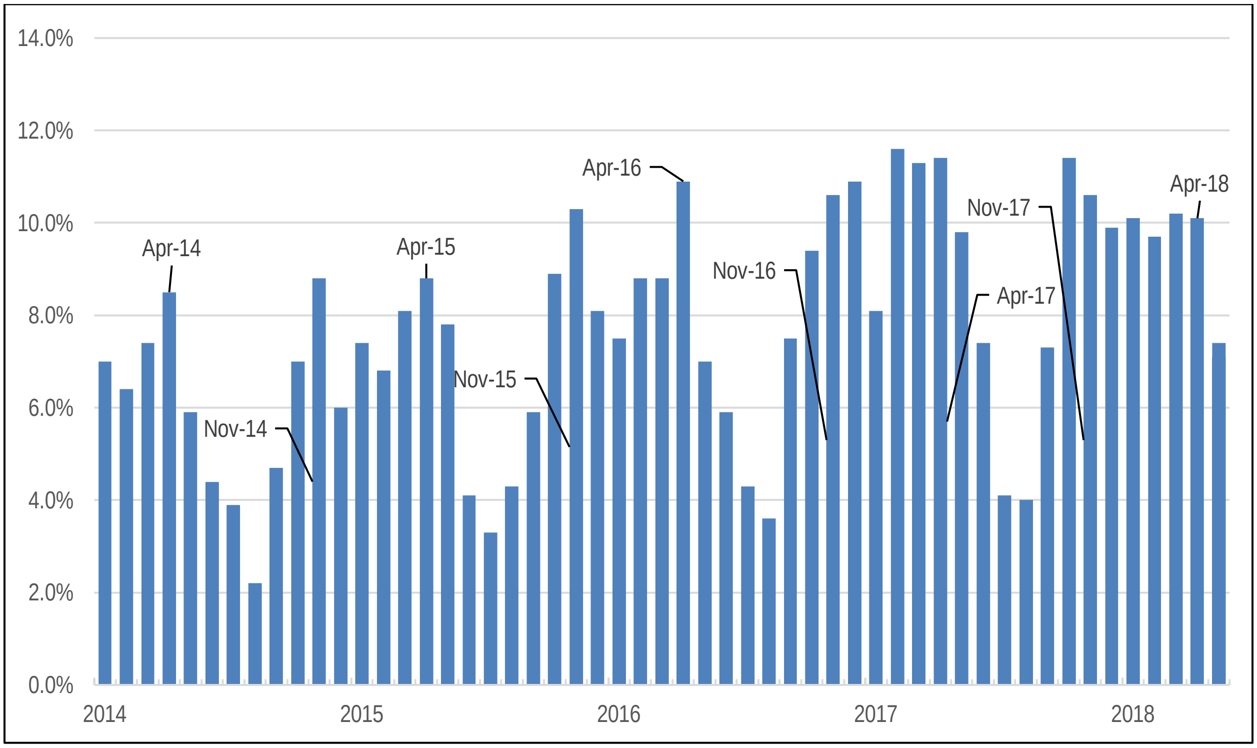
[11] This statement applies to utilities under the Commission's ratemaking jurisdiction. DPC is not under the Commission's jurisdiction and relies on its cooperative members to assess reasonable price.

[12] Source: "Levelized Costs and Levelized Avoided Cost of New Generation Resources," EIA, March 1, 2018, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[13] Source: www.misoenergy.org.

Figure 4 Wind Energy as Percent of MISO Footprint-Wide Energy 2014–2018[14]



Utilities' Perspectives – Peak Demand and Supply

Demand

Demand is a measure of the instantaneous rate of electricity use measured in MW. The volume of electricity used is measured over time and expressed in megawatt hours (MWh).

Demand for electricity fluctuates both throughout the day and throughout the year. In any day there are peak hours of demand. In the summer, the demand usually has one peak in the afternoon hours. In the winter, it is common to have morning and evening peaks. Over the course of a year, demand for electricity is traditionally higher in the summer, lowest in the spring and autumn "shoulder" months, and smaller peaks occur in the winter. These peaks have been shifting to "shoulder" months due to changes in weather, technology, and demand.

Table 2 shows the actual, aggregated peak electric demand and supply for Wisconsin electricity providers from 2015 through 2017. Wisconsin electricity providers maintained sufficient reserves to meet the summer peak in recent years.

[14] Source: www.misoenergy.org.

Table 2 Wisconsin Aggregated Historic Supply and Demand[15]

Wisconsin Peak Electric Demand (MW)	2015	2016	2017
Date of Peak Load	July 18	August 3	June 12
Peak Load Data and Forecast (non-coincident)	13,228	13,803	13,190
Direct Load Control Program	(56)	(56)	(10)
Interruptible Load	(54)	(86)	(34)
Capacity Sales Incl. Reserves	922	863	703
Capacity Purchases Including Reserves	(685)	(680)	(565)
Miscellaneous Demand Factors	0	0	0
Adjusted Electric Demand	13,356	13,845	13,285
Electric Power Supply (MW)			
Owned Generating Capacity (in, or used, for Wis. customers)	14,147	14,192	14,375
Merchant Power Plant Capacity Under Contract (in, or used, for Wis. customers)	1,847	1,852	1,924
New Owned or Leased Capacity\Additions	0	33	-6
Net Purchases W\O Reserves	39	45	227
Miscellaneous Supply Factors	(103)	(42)	(231)
Electric Power Supply	15,930	16,080	16,289
Transmission Data (MW)			
Resources Utilizing PJM/WUMS-MISO Interface	590	601	590

Table 3 shows the forecasted aggregated peak electric demand, supply and anticipated UCAP planning reserve level for the years 2018 through 2024. As with the last SEA, data collected were consistent with the MISO planning reserve methodology. As noted above, the MISO planning methodology uses multiple LRZs to take advantage of the diversity of the footprint and keep individual LSEs from over-relying on the market for too much capacity that would not be deliverable to load at system peak. Table 3 is an estimate that re-aligns the multiple zones that the Wisconsin utilities serve, send to, or receive capacity load from. The summary table indicates that Wisconsin utilities will meet suggested planning reserve requirements through 2024, although some additional purchases may be necessary in 2019.

[15] Source: Aggregated electricity provider data responses, docket 5-ES-109.

Table 3 Wisconsin Aggregated Forecasted Supply and Demand[16]

Report Line MISO Description	2018	2019	2020	2021	2022	2023	2024
Capacity (MW)	Unforced Capacity Capability (UCAP)[1]						
High Certainty Resources (not including registered behind the meter generation, below)	14,224	14,075	14,099	14,122	14,126	14,126	14,126
Low Certainty Resources	-	5	5	-	-	-	-
Behind the Meter (Receiving MISO capacity credit)	380	348	348	336	336	336	336
Demand Response Resources plus Registered Demand-Side Management	906	979	979	984	985	985	985
New Capacity	42	108	544	763	860	860	860
LRZ Internal Transfer-In	2,465	2,248	1,948	2,054	2,045	1,679	1,679
LRZ Internal Transfer-Out	(981)	(1,066)	(664)	(793)	(793)	(588)	(588)
Net Imports	363	362	351	372	372	372	372
Retired	(1,522)	(2,035)	(2,213)	(2,227)	(2,234)	(2,240)	(2,397)
Net Capacity (MW)	15,878	15,023	15,397	15,610	15,697	15,530	15,373
Demand (MW)							
Non-Coincident LSE Peak gross of DR (equals MISO survey)	14,508	14,542	14,578	14,675	14,727	14,846	14,889
Full Responsibility Transactions (FRT)	(235)	(235)	(240)	(243)	(244)	(169)	(169)
Zonal Coincident Factor (average of all LSEs)	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Coincident LSE Peak with Zonal Peak gross of DR Net FRT (a coincident weighted sum of individual LSEs)	14,071	14,099	14,138	14,235	14,285	14,315	14,363
MISO Coincident Factor (average of all LSEs)	0.9568	0.9558	0.9558	0.9558	0.9558	0.9558	0.9558
Coincident LSE Peak to MISO Peak gross of DR Net FRT (a coincident weighted sum of individual LSEs)	14,179	14,190	14,229	14,326	14,376	14,403	14,451
Reserve Requirement (MW)							
Local Clearing Requirement	9,674	12,392	12,643	12,716	12,748	12,788	12,830
Planning Reserve Requirement	15,269	15,276	15,318	15,427	15,485	15,519	15,571
Average UCAP Planning Reserve Margin Requirement per unit	1.08	1.08	1.08	1.08	1.08	1.08	1.08
Resources above Local Clearing Requirement	6,204	2,631	2,754	2,895	2,949	2,742	2,544
Resource above Planning Reserve Requirement	609	(253)	79	183	212	11	(198)
UCAP Planning Reserve Margin[2] (%)	12.0%	5.9%	8.2%	9.0%	9.2%	7.8%	6.4%

[1] UCAP refers to the generator tested capacity multiplied by 1 - Equivalent Generator's Forced Outage Rate.
[2] MISO's required UCAP PRM of 7.8 percent per LOLE study is only required for the next planning year; 2018-2019 for this assessment.

Table 4 shows historic non-coincident monthly peaks since 2003 and forecasted non-coincident monthly peak demand, in MW.[17] Non-coincident peak demand refers to the sum of each electricity provider's monthly peak load, which does not necessarily occur on the same days or hours. Data presented in Table 2 through 4 do not necessarily correlate because different electricity providers may have different months in which their highest peak occurs. Table 2 and Table 3 show the combined total of each electricity provider's maximum peak within the year, while Table 4 shows the maximum non-coincident demand within each month.

[16] Source: Aggregated electricity provider data responses, docket 5-ES-109.
[17] These are electricity provider forecasts; Commission staff does not conduct an independent demand or energy forecast.

Table 4 Assessment of Electric Demand and Supply Conditions, Monthly Non-Coincident Peak Demands, MW[18]

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Historical:												
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	10,726	10,157	9,601	9,007	9,910	12,993	13,089	12,340	13,000			
Forecasted:												
2017										9,837	10,211	10,804
2018	10,853	10,487	10,039	9,340	10,467	13,061	14,300	14,026	12,436	9,763	10,158	10,772
2019	10,831	10,468	10,015	9,380	10,489	13,104	14,333	14,055	12,457	9,772	10,160	10,766
2020	10,846	10,485	10,035	9,402	10,523	13,143	14,373	14,100	12,498	9,790	10,188	10,790
2021	10,878	10,516	10,064	9,431	10,563	13,188	14,418	14,153	12,542	9,838	10,215	10,821
2022	10,905	10,542	10,094	9,549	10,604	13,237	14,470	14,212	12,589	9,858	10,247	10,852
2023	10,938	10,579	10,127	9,492	10,652	13,293	14,529	14,278	12,644	9,894	10,281	10,888
2024	10,972	10,609	10,159	9,526	10,696	13,347	14,584	14,341	12,694	9,930	10,315	10,921

Traditionally, as shown in Table 4, the maximum non-coincident peak demand is highest in the summer (June, July, and August), with a smaller peak in the winter (December, January, and February). While actual demand remains weather-dependent, the non-coincident peak demand is expected to increase by less than 0.5 percent annually from 2018 to 2024. The large increase from 2017 to 2018 is attributable to less extreme temperatures in 2017 and is part of the shift to higher peaks in the "shoulder" months. The non-coincident monthly peak demand forecast provided in this SEA shows less demand growth than what was forecast in the last SEA, docket 5-ES-108.

Programs to Control Peak Electric Demand

Peak load management involves removing load from the system at times when electricity provider resources for generation are not able to meet customer demand for energy. These programs were traditionally expected to be used primarily in the summer months, usually on very hot days when demand for electricity is at its highest. However, under certain circumstances, when the winter peak

[18] Source: Aggregated electricity provider data responses, docket 5-ES-109.

demand for electricity has outpaced available generation, these programs have been used to assure a balance between demand and available supply.[19]

Wisconsin electricity providers have two primary mechanisms for managing their peak demand: curtailment by direct load control and tariffs that establish interruptible load. Direct load control gives electricity providers the ability to turn off specific equipment at certain times, such as residential air conditioners, at certain times to reduce load on the system. When electricity providers implement direct load control, affected customers who volunteered to participate in the program receive a credit on their bill. An industrial customer choosing an interruptible load tariff receives a lower electric energy rate in cents per kilowatt-hour (kWh) by agreeing to allow the electricity provider to interrupt load during periods of peak demand on the system. Typically, the electricity provider notifies each industrial customer on an interruptible load tariff before its load is taken off the system.

The need to utilize load control programs depends upon the generation supply that is available on the days when peak demand occurs. Curtailment can occur on extremely hot summer days, or days when available generation is limited due to planned or unexpected (forced) outages. If available load control programs were fully subscribed, this would represent approximately 6.0 percent of projected electric generating capacity in Wisconsin in 2024. Historically, these numbers have been closer to 3.5 percent of the total capacity.

Table 5 shows the total load (in MW) actually subscribed or forecast to be subscribed to direct load control or interruptible tariffs since 2003. The amount of load that is actually interrupted in any given year has historically been much less than the available load covered by these programs. For example, from 2015 through 2017, up to 56 MW of direct load control were called upon, which is less than half of the load available. The change in the relative size of MWs over time in each column has to do with the newer reliability definitions used in the MISO reliability assessment.

[19] This is a general summary of how peak load management is used, though different electricity providers address the issue differently.

Table 5 Available Amounts of Programs and Tariff to Control Peak Load, MW[20]

Year Historical	Direct Load Control Available (MW)	Direct Load Control Used (MW)	Interruptible Load Available (MW)	Interruptible Load Used (MW)
2003	186	86	554	251
2004	193	40	629	265
2005	225	37	693	315
2006	282	99	830	243
2007	246	88	776	164
2008	222	51	707	0
2009	170	31	597	20
2010	202	53	689	16
2011	230	108	842	179
2012	203	84	632	188
2013	144	62	667	152
2014	130	73	598	158
2015	132	56	760	54
2016	135	56	796	86
2017	131	10	667	34
Forecasted				
2018	53		853	
2019	53		853	
2020	54		869	
2021	54		870	
2022	54		870	
2023	54		870	
2024	54		870	

Summer Peak Demand

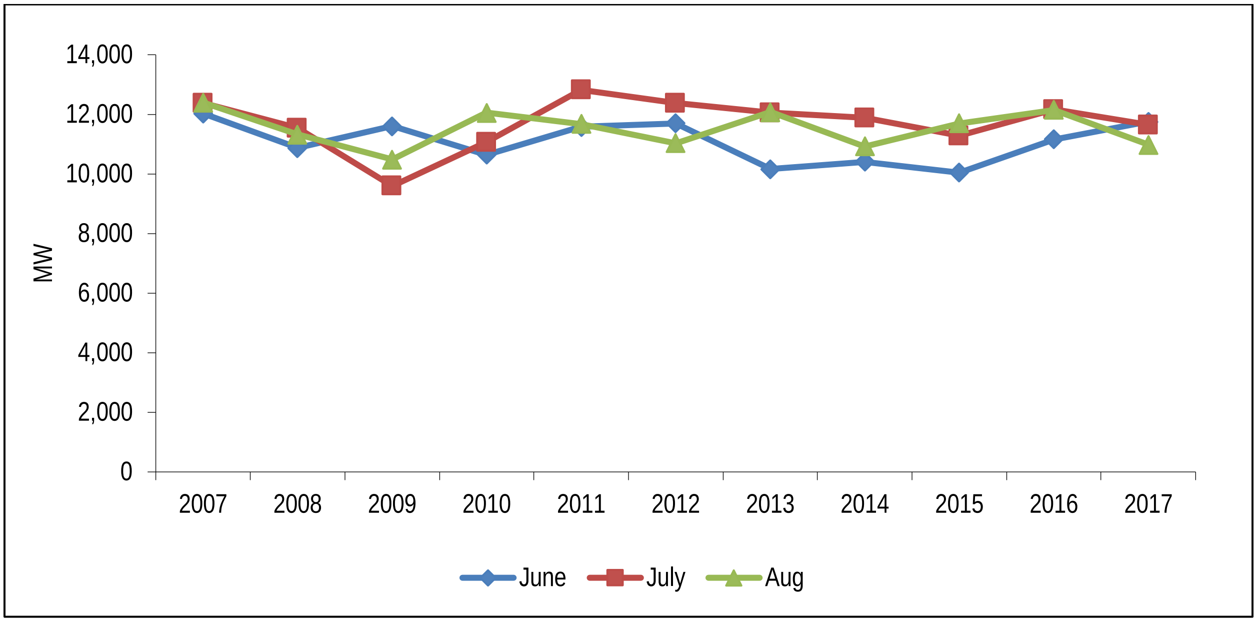
Figure 5 shows the maximum coincident summer peak demand (June, July, and August) since 2007 on ATC's transmission system, which serves a majority of the load in Wisconsin. "Shoulder" periods in the spring and autumn generally have more temperate weather conditions, resulting in lower residential cooling or heating loads, so they will not tend to have peak load demands. Summer periods traditionally have the largest load demands, so they can serve as an indicator for overall load growth in the state.

The summer peak is dependent on temperature and humidity because these weather conditions affect air conditioner load. Air conditioning requires significant electric power, so there is a correlation between warmer temperatures and higher electric loads. Data shown in Figure 5 are actual peak demand and are not weather-normalized. Summer peak demand, while variable, has not increased over the past 10 years.

[20] Source: Aggregated electricity provider responses, docket 5-ES0-109, and previous SEA reports.

Flat load growth in the state is primarily responsible for the flattened ATC summer peaks in recent years. Direct load controls, interruptible tariff programs, energy efficiency and distributed generation may also be contributing factors.

Figure 5 Monthly Summer Coincident Peak Demand – ATC[21]



Winter Peak Demand

Figure 6 shows the maximum coincident winter peak demand (December, January, and February) on ATC's transmission system since 2007. Historically, the maximum winter peak occurred in December—likely due to holiday lighting—but in recent years the winter peak shifted to January, possibly due to more efficient lighting. The sharp increase in 2014 is attributable to an unusually cold winter.

Winter load is also attributable to home heating requirements, with electricity used either directly (electric heating) or indirectly (electric power used in conjunction with heating equipment fueled by other sources). About 15 percent of Wisconsin homes use direct electric heating while 65 percent of homes use natural gas heating,[22] which can include electric fans or blowers to circulate the heat from the natural gas furnace. The winter peak is about 80 to 90 percent of the summer peak for Wisconsin electricity providers.

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[21] ATC Hourly Load Data from http://www.atcllc.com/oasis-directory/. ATC Disclaimer: This load is the total of daily/hourly loads provided by MGE, Upper Peninsula Power Company, We Energies, WPPI, WP&L, and WPSC. The load excludes any duplication of load reported between the entities. These values are not updated for load adjustments that occur over time.

[22] American Community Survey, 2016 ACS 5-year estimate, Table B25040: House Heating Fuel, www.factfinder.census.gov.

Flat or decreasing demand in recent years may be partially attributable to warmer-than-average winter seasons. Warmer temperatures require less overall heating, reducing electric demand.

Figure 6 Monthly Winter Coincident Peak Demand – ATC[23]

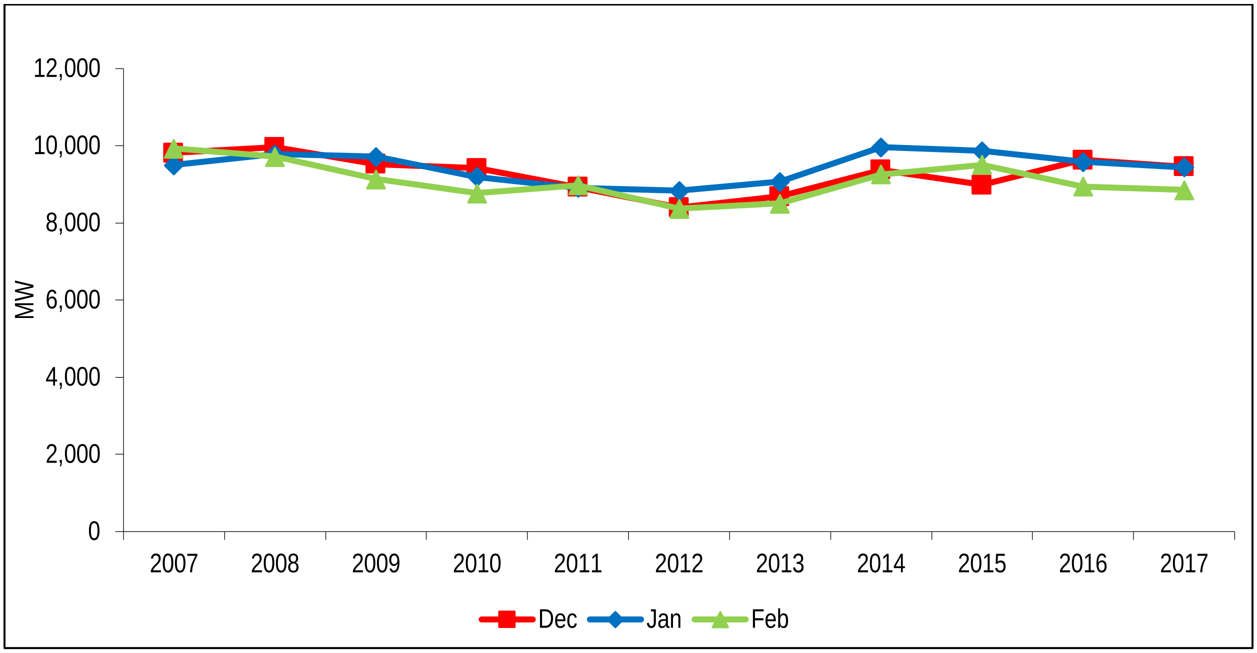
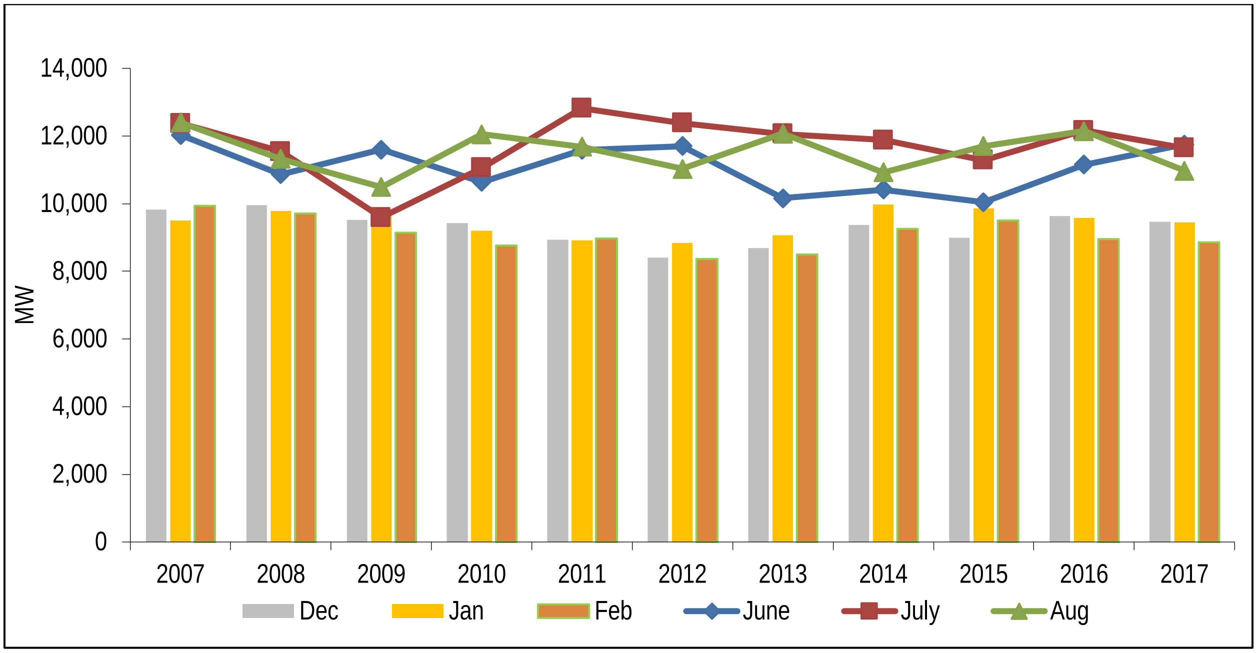


Figure 7 shows a comparison between the summer and winter seasonal peak demands, demonstrating the overall lower winter peak demands and the relatively flat trends for demand growth in the state over the past 10 years.

[23] Source: ATC Hourly Load Data from http://www.atcllc.com/oasis-directory/. ATC Disclaimer: This load is the total of daily/hourly loads provided by MGE, Upper Peninsula Power Company, We Energies, WPPI, WP&L, and WPSC. The load excludes any duplication of load reported between the entities. These values are not updated for load adjustments that occur over time.

Figure 7 Seasonal Coincident Demand Peak Comparisons – ATC[24]



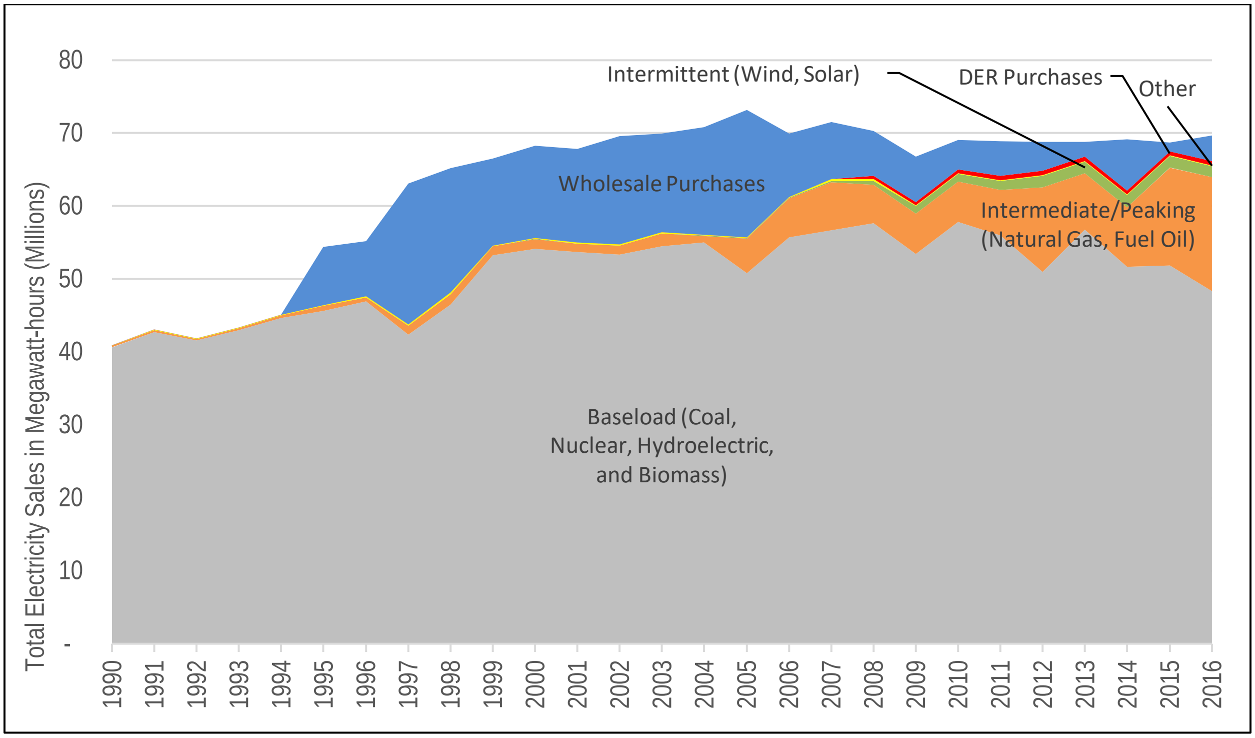
Peak Supply Conditions – Generation

Historical Energy Mix

A diverse yet balanced mix of energy resources is crucial to the safe, reliable and affordable supply of electricity and provide Wisconsin's electric service providers with the ability to serve customers. Figure 8 shows a breakdown of Wisconsin's energy mix by type of generation for the years 1990 to 2016.

[24] Source: ATC Hourly Load Data from http://www.atcllc.com/oasis-directory/. ATC Disclaimer: This load is the total of daily/hourly loads provided by MGE, Upper Peninsula Power Company, We Energies, WPPI, WP&L, and WPSC. The load excludes any duplication of load reported between the entities. These values are not updated for load adjustments that occur over time.

Figure 8 Wisconsin Electricity Generation as a Portion of Total Sales, by Type of Generation[25]



Note: Wholesale purchases are estimated by subtracting total in-state energy produced from total retail sales. Total sales prior to 1995 are not available, so no wholesale purchases are estimated for that period. In-state energy produced is shown for the period prior to 1995 to provide context to overall trends in the generation mix.

Hydroelectric, nuclear, coal, and combustible biomass remain baseload resources, and account for 69 percent of energy sold in 2016, compared to 80 percent in 2006. The trend toward fuel diversity can be attributed to sustained, low cost for natural gas and changes in regulation.

From 2010 to 2016, Wisconsin's total energy sales are relatively flat, holding steady around 68.7 million MWh per year, following the economic volatility of the 2008 recession.

Table 6 Type of Generation, millions of MWhs[26]

Year	Baseload	Intermediate and Peaking	Intermittent	Net Purchases	Total Sales
2006	55.7	5.4	0.1	8.8	70.0
2016	48.4	15.6	1.5	4.2	69.7

[25] Source: Utility annual reports filed with the Commission, the federal Rural Utility Service, US Energy Information Administration, compliance data filed with the Commission for the Renewable Portfolio Standard, and distributed energy resource data from SEA2024.

[26] Source: Utility annual reports filed with the Commission and the federal Rural Utility Service, US Energy Information Administration, compliance data filed with the Commission for Wisconsin's RPS, and distributed energy resource data from SEA2024.

A comparison of the percent of energy sales by generation type in year 2006 and 2016, shown in Table 6, highlights the transition of natural gas-fired generation from a fuel used primarily for peaking generation in 2006 to primarily intermediate generation in 2016. This transition is most likely due to a combination of low natural gas prices and a reduction of baseload energy produced over the period. If prices remain low in the coming years, natural gas could transition to a baseload energy resource in the future.

The wholesale purchases generation type represents all net purchases, and includes out-of-state purchases either to meet demand or to comply with Wisconsin's RPS requirements. The reduction in net purchases in 2016 compared to 2006 is likely due to Wisconsin's increased export of energy from conventional sources and flat demand. Increased export of conventional generation sources partially contributes to the offset of renewable imports into the state.

Energy generated from intermittent resources is steadily increasing, but accounts for less than 3 percent of energy sold in 2015.

Current Generation Fleet

Figure 9 shows the in-state generation[27] resources operated by electricity providers as of January 2018. The totals indicate in-service nameplate and uprate capacity (MW), by fuel source. Approximately 45 percent of Wisconsin's nameplate capacity is coal-fired, with natural gas combustion turbine and combined cycle facilities providing 37 percent of Wisconsin's nameplate capacity. The generation capacity fuel mix in Wisconsin is largely unchanged since the last SEA.

[27] Does not include generation outside of Wisconsin.

Figure 9 Wisconsin Electricity Generation Capacity by Fuel Source, January 2018 (MW)[28]

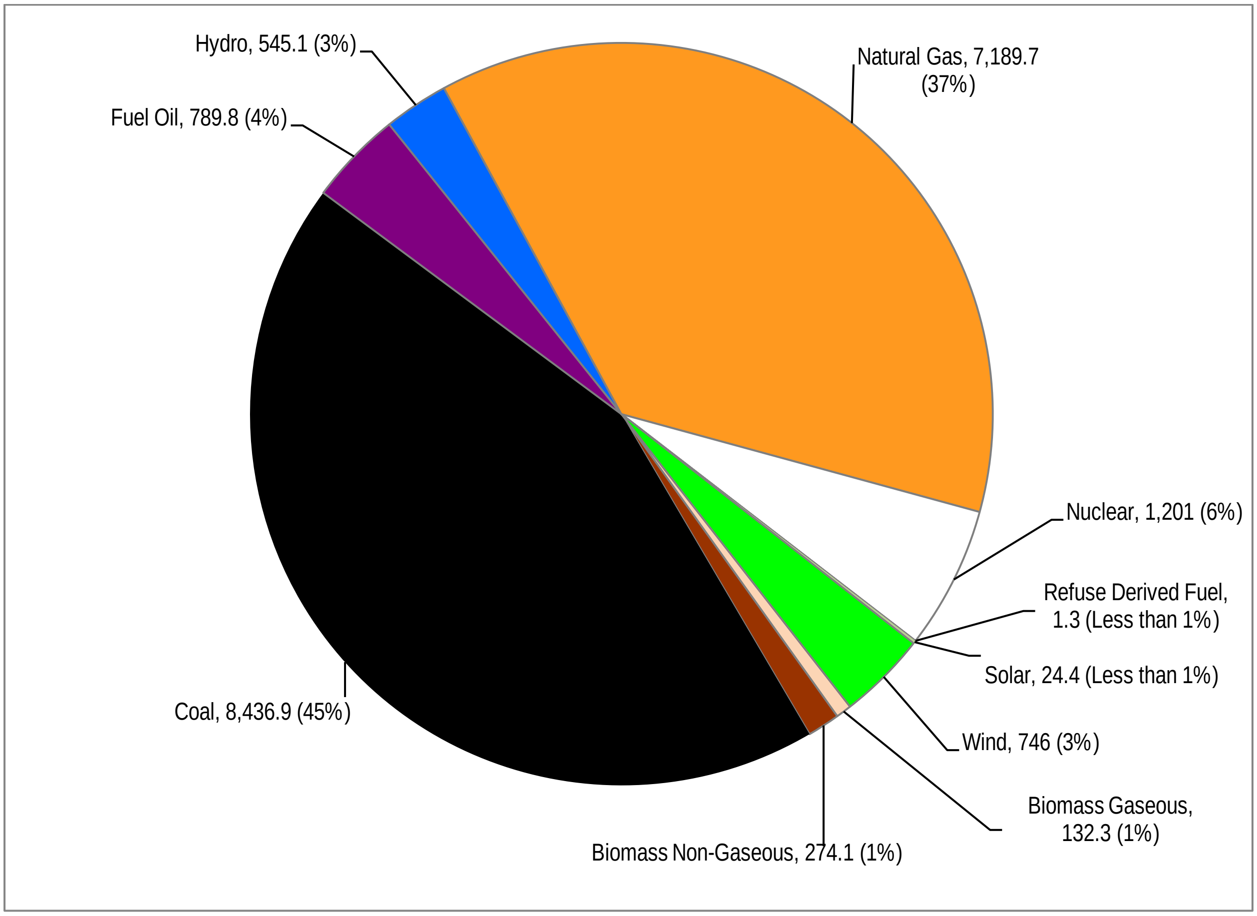
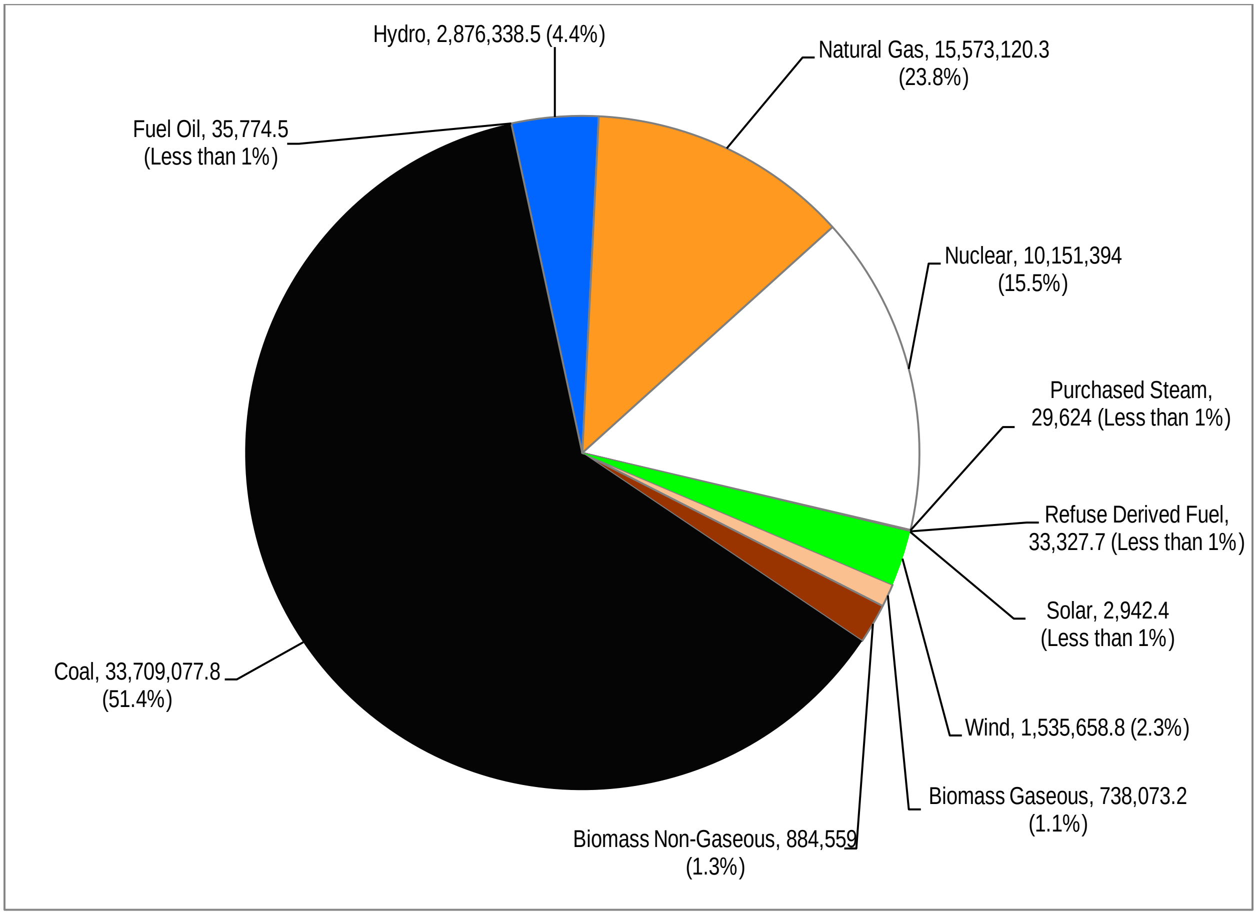


Figure 10 shows the actual electricity generated by in-state generating units in 2016. Approximately 51.4 percent of electricity was supplied by coal-fired units, and 23.8 percent was supplied by natural gas. The percentage of electricity generated by natural gas almost doubled from 2014 to 2016, reflecting favorable natural gas prices.

[28] Source: Utility annual reports filed with the Commission and the federal Rural Utility Service, US Energy Information Administration, and compliance data filed with the Commission for Wisconsin's RPS.

Figure 10 Wisconsin Electricity Generated by Fuel Source 2016 (MWh)



New Generation

Since the last SEA, Wisconsin electricity providers have added relatively little new generation capacity, primarily due to slow demand growth and an adequate PRM. With the 2013 closure of the Kewaunee nuclear plant (556 MW) and the pending retirements of several smaller and older coal facilities, electricity providers expect a combined need for an additional 2,100 MW of capacity by 2020.

Table 7 shows a number of new generation projects proposed to meet this combined need:

- Xcel Energy, Inc., NSPW's parent company, estimates it will add approximately 700 MW of capacity by 2019, including: 73 MW of hydroelectric; 60 MW of wind; 170 MW of solar photovoltaic; and, 480 MW of natural gas-fired generation. Northern States Power Company-Minnesota (NSPM), NSPW's sister company, also anticipates additional capacity due to upgrades to existing electric generating facilities. All the upgrades planned by NSPM are expected to be at plants located outside of Wisconsin, and are not included in Table 7. Under the terms of an interchange agreement between Xcel and NSPW, NSPW would be entitled to receive 16 percent of the capacity and energy from the facilities.

- WEPCO indicated that it will add approximately 105 MW of solar generating capacity by 2020.
- WEPCO indicated that it will add approximately 30 MW of capacity from upgrades to the Port Washington facility
- On May 6, 2016, the Commission authorized WP&L to construct a 667 MW natural gas-fired, combined-cycle electric generating facility at its existing Riverside site in the town of Beloit.[29] WP&L expects the Riverside unit to begin operation in 2020.
- DPC has announced plans to add a 550 MW natural gas-fired, combined-cycle generating station by 2025. This effort will be in cooperation with SWL&P, a subsidiary of ALLETE.

Table 7 New or Upgraded Utility-Owned or Leased Generation Capacity 2018-2024

Year	Type of Load Served	Nameplate Capacity (MW) [2]	Name	New or Existing Site	Owner/ Leaser	Fuel	Location (County: Locality)	PSC Status and Docket #
2018	Intermediate	30	Port Washington	Existing upgrade	WEPCO	Natural Gas	City of Port Washington	
2020	Intermediate	661	Riverside	New	WP&L	Natural Gas	Town of Beloit	6680-CE-176, Approved 5/6/2016
2020	Intermittent	105	Solar A	New	WEPCO	Solar	Unknown	
2025	Intermediate	550	Nemadji Trail Energy Center	New	DPC, SWL&P	Natural Gas	City of Superior	5-CE-148

Emission Control Projects

In general, Wisconsin's generation fleet is operated with environmental controls that meet or exceed pollution control requirements. Wisconsin electricity providers continue to update existing facilities to comply with federal regulations. Between 2000 and 2013, Wisconsin electricity providers invested $184 million in efficiency upgrades and more than $3 billion in pollution control equipment at existing plants.

Most major projects identified in previous versions of the SEA and associated with air emissions are completed, though project work associated with the Clean Water Act may begin in the near future at specific plants. Table 8 shows the current status of major emissions control projects[30] at Wisconsin power plants as of January 2018.

[29] Docket 6680-CE-176.

[30] Major emissions control projects are those with a capitol cost of $25 million or more. The table does not include lower capital cost projects such as combustion control projects for NO_x, and activated carbon control projects for mercury, because these actions are below the threshold dollar amount required for a Certificate of Authority from the Commission.

Table 8 Major Emissions Control Projects at Wisconsin Electricity Provider's Power Plants

Unit Name	Electricity Provider Owner	Project Status	Type of Emission Control[31]	Year of Commercial Operation	Estimated Cost (in $million)
Elm Road Generating Station	We Energies	Pending	Wastewater treatment	2010-2011	$45
				Total	$45

Investment in Generation and Pollutant Emission Controls

Many of the emission control projects and upgrades resulted from Consent Decrees between the electricity providers and the federal Environmental Protection Agency (EPA), which can include the implementation of advanced pollution controls or other environmental remediation. The investments Wisconsin generators make to update existing coal facilities may impact rates and bills. Due to previous and ongoing air emissions investment, the amount of criteria pollutants (carbon monoxide, lead, NO_X, particulate matter, ozone, SO_X, and mercury) are decreasing.

The following list summarizes rules that may impact the state's generating units:

- Mercury and Air Toxics Standard (MATS) – On April 24, 2013, EPA published the final version of the MATS rule. Since it was first published, the rule has been challenged, most notably on the basis that EPA did not consider costs to regulate the emissions of toxic air pollution from power plants when developing the rule. Subsequent to that challenge, EPA found that consideration of costs does not alter its previous conclusion that the rule is appropriate and necessary under Section 112 of the Clean Air Act (CAA). In March 2016, a request to stay the MATS rule was rejected by the U.S. Supreme Court. All units in Wisconsin are in compliance.[32]

  The elimination of mercury is frequently achieved by the implementation of activated carbon injection (ACI) which allows for the capture and removal of mercury from effluent gas streams before it reaches the environment. Some utilities chose to retire older coal units to reduce the overall mercury emissions across their fleet. Another targeted emission, hydrogen chloride—which can become hydrochloric acid—is also targeted by this standard and can be reduced by the use of technologies such as dry sorbent injection (DSI), which captures acidic gases and removes them from the effluent gas stream. Through project work, operational changes, and other methods, Wisconsin's electric service providers assert they will meet the MATS standards.

- National Ambient Air Quality Standards (NAAQS) Proposed Ozone Standard – EPA strengthened the air quality standard for ground-level ozone in October 2015 to 0.07 ppm.

[31] Wastewater treatment and bottom ash conversion may be used to address proposed Effluent Limitations Guidelines (ELG) which seek to remove heavy metals such as mercury, arsenic, lead, and selenium from process effluent wastewater streams. The projects listed above are pending due to federal EPA re-consideration of the proposed rules, from the standpoint of materials covered and dates of possible implementation.

[32] Source: Federal Energy Information Administration EIA-860, Schedule 6B, "Emission Standards and Control Strategies."

The previous 2008 standard was 0.075 ppm. Although levels of ground-level ozone pollution are substantially lower than in the past, EPA has determined levels are unhealthy in numerous areas of the country. Ozone emissions from diverse sources travel long distances and across state lines.

Ground-level ozone pollution often results from interaction with other pollutants, especially NO_X and volatile organic compounds (VOC), both of which can chemically interact with sunlight to produce ozone. Some parts of Wisconsin will be at low enough levels that additional steps to meet the NAAQS ozone standard are not necessary. Using technologies that reduce NO_X and VOCs are other routes utilities can take to reduce the level of ozone in areas that do not meet the current EPA standards. All Wisconsin electric service providers indicate they are taking steps to ensure compliance with the standard.

- EPA Cross State Air Pollution Rule (CSAPR) – This rule continues to be modified and challenged since its introduction as the Clean Air Interstate Rule in 2005, and the Clean Air Transport Rule in 2010. CSAPR was finalized July 6, 2011, but implementation of the rule has been affected by a number of challenges, court actions, and changes. The rule is designed to address: sulfur dioxide (SO_2) and NO_X emissions that significantly contribute to the inability of downwind states to meet NAAQS for fine particulate matter; and, ozone transport to downwind states. CSAPR implementation began in 2015. On September 7, 2016, EPA finalized an update to the rule that requires reductions of summertime NO_X emissions from power plants in 22 states in the eastern U.S. beginning in 2017.

  Various technologies have been implemented by plants within the state, including the use of wet or dry flue gas desulfurization (FGD) to reduce SO_2 emissions, and selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) to reduce NO_X emissions. Other techniques used by plants include the use of lower sulfur Powder River Basin (PRB) coal and the inclusion of low NO_X burners and overfire air on boilers. Electric service providers can also buy emissions credits from other entities that have reduced their SO_2 and NO_X emissions as part of a "cap and trade" program.

- Carbon Pollution Standard for new power plants under Section 111, CAA – On October 23, 2015, EPA published rules on greenhouse gas emissions from new, modified, and reconstructed sources by establishing standards under section 111(b) of the CAA. The rule applies to new power plants, as opposed to existing plants. On April 4, 2017, EPA announced that it is reviewing the standards for this rule and if appropriate will initiate proceedings to suspend, revise, or rescind the rule. The EPA review is currently underway.

- Clean Water Act, Section 316(b) for Cooling Water Intake Structures – On August 15, 2014, EPA finalized rules for cooling water intake structures under section 316(b) of the Clean Water Act, effective October 14, 2014. The final rule establishes requirements for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than two million gallons of water per day from an adjacent body of water and use at least 25 percent of the water withdrawn exclusively for cooling purposes.

Existing facilities with a design intake flow of greater than two million gallons per day are required to reduce fish impingement, with the owner or operator of the facility able to choose one of seven options for meeting best available technology requirements. Facilities that withdraw very large amounts of water, at least 125 million gallons per day, are required to conduct studies to help the permitting authority determine site-specific mortality controls. New units at an existing facility that are built to increase the generating capacity of the facility are required to reduce the intake flow to a level similar to a closed-cycle, recirculation system, either by incorporating a closed-cycle system into the design of the new unit, or by making other design changes equivalent to the reductions associated with closed-cycle cooling.

Proposed methods of implementing the requirements of this rule include the use of improved fish screens with intake velocities of less than 0.5 feet per second (fps) and returns to prevent undue impingement and entrainment mortality at affected sites. Other solutions can involve modification of plant operational practices or the use or implementation of closed water recirculating systems with cooling towers. Still other plants have installed an offshore velocity cap, which changes the direction of water withdrawal to decrease the danger to fish and other aquatic life. In some cases, compliance with the rules will be predicated on plant studies and subsequent approval by the Wisconsin DNR during the normal water re-permitting cycle. All of Wisconsin's electric service providers are in the process of evaluating the requirements, or implementing solutions to bring them into compliance with this rule, when applicable.

- Effluent Limitations Guidelines (ELG) – On November 3, 2015, EPA finalized a rule revising regulations relating to effluent limitations guidelines for steam-powered electric generating plants. On September 18, 2017, EPA postponed certain compliance dates with the November 2015 rule.

  The largest areas for utility compliance with this rule include disposal of wastewater associated with bottom ash processing, fly ash processing, and effluent water from FGD "wet" scrubbers. Some larger plants are exploring or in the process of converting to dry bottom ash handling systems that do not produce a wastewater stream, which eliminates the need for compliance with this regulation. Other utilities are considering a switch to dry fly ash handling systems or similar moves to systems that do not generate a water effluent.

- Disposal of Coal Combustion Residuals from Electric Utilities – On April 17, 2015, EPA published coal ash specific federal regulations under Subtitle D of the Resource Conservation and Recovery Act to establish technical requirements that further ensure the protection of ground water and surface waters by safe management of coal ash that is disposed of in surface impoundments and landfills. Risks addressed include potential leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the potential catastrophic failure of coal ash surface impoundments. Some facilities around the state are looking to modify or close their bottom ash settling ponds and make changes to their on-site ash landfills to comply with these regulations.

Wisconsin electric service providers assert that they are, or will be, in compliance with federal regulations, using a combination of technology, different operating practices, and generating unit retirements. The Commission will continue to monitor these rules.

Planned Retirements

Wisconsin electricity providers face a constant challenge in providing safe, reliable, and affordable electricity while complying with all state and federal pollution control rules. In meeting this challenge, electricity providers must evaluate whether to retire aging facilities that are not economic or where pollution control is too costly or infeasible. Decisions to retire, mothball, or retrofit generation resources must be evaluated for the impact to reliability both within Wisconsin and in the larger MISO footprint. By 2024, Wisconsin's electricity providers estimate they will retire approximately 2,100 MW of existing Wisconsin-based electric generation.

Table 9 shows additional information about planned retirements.

Table 9 Retired Utility-Owned or Leased Generation Capacity 2018-2024[33]

Year	Name	Owner/ Leaser	Type of Load Served	Capacity (MW)[34]	Fuel	Location
2017	Flambeau 1	NSPW	Peaking	16	Natural Gas	Park Falls, WI
2018	Edgewater 4	WP&L/WPSC	Base	320	Coal	Sheboygan, WI
2018	Fitchburg 1,2	MGE	Peaking	29, 29	Natural Gas	Madison, WI
2018	Nine Springs	MGE	Peaking	16	Natural Gas	Madison, WI
2018	Sycamore 1,2	MGE	Peaking	18, 24	Natural Gas	Madison, WI
2018	Pleasant Prairie 1, 2	WEPCO	Base	617, 617	Coal	Pleasant Prairie, WI
2019	Pulliam 7,8	WPSC	Base	82, 150	Coal	Green Bay, WI
2020	Rock River 3,4,5,6	WP&L	Peaking	27, 15, 51, 51	Natural Gas	Beloit, WI
2020	Sheepskin 1	WP&L	Peaking	40	Natural Gas	Beloit, WI

TRANSMISSION SYSTEM PLANS, ISSUES, AND DEVELOPMENTS

Locations and Descriptions of Proposed Transmission Projects

As part of each SEA, the Commission is required to identify all transmission lines designed to operate at voltages larger than 100 kilovolts (kV) on which an electric utility proposes to commence construction before 2024. "Construction" refers to building new lines, rebuilding existing lines, or upgrading existing lines. To address this requirement, the Commission compiled Wisconsin-specific data from the four transmission owners in the state: ATC, DPC, NSPW, and SWL&P.

[33] NSPW and WEPCO stated their intent to retire other generation in 2019 and 2022. These plants are not located in Wisconsin and are not included in this table.
[34] Capacity listed is the summer net-accredited capacity.

In addition to approving new transmission construction, the Commission approves the rebuilding or upgrading of certain existing lines, which may also require new structures or new right-of-way (ROW).

- To rebuild a line means to modify or replace an existing line; in other words, to keep it at the same voltage and improve its capacity to carry power through new hardware or design.
- To upgrade an electric line means to modify or replace an existing line, but at a higher voltage or current carrying capability. An upgrade also improves the line's capacity to carry power.

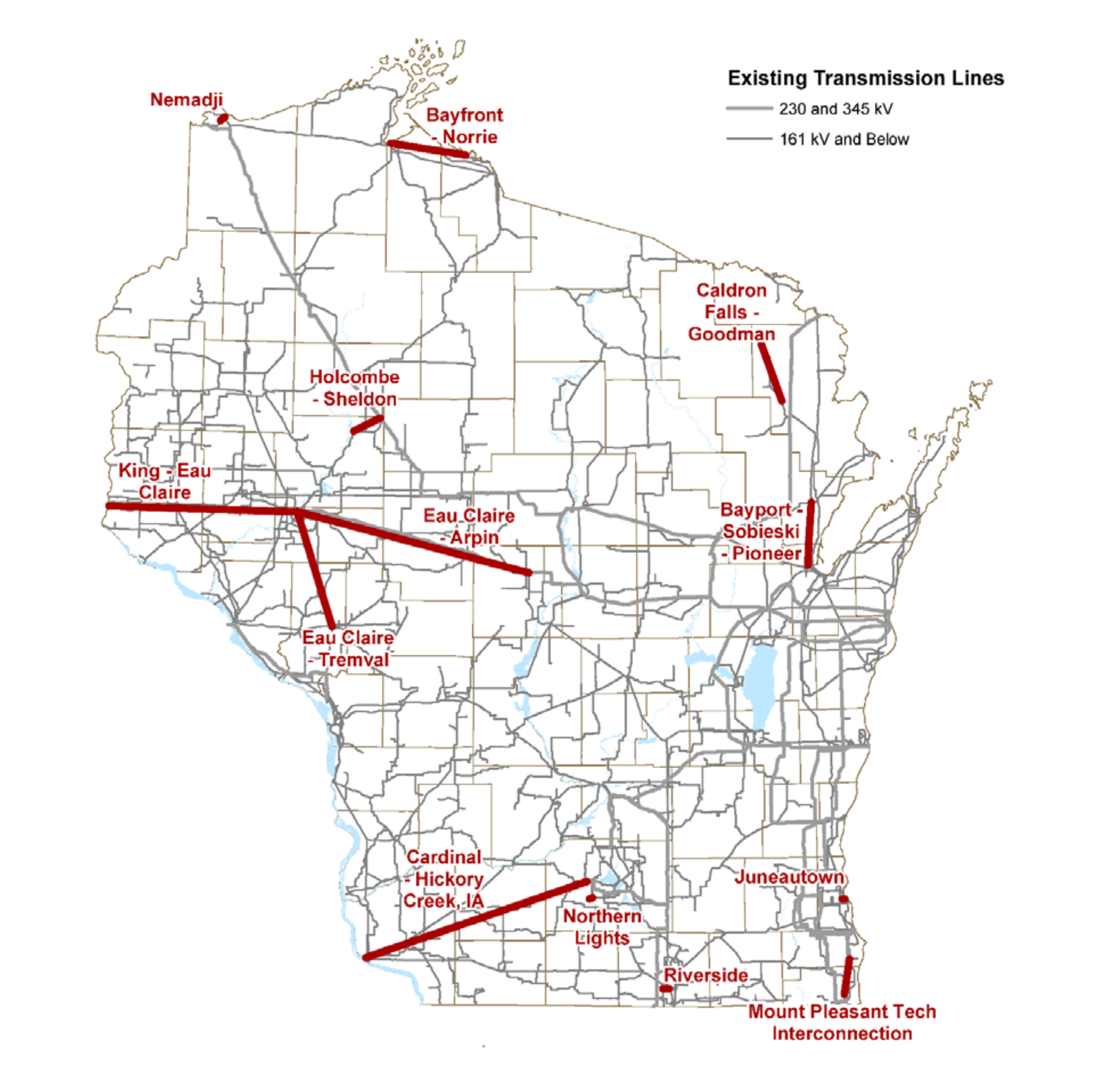
Both rebuilding and upgrading may require new, taller structures. New ROW may also be needed if the new structures require a wider ROW, or if the line route requires relocation to reduce environmental impacts. Either way, rebuilt or upgraded transmission lines usually need significantly less new ROW than new lines.

The primary reasons for upgrading, rebuilding, or building additional transmission lines is to maintain system reliability and performance due to one or more of the following reasons:

- Growth in an area's electricity use, which often requires new distribution substations and new lines to connect them to the existing transmission system, or the need for increased capacity of existing transmission lines to address contingencies, such as loss of one or more transmission or generation system elements;
- Aging of existing facilities that results in reduced reliability;
- Maintaining operational reliability in anticipation of the loss of one or more transmission or generation elements;
- Increased power transfer capability for energy or capacity purchases or sales;
- Improved economics or increased efficiency in the wholesale electric market;
- Generation interconnection agreements and transmission service requirements for new power plants; and
- Maintenance and assurance of local reliability when older generation is retired.

In general, the higher the operating voltage, the more power a line can carry with fewer losses. Higher voltage transmission lines are important in delivering large amounts of power on a regional basis, and lower voltage lines primarily deliver power to more limited geographic areas. The ability to deliver power reliably to local substations and the ability to import power from, or export to, other regions are both important functions of providing adequate, reliable service to customers. Table A-2 in the Appendix lists projects in Wisconsin on which construction is expected to start by 2024.

Figure 11 Major Transmission Projects–Construction Anticipated, 2018-2024[35]



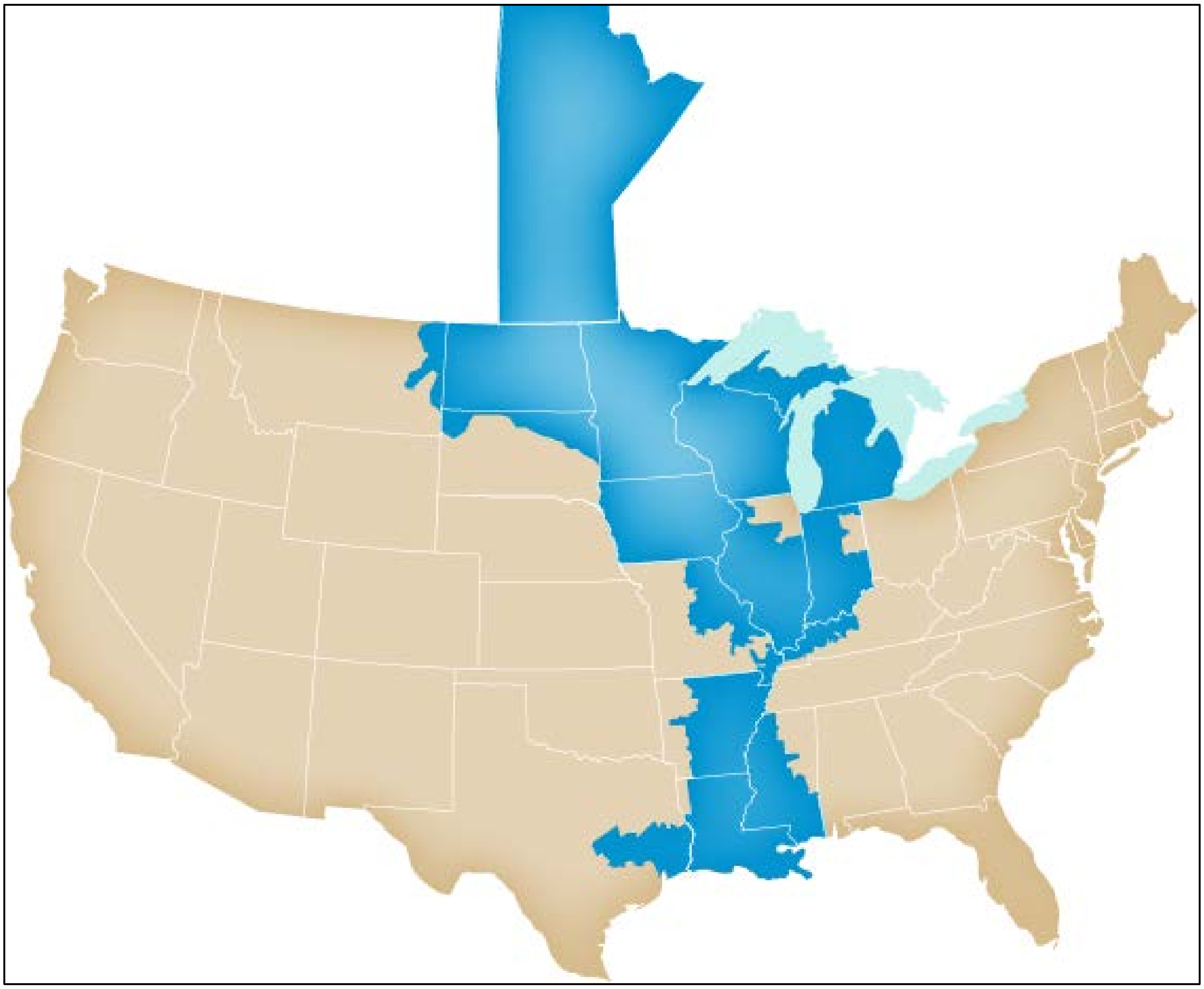
Transmission Planning in the MISO Region

Wisconsin electricity providers participate in the MISO wholesale energy market. MISO is a not-for-profit, member-based organization that administers a wholesale electricity market and is the NERC Reliability Coordinator for the MISO footprint. As shown in Figure 12, MISO covers

[35] Source: Electricity provider data responses, docket 5-ES-109. Proposed transmission projects are graphic representations and do not reflect actual routes.

15 states and one Canadian Province. The real-time market footprint is approximately the same footprint except for the Canadian Province of Manitoba.

Figure 12 MISO Reliability Footprint[36]



As a FERC-designated Regional Transmission Organization (RTO), MISO has functional responsibilities and control of the region's bulk electric system, including both transmission planning and generation dispatch. MISO has 50 Transmission Owner members with approximately $38 billion in assets. MISO has 131 non-transmission owner members that participate in the operation of the real-time market. As the NERC Reliability Coordinator, MISO controls reliability operations for 191,062 MW of nameplate generation capacity, with a peak load of approximately 130,917 MW. There are 453 market participants serving approximately 42 million people. The market has $26.9 billion in annual gross market charges. MISO's operations system performs a "what-if" contingency analysis every five

[36] Source: misoenergy.org.

minutes from approximately 300,000 data points and checks more than 8,000 potential contingencies to maximize the use of the bulk electric system.

MISO Transmission Planning – Objectives and Scope[37]

The MISO Transmission Expansion Plan (MTEP) process is a collaborative process among MISO planning staff and stakeholders[38] designed to ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and enable a competitive energy market. Each MTEP cycle lasts 18 months. MTEP17, which was approved by the MISO Board in December 2017, is the 14th edition of the process.

The MTEP process produces an annual report which identifies a number of transmission projects and alternatives under consideration. The planning process is conducted at many different levels, including special task forces, work groups, sub-committees, and, finally, the Advisory Committee.[39] The Organization of MISO States (OMS) is also heavily engaged in this stakeholder process. OMS is a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in MISO. The Commission participates in OMS and actively participates or leads several work groups. The purpose of OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, FERC, and other relevant government entities and state commissions, as appropriate.

MISO Transmission Expansion Plan 2017 Overview and Summary

MTEP17 contains 354 new projects throughout the MISO footprint that total an incremental $2.7 billion in transmission facilities. The following is a summary of the four categories of projects:[40]

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[37] This section of the SEA relies significantly on documents produced and made available from MISO, and used with permission. https://cdn.misoenergy.org/Corporate%20Fact%20Sheet147649.pdf

[38] The Commission is a stakeholder at MISO.

[39] The Advisory Committee is a forum for its members to be apprised of MISO's activities and to provide information and advice to the management and Board of Directors of MISO on policy matters of concern to the Advisory Committee, or its constituent stakeholder groups. Neither the Advisory Committee nor any of its constituent groups exercise control over the MISO Board.

[40] Some project designs have been approved by MISO, but projects located in Wisconsin are not yet under Commission review. Cost allocation of the projects is controlled by federal tariffs which vary by category.

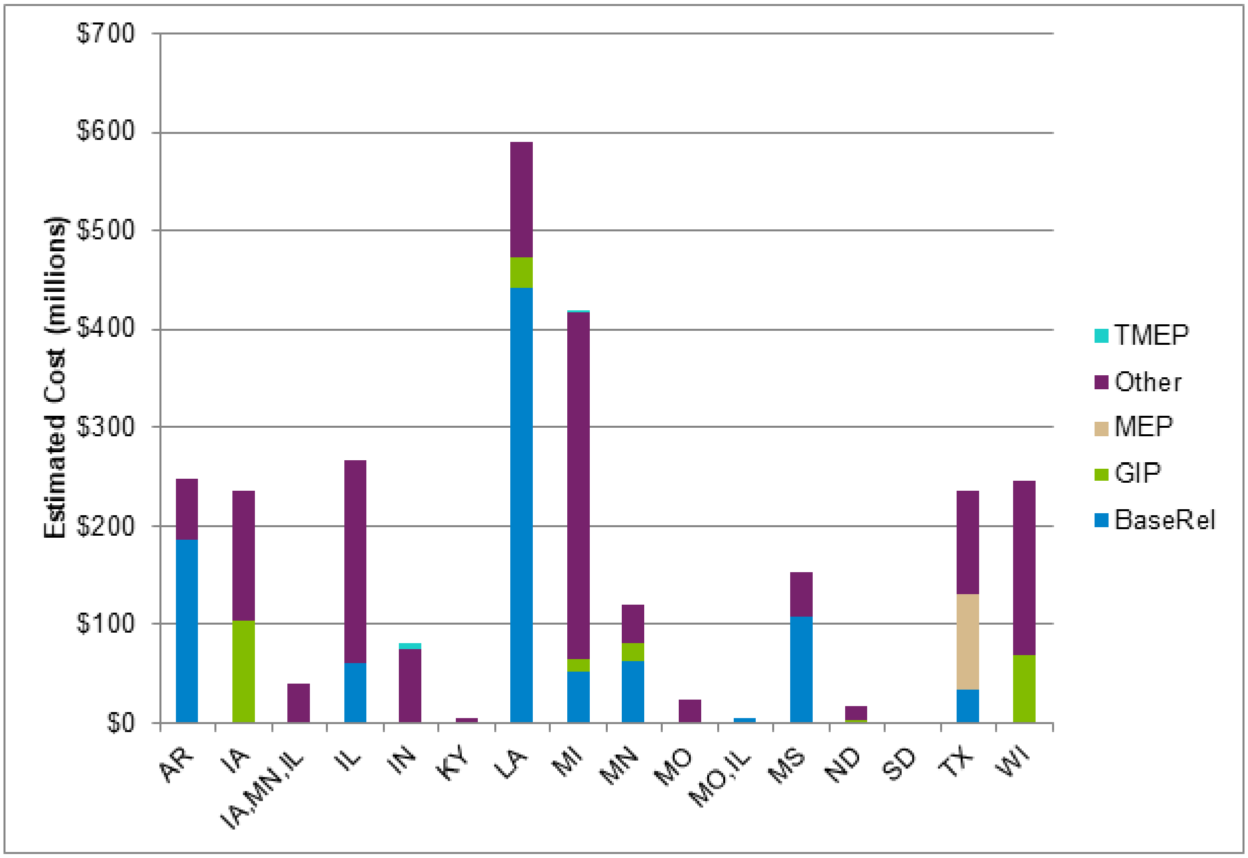
Table 10 MISO Categories of Projects

Project	Description	Number	Cost
Baseline Reliability Projects (BRP)	Projects required to meet NERC reliability standards	77	$957 million
Generator Interconnection Projects (GIP)	Projects required to reliably connect new generation to the transmission grid	23	$238 million
Market Efficiency Projects (MEP)	Projects that have a benefit to cost ratio greater than 1.0 for the purpose of reducing the market congestion pricing component	1	$130 million
Other Projects	A wide range of maintenance projects and lower voltage projects, such as those designed to provide local economic benefit	248	$1.4 billion
Targeted Market Efficiency Projects (TMEP)	Projects on the MISO seam with the PJM[41] market that have low costs and pay back the real time congestion in 4 years	5	$4.9 million MISO cost responsibility

The new MTEP17 Appendix A projects are primarily located in nine states. Some projects are in multiple states, but the dollar amount is aggregated to the primary state. Figure 13 illustrates the dollar amount, the type of project, and the state where the project is located. The geographic area of projects varies from year to year. The details of all the approved projects can be found in MTEP17 Appendix A.[42]

[41] PJM is an RTO, like MISO, operating on the eastern border of MISO.
[42] Source: https://www.misoenergy.org/planning/transmission-studies-and-reports/#/report-study-analysistype|MTEP/mtepdoctype|MTEP Report/mtepreportyear|MTEP17.

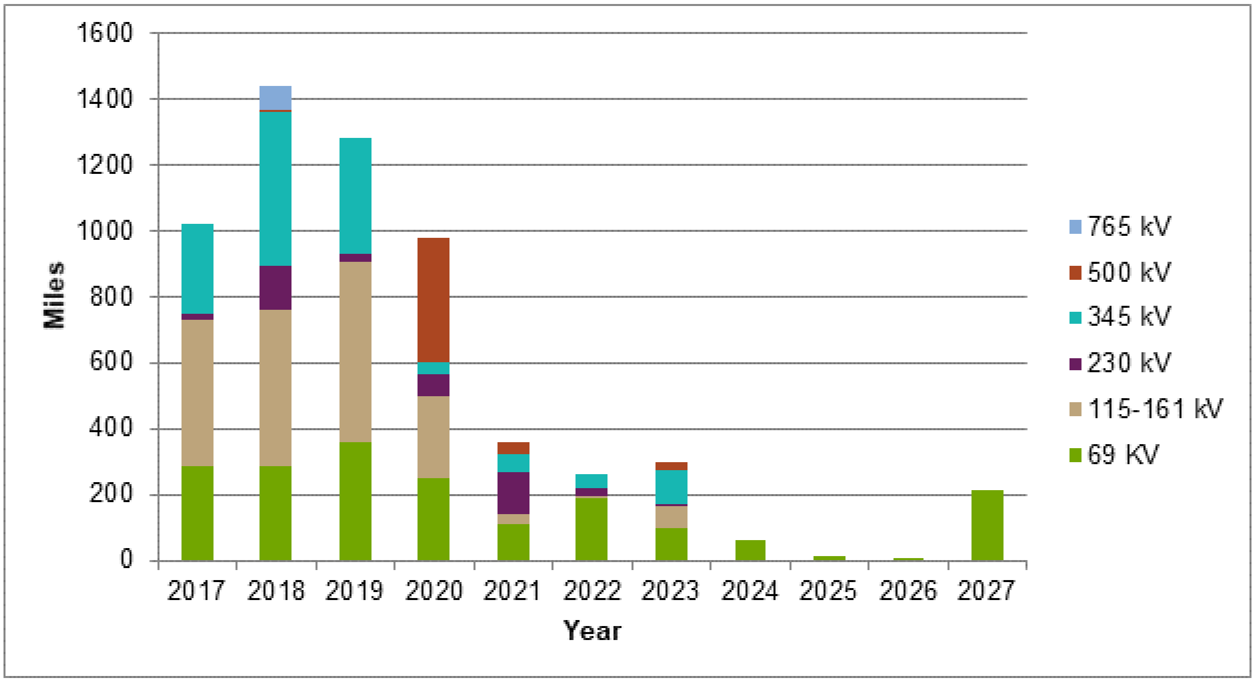
Figure 13 New MTEP17 Appendix A Projects Categorized by State[43]



Approximately 68,500 miles of existing transmission lines are located in the MISO area. Within the 10-year planning horizon, approximately 6,129 miles of new or upgraded transmission lines are envisioned. Of the upcoming planned projects, 3,500 miles of upgraded transmission lines are on existing corridors, and 2,600 miles of new transmission lines are planned on new corridors. Figure 14 shows the mileage by voltage and MTEP planning year.

[43] Source: misoenergy.org.

Figure 14 New or Upgraded Line Mileage by Voltage Class (kV) through 2027[44]



Long-Term Resource Assessment for the MISO Footprint

MISO annually conducts a Long-Term Resource Assessment (LTRA), which includes a review of projected resources and load with the Load Serving Entities (LSE). The MISO LTRA is conducted in conjunction with the annual NERC LTRA. The forecast shows adequate capacity to meet expected demand and the Planning Reserve Margin Requirement of (PRMR) of 15.8 percent ICAP until 2023. A planning gap exists when planning reserve numbers fall below the near term requirement. This practice reflects the normal planning process to deal with uncertainty and not over commit resources.

MISO anticipates the projected margins will change as LSEs and state commissions firm up their capacity plans. Ninety-one percent of the MISO load is served by LSEs that have an obligation to serve. That obligation is reflected as a part of state and other jurisdictional resource plans that become finalized through each state's review and approval process. Table 11 shows the results of the planning survey.

[44] Source: misoenergy.org.

Table 11 MISO Planning Year Reserve Margin Survey Results (ICAP, Gigawatts)[45]

In GW (ICAP)	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27	PY 2027/28
(+) Existing Resources	150.0	149.3	148.9	148.6	146.7	145.0	144.7	144.2	144.0	144.0
(+) New Resources	2.0	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5
(+) Imports	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2
(-) Exports	4.1	3.9	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
(-) Low Certainty Resources	1.0	1.1	1.4	1.5	1.5	2.3	2.3	2.4	2.4	2.4
(-) Transfer Limited	2.5	2.3	2.1	1.8	1.1	0.0	0.0	0.0	0.0	0.0
Available Resources	148.5	150.4	150.3	150.4	149.2	147.8	147.5	147.0	146.8	146.8
Demand	125.9	126.5	127.0	127.6	128.3	128.9	129.4	129.1	128.9	128.9
PRMR	145.8	146.5	147.1	147.8	148.5	149.2	149.9	149.5	149.3	149.3
PRMR Surplus/Shortfall	2.7	3.9	3.2	2.6	0.6	-1.4	-2.4	-2.5	-2.5	-2.5
Reserve Margin %	17.9	18.9	18.3	17.9	16.3	14.7	14.0	13.9	13.8	13.8

Seasonal Assessments

In coordination with neighboring Reliability Coordinators, MISO also conducts Summer and Winter Assessments based on capacity resource capability, forced outage rates, and expected loads. The goal is to manage risk with a short term MW reserve margin in the LRZs. This operating, seasonal, risk management reserve is ***not*** the same metric used in the annual PRM which is based primarily on the summer period.

Regional Transmission Overlay Study

In 2017, MISO conducted the Regional Transmission Overlay Study to establish an integrated planning approach resulting in a system that supports possible future scenarios developed in the MTEP process. The study included power flow and production cost models looking at limiting transmission flow and market congestion. Indicative overlays were modeled for the Existing Fleet Future, the Policy Regulations Future, and the Accelerated Advanced Technologies Future. The study provides insight to how planning can be performed and what may be done to meet the changing needs of the transmission system. An interrelated set of issues were identified by the stakeholders and will be used in future MTEP planning cycles, including:

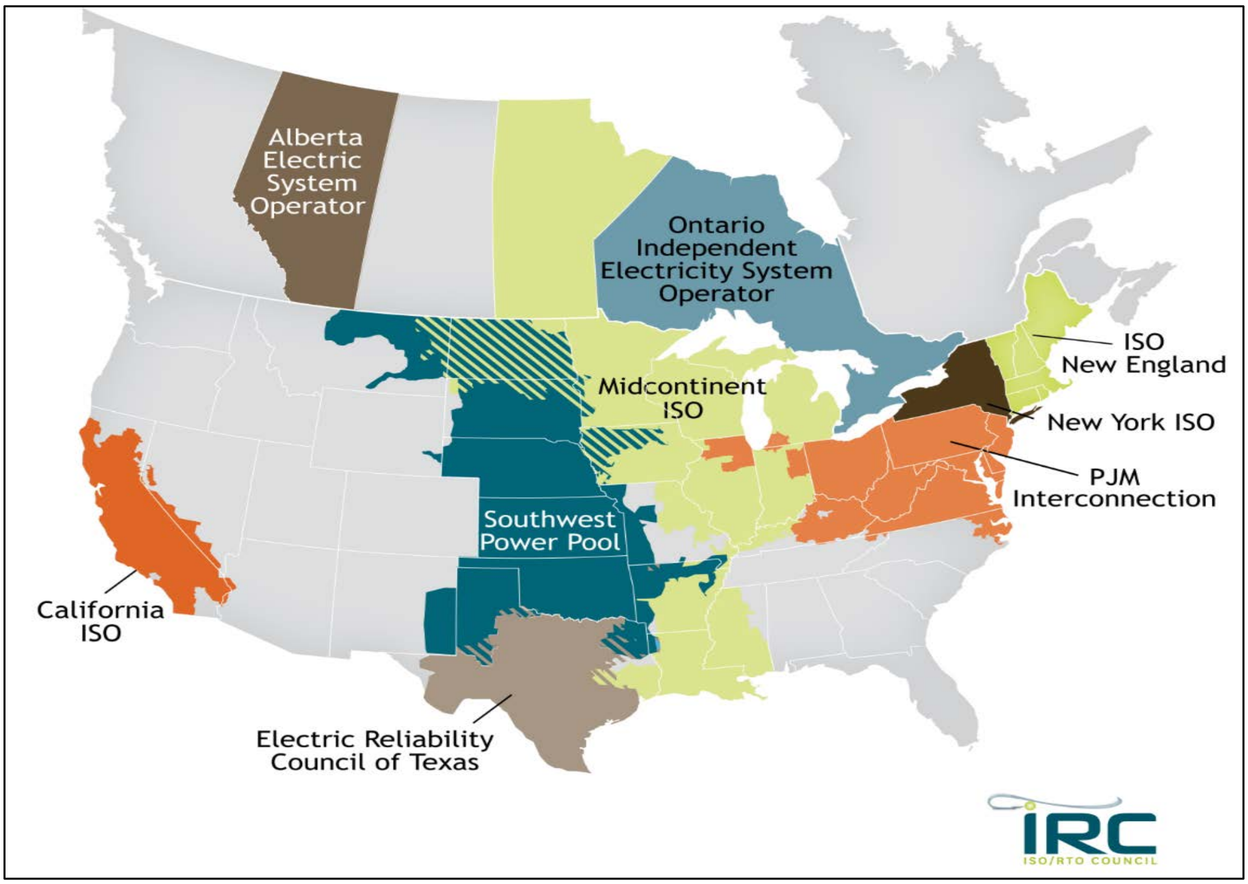
45 Source: misoenergy.org.

- Renewable Integration Impact Assessment
- Network Stability
- Grid Resilience
- Distributed Energy Resources
- Generation Retirements
- Seams Coordination

Interregional Studies

FERC Order 1000 requires interregional coordination with neighboring regions, whether they are RTOs or transmission planning regions without real-time markets. The purpose of the interregional process is to work together to identify and evaluate possible projects that could help neighboring regions with cost-effective measures to address market issues, reliability or other expansion plans. Figure 15 illustrates the major interregional planning entities.

Figure 15 Interregional Planning Entities[46]



[46] Source: www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf.

MISO – PJM Interregional Studies

In 2017, MISO and PJM concentrated on two types of studies. The first was a Targeted Market Efficiency Project type. These were small projects (less than $20 million) focused on real-time congestion, that would be cost-effective in four years. MISO filed the interregional cost allocation methodology proposal with FERC in August 2017, and received approval in October 2017, with minimal compliance changes. Five projects from 345 kV to 138 kV were selected along the MISO-PJM border as part of this study. The projects listed in Table 12 were evaluated to determine the benefit to each region, and were approved in MTEP17.

Table 12 MISO-PJM Targeted Market Efficiency Projects[47]

Facility	State(s)	Transmission Owner(s)	TMEP Cost	TMEP Benefit	Benefit Allocation (% PJM / % MISO)
Burnham – Munster 345 kV	IL and IN	CE, NIPS	$7,000,000	$32,000,000	88/12
Bayshore – Monroe 345 kV	MI and OH	ATSI, ITC	$1,000,000	$17,000,000	89/11
Michigan City – Bosserman 138 kV	IN	NIPS, AEP	$4,600,000	$29,600,000	90/10
Reynolds – Magnetation 138 kV	IN	NIPS	$150,000	$14,500,000	41/59
Roxana – Praxair 138 kV	IN	NIPS	$4,500,000	$6,500,000	24/76

SALES, RATES, AND AFFORDABILITY

The sales of electricity and the rates that customers pay for electricity are interconnected, dynamic variables. This section looks at the interrelationship between sales, rates, and the overall affordability of electric service to customers in Wisconsin, compared with neighboring states and national averages.[48]

Sales

In 2008, Wisconsin electricity sales fell in response to the recession. While sales have increased every year since 2013, total electricity sales in 2016 remained three percent lower than sales in 2007. This is true for both residential and non-residential customers: the two major customer categories for electric sales.

Energy efficiency is one key reason electric sales have not exceeded pre-recession levels. The graph below in Figure 16 shows the last 10 years of sales along with the energy savings from Focus. The graph along with Table 13 demonstrates that if net annual energy savings from the Focus program were added to total electric sales, the result would be slightly positive sales growth during the last 10 years.

[47] Source: misoenergy.org, Table 8.1-1, MTEP17.

[48] Note that this section is developed considering IOU and municipal utility information, and does not include electric cooperatives.

The energy savings from Focus are a conservative estimate; they capture only those savings from measures funded through Focus and are not meant to show the impact of energy efficiency adoption outside of the program. Therefore, the effect of energy efficiency is likely understated.

In this analysis, weather-normalized sales for residential customers are used to remove data outliers from unseasonable weather such as the polar vortex of 2014.

Figure 16 Retail Sales of Electricity, by sector (MWh)[49]

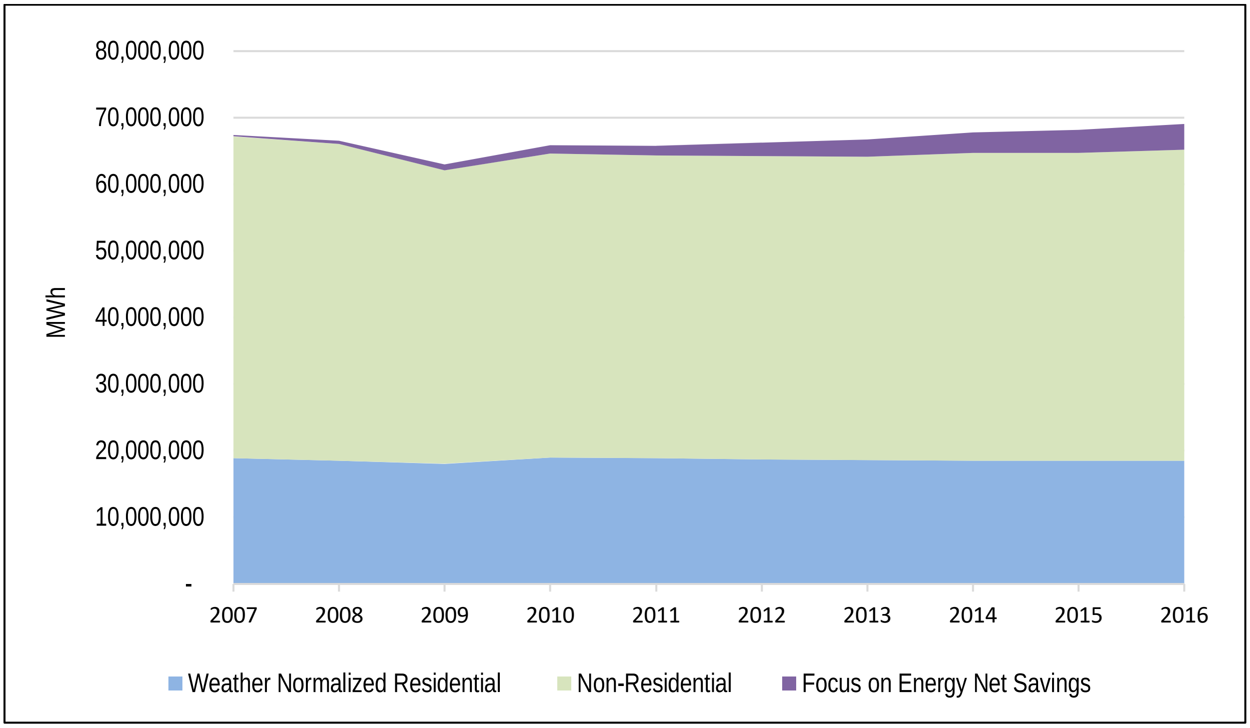


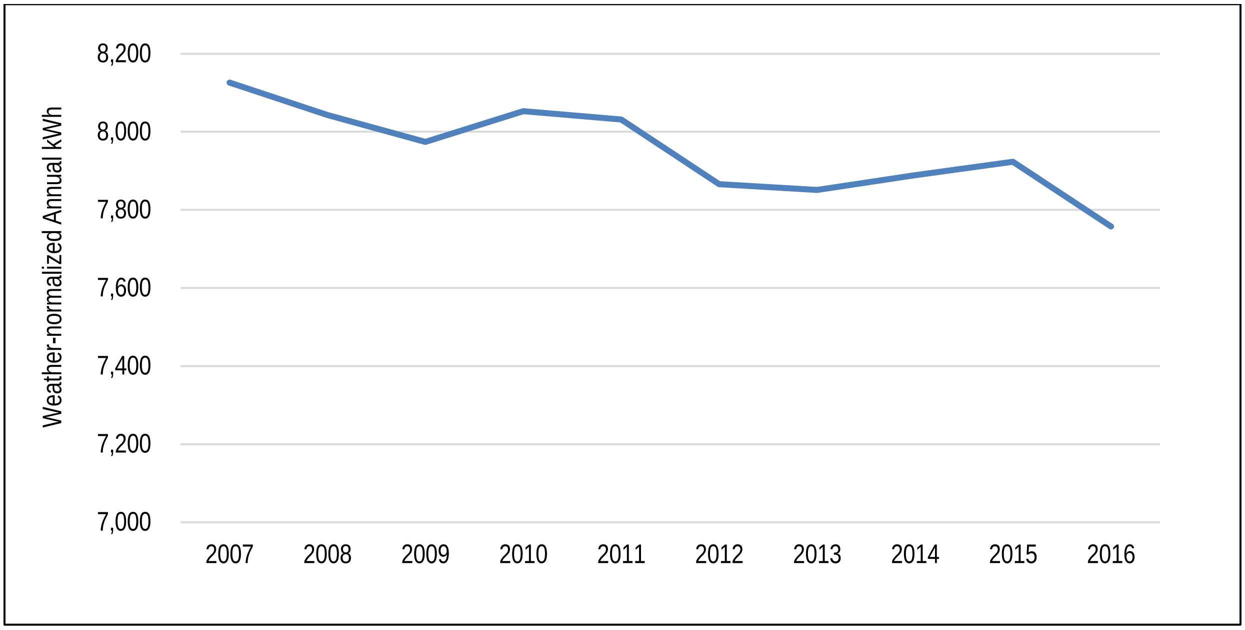
Table 13 Annual Growth Rates for Retail Electricity Sales (%)

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

Absolute sales numbers are important for showing the impact to utilities' bottom lines, but the impact on customers and the state's economy is best shown through average usage information. Usage information shows how residential customers reduce their bills by using less energy. For residential customers, weather-normalized use-per-customer is shown in Figure 17.

[49] Source: Utility annual reports filed with the Commission; Focus on Energy,

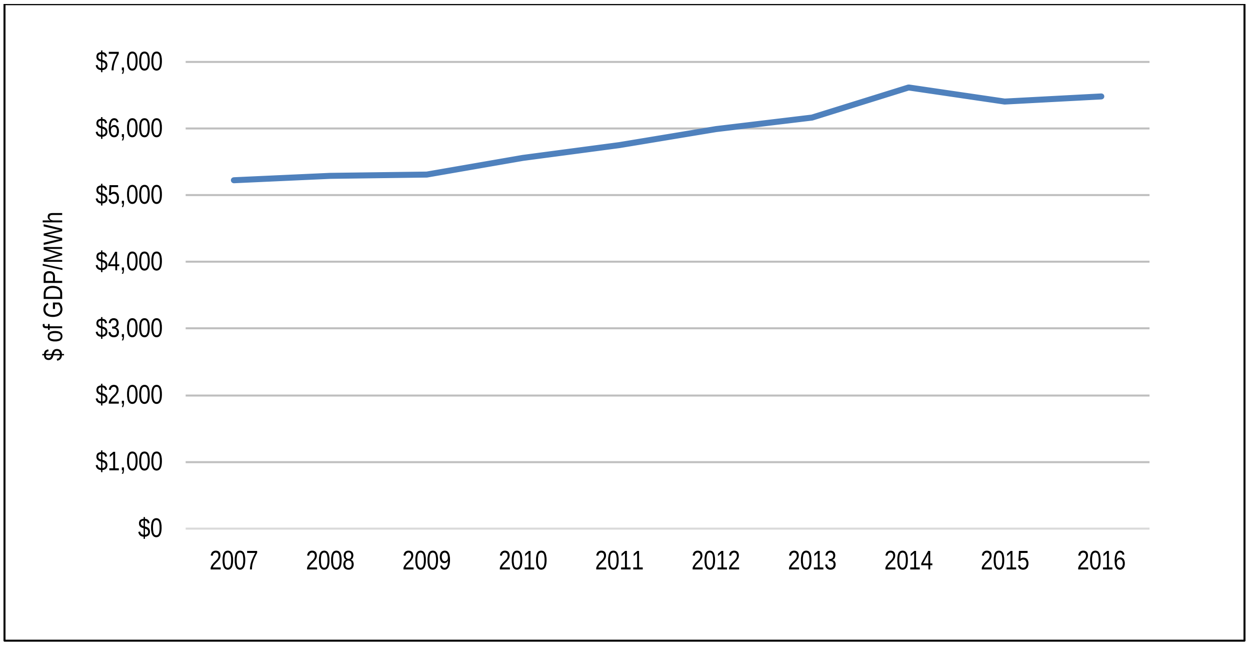
Figure 17 Weather-normalized Annual Use, per Residential Customer (kWh)[50]



Average usage would not be an appropriate metric for a widely varying population such as non-residential customers. The common denominator for this population, however, is the value of goods and services produced. Energy intensity is the amount of electricity consumed per dollar of economic output. Therefore, the average energy intensity is shown instead for non-residential customers in Figure 18.

[50] Utility annual reports filed with the Commission.

Figure 18 Energy Intensity – Non-Residential Sales ($ of GDP/MWh)[51]



Over the last 10 years, residential and non-residential customers have become more efficient in their electricity use. Efficient use of electricity for non-residential customers, means they are producing more economic output with less electricity. Both of these metrics contribute to lower bills for residential customers and higher profits for businesses.

Slow or declining energy sales growth is good for customers who can manage, and even reduce, their energy bills. But this is only half the story. As utilities continue to invest in and replace aging infrastructure, the lack of robust sales growth means those costs must be spread over the same purchased units. In other words, as the cost to provide electric service increases, without a growing sales base to absorb those costs, it is likely that customers' rates will go up.

Rates

The regulated utility ratemaking process is intended to simulate a free market for monopoly utilities. When rates are designed properly, the rate structure signals to customers the actual cost of providing reliable service and electricity to each customer class. Setting price signals correctly is important because those signals influence customer behavior, which in turn influences how utilities incur costs.

Rate Metrics and Cost Drivers

The rates customers see on their bills are tied directly to the authorized revenue requirement for each utility, which is determined in the rate case process. The revenue requirement is the amount of

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

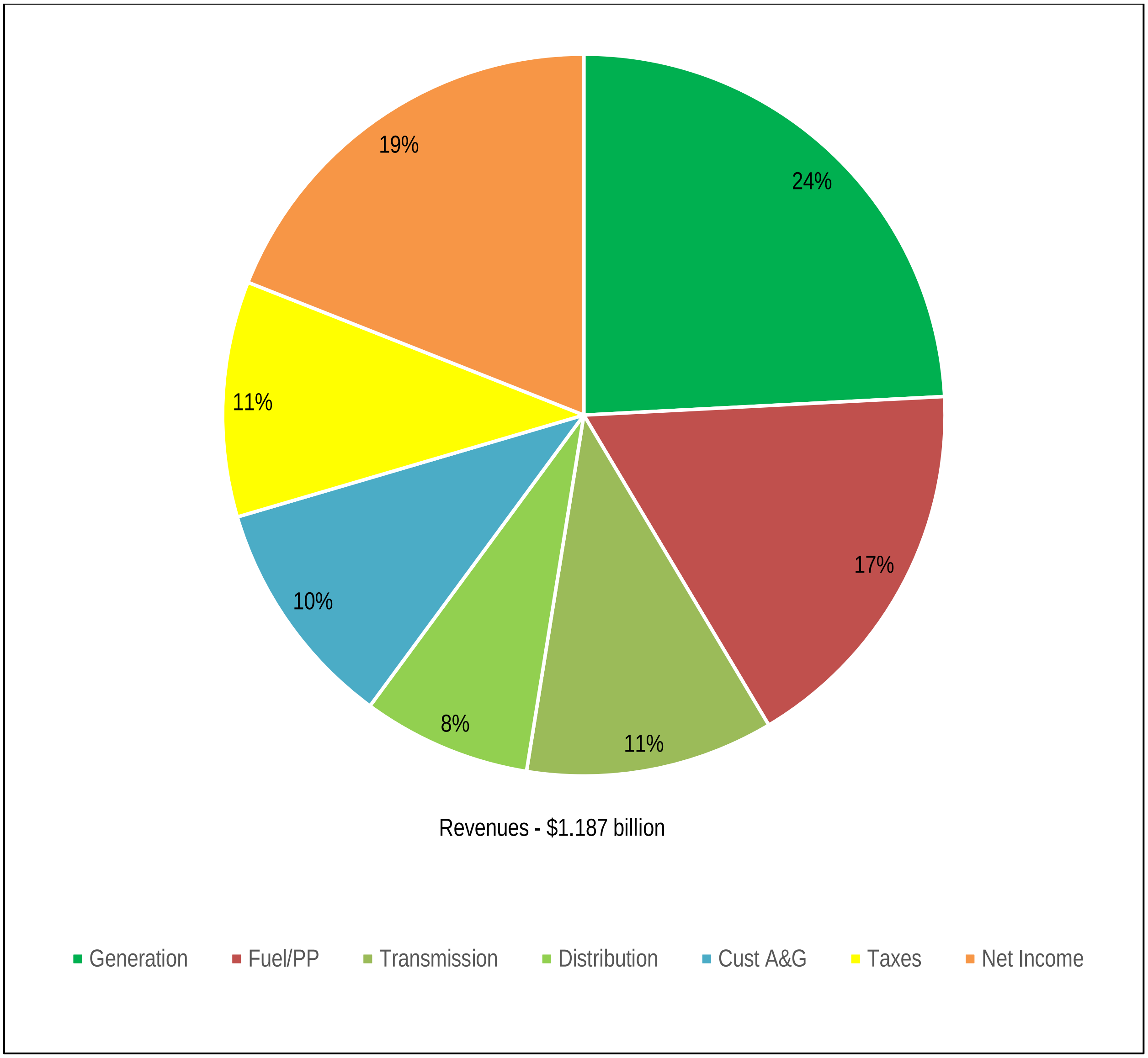
money a utility is authorized by the regulatory authority to collect to cover its costs and make a reasonable profit. The revenue requirement is composed of several cost classifications:

- Generation
- Fuel and Purchased Power
- Transmission
- Distribution
- Customer and Administrative/General
- Taxes
- Net Operating Income

Investor-Owned Utilities with Generation

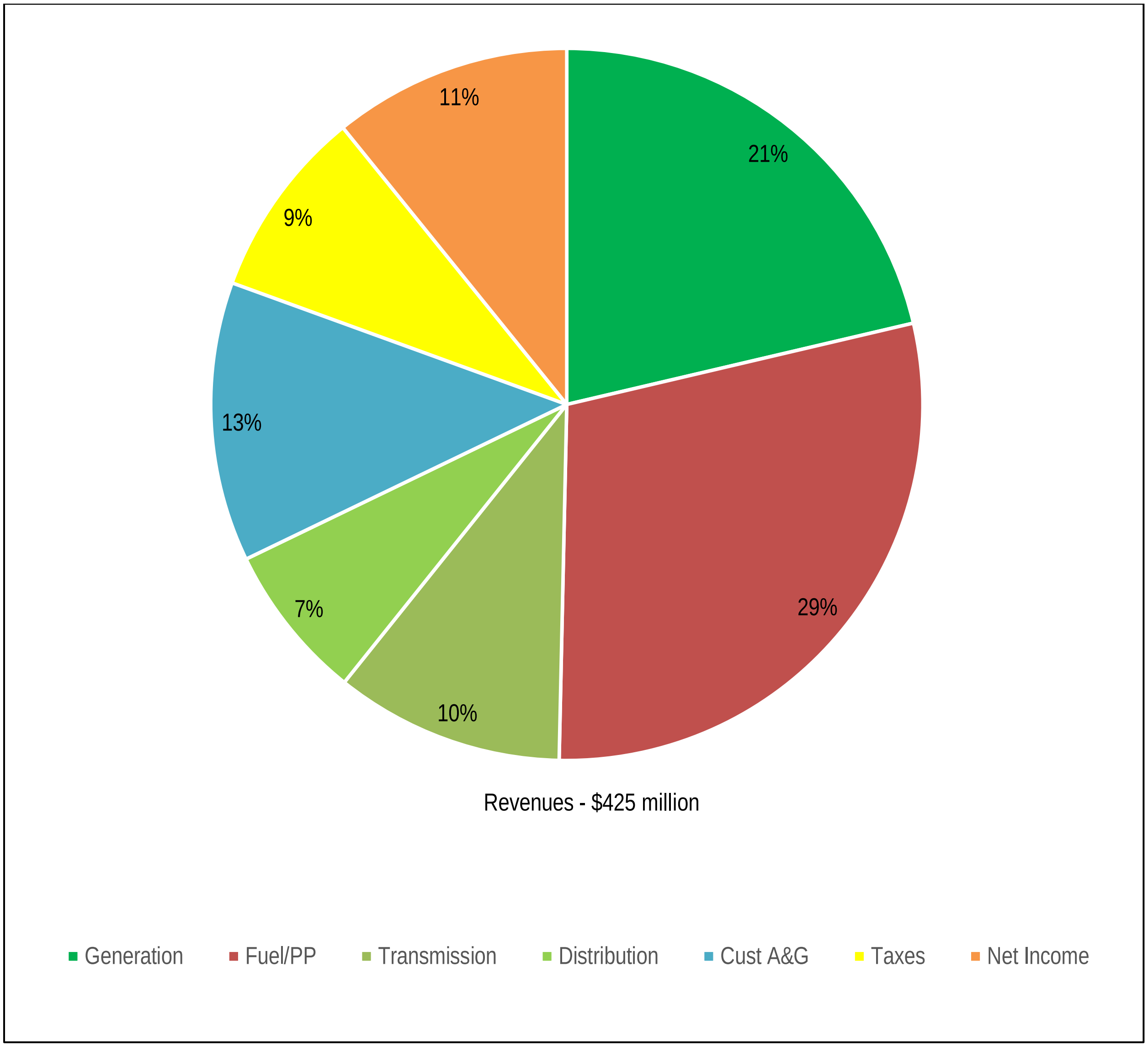
For each of Wisconsin's Class A generating investor-owned utilities (IOUs), the components of the most recently authorized revenue requirements are shown below in Figures 19 through 23. The majority of the revenue requirements for all of the major IOUs comes from power supply and transmission. These costs comprise between 55 and 65 percent of the revenue requirements. Power supply expenses relate to the generation investments made by each utility as well as the cost of fuel and buying power from other generators. The relative shares of the revenue requirement is a function of the age of the utility's power plants, the fuel mix, the price contained in bilateral contracts, and the wholesale market price of energy. For all of the major IOUs except Xcel, transmission is a pass-through expense from ATC.

Figure 19 Revenue Requirement Components, Wisconsin Power and Light[52]



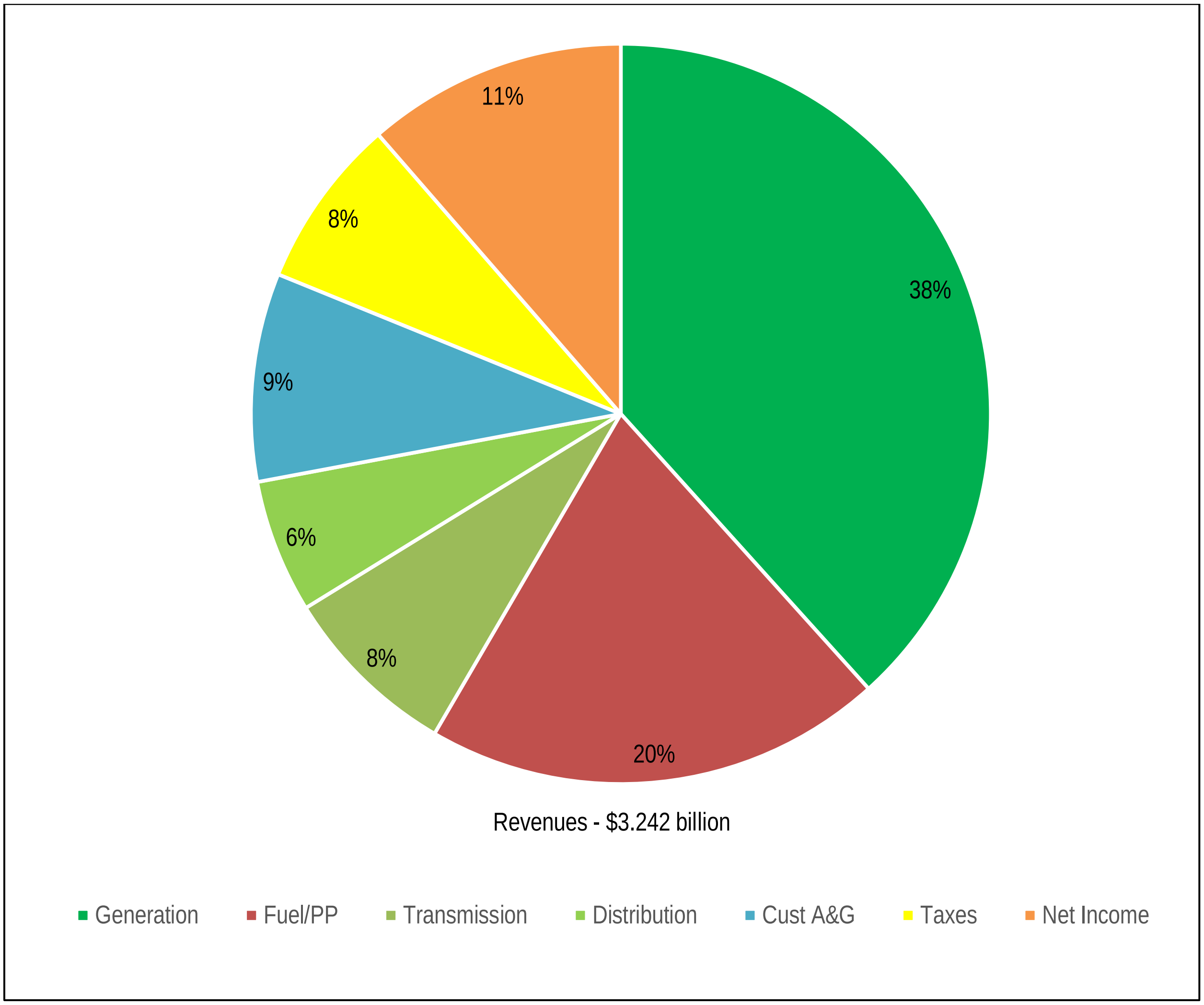
[52] Docket 6680-UR-120.

Figure 20 Revenue Requirement Components, Madison Gas and Electric[53]



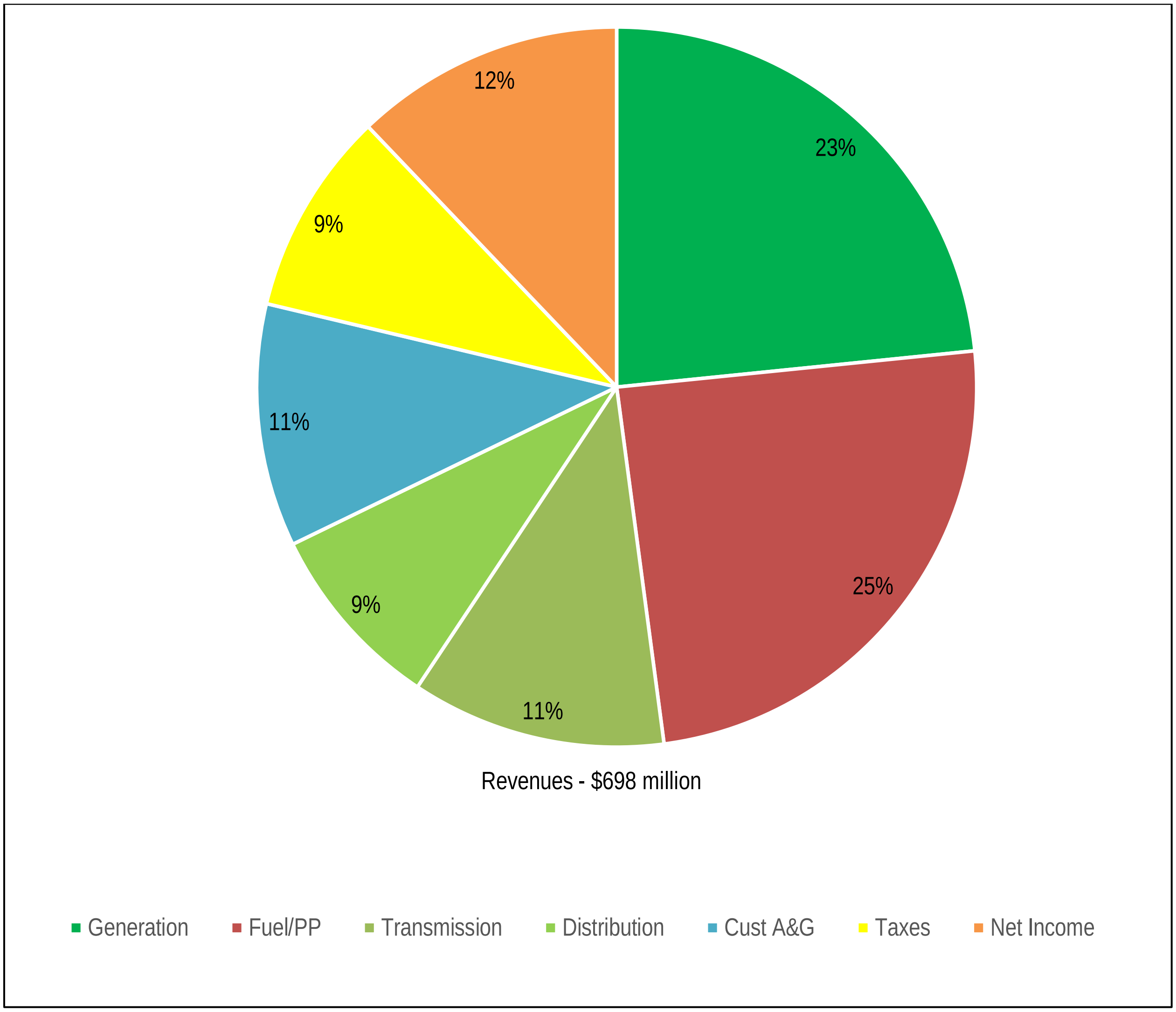
[53] Docket 3270-UR-121.

Figure 21 Revenue Requirement Components, Wisconsin Electric Power Company[54]



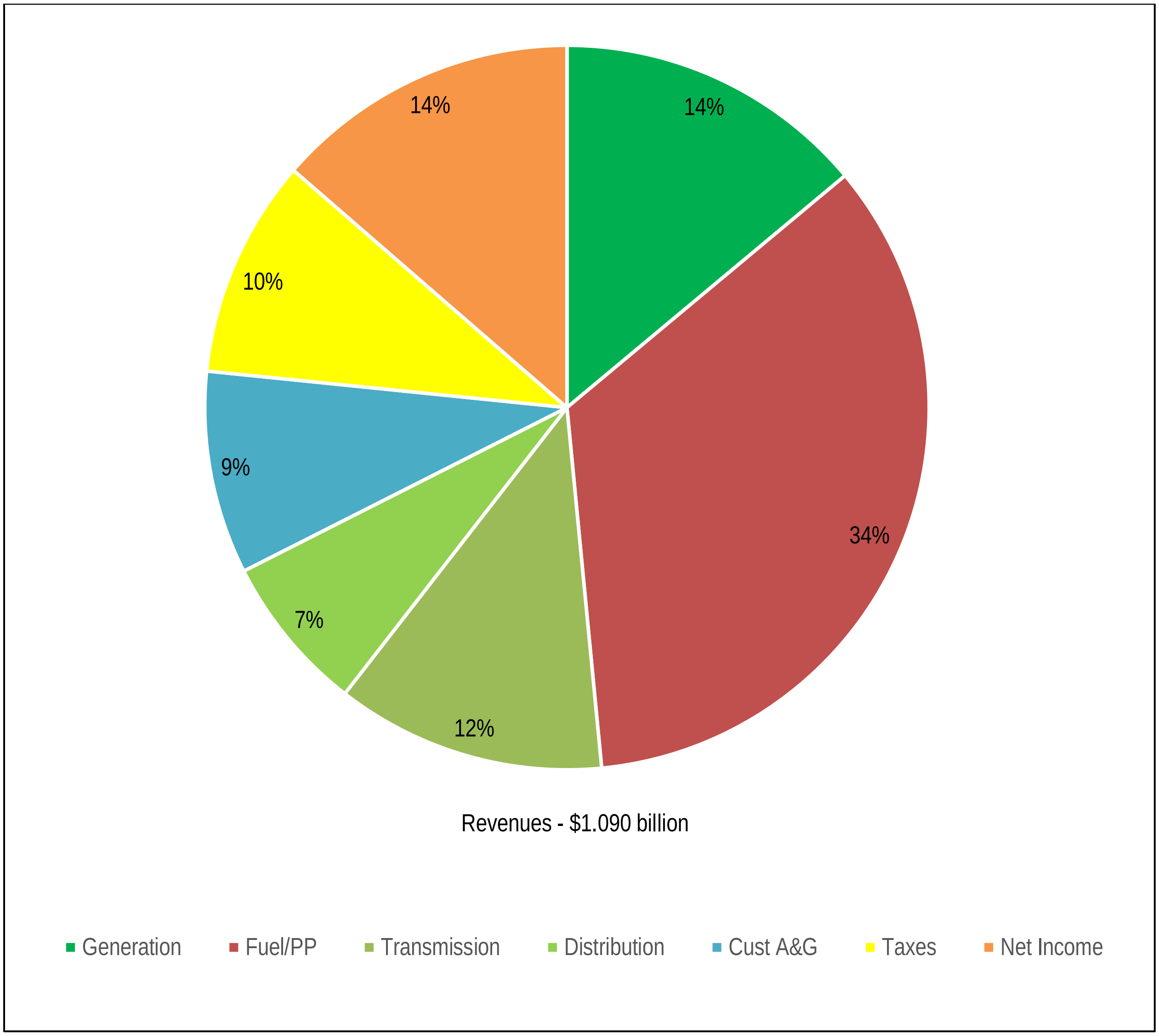
[54] Docket 5-UR-107.

Figure 22 Revenue Requirement Components, Northern States Power Company-Wisconsin[55]



[55] Docket 4220-UR-123.

Figure 23 Revenue Requirement Components, Wisconsin Public Service Corporation[56]



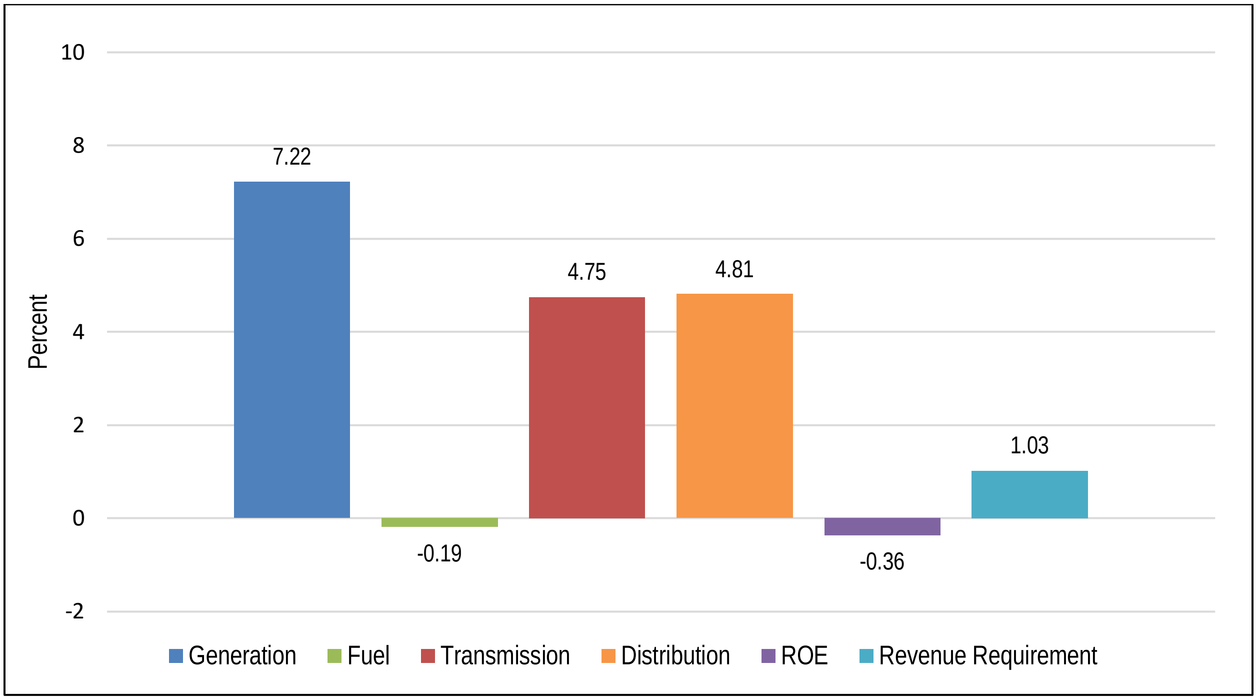
Figures 19 through 23 show the components of each major IOU's revenue requirement. Over time these components have grown at different rates, contributing to the growth in the overall revenue requirements and the subsequent growth in rates.

The components in Figures 24 and 25 are 5- and 8-year growth rates that exert upward or downward pressure on the overall revenue requirement. These statewide annual growth rates in 2016 provide context for the changes seen in revenue requirement at the end of the rate case process.

[56] Docket 6690-UR-124.

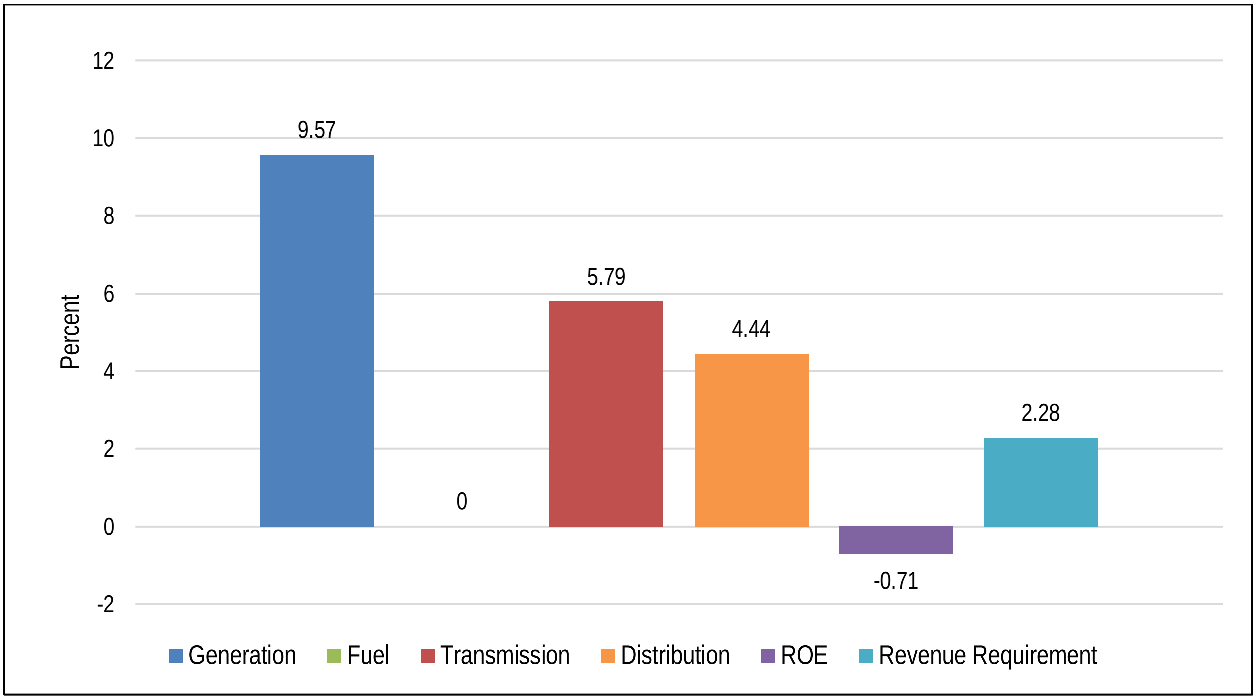
Of the revenue requirement components, the Commission has direct control[57] over generation, return on equity, and distribution investment for those projects exceeding the cost threshold. Fuel costs and transmission rates are mostly outside the Commission's control, and generally represent pass-through expenses.

Figure 24 Five-year Annual Growth, Rate of Revenue Requirement Components—Major IOUs (%)



[57] The Commission has direct control over operations and maintenance, but these growth rates are not included in the analysis due to data availability.

Figure 25 Eight-year Annual Growth, Rate of Revenue Requirement Components—Major IOUs (%)



While the corresponding components in the revenue requirement pie charts are figures from final rate case orders, the components in Figures 24 and 25 are compiled from proxy data[58]:

- Generation and distribution growth rate shows the increase in gross plant investment. This rate does not directly make up the generation or the distribution investment, but shows the recovery of that investment as depreciation expense, which is directly tied to new plant investment. In a rate case the Commission authorizes a projected amount of investment in distribution plant for the forward-looking test year for inclusion in the utility's revenue requirement.
- Fuel represents the monitored fuel costs subject to reconciliation under Wis. Admin. Code § PSC 116.
- Transmission shows the growth in the Schedule 9 network transmission charges (see Figure 26).
- The return on equity growth rate presented in Figures 24 and 25 reflects the growth in annual authorized returns on equity (ROE), weighted by each major IOU's net plant in service[59]. The ROE reflects the Commission's authorized compensation to the utilities' investors for providing equity capital to the utilities.

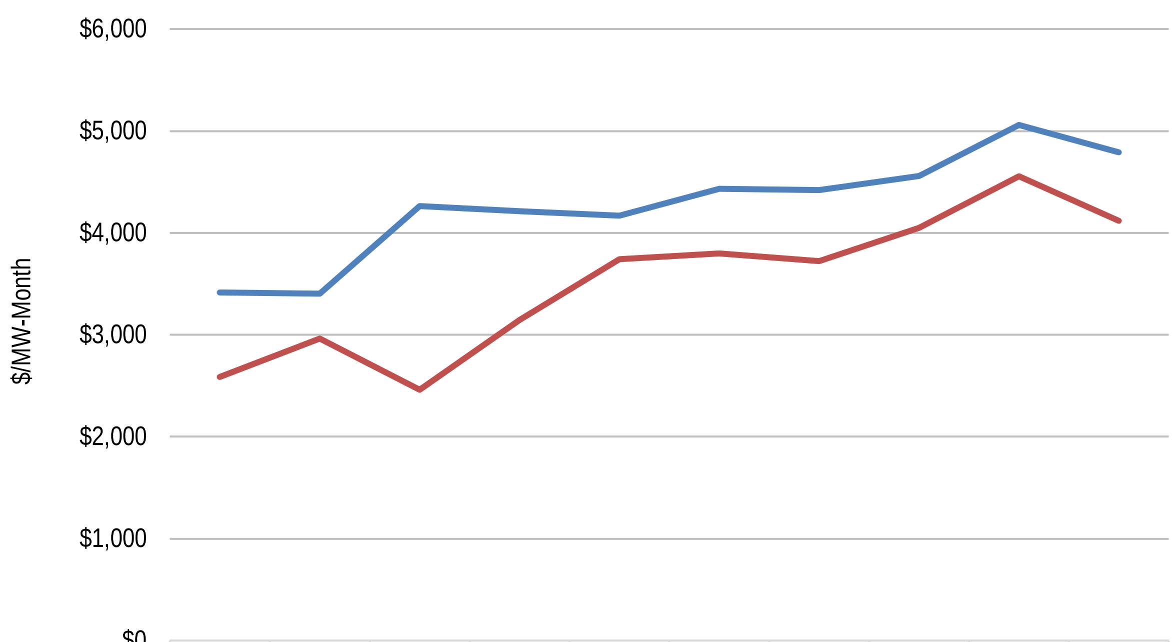
[58] Rate cases are not conducted annually, requiring the use of proxies when evaluating the pressure exerted by each component.
[59] Net plant in service is the gross plant less the accumulated depreciation reflected in the IOU's annual report, filed with the Commission.

Transmission expense is about 11 percent of a utility's revenue requirement, but it is an expense that is not under the direct control of most load-serving utilities. Over the last 10 years, the network transmission rates have increased by more than 40 percent. These are costs that the utilities must pass through to customers, and the PSCW does not have regulatory oversight of transmission rates.

Wisconsin is served by two transmission owners, ATC and Xcel Energy, whose network access transmission rates are approved at the federal level by FERC.

The Commission monitors and participates in workgroups and stakeholder processes through OMS and at MISO that help determine the cost allocation and need for future transmission lines within the regional grid prior to the submission of transmission tariffs at the federal level. Additionally, the Commission has the statutory authority to approve or deny any new transmission lines in Wisconsin if the Commission finds the new lines are not needed or too expensive. The Commission also may challenge transmission costs at FERC.

Figure 26 MISO Schedule 9 Network Transmission Charges ($/MW-Month)[60]



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
ATC	$3,416	$3,404	$4,260	$4,215	$4,169	$4,431	$4,419	$4,556	$5,059	$4,792
Xcel Energy	$2,588	$2,963	$2,461	$3,145	$3,744	$3,796	$3,721	$4,051	$4,555	$4,116

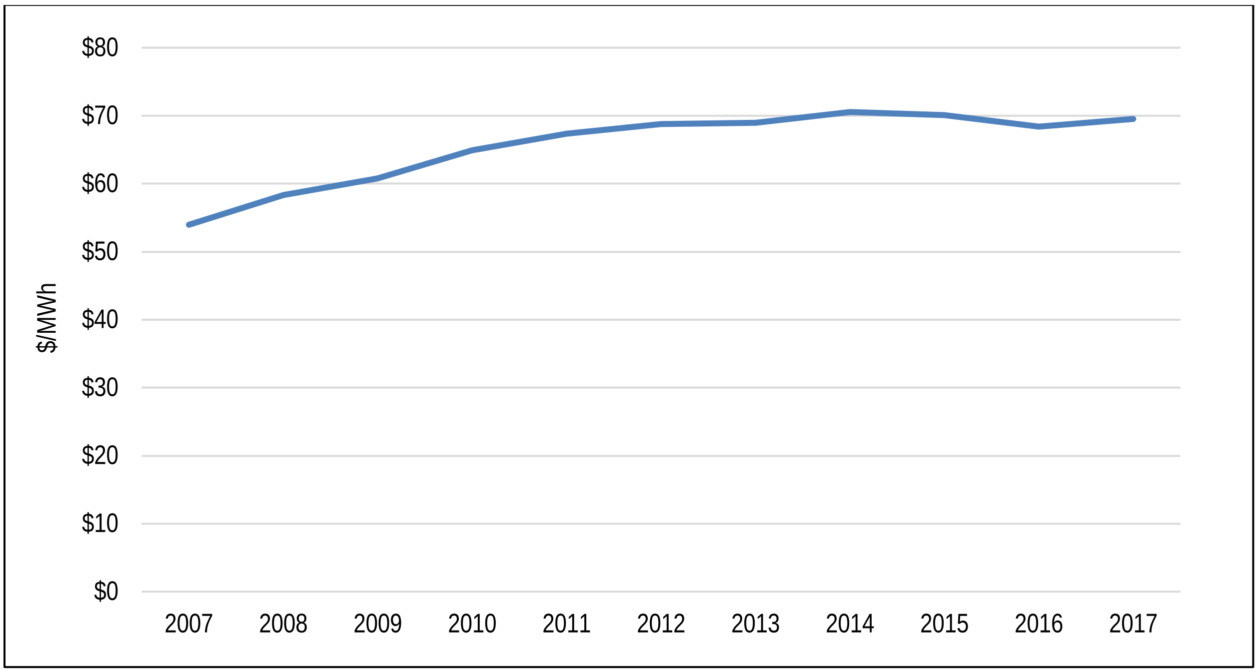
[60] Source: MISO Open Access Tariff, Schedule 9.

Non-Major Investor-Owned Utilities and Municipal Utilities

The non-major IOUs and all the municipal utilities have the same cost components as the major IOUs, with one exception. The majority, if not all, of their power supply and transmission expenses are contained within their wholesale energy contracts. Therefore, wholesale power costs are the main driver for rates for these utilities.

Statewide, the average cost of power has increased over the last 10 years, but has been relatively stable for the last five (see Figure 27). Even though this represents the wholesale cost of power, the costs do not follow the MISO market price of power. This is because most of the non-major IOUs and municipal utilities buy power under a wholesale tariff, which reflects the embedded cost of providing generation and transmission service.

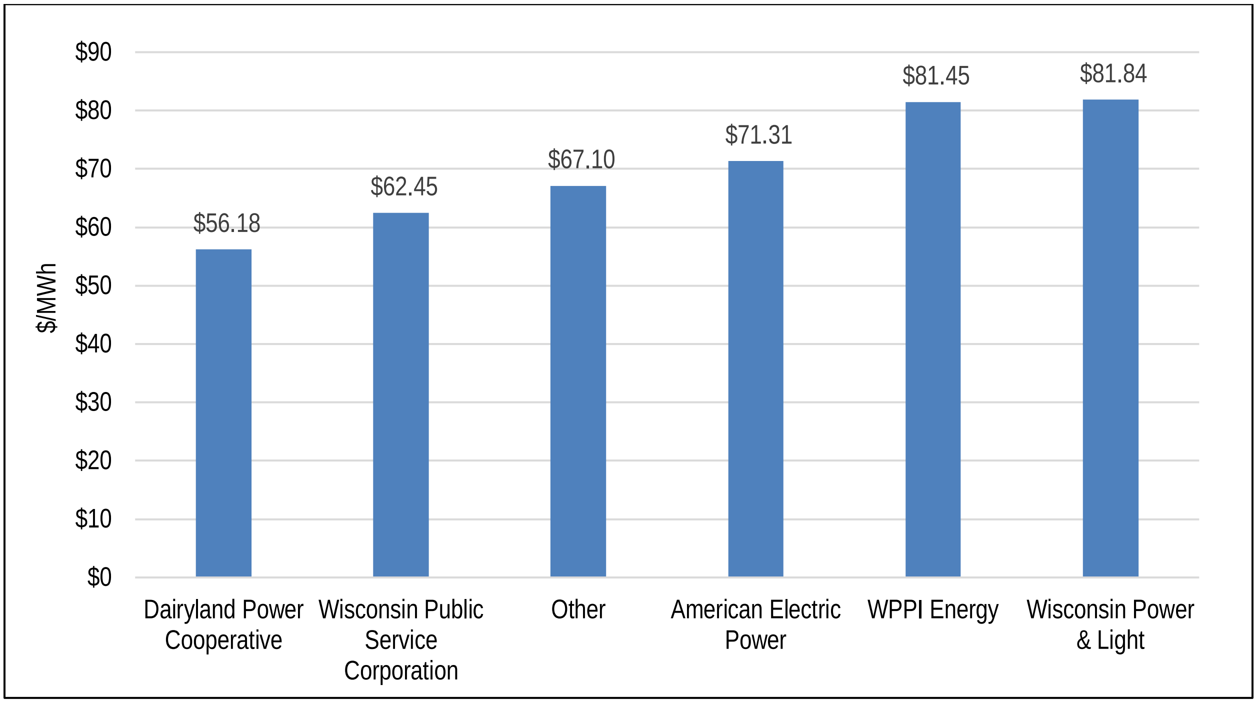
Figure 27 Statewide Average Purchased Power Cost ($/MWh)[61]



As a result, different wholesale suppliers can have different wholesale rates for the power they sell. Figure 28 shows the average wholesale power cost for each of the major wholesale providers in the state. These numbers reflect the total cost of power that the utilities pay for their power supply. If a utility has its own generation or flexibility in its power supply, its cost of power may be less than the contracted price from the wholesale supplier.

[61] Source: Monthly purchased power cost (PCAC) filings with the Commission.

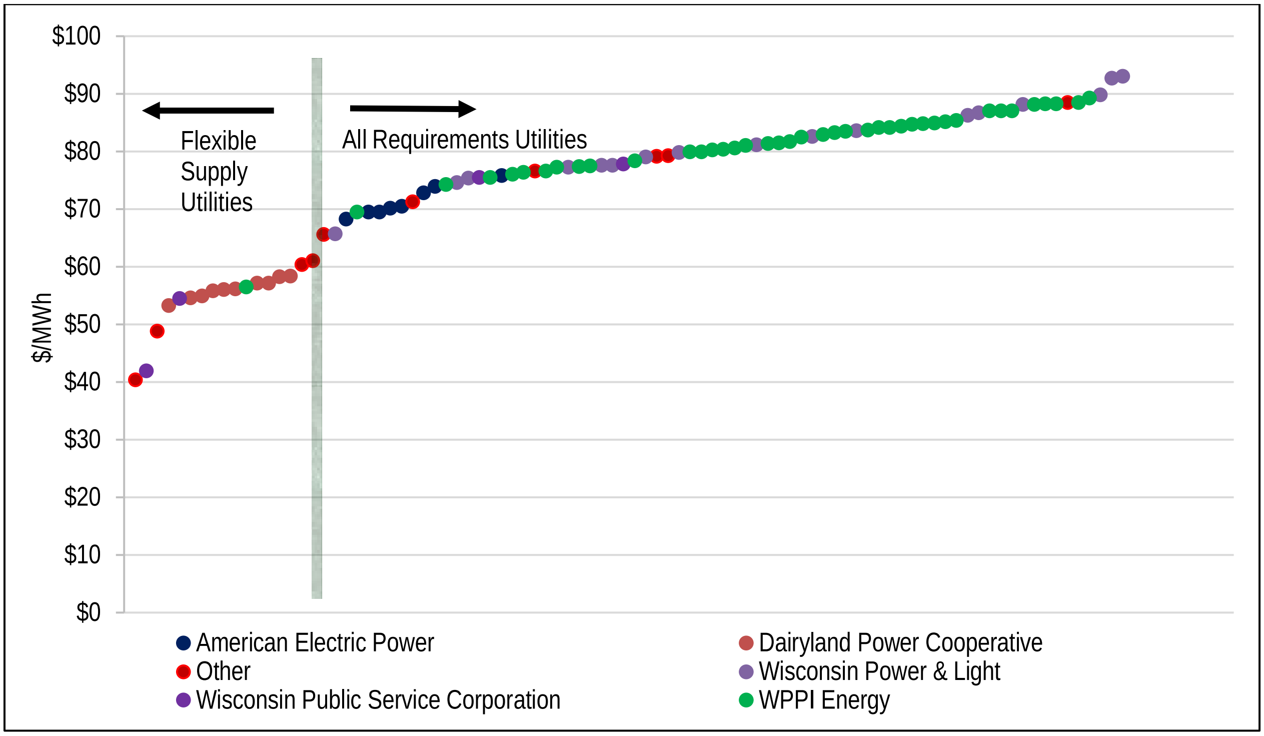
Figure 28 Average Power Cost by Vendor, 2017 ($/MWh)[62]



The actual cost of power paid by each retail utility can vary widely. In 2017, the cost of power ranged from $41/MWh to more than $90/MWh (see Figure 29). Figure 29 shows the cost curve for all the non-major IOUs and municipal utilities. Utilities that have flexibility in their power supply, either through owning their own generation or having the ability to source power from multiple suppliers, pay the lowest cost of power in the state. Utilities that take service under all requirements contracts pay more for power.

[62] Source: Monthly purchased power cost (PCAC) filings with the Commission.

Figure 29 Power Costs by Supplier, 2017 ($/MWh)[63]



Moving from Rates to Bills

In the earliest days of electric utility service, metering technology was not available to quantify customer consumption of electricity. Because this absence of technology made it impossible to measure actual usage, utilities charged its customers a flat fee that did not vary with usage.[64] As technology advanced, electric utilities have employed sophisticated measuring equipment to accurately quantify the customer consumption of electricity. Along with this advancement in measuring capability, utilities introduced more sophisticated rate structures with multiple billing determinants.

Billing determinants measure consumption used to calculate a customer's bill. A utility's billing determinants must follow its rate structure, which may be comprised of various charges, such as customer charges, energy charges, and/or demand charges.

For many customers, the most common component of their electric bill is the customer charge. The customer charge is a fixed charge added to each customer's monthly bill to cover the costs that typically do not vary by the amount of electricity used. Another common element of an electric utility bill is the energy charge. The energy charge bills customers for their volume of electric consumption in kWh. A final, less common billing element is a demand charge, which is based

[63] Source: Monthly purchased power cost (PCAC) filings with the Commission.
[64] Source: Public Utilities Reports, Inc., "Public Utilities Reports Guide: Principles of Public Utilities Operations and Management." Public Utilities Reports, Inc., 2011.

upon the peak electric capacity (measured in kW) demanded by a customer. Power service customer classes (e.g., small commercial and large industrial), in addition to a monthly customer charge and volumetric energy charge, pay demand-related charges. Power service customers have vastly different demand requirements and this variability makes it necessary for utilities to offer multiple rate structures that more closely align capacity needs with the costs those requirements place on the utility's system. To further pass along costs of service to its power service customers, many utilities have included discounts and adjustments to their demand rates. Ultimately, the complexity and unevenness of the demand billing determinants make it difficult to draw accurate comparisons among Wisconsin utility's power service rate classes.

In comparison, developing a residential rate comparison is relatively straightforward because the billing structure for residential customer classes is identical in most cases. The typical residential customer monthly bill is comprised primarily of two charges—a customer charge and an energy charge. The customer charge is set by the Commission in a utility's rate case and includes costs that do not vary with the usage of electricity such as metering, billing, and payment processing. To date, the Commission does not have evidence suggesting that the increase in residential and small commercial fixed charges has had an effect on energy use per customer. Encompassed within the energy charge are all the costs that are not included in the customer charge. Largely, the energy rate will include distribution service costs, as well as power supply and fuel costs, which are calculated as a price per kWh. The amount a customer pays for energy will depend on the electricity consumed during the billing period. Figure 30 compares the average monthly residential electric bills for the five largest Wisconsin IOUs, and Figure 31 compares the average monthly residential electric bill for municipal utilities. Both graphs are based on an assumed monthly usage of 650 kWh.

Figure 30 Average Monthly Residential Bills, Wisconsin Large IOUs[65]

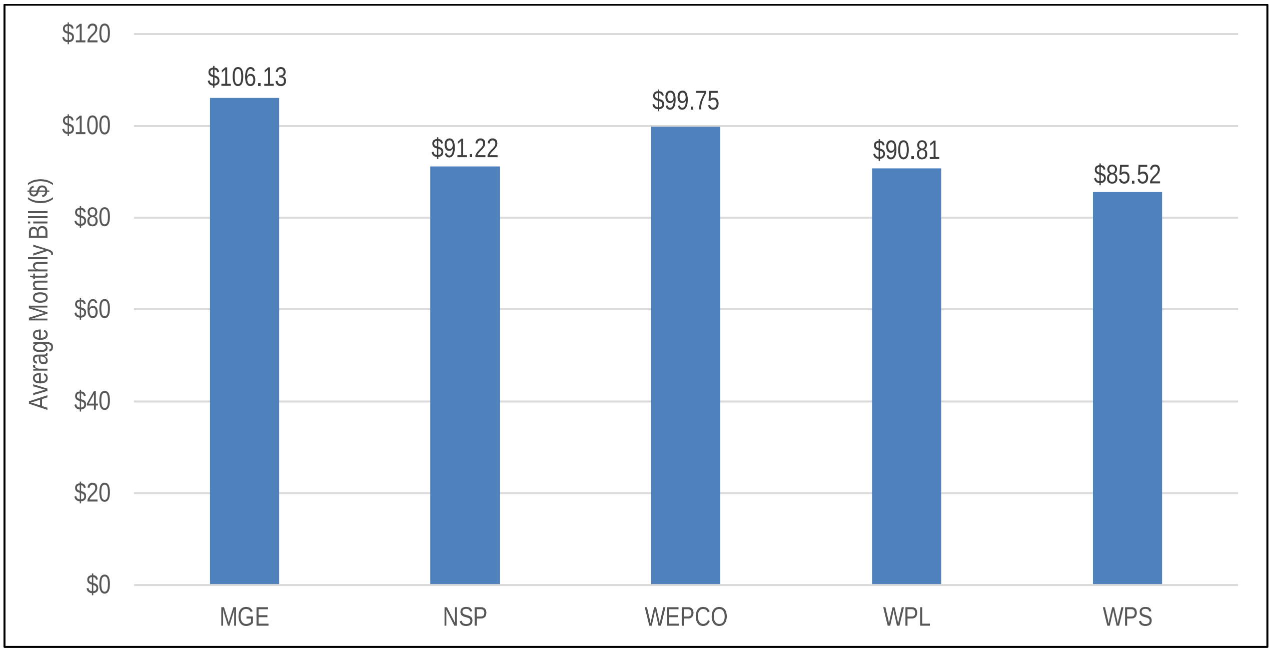
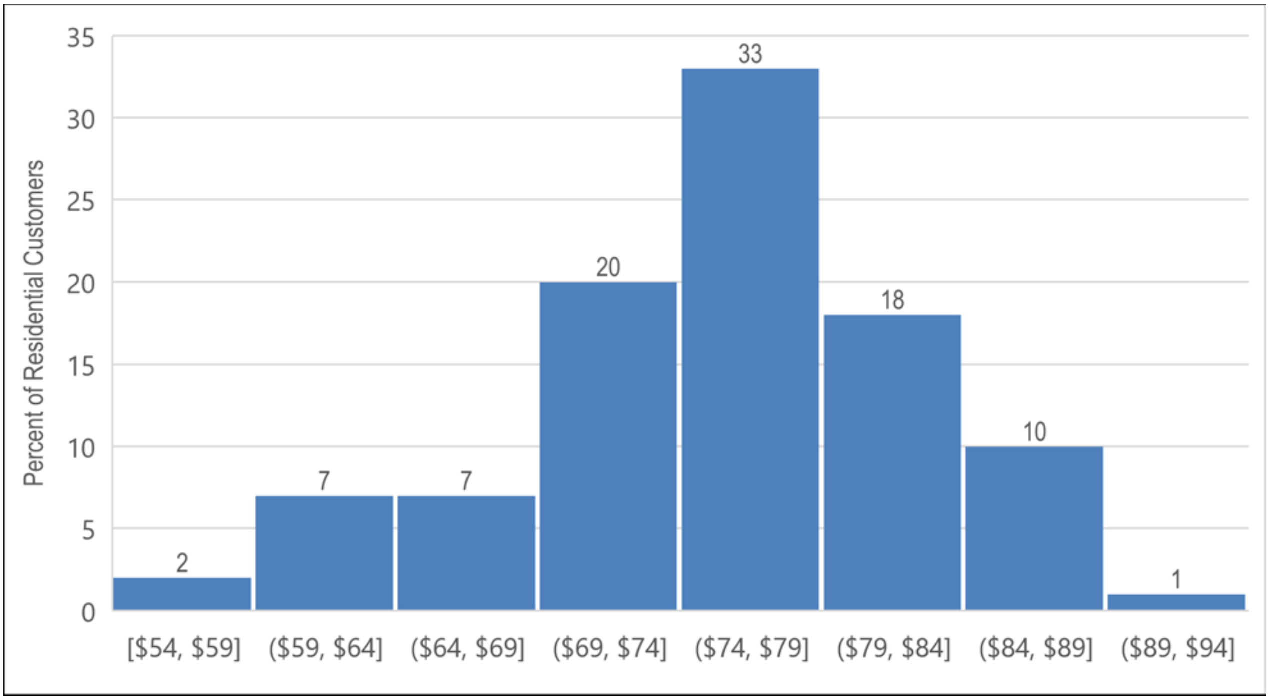


Figure 31 Distribution of Monthly Average Residential Bills, Municipal Utilities[66]

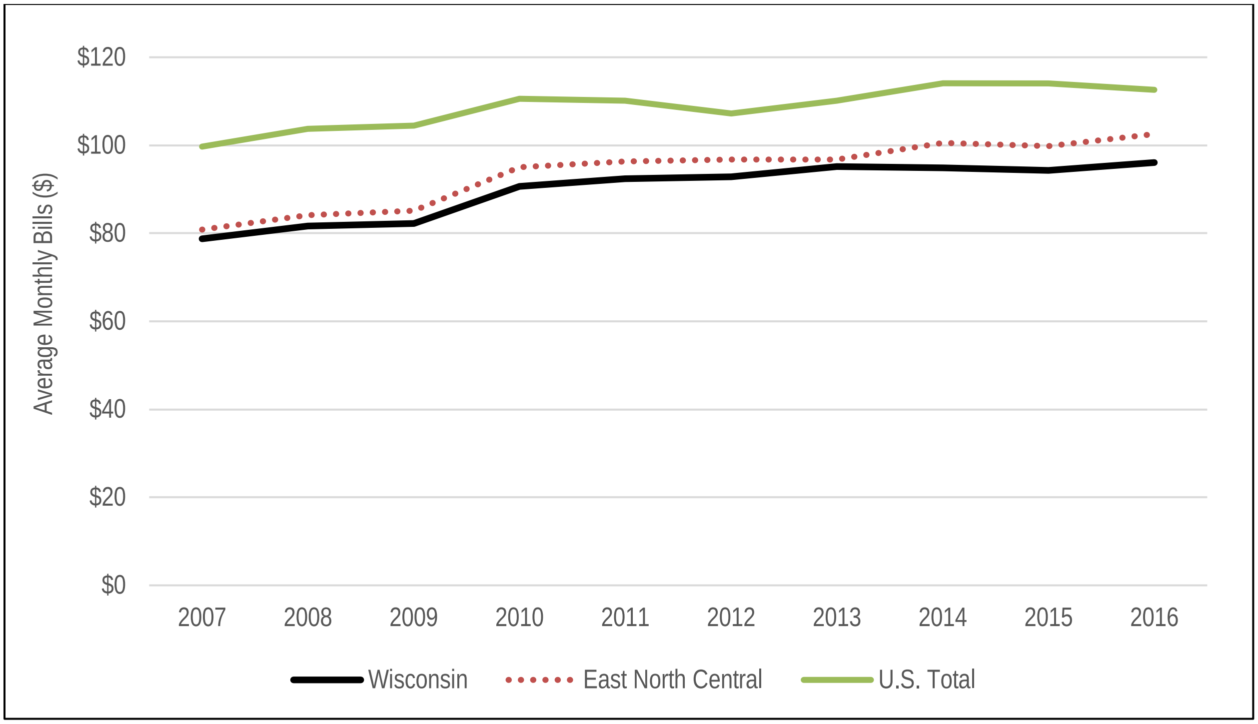


[65] Source: Major utility tariffs filed with the Commission, http://apps.psc.wi.gov/vs2010/tariffs/default.aspx.
[66] Source: Major utility tariffs filed with the Commission, http://apps.psc.wi.gov/vs2010/tariffs/default.aspx.

The above-referenced figures demonstrate that the average residential bill for Wisconsin utility customers ranges from $54 to just over $106 per month. For a large number of municipal utilities, the average residential bills range from $74 to $79.

As presented throughout this report, there are specific factors that account for the wide range of variability of monthly bills. However, as shown by Figure 32, the average Wisconsin residential electricity bill has trended below the national average and below that of the East North Central census division, which includes Wisconsin.[67]

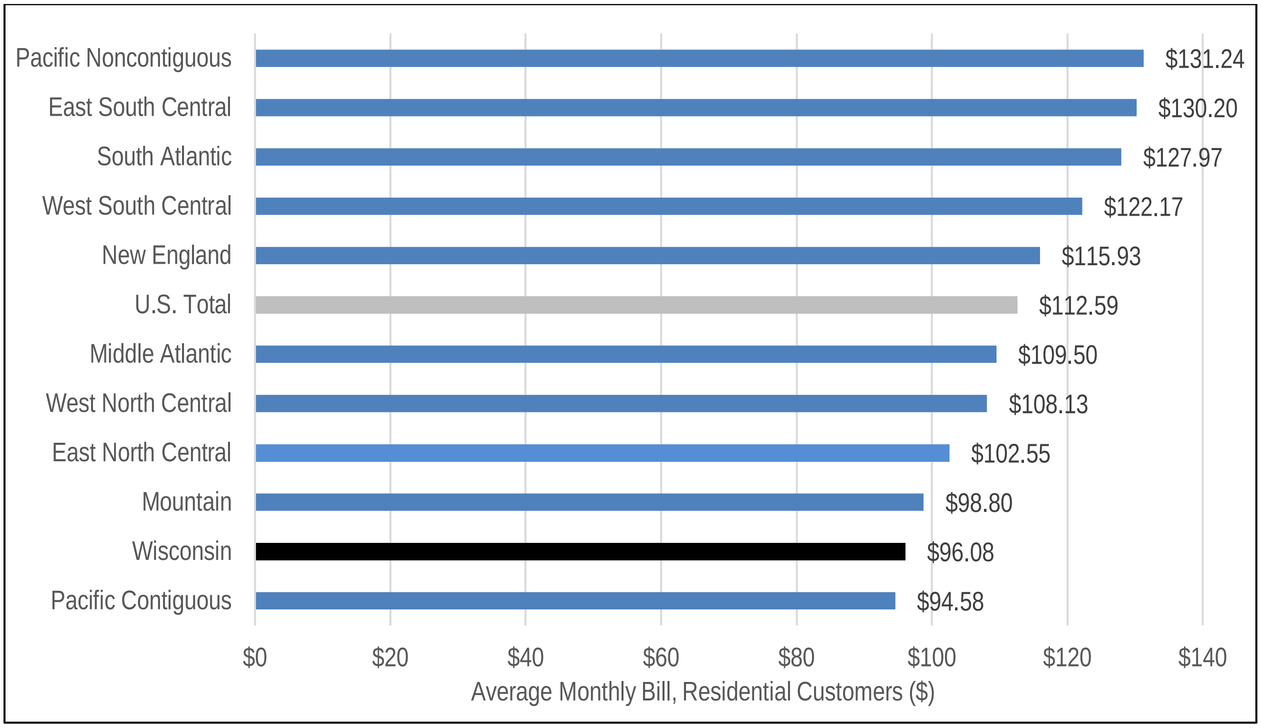
Figure 32 Ten-year History of Average Monthly Bills – Residential, 2007-2016[68]



A review of the 2017 monthly residential billing data compiled by the U.S. Energy Information Administration (EIA) further demonstrates how the residential bills of Wisconsin customers compare to other areas of the of the U.S. Figure 33 presents the results of EIA's analysis of the residential electric bills by census division, including Wisconsin and the U.S. average.

[67] According to the U.S. Energy Information Administration, the East North Central region is comprised of Illinois, Indiana, Michigan, Ohio, and Wisconsin.
[68] See previous editions of Residential Average Monthly Bill by Census Division and State at https://www.eia.gov/electricity/sales_revenue_price/.

Figure 33 2016 Average Monthly Bill – Residential, by Census Division[69]



The information presented in this assessment indicates that the actual bills paid by Wisconsin's residential customers are lower compared to the average monthly bills of residential customers throughout the U.S.

See the Appendix Figure A-1 for a map comparing the 2017 average residential bill for Wisconsin's municipal and investor owned utilities.

Wisconsin, Midwest, and National Rates and Trends

Direct rate comparisons between states can be misleading due to the complexities of energy regulation and the energy markets in general. For example, Wisconsin has several traditionally regulated and integrated utilities with regulated retail rates, and one stand-alone transmission company. Other states, such as Illinois, use a partially deregulated retail rate structure.

As described earlier, rates can vary widely based on several factors, such as whether a state is in a construction cycle for generating facilities or transmission infrastructure. Rates are also influenced by various regulatory rate structures used in the Midwest.[70] How a state and its electricity providers

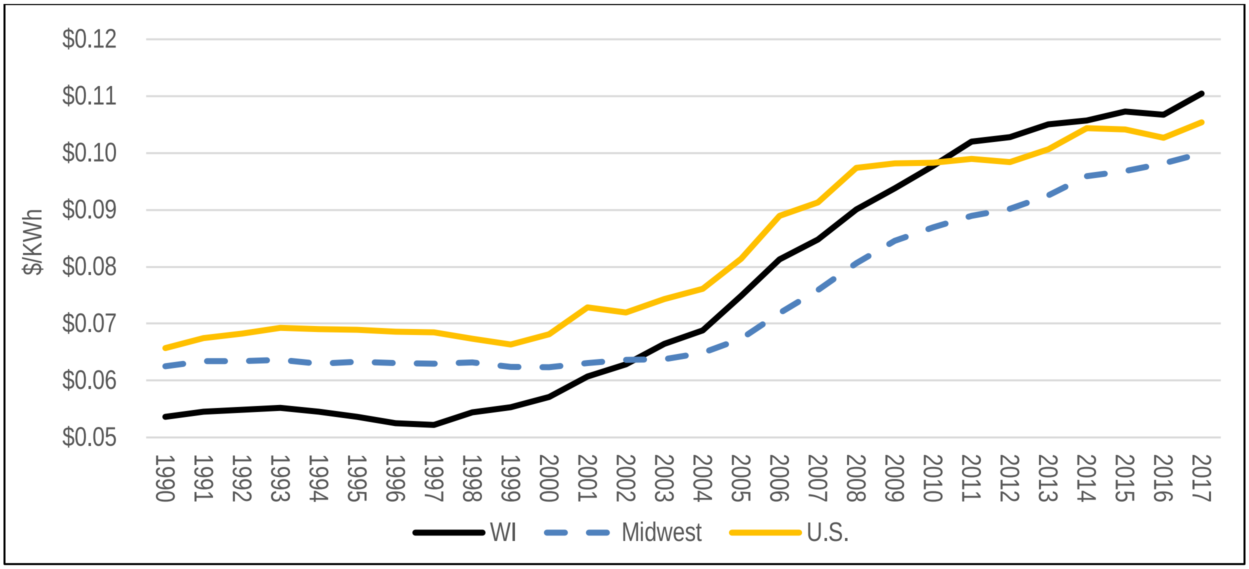
[69] Source: U.S. Energy Information Administration. 2016 Average Monthly Bill – Residential. https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf. Accessed 27 December 2017.

[70] The Midwest region as defined by the U.S. Census Bureau; includes Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin. The calculated Midwest average listed for all figures and tables includes all twelve of the regionally defined Midwest states.

handle the accounting behind the rate setting process—for example, if cost deferrals are allowed—can affect the timing of rate impacts. The treatment of fuel costs can also vary from state to state, and federal policy and regulations can also affect rates.

According to the EIA's June 2018 Electric Power Monthly report, the U.S. average electricity rates in the residential, commercial, and industrial classes has decreased. Wisconsin rates are slightly higher than the Midwest region and U.S. average for all rate class sectors.

Figure 34 Wisconsin, Midwest and U.S. Average Residential Utility Rates 1990-2017[71]



Tables 14 through 17 summarize average rates for residential, commercial, industrial, and all sectors in the Midwest and the country. [72]

Table 14 Residential Average Rates in the Midwest and U.S. (in cents)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Illinois	10.12	11.07	11.27	11.52	11.78	11.37	10.63	11.91	12.50	12.54	12.70
Indiana	8.26	8.87	9.50	9.56	10.06	10.53	10.99	11.46	11.57	11.79	11.95
Iowa	9.45	9.49	9.99	10.42	10.46	10.82	11.04	11.16	11.63	11.94	12.60
Michigan	10.21	10.75	11.60	12.46	13.27	14.13	14.59	14.46	14.42	15.22	15.47
Minnesota	9.18	9.74	10.04	10.59	10.96	11.35	11.81	12.01	12.12	12.67	13.19
Missouri	7.69	8.00	8.54	9.08	9.75	10.17	10.60	10.64	11.21	11.21	11.27
Ohio	9.57	10.06	10.67	11.31	11.42	11.76	12.01	12.50	12.80	12.47	12.37
Wisconsin	10.87	11.51	11.94	12.65	13.02	13.19	13.55	13.67	14.11	14.07	14.68
Midwest	9.24	9.78	10.29	10.78	11.19	11.54	11.70	12.09	12.43	12.61	12.81
U.S. Average	10.65	11.26	11.51	11.54	11.72	11.88	12.13	12.52	12.65	12.55	12.90

71 Source: U.S. Department of Energy, Energy Information Administration, Monthly Electric Utility Sales and Revenue Data (Form EIA-861M), June 27, 2018. Data for 2017 are preliminary EIA data.

72 Source: U.S. Department of Energy, Energy Information Administration, Monthly Electric Utility Sales and Revenue Data (Form EIA-861M), June 27, 2018. Data for 2017 are preliminary EIA data.

Table 15 Commercial Average Rates in the Midwest and U.S. (in cents)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Illinois	8.57	9.25	9.04	8.88	8.64	7.99	8.14	9.26	9.02	9.02	8.87
Indiana	7.29	7.82	8.32	8.38	8.77	9.14	9.60	9.96	9.78	10.01	10.30
Iowa	7.11	7.18	7.55	7.91	7.85	8.01	8.44	8.67	8.92	9.17	9.62
Michigan	8.77	9.17	9.24	9.81	10.33	10.93	11.06	10.87	10.55	10.64	11.02
Minnesota	7.48	7.88	7.92	8.38	8.63	8.84	9.42	9.85	9.44	9.86	10.58
Missouri	6.34	6.61	6.96	7.50	8.04	8.20	8.80	8.90	9.16	9.26	9.32
Ohio	8.67	9.23	9.65	9.73	9.63	9.47	9.35	9.83	10.07	9.97	9.97
Wisconsin	8.71	9.28	9.57	9.98	10.42	10.51	10.74	10.77	10.89	10.77	11.08
Midwest	7.91	8.38	8.58	8.83	9.05	9.11	9.37	9.75	9.71	9.81	9.97
U.S. Average	9.65	10.26	10.16	10.19	10.24	10.09	10.26	10.74	10.64	10.43	10.68

Table 16 Industrial Average Rates in the Midwest and U.S. (in cents)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Illinois	6.61	7.34	7.01	6.82	6.42	5.80	5.94	6.85	6.67	6.51	6.37
Indiana	4.89	5.46	5.81	5.87	6.17	6.34	6.70	6.97	6.86	6.97	7.39
Iowa	4.74	4.81	5.27	5.36	5.21	5.30	5.62	5.71	5.90	6.05	6.31
Michigan	6.47	6.73	6.98	7.08	7.32	7.62	7.72	7.68	7.02	6.91	7.32
Minnesota	5.69	5.87	6.26	6.29	6.47	6.54	6.98	6.72	7.02	7.37	7.73
Missouri	4.76	4.92	5.42	5.50	5.85	5.89	6.29	6.36	6.44	7.12	7.06
Ohio	5.76	6.20	6.72	6.40	6.12	6.24	6.22	6.77	7.02	6.98	6.69
Wisconsin	6.16	6.51	6.73	6.85	7.33	7.34	7.40	7.52	7.58	7.49	7.79
Midwest	5.66	6.08	6.35	6.32	6.39	6.44	6.65	6.96	6.94	6.99	7.11
U.S. Average	6.39	6.96	6.83	6.77	6.82	6.67	6.89	7.10	6.91	6.76	6.91

Table 17 All Sectors Average Rates in the Midwest and U.S. (in cents)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Illinois	8.46	9.23	9.15	9.13	8.97	8.40	8.26	9.36	9.40	9.38	9.33
Indiana	6.50	7.09	7.62	7.67	8.01	8.29	8.73	9.06	8.99	9.22	9.61
Iowa	6.83	6.89	7.37	7.66	7.56	7.71	8.07	8.15	8.35	8.55	8.92
Michigan	8.53	8.93	9.40	9.88	10.40	10.98	11.21	11.03	10.76	11.05	11.39
Minnesota	7.44	7.79	8.14	8.41	8.65	8.86	9.41	9.52	9.53	9.99	10.53
Missouri	6.56	6.84	7.35	7.78	8.32	8.53	9.04	9.11	9.44	9.74	9.83
Ohio	7.91	8.39	9.02	9.14	9.03	9.12	9.20	9.73	9.98	9.84	9.71
Wisconsin	8.48	9.00	9.38	9.78	10.21	10.28	10.51	10.57	10.73	10.67	11.05
Midwest	7.60	8.07	8.46	8.69	8.89	9.02	9.26	9.60	9.68	9.82	10.00
U.S. Average	9.13	9.74	9.82	9.83	9.90	9.84	10.07	10.44	10.41	10.27	10.54

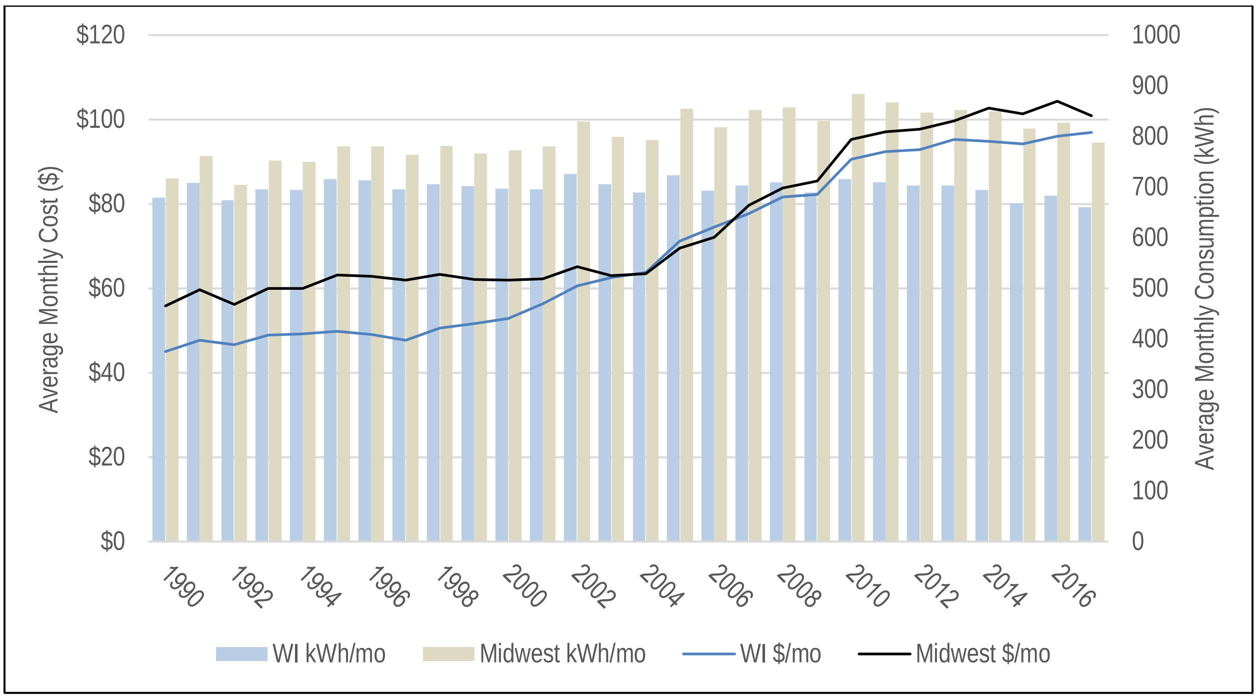
Beyond Rates: Electric Bill Affordability

The interplay among electric sales and rates components, and how rates compare across states, provides context to the larger question of how affordable and reasonably priced electric service is for Wisconsin's ratepayers.

One method of analyzing how customers are affected by current utility rates is to review the affordability of their rates. Affordability reviews the impact of monthly expenditures, including electric utility rates, on a customer's income to identify that portion of a customer's monthly income or expenditures that go toward electricity usage.[73] This also provides a useful comparison when reviewing the cost of utility service across states and the U.S. This approach to affordability is not necessarily a perfect picture of a customer's energy expenditures or energy burden, but it can reveal more information about how much customers pay each month for electric service, in contrast to evaluating only the rates charged by electric utilities.

Figure 35 shows that Wisconsin customers, on average, use about 200 kWh less per month than other Midwest customers (the bars in the graph) and have average monthly bills (the lines on the graph) that trail other Midwest customers by at least $10 a month.

Figure 35 **Average Residential Monthly Cost and Electricity Consumption in Wisconsin and the Midwest 1990-2017[74, 75]**



A key component of affordability is how much customers pay as a portion of their income on electricity costs. As Figure 36 shows, the percentage of monthly income that residential Wisconsin

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[73] Peter Heindl and Rudolf Schüssler, "Dynamic properties of energy affordability measures," *Energy Policy* 86 (2015): 123-126.

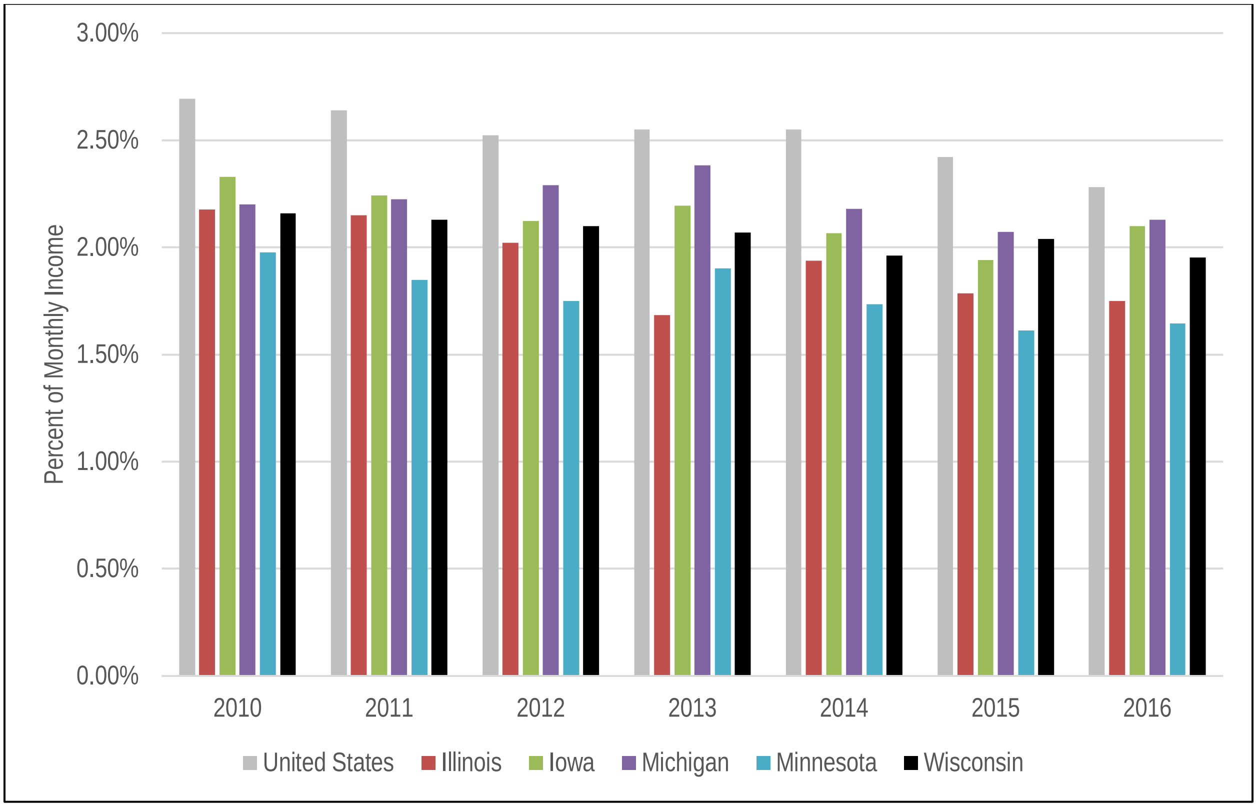
[74] The Midwest region as defined by the U.S. Census Bureau; includes Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin.

[75] Source: U.S. Department of Energy, U.S. Energy Information Administration, Monthly Electric Utility Sales and Revenue Data (Form EIA-861M), June 27, 2018. Data for 2017 are preliminary EIA data.

customers pay, on average, for electricity is in the middle of those states adjacent to Wisconsin, while clearly lower than the national average.

This measure does not necessarily consider the impacts of rate prices on customers across income types, as electricity prices may have a more significant burden on lower income households. Table 18 shows the impact of electricity costs on Wisconsin customers near the median income level of $59,817.[76]

Figure 36 Average Residential Electricity Costs as a Percentage of Monthly Income for Wisconsin, Adjacent States, and U.S.[77]



A more in-depth review of the impact of electric usage on monthly expenditures, as shown in Table 18, details that for those customers at or below 100 percent of the Federal Poverty Level, electric expenditures account for potentially 5 to 13 percent of monthly expenditures.[78] Looking

[76] For 2016. Source: Table H-8. Median Household Income by State," US Census Bureau, last modified August 20, 2017, accessed January 4, 2018, https://www.census.gov/data/tables/time-series/demo/income-poverty/historical-income-households.html.

[77] Source: U.S. Department of Energy, U.S. Energy Information Administration; US Census Bureau, Current Population Survey, Annual Social and Economic Supplement (ASEC)[77]

[78] Income thresholds for the Federal Poverty Guidelines (FPG) are based on a household size of three as the average Wisconsin household was reported to be 2.43 persons according to "QuickFacts: Wisconsin," U.S. Census Bureau, accessed February 26, 2018, https://www.census.gov/quickfacts/fact/table/WI/HSD310216#viewtop.

over the past few years, it does appear that there has not been a significant change in how much of a customer's monthly expenditures goes toward electricity usage. The income impact of electric usage on Wisconsin residential customers has consistently been in the middle of its adjacent neighbors, while below the average in the U.S.

Table 18 Residential Electricity Costs as a Percentage of Monthly Income at Varying Income Levels for Wisconsin, Adjacent States, and U.S.[79]

2016	Median Income	200% of FPL	100% of FPL	50% of FPL
United States	2.28%	3.34%	6.68%	13.37%
Illinois	1.75%	2.66%	5.33%	10.65%
Iowa	2.10%	3.08%	6.15%	12.30%
Michigan	2.13%	3.02%	6.03%	12.06%
Minnesota	1.64%	2.86%	5.73%	11.46%
Wisconsin	1.95%	2.90%	5.80%	11.59%
2015				
United States	2.42%	3.41%	6.81%	13.62%
Illinois	1.79%	2.69%	5.37%	10.74%
Iowa	1.94%	2.94%	5.88%	11.77%
Michigan	2.07%	2.80%	5.59%	11.18%
Minnesota	1.61%	2.76%	5.52%	11.03%
Wisconsin	2.04%	2.81%	5.63%	11.26%
2014				
United States	2.55%	3.46%	6.92%	13.84%
Illinois	1.94%	2.69%	5.38%	10.76%
Iowa	2.07%	3.02%	6.03%	12.06%
Michigan	2.18%	2.87%	5.73%	11.46%
Minnesota	1.74%	2.95%	5.90%	11.79%
Wisconsin	1.96%	2.88%	5.76%	11.51%

Table 18 shows that Wisconsin residential customers pay a similar portion of their income each month for electric costs when compared with adjacent states in the Midwest, across income levels. For those customers at lower incomes or with a greater energy burden, some state-level assistance is available to mitigate the monthly costs for electricity, although the remaining, monthly electric costs could still remain high for those customers.

ENERGY EFFICIENCY

Energy efficiency programs provide incentives and technical assistance for residents and businesses to take measures that reduce energy use. In 1999, state legislation established a statewide electric and natural gas energy efficiency and renewable resource program, Focus on Energy (Focus). 2005 Wisconsin Act 141 made a number of statutory changes related to Focus, including moving oversight of the program from the Department of Administration to the Commission, and requiring

[79] Prior HHS Poverty Guidelines and Federal Register References," U.S. Department of Health & Human Services, last modified January 13, 2018, accessed February 26, 2018, https://aspe.hhs.gov/prior-hhs-poverty-guidelines-and-federal-register-references/.

IOUs to fund Focus at a level of 1.2 percent of annual operating revenues. Municipal electric utilities and electric cooperatives are required to collect an average of $8.00 per meter per year, and have the option of using this revenue for either joining Focus or running their own energy efficiency programs.

As of 2017, all IOUs and municipal electric utilities are participants in Focus. Of the 24 electric cooperatives in the state, 13 run their own programs while 11 participate in Focus. Some investor-owned and municipal utilities run voluntary energy efficiency programs that provide additional benefits to their customers beyond what Focus offers.[80]

Focus offers energy efficiency support through a portfolio of multiple programs that offer different types of energy efficiency products and services to different customer segments, from homeowners and farms to small businesses and industrial facilities. Energy efficiency program expenditures in a given year typically result in energy savings that persist for multiple years in the future, as participants continue to use their energy-saving products and services.

Independent program evaluators, led by the Cadmus Group (Cadmus), report on Focus' cost-effectiveness and take the persistence of the measures into consideration. For 2016, Cadmus's program cost-benefit analysis concluded that for every dollar spent, Focus' full portfolio of programs achieved $3.00 in lifecycle benefits.[81] In order to realize energy savings on the electric side, it cost an average of $.0169 cents per kilowatt-hour (cost of conserved energy). These analyses only count benefits from savings that the program evaluator affirms were attributable to Focus program implementation, and exclude the savings from "free-rider" participants who would have taken the same energy-saving actions without Focus' support. This continual evaluation process allows the Focus program to follow the objective of creating cost-effective reduction in energy use and demand that would not have occurred had the program not existed.

Under Wis. Stat. § 196.374(2)(a), Focus is operated by a third-party program administrator, under a contract established by IOUs and approved by the Commission. 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 first quadrennial planning process was completed in 2010, and set electric and natural gas savings goals. APTIM (formerly Chicago Bridge and Iron (CB&I)) was selected to serve as the Focus program administrator for 2011 to 2014 under a performance contract which provided financial incentives for exceeding the Commission's savings goals. The second quadrennial planning process set updated savings goals for 2015-2018 and was followed by an extension of APTIM's program administration

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

[81] Focus reports cost-effectiveness based on a modified Total Resource Cost (TRC) test which compares the benefits of energy savings and avoided emissions of regulated air pollutants to the costs of program administration and implementation and the costs borne by participants. For informational purposes, Focus also conducts an "expanded TRC" test which incorporates the economic benefits created by Focus. In 2016, the program evaluator's expanded TRC analysis found that Focus created net economic benefits of $348 million and achieved $4.32 in benefits for every $1.00 in costs.

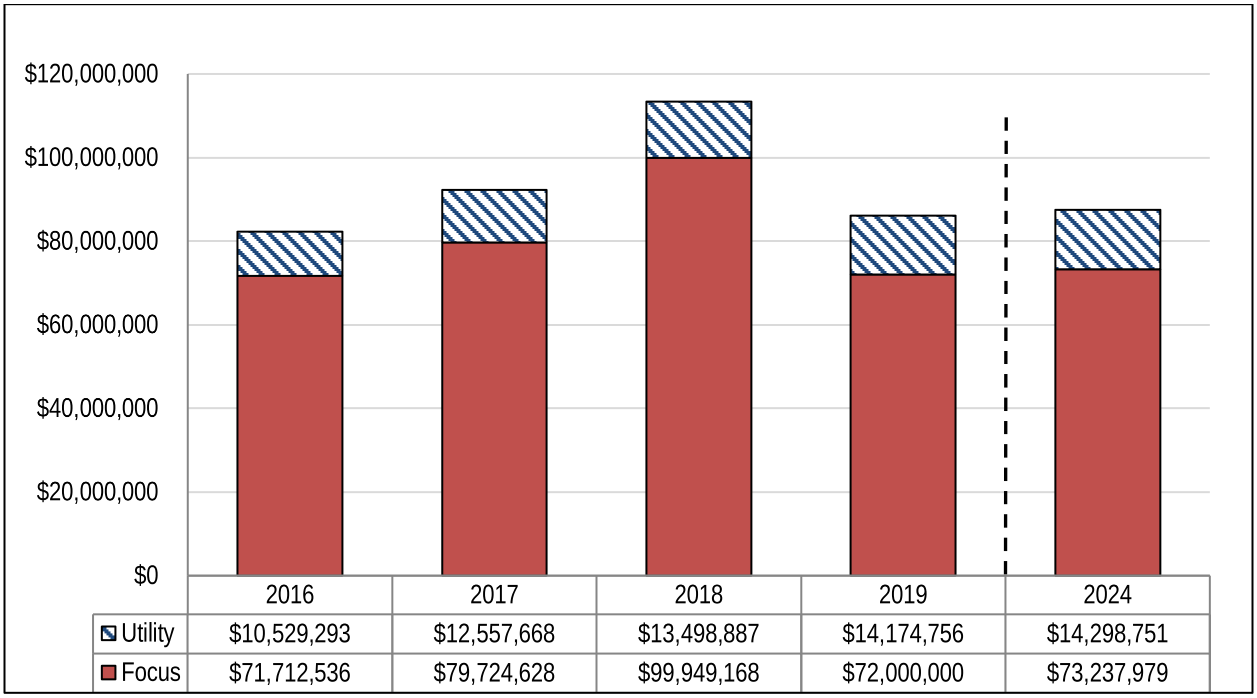
contract. The third quadrennial planning process will be completed in the spring of 2018. In summer of 2018, a request for proposal process will be initiated to select a program administrator for the 2019 to 2022 period.

To inform the determination of savings goals for 2019 to 2022 and beyond, the Commission authorized the independent program evaluator to conduct a potential study projecting the amount of future energy efficiency savings Focus could achieve. The final study, released in July 2017, used data on customers' existing energy use practices and available energy efficient technologies to assess achievable energy savings under a "business as usual" scenario that maintained Focus' existing program policies and funding levels. The study also assessed how the amount of available savings could change under alternative scenarios, such as policy changes the Commission could make in the 2018 quadrennial planning process. In the absence of any policy changes to date, the business as usual scenario is used as the basis for projected Focus on Energy expenditures and savings below.

As shown in Figure 37, projected Focus expenditures on electric energy efficiency increased in 2017 and more substantially in 2018, before returning to 2016 levels for 2019 onwards. This temporary increase reflects the Commission's decision in 2016 to allocate $26 million in surplus Focus funds on programs targeting rural customers, who have been historically underserved by Focus programs. Total funds were allocated for the 2-year period of 2017 and 2018; because spending has been limited in 2017 as programs are designed and implemented, Figure 37 projects that the substantial majority of funds will be spent in 2018.

These projections are based on available budgets, but it is possible that some rural programs may not use all allocated funding. If that occurs, unspent funds may be allocated to 2019 programs and increase total spending above the current projection. Spending projections in 2024 reflect a limited increase from actual 2016 and projected 2019 levels, based on the projections of some utilities that their Focus contributions will gradually increase throughout the analysis period.

Figure 37 Actual and Projected Annual Electric Energy Efficiency Expenditures 2016-2024[82]



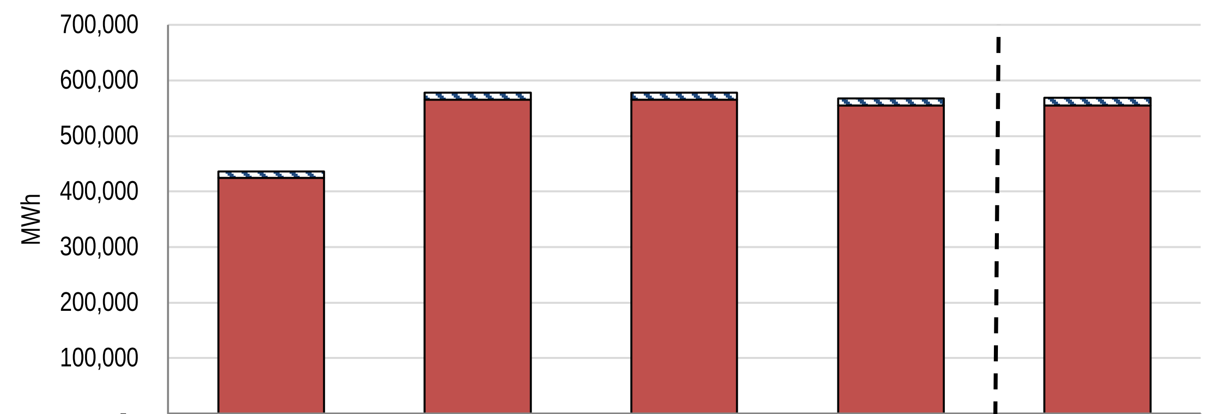
As shown in Figures 38 and 39, Focus savings do not increase as much as expenditures in 2017 and 2018. This reflects the Commission's recognition that many of the programs supported by the rural initiative are either "pilot" efforts intended to explore new technologies and program approaches, or relatively high-cost efforts compared to existing Focus programs, due to the increased customer service and outreach costs necessary to reach rural customers. Although these higher-cost efforts may decrease Focus' cost-effectiveness relative to its current achievement of $3.00 in benefits for every $1.00 in costs, the program can be expected to retain benefits in excess of cost while improving its service to rural customers.

Projected savings in 2019 reflect the finding of the potential study that Focus' current levels of savings achievement can be sustained—and for electric demand, increased—in the 2019 to 2022 quadrennial period. Although Focus will be able to achieve diminishing amounts of savings from long-established measures, such as Compact Fluorescent Light (CFL) bulbs and furnaces, the study found those decreases are offset by increased savings opportunities from newer technologies such as Light Emitting Diode (LED) light bulbs and smart thermostats. Savings are projected to stay at the same level through 2024, reflecting the assumption that new savings opportunities will continue to arise in future years. The potential study's review of alternative scenarios found that available savings should remain at the projected levels even if the Commission implements Focus policy changes, as long as funding levels remain the same. Projected savings would only change if Focus

[82] Sources: Aggregated electricity provider data responses, docket 5-ES-109; Focus on Energy 2016 Evaluation Report; Focus on Energy 2015 to 2018 Program Administration Contract.

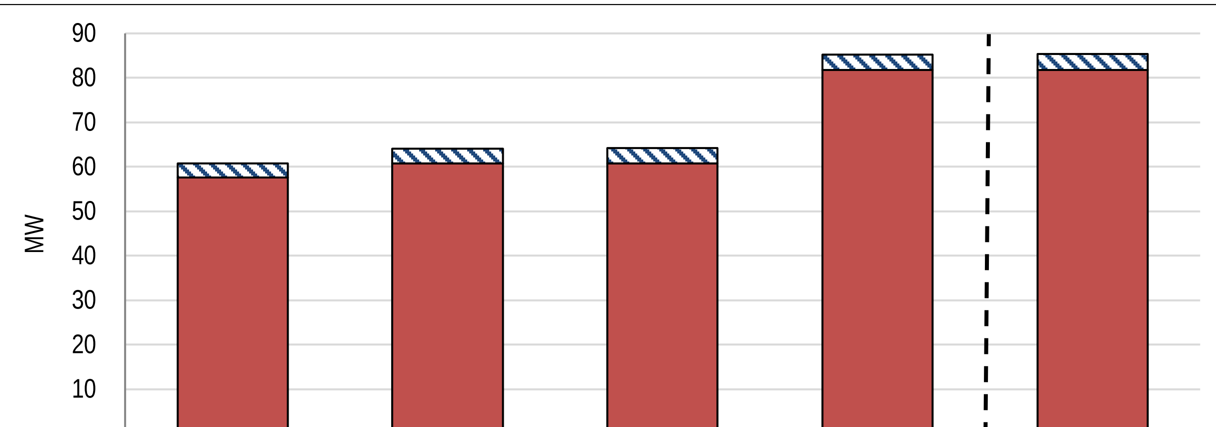
funding was modified, in which case savings would decrease or increase in accordance with the change in funding levels.

Figure 38 Actual and Projected First-Year Annual Energy Savings 2016-2024[83]



	2016	2017	2018	2019	2024
Utility	12,291	12,516	12,629	12,744	13,344
Focus	424,177	565,373	565,373	555,300	555,300

Figure 39 Actual and Projected First-Year Annual Demand Savings 2016-2024[84]



	2016	2017	2018	2019	2024
Utility	3	3	3	3	4
Focus	58	61	61	82	82

While Focus accounts for the largest share of energy efficiency activity in the state, DPC, MGE, NSPW, SWL&P, WEPCO, WP&L, WPPI, and WPSC all provide additional energy efficiency

[83] Sources: Aggregated electricity provider data responses, docket 5-ES-109; Focus on Energy 2016 Evaluation Report; Focus on Energy 2015 to 2018 Program Administration Contract; 2017 Focus on Energy Potential Study.

[84] Source: Aggregated electricity provider data responses, docket 5-ES-109; Focus on Energy 2016 Evaluation Report; Focus on Energy 2015 to 2018 Program Administration Contract; 2017 Focus on Energy Potential Study.

services, as shown in Figures 37, 38, and 39. Some of the expenditures for these energy efficiency services include educational and marketing activities. These do not have quantifiable savings of their own but help increase Focus savings by informing customers of Focus offerings and encouraging participation. Some utilities also fund and operate their own energy efficiency programs,[85] although savings achieved by those programs remain small relative to Focus savings achievements. Figures 37 through 39 show that all utilities expect that funding levels and savings achieved from their own activities will remain generally consistent with current levels through 2024.

RENEWABLE RESOURCES

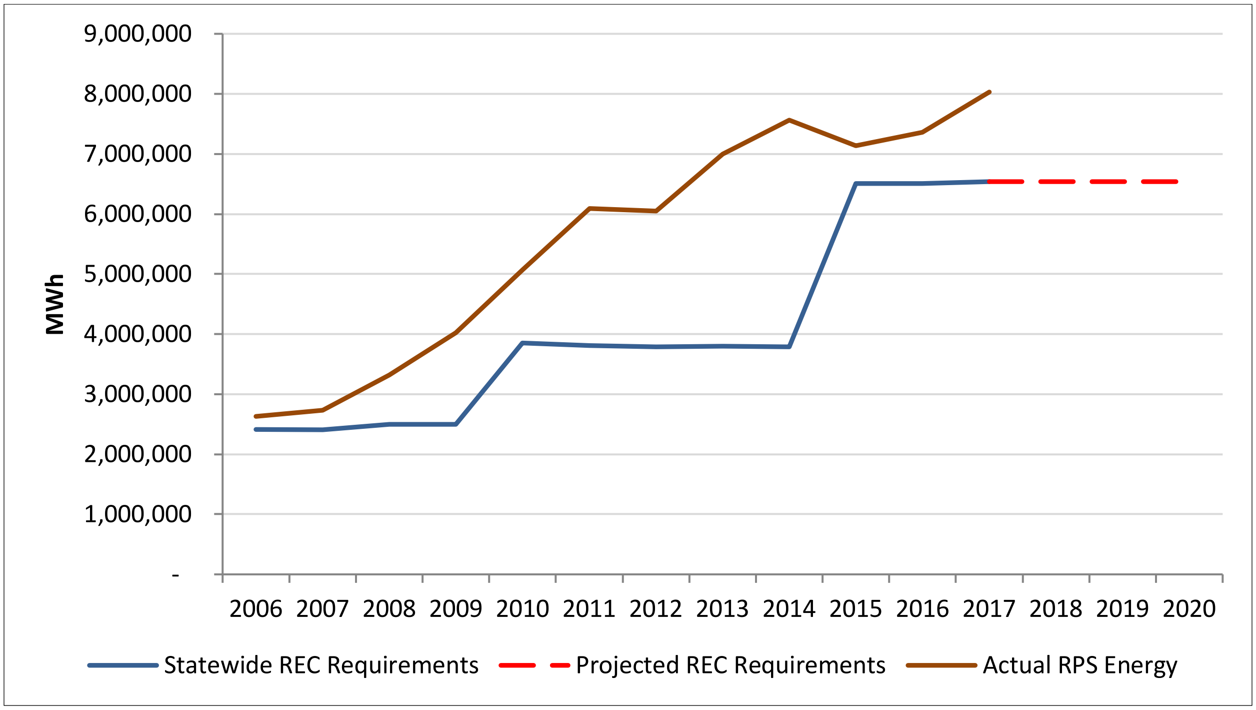
The primary driver for renewable resource development by Wisconsin electric providers over the last decade has been Wisconsin's RPS. However, recent electric provider investments in renewable resources have been driven by several other factors, including declining costs, customer demand, tax incentives, and utility corporate sustainability goals.

The RPS requires electric providers to add to their individual 2001 through 2003, 3-year average renewable baseline percentages. These baselines represent the renewable energy percentage amounts that electric providers used to serve their customers during that period. The RPS requires electric providers to increase their renewable percentages by two percent above baseline by 2010, increase to 6 percent above baseline by 2015, and sustain that level thereafter. These requirements support the RPS statewide goal to have at least 10 percent of all electricity provided to Wisconsin retail customers from renewable resources by 2015.

Individual electric provider requirements have been met every year, and the statewide goal was achieved every year from 2013 through 2017. Based on electric provider announced expansion plans, this goal will be achieved through at least 2020. As shown in Figure 40, electric providers will likely generate or procure annually eight million MWh from renewable resources for the foreseeable future.

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

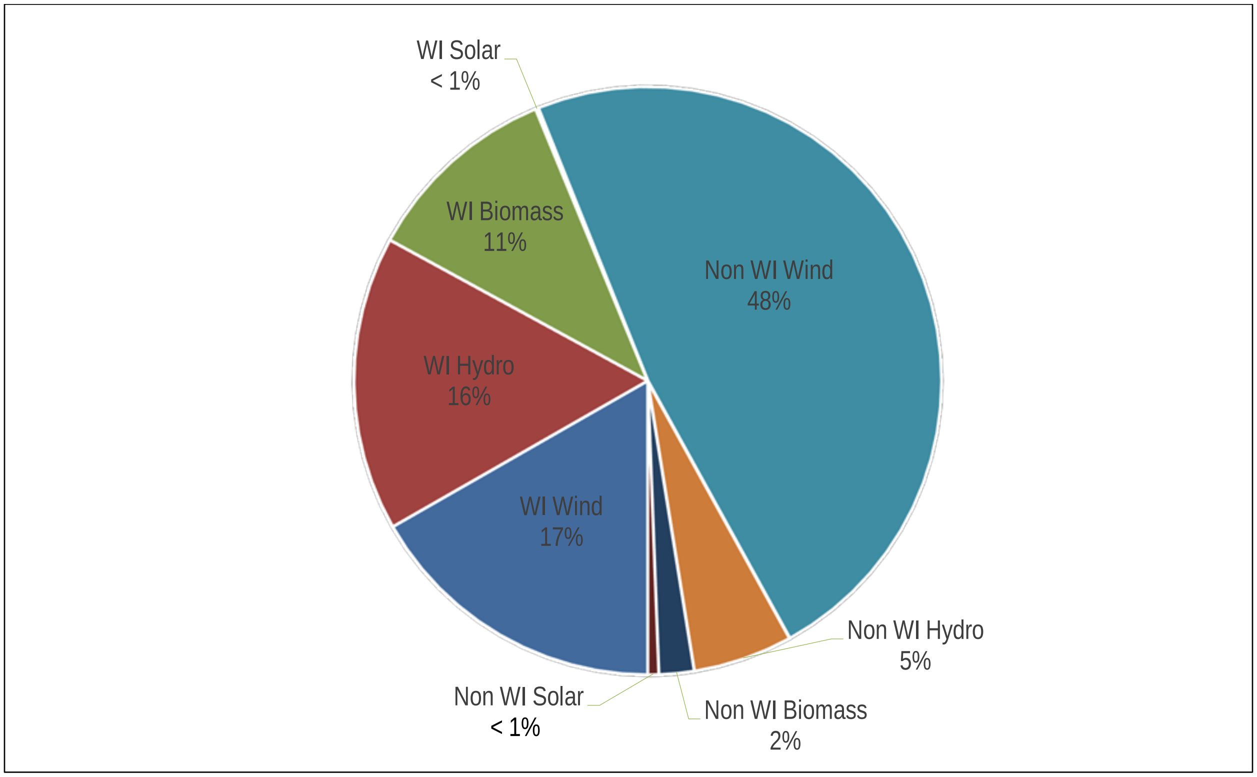
Figure 40 Statewide RPS Renewable Energy (Actual vs. Required 2006-2020)[86]



Figures 41 and 42 below present renewable statistics by resource type and location for 2017, as well as renewable generation over time, from 2010 through 2017. Figure 41 shows that, of the renewable resources serving Wisconsin retail customers in 2017, almost two-thirds came from wind. Most of these wind facilities are located in states west of Wisconsin. Figure 42 shows that, in general, wind generation by Wisconsin electric providers grew significantly over the 2010 through 2017 period, while biomass and hydro resources remained relatively constant. Solar resources registered for the RPS are relatively minimal, and as a result solar generation is not included in Figure 42. Solar energy statistics are better captured in the Distributed Energy Resources section of this report.

[86] Requirement projection out to 2020 based on 0 percent electricity use growth. Source: Commission Staff 2016 RPS Compliance Memorandum (PSC REF#: 344905).

Figure 41 2017 Renewable Energy by Resource and Location[87]



Most electric providers also have voluntary programs that go beyond RPS requirements. Green Pricing Programs allow customers to sign up and pay a small premium for additional renewable energy. For these programs, electric providers must either build renewable facilities, or contract with independent power producers to generate enough renewable energy to ensure supply meets customer demand. Electric providers are also starting to investigate customer demand for community-based renewable facilities. MGE's Shared Solar program[88] allows customers to subscribe to shares from a 500 kW solar array within its service territory. The program quickly became fully subscribed, and MGE created a waitlist to measure demand for additional capacity. Electric providers also cite business case reasons for investing in new renewable resources, such as hedging against the wholesale electricity market and fuel price volatility, as well as investing in resource diversification. All these drivers result in additional renewable resource development beyond minimum RPS requirements.

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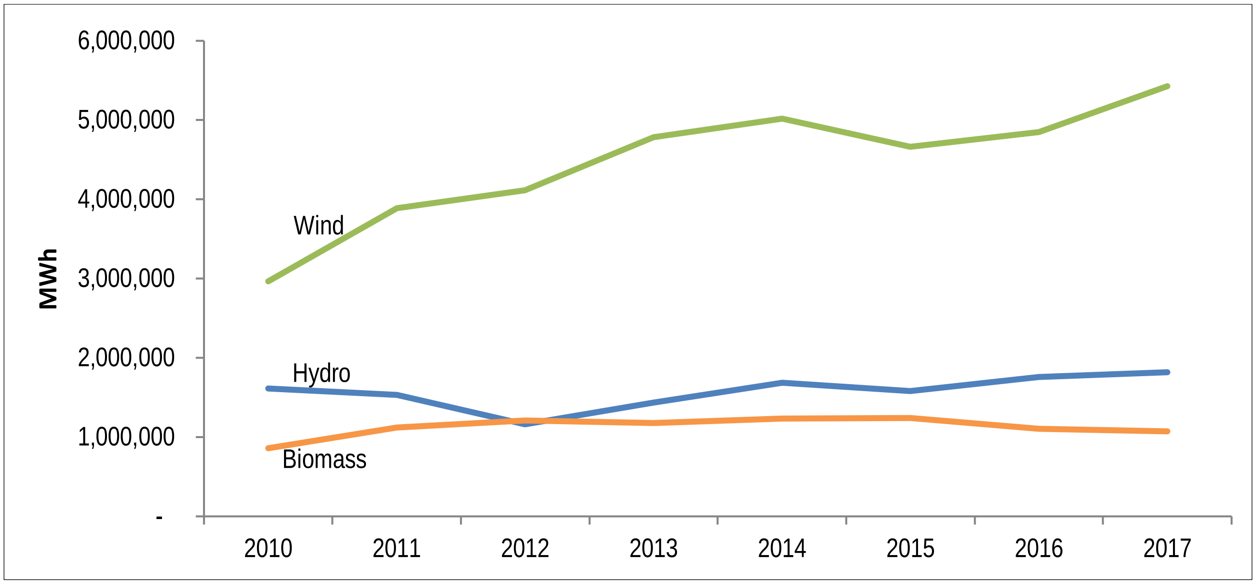
[87] Source: Commission Staff 2016 RPS Compliance Memorandum (PSC REF#: 344905).
[88] See MGE's website: https://www.mge.com/environment/green-power/shared-solar/.

Figure 42 Electric Provider Renewable Energy Production 2010 to 2017[89]



The federal Production Tax Credit (PTC) for wind development and Investment Tax Credit (ITC) for solar development also play significant role in electric provider investment decisions. Wind facilities must commence construction before 2020 to qualify for the PTC, and solar facilities must commence construction before 2023 to qualify for the ITC. There is also greater tax credit value for the PTC and ITC the sooner the construction of facilities begins. As a result, these tax credits provide incentives to move forward with renewable planning and construction in the near term before the value decreases and then these credits expire completely.

MGE's recently approved[90] application for the 66 MW Saratoga Wind Farm[91], scheduled to be operational in 2019, is an example of the factors mentioned above driving renewable resource development. Although RPS requirement needs were cited in the application, MGE already met its RPS requirements for the immediate future. Other factors, such as the PTC, drove the electric provider to make this investment now. Compared to alternatives, the wind project provides a cost-effective option to meet an incremental need for capacity and provides a hedge against fuel volatility. The primary reason why the project was more cost-effective than a delayed investment was the current benefits from the PTC.[92]

Electric provider renewable resource development plans can often be found on their public websites. Dairyland Power Cooperative (DPC) has been working with developers to install 15 large solar projects in their cooperative member service territories, which will result in more than 20 MW

[89] Source: Commission Staff 2016 RPS Compliance Memorandum (PSC REF#: 326919)
[90] Commission docket 3270-CE-127 Final Decision (PSC REF#: 334359).
[91] See MGEs' website: https://www.mge.com/environment/green-power/wind/saratoga.htm.
[92] See WPPI's website: https://wppienergy.org/News/NewsItem?item=47.

of new solar in Wisconsin.[93] DPC also announced that it has entered into a Purchase Power Agreement (PPA) to purchase energy from the 98 MW Quilt Block Wind Farm near Platteville, Wisconsin.[94] WPPI Energy recently began to purchase power from the 132 MW Bishop Hill III Wind Energy facility in Illinois,[95] and is planning to purchase power from a 100 MW solar facility planned for construction to be built near the Point Beach nuclear facility by 2021.[96] The Commission has also opened dockets to investigate developer applications for new utility-scale solar facilities.[97]

Many Wisconsin utilities also have corporate sustainability and carbon reduction goals. These corporate goals influence decisions to construct more renewables to replace fossil fuel generation sources. For example, WEC Energy Group has a corporate carbon reduction goal of 40 percent by 2030, and Xcel Energy has a carbon reduction goal of 31 percent by 2020. Other utilities have set renewable generation goals, such as Minnesota Power with a goal of 44 percent by 2026 and MGE with 30 percent by 2030. Such goals reflect the lower prices of renewable energy, customer preferences, state and federal policy, and environmental stewardship.

GRID MODERNIZATION

Current Activities

The conversation regarding grid modernization encompasses a wide variety of activities related to the continued evolution of the electric transmission and distribution systems. The U.S. Department of Energy describes its grid modernization efforts as focused on ensuring "[t]he grid of the future will deliver resilient, reliable, flexible, secure, sustainable, and affordable electricity."[98] Critical to the grid modernization discussion is evaluating the impact of new technologies and customer preferences, while ensuring the electric system remains reliable and safe. Successfully addressing these factors provides the potential to facilitate customer engagement and reduce customer costs through applications of new technologies and approaches such as: smart meters, smart appliances, real time pricing, community solar and other distributed electric generating facilities, renewable energy riders, and innovative rate offerings.

States have taken very different approaches to addressing the concept of grid modernization. In Wisconsin, the Commission has elected to take a collaborative approach to grid modernization involving energy providers, stakeholders, and regulators. Given how broad the topic of grid modernization can be, the Commission elected to focus on Wisconsin's electric distribution system

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93 See DPC's website: http://www.dairylandpower.com/article.php?id=4158.

94 See DPC's website: http://www.dairylandpower.com/dcontent/article/BartonWindFarmFeb2017.pdf.

95 See WPPI's website: https://wppienergy.org/News/NewsItem?item=50.

96 See WPPI's website: https://wppienergy.org/News/NewsItem?item=47.

97 The application for Two Creeks is in Commission docket 9696-CE-101 (PSC REF#: 343610), and the application for Badger Hollow is in Commission docket 9697-CE-100 (PSC REF#: 343803).

98 Taken from Energy.gov's Grid Modernization Initiative web page: https://energy.gov/under-secretary-science-and-energy/grid-modernization-initiative (last accessed on February 9, 2018).

and identify areas of common interest. During the fall of 2017, the Commission conducted a survey of Wisconsin's energy stakeholders[99] to identify the top five priorities for grid modernization in Wisconsin. The top five priorities were:

1. Interconnection of customer-owned distributed energy resources;
2. Identification of customers' changing expectation, preferences and behaviors;
3. Uses and benefits of advanced meters;
4. Safety and reliability of the distribution system; and
5. Increased electrification.

These survey results have and will continue to inform collaborative grid modernization discussions and stakeholder meetings to identify a consensus around specific action items. Another part of the Commission's grid modernization efforts is to inventory the items that have already been accomplished, but may not have been labeled specifically as being a grid modernization initiative.

As discussed in detail below, some of the grid modernization efforts in Wisconsin include:

- Technical efforts related to maintaining the resiliency, reliability, and safety of the electric system, including Commission actions to address needed electric distribution system upgrades.
- Upgraded customer information systems to provide customers with information to make informed choices about energy use.
- Advanced metering infrastructure that allows for information to flow between the utility and its customers, potentially reducing outage time and improving service restoration time.
- Innovative rate design and tariffs—including electric vehicle and community solar tariffs; time-of-day rates, market-based rates, and new load market pricing rate designs. The Commission has implemented some aspects of innovative rate design and tariffs since the late 1970s.

Resiliency, Reliability, and Safety

The core tenets of grid modernization in Wisconsin include, first and foremost, ensuring that the electric grid remains reliable and safe.

Reliability, from a systems engineering perspective, is the ability of an electric system to perform its functions under normal and extreme circumstances. Reliability indices provide a measure of overall electric system performance.

[99] Stakeholders include customer advocacy groups, investor owned and municipal utilities, industrial customers, trade association, power cooperatives, and environmental groups.

Reliability Indices

The electric utility industry uses indices defined by the Institute of Electric and Electronic Engineers (IEEE) to measure reliability. The System Average Interruption Duration Index (SAIDI) [100] is the predominant measure and represents the *average customer-minutes of interruption* per customer.

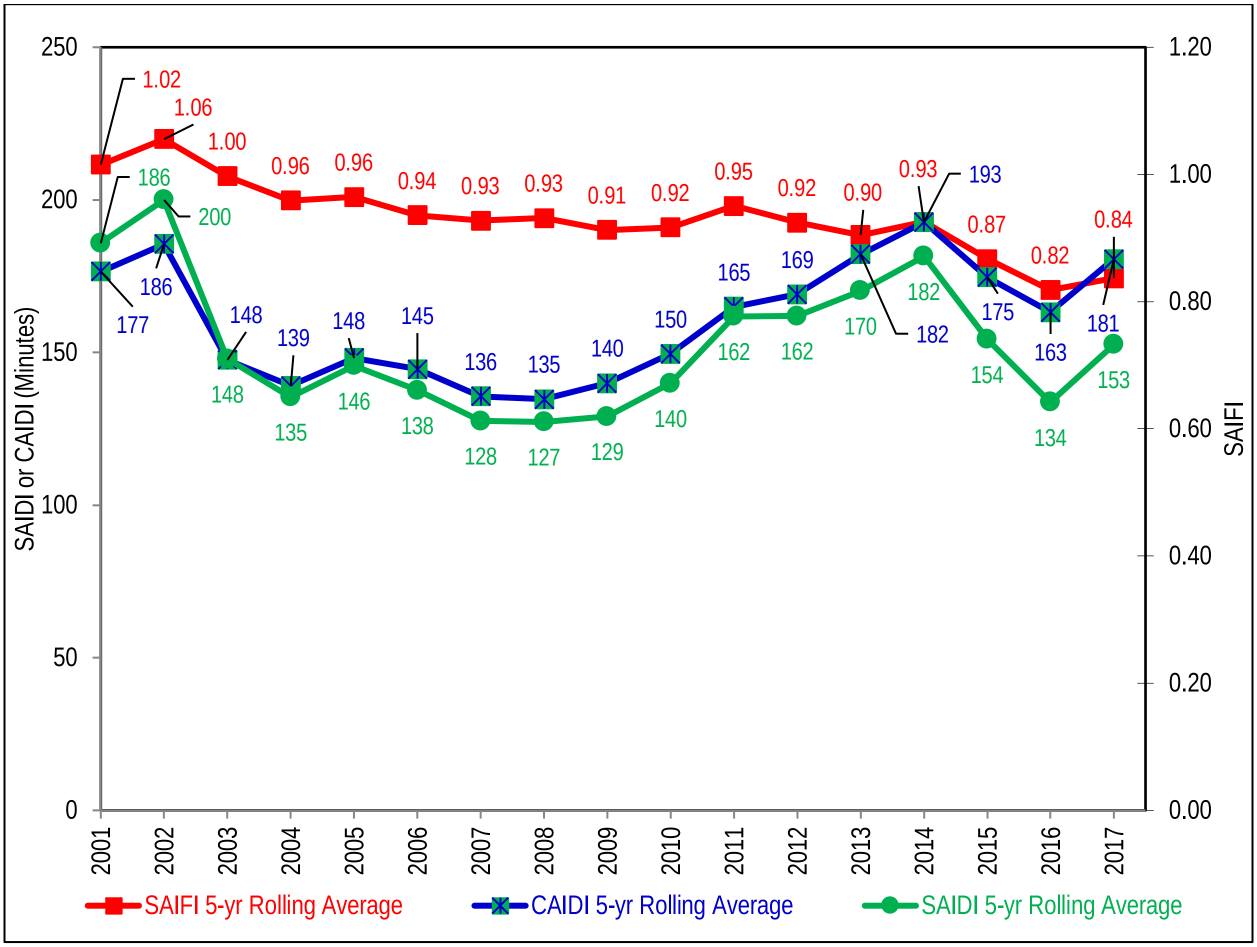
Other IEEE benchmarking standards take a different approach to quantifying reliability.

- The Customer Average Interruption Duration Index (CAIDI)[101] is the average *customer-minutes of interruption* per *customer interruption*, approximating the average length of time required to complete service restoration.
- The System Average Interruption Frequency Index (SAIFI)[102] is the average *number of interruptions per customer during a year* which shows a clear downward trend since 2001.

Figure 43 shows statewide SAIFI, SAIDI and CAIDI for the five major Wisconsin IOUs.

[100] SAIDI = annual sum of customer-minutes of interruption/average number of customers served during the year.
[101] CAIDI = annual sum of all customer-minutes of interruption durations/annual number of customer interruptions.
[102] SAIFI = total annual number of customer interruptions/average number of customers served during the year.

Figure 43 Statewide SAIFI, SAIDI, and CAIDI[103]



Under Wisconsin Admin. Code § PSC 113.0606, electric utilities with more than 100,000 customers must report annually to the Commission their reliability measures for the preceding year, including customer interruptions due to storms, catastrophic events, or police actions. Overall, SAIDI, SAIFI and CAIDI values for the major utilities have remained stable or improved since reporting requirements became effective in 2001.

Distribution Rebuild

Investment in the distribution system, which delivers electricity to customers, is an important aspect of system reliability. A distribution system in disrepair may be more vulnerable to storms and inclement weather, and may also present a danger to customers and the general public. The following are descriptions of distribution projects authorized by the Commission:

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

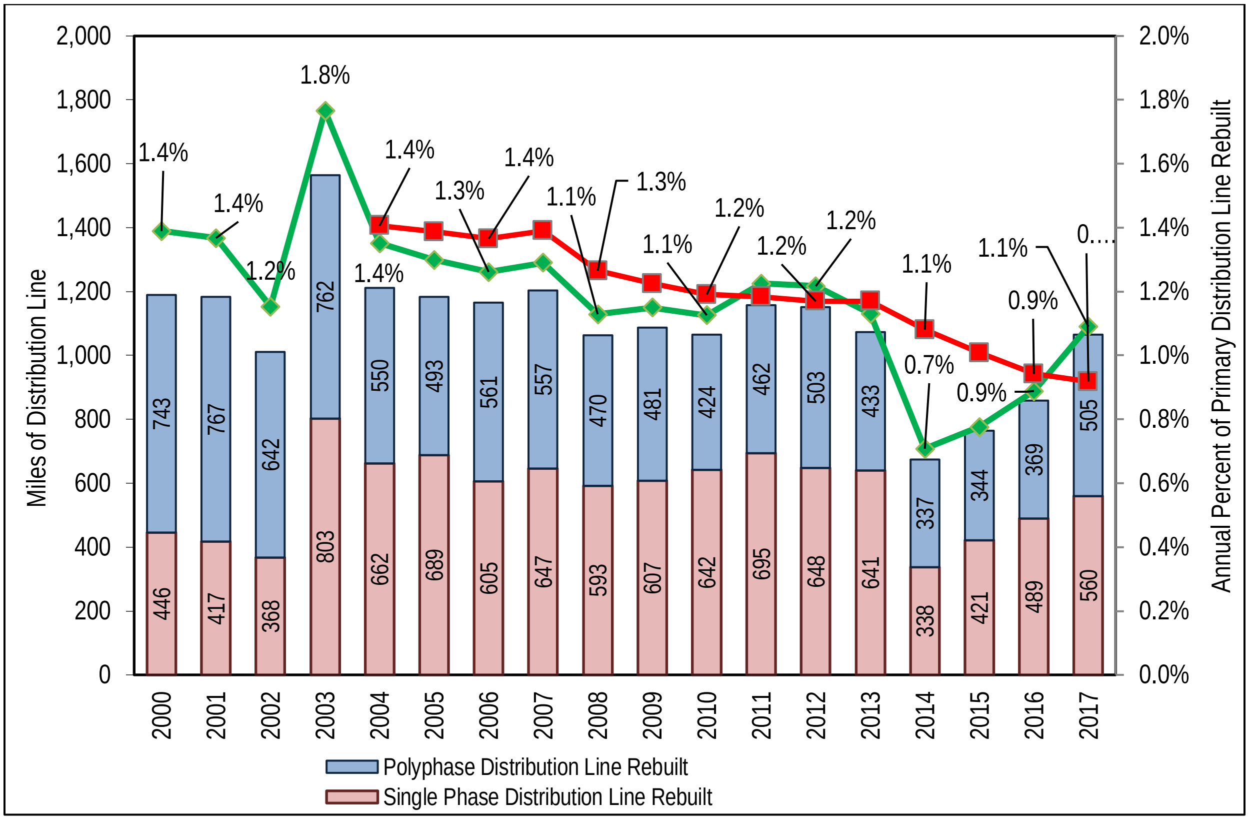
- Wisconsin Public Service Corporation (WPSC) Electric Distribution System Modernization and Reliability Projects:
  - Phase 1 ($222.5 million): On June 19, 2013, the Commission approved a 5-year project to improve electric distribution reliability through targeted replacement of existing overhead distribution lines with underground lines, distribution automation equipment, or both. WPSC will replace 200 to 300 miles of electric distribution during each year of the 5-year period, focusing on areas and facilities with the poorest reliability.
  - Phase 2 ($211.5 million): On March 9, 2017, the Commission authorized Phase 2 to increase reliability by targeted replacement of additional existing overhead distribution lines with underground lines. The project includes installation of an estimated additional 960 miles of underground facilities—focusing on areas and facilities with the poorest reliability—over an additional 4-year period.
- On June 26, 2017, the Commission approved the sale of Centuria Municipal Electric Utility (CME) to Northwestern Wisconsin Electric Company (NWE).[104] As a part of acquisition, NWE will update the distribution facilities of CME to increase reliability, including upgrading meters, replacing poles, and implementing billing software improvements.

Figure 44 shows statewide distribution system rebuild status[105] with miles of distribution line rebuilt as stacked bars, and the percent of total miles of line rebuilt, by year.

[104] Docket 5-BS-218.

[105] Source: Reports filed with the Commission per Wis. Admin. Code § PSC 113.0604(3)(a) by the five major utilities.

Figure 44 Statewide Distribution System Rebuild Status



Updated Standards and Rules

National Electrical Safety Code: Wisconsin's electrical safety code is based on the IEEE National Electrical Safety Code (NESC). Wisconsin Admin. Code ch. PSC 114 incorporates the NESC by reference, with certain additions and modifications. The Commission is currently working to adopt the 2017 NESC through rulemaking in docket 1-AC-250.[106] The next revision of the NESC is anticipated in 2022. By participating in the NESC development process, and adopting code revisions in a timely manner, the Commission ensures that the electric system is constructed and operated in the safest and most reliable manner possible.

Distributed Generation Interconnection Rules: 2001 Wisconsin Act 16 (Act 16) required the Commission to promulgate uniform rules to support the development of distributed generation and address engineering, electric reliability, safety concerns, and the methods for determining charges for interconnection. Wisconsin Admin. Code ch. PSC 119 applies to all distributed generation facilities with a capacity of 15 MW or less that are interconnected to an electric public utility's distribution

[106] In the Matter of the Proposed Revision of Wis. Admin. Code ch. PSC 114 as Wisconsin State Electrical Code, Volume I, 2018.

system, and the utility to which a distributed generation facility is interconnected. The rules are based, in part, on UL 1741[107] and IEEE 1547.[108]

FERC and NERC Standards: In 2003, the Northeast Blackout impacted 50 million people in the U.S. and had a significant effect on the economy. From the resulting investigation of that event, FERC certified NERC in 2006 to develop reliability standards subject to FERC review and approval. NERC standards address a wide variety of aspects of the electric grid and Commission staff participate in the development of NERC standards by sitting on the NERC Standards Committee, working to ensure that applicable standards serve the best interests of Wisconsin stakeholders, considering safety and reliability, and cost.

Advanced Customer Information Systems

Wisconsin utilities are making upgrades to their customer information systems (CIS) as their legacy systems become obsolete. These new CIS allow utilities to integrate new technologies and meters into their overall distribution systems, while providing additional information to customers about their energy usage. Without upgrades to utility CIS, the information provided to customers about their energy usage is limited, which in turn limits customers' ability to control their energy usage.

Municipal utilities and IOUs have or are implementing new CIS that more closely integrate distribution-side technologies with customer-side enhancements. Other benefits include data security improvements and the generation of cost savings through operational efficiencies. Examples of utilities in the process of upgrading or recently implementing an upgraded CIS include:

- MGE is in the process of designing a new CIS, which required partial Commission approval.[109] MGE indicated its new CIS is foundational to the improvement of other systems that MGE has installed or plans to install at a later date. MGE plans to establish a new data model that would allow MGE to enhance its customer analytics, improve customer billing options, increase billing transparency, and improve forecasting and predictive analytics. MGE states that the new CIS would improve billing granularity and options for customer self-service.
- WPSC implemented its upgraded customer information system, as part of its Improved Customer Experience (ICE) project, in January 2016.[110] The ICE project was undertaken by Integrys Business Support, LLC to standardize the customer information systems and customer operations model across all Integrys companies. In 2015, the Wisconsin Energy

[107] Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, https://standardscatalog.ul.com/standards/en/standard_1741_2.

[108] IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

[109] The Commission approved the gas portion of an approximately $48 million investment by MG&E in a new customer information system (CIS). No approval was necessary for the $28.8 million electric portion of the new CIS. Dockets 3270-UR-121, 3270-CG-123.

[110] WPSC included a portion of the cost of ICE in docket 6690-UR-123.

Corporation acquired Integrys Energy and formed the WEC Energy Group. The project's benefits include numerous technology upgrades, functional improvements, and enhanced customer data security.

- WP&L and its sister company Interstate Power and Light Company (IPL) placed in service a new CIS in October 2015 as part of its Modern Customer Information System project. In 2017, the Commission approved WP&L's request to consolidate customer service functions with IPL[111] to achieve operational efficiencies and savings, while enhancing customer service capabilities. This consolidation would not have been possible without the new CIS. This new customer billing and information system provides customers with enhanced payment and billing options, new self-service features, increased access to information, and expanded options for communication. According to WP&L, customer care and billing allows the utility to provide exceptional customer service, including emergency and outage response, and is part of the utility's mission and commitment to customers.

Several other utilities are in the process of designing and implementing new CIS to best utilize distribution system improvements and integration of customer-side technologies.

Metering Upgrades

In January 2017, the Commission conducted a survey regarding the capabilities of Wisconsin utilities' residential electric meters.[112] The purpose of the survey was to better understand how our state's electric utilities are using, or plan to use, advanced meters and meter data to benefit customers and improve system operations. The survey addressed four major areas: meter capabilities, meter data management systems, advanced metering enabled programs, and plans for future meter upgrades.

Based on the utilities' survey responses, there are approximately 2.6 million residential electric meters in service in Wisconsin. Approximately 5 percent of these meters are read manually, with no automatic or remote-read capabilities. Seventeen percent of the electric meters employ an automated meter reading (AMR) technology, where the meter is read through drive-by or another field visit process, but which do not have any remote read capabilities. The remaining 78 percent of all residential electric meters employ an AMR or advanced metering infrastructure (AMI) that allows the utility to retrieve meter data remotely via daily, or more frequently, transmittal over a fixed communication network to a central collection point, eliminating the need for a field visit. About half of these meters employ two-way AMI communications.

Electric meters with advanced technology can provide additional data points that can translate into tangible benefits, including the potential for: more quickly detecting and restoring service outages, developing innovative rate designs, greater billing accuracy, and providing more granular and potentially real-time information to customers about their usage.

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[111] Docket 6680-AE-118.

[112] See PSC REF#: 296929.

Innovative Rate and Tariff Design

Wisconsin electricity providers have long offered time of use (TOU) rates as a way for customers to manage their bills. At present, the vast majority of IOU and municipal electricity providers have mandatory or optional TOU rates for all customer classes. Optional retail rate options provide useful information in designing rates that meet customer needs and generate opportunities for Wisconsin customers to control energy costs while contributing to economic growth in the state. The following is a summary of innovative rate design offerings recently approved by the Commission:

- **Residential Fixed Bill:**[113] In 2016, the Commission approved a Fixed Bill program for WP&L customers, based on customer feedback suggesting that customers value certainty and convenience in their electric bills. Under the Fixed Bill program, customers would pay a consistent monthly bill for 12 months, there would be no periodic true-up for any over- or under-usage. The fixed bill is based on 12 months of a customer's weather-normalized historic usage at the property.
- **Residential and General Service Optional Demand Rate:**[114] In 2015, the Commission approved a demand rate for WP&L residential and general service customers, similar to that in place for other commercial and industrial rate classes. The demand rate includes a customer charge, on-peak monthly demand charge, and three-tiered time of use energy charges. The on-peak demand charge is intended to cover demand-related costs associated with a customer's production and transmission of energy during the time period in which the utility is likely to encounter monthly system peaks.
- **Unbundling of Residential and Small Commercial Energy Rate:**[115] In 2017, the Commission authorized NSPW to unbundle its present energy rate into two distinct rates—a delivery charge and an energy charge. The purpose of unbundling the rate was to increase transparency and understanding of the services that NSPW provides to its customers, and the services for which customers are paying. The delivery charge includes customer- and distribution-related costs that are not covered in the customer charge and transmission system costs. The energy charge will include the production-related costs necessary to produce the energy that a customer consumes. Ultimately, the new rates do not materially impact the way customers are billed other than providing customers with increased visibility on what they are paying for.
- **Smart Thermostat Demand Response Pilot Program**: MGE's Commission-approved Smart Thermostat Demand Response Pilot Program[116] aims to test the use of smart thermostats to manage automatically residential customers' air conditioner usage to help manage the utility's system peak. The results of the pilot program will help MGE

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113 Docket 6680-UR-120, PSC REF#: 296673.
114 Docket 6680-UR-120, PSC REF#: 296673.
115 Docket 4420-UR-123, PSC REF#: 335158.
116 Docket 3270-UR-121, PSC REF#: 295447.

understand how this type of program can help reduce costs and improve convenience of demand response programs.

- **Market Based Rates**: The New Load Market Pricing (NLMP) rate is similar to the economic development rate that the Commission approved in 2015, for WEPCO. Presently, 24 municipal electric utilities and two investor-owned utilities offer a NLMP tariff to their large commercial and industrial customers.[117] These tariffs are intended to attract new load by allowing customers to pay wholesale market rates for any new load. NLMP customers are charged incremental energy and demand rates on eligible load growth above baseline levels of consumption and normal tariffed rates on consumption up to the baseline levels. In 2017, the Commission approved new market rate offerings for WP&L[118] and WEPCO. These programs allow industrial customers to pay wholesale market rates for some or all of their power needs. Wisconsin state law allows these rates, and contains protections so that no other customers subsidize the discounted rates.
- **Electric Vehicle Pilots**: In its 2016 rate case, MGE requested and was authorized to pilot its Charge@Home program on a limited basis. The pilot allows single family residential customers with electric vehicles to have MGE install a charging station in their home with no upfront cost. The customer pays a fixed monthly fee for the charger and this program is intended to be coupled with MGE's existing residential TOU rates. The Commission granted a limited expansion of the pilot in 2017.
- **Distributed Energy Resources Special Tariffs:** In 2017, MGE was granted authority to offer its Renewable Energy Rider (RER). The RER provides a framework for MGE to enter into a future contract with a commercial or industrial customer to provide dedicated renewable generation to the specific customer at a renewable resource rate.
- **Green Power Tomorrow:** All major IOUs offer their customers the opportunity to source some or all of their energy needs from renewable sources for a small surcharge. For example, MGE's Green Power Tomorrow program lets residential and commercial customers purchase a fixed percentage of their needs or a set block of renewable-sourced energy for an extra 2.4 cents per kWh. In MGE's rate case in 2016, the company forecasted that more than 79 million kWh will be sold under this program.

Renewable Energy Projects

As noted above, some utilities are pursuing tariff changes to respond to customers' desires to have some of their energy come from renewable energy sources. Utilities are also pursuing renewable energy projects, such as solar and wind, for a variety of reasons including increased customer demand for these programs.

Community solar programs provide a unique opportunity for utilities to test new business models and products, while increasing deployment of solar energy. In addition, community solar programs

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[117] Customers with a maximum measured demand in excess of 200 kW.
[118] Docket 6680-TE-102, PSC REF#: 304770.

offer customers who may not have the ability to install rooftop solar with access to more renewable energy choices. Since 2015, the Commission has approved community solar programs for NSPW,[119] New Richmond Municipal Utility,[120] River Falls Municipal Utility,[121] and MGE.[122]

The most recent Commission-approved utility scale wind project is MGE's 66 MW Saratoga Wind Farm in Iowa, which is scheduled to be built in 2018 and operational in 2019.[123]

Utilities' community solar and wind projects are discussed in greater detail in the Renewable Energy section of this report.

Focus on Energy Programs

Focus provides utility customers with programs and tools to be a more active participant in their own energy usage. More than 100 of Wisconsin's electric and natural gas utilities participate in Focus through a variety of energy efficiency and renewable energy projects.

In addition to MGE's Smart Thermostat Demand Response Pilot program, the Commission's approval of residential smart thermostat rebate programs provides another reasonably priced tool for customers to take greater control over their energy use. Thermostats have achieved demonstrated reductions in energy use, and also provide ongoing opportunities in the future to support and integrate with broader-based grid initiatives like demand response and load management programs.

Focus partners with utilities on several grid modernization-related projects. One of these programs is WP&L's Sense Home Energy Meter pilot program,[124] which will deploy 100 of these meters to homes in its service territory. These meters provide real-time information on energy use and disaggregate usage among all end uses, including down to the level of individual appliances. This is a pilot program designed to gather information specifically on:

- If customers achieve savings thanks to behavioral changes due to receiving additional information about their energy use;
- If the detailed energy usage data will aid WP&L in designing future rate and demand response programs;
- If there are specific high use in-home appliances and technologies that would benefit most from replacement, which would help direct funding and enhance participation in Focus programs.

[119] Docket 4220-TE-101, PSC REF#: 236916.
[120] Docket 4139-TE-102, PSC REF#: 273771.
[121] Docket 5110-TE-102, PSC REF#: 273771.
[122] Docket 3270-TE-101, PSC REF#: 284022, updated in docket 3270-UR-121.
[123] See MGEs' website: https://www.mge.com/environment/green-power/wind/saratoga.htm.
[124] Docket 6680-EE-2018.

CYBER AND PHYSICAL SECURITY

Protecting the nation's electric grid from potential cyber threats is a top priority for Wisconsin's utilities. The December 2015 cyberattack on Ukraine's power grid heightened Wisconsin's awareness of this growing threat. Cybersecurity is a broad term encompassing a wide range of utility actions to protect the grid and prevent attacks. These include: monitoring internet traffic into and out of the utility's local computer networks; staff training to identify and prevent potential braches in network security; continual updates of software systems and programs; and mitigation measures to minimize the impacts of a successful attack.

All of Wisconsin's electric utilities are required to meet all NERC reliability standards. These standards cover a wide range of potential threats to the electric grid, including cyber threats. The NERC reliability standards include 13 Critical Infrastructure Protection standards specific to cybersecurity. These standards mandate the type of security protocols each electric utility must implement, the training utility personnel must complete, and mitigation measures to be put in place in case of a successful cyberattack.

The Wisconsin Department of Military Affairs Division of Emergency Management (WEM) led Wisconsin state agencies in the November 2017 national GridEx IV biennial exercise sponsored by NERC— a simulation exercise for large cyber and physical attacks on the critical infrastructure of the North America Bulk Electric System, and other critical infrastructure sources. The objectives for GridEx IV were:

- Exercise incident response plan
- Expand local and regional response
- Engage interdependent sectors
- Improve communication
- Gather lessons learned
- Engage senior leadership

WEM conducted a large-scale, multi-agency, state operations exercise called Operation Dark Sky in May 2018. The exercise focused on responding to a wide-scale disruption of electrical power and communication systems caused by cyber and physical attacks. The exercise included the State Emergency Operations Center and field exercises in certain counties and at some utility sites.

DISTRIBUTED ENERGY RESOURCES

Customer-owned Distributed Energy Resources

Customer-owned distributed energy resources (DER) continue to grow across Wisconsin, a trend that is expected to continue. To better understand the breadth and scope of DER, an inventory was conducted for the first time as part of the previous SEA to provide the Commission and other stakeholders with meaningful data to understand this aspect of Wisconsin's electric system.

Data collected in the last SEA did not allow linking to the customer class categories with DER technology type. Data collection for this SEA incorporates the customer type with the DER technology type. All municipal and investor-owned electricity providers were surveyed for this inventory. Commission staff also collected data from DPC on behalf of its members.

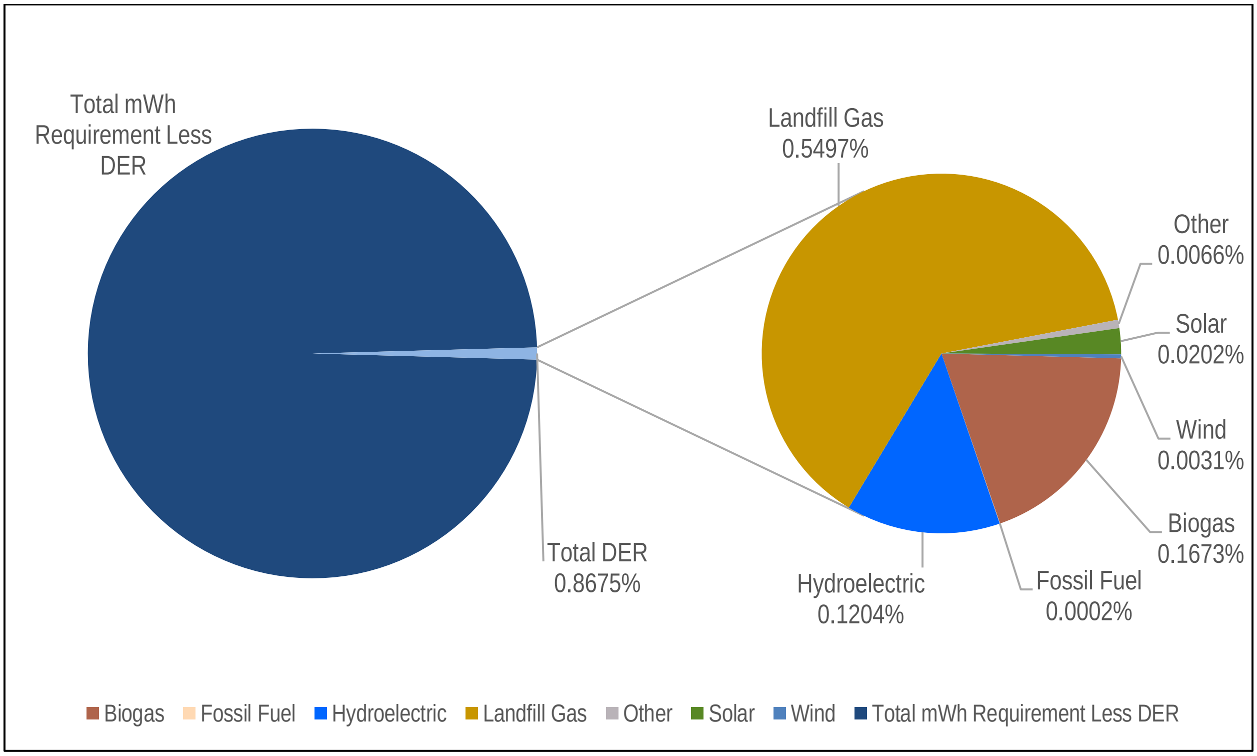
Data collected runs from January 2008 through September 2017. The following discussion and figures summarize the results of the DER inventory for complete data collection years of 2008 through 2016. Data collected for 2017 are partial year data, from January to September. Complete summary data can be found in the Appendix to this report.

Data for DER are organized according to capacity, number of installations, and the value and amount of energy delivered to the electricity provider. Not every installation delivers energy to the electricity provider. For some installations, all energy is used on-site at the owner's location, and no "excess" energy is delivered to the electricity provider.

The DER technologies inventoried include: biogas (e.g., agricultural methane), fossil fuel, hydroelectric, landfill gas, solar photovoltaic, storage, wind, and other. The other category includes installations with a range of generation sources with a single meter.

All DER figures shown in the SEA, with the exception of Figures 45, 50, and 51 do not include electric cooperative data. DPC submits data on behalf of its members but is unable to provide customer class information due to the varied ways cooperatives classify customers. Figure 45 provides context for the magnitude of energy generated by customer-owned DER. The dark blue in the pie chart on the left shows the amount of energy provided to all customers by the electric service providers reporting at least one DER in their service territory. This energy comes from: electricity provider-owned generation units, purchase power agreements with independent power producers, purchases from the regional energy market, and customer-owned DER. The pie graph on the right shows the break-down of customer-owned DER, which comprises less than one percent of overall energy requirements.

Figure 45 Electricity Provider DER Energy Purchases as a Percent of Total Electricity Provider Energy Requirements 2016



DER is a statewide development in Wisconsin: Sixty-seven percent of the state's 12 IOUs, and 78 percent of the municipal electricity providers reported at least one DER installation in their service territories.

The type of technology influences the relationship between the number of installations and the amount of capacity. For example, while there are a significant number of residential solar installations (Figure 46) the amount of solar capacity is less significant when considering capacity of all DER installations (Figure 47). The bulk of the installations are owned by residential customers (Figure 48) while the bulk of the capacity is owned by commercial and industrial customers (Figure 49).

Figure 46 Total Number of Installations, by Technology Type and Customer Class, 2017[125]

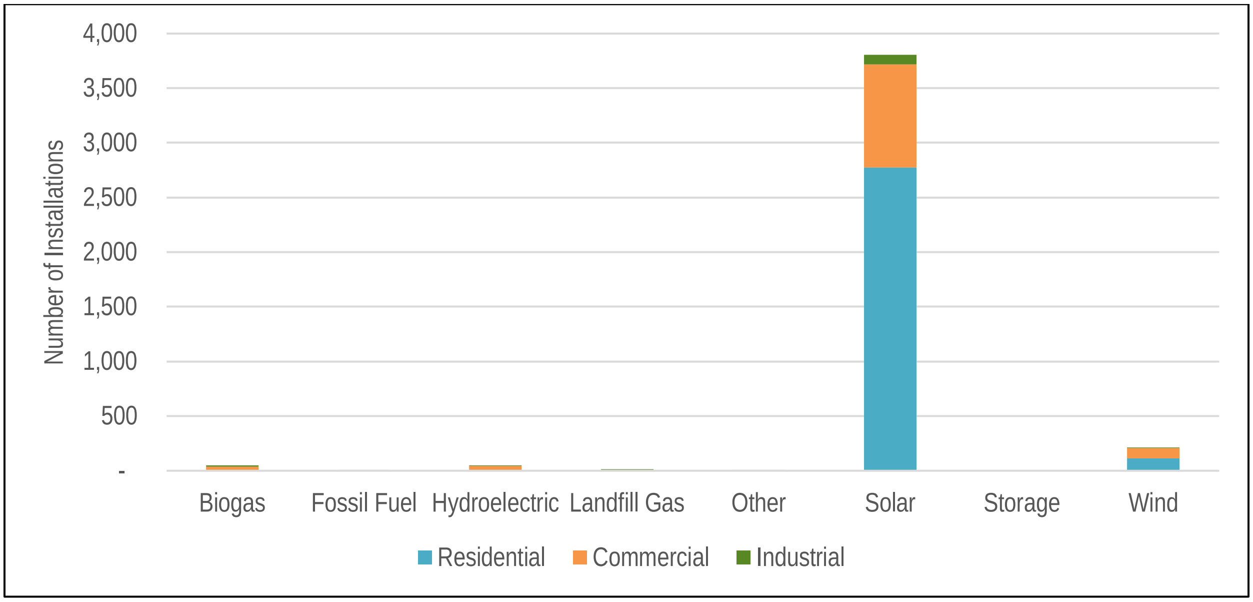
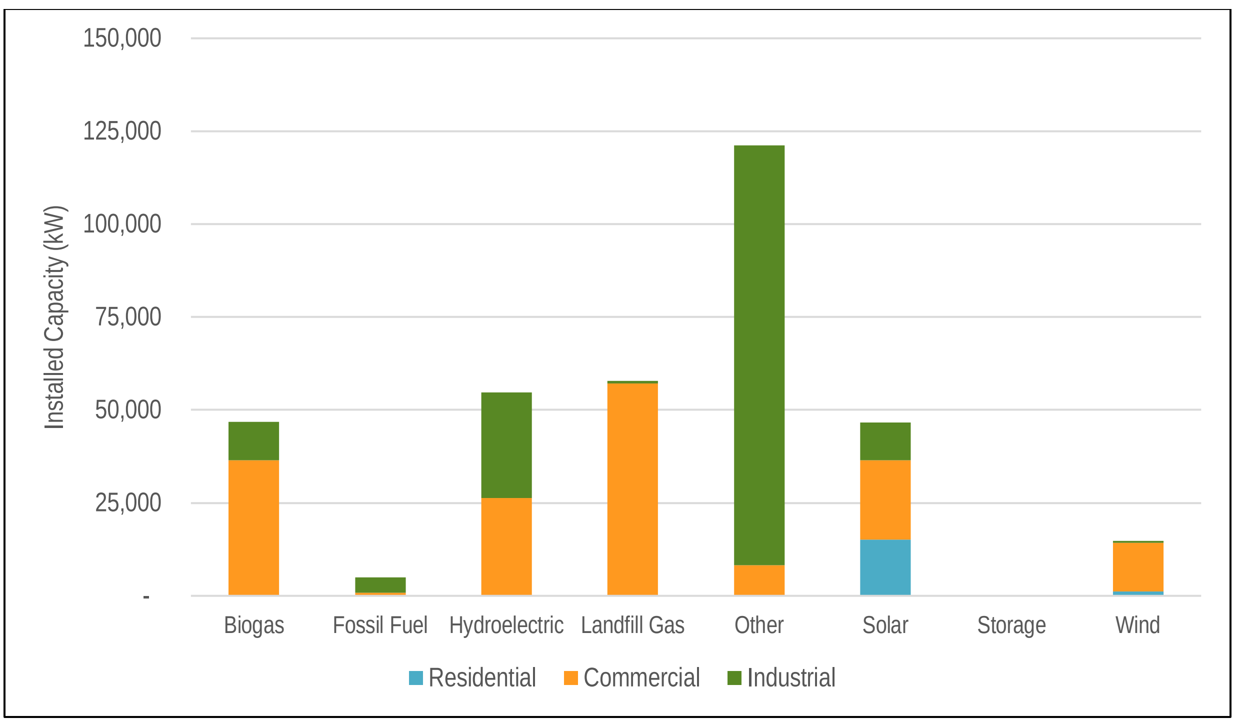


Figure 47 Cumulative Number of Kilowatts of Installed DER Capacity, by Technology Type and Customer Class, 2017[126]



[125] This chart does not include power cooperative data.
[126] This chart does not include power cooperative data.

Figure 48 Cumulative Number of DER Installations, by Customer Class, 2008-2017[127]

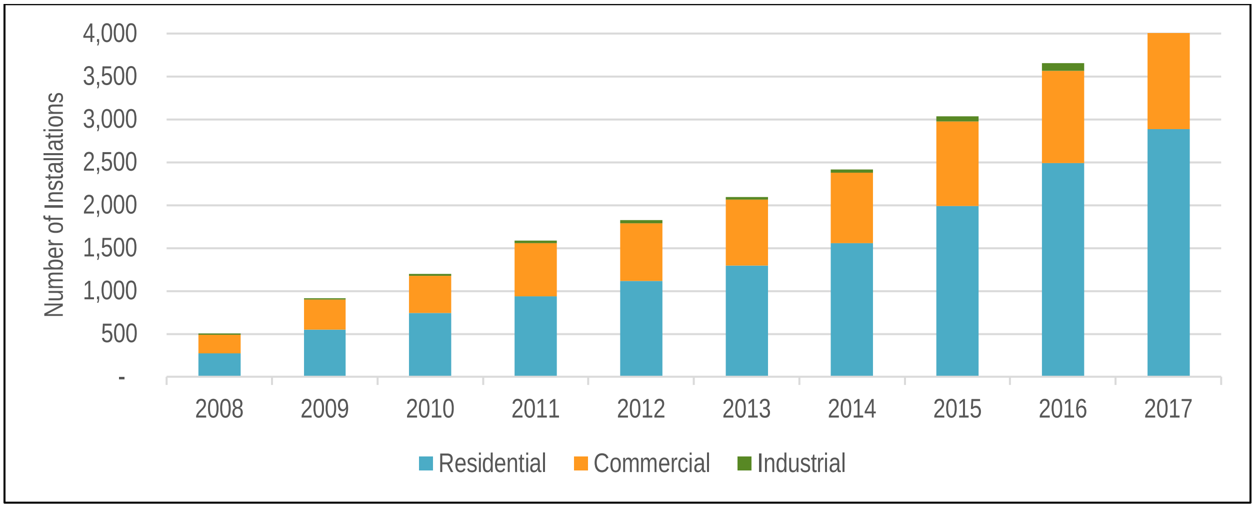
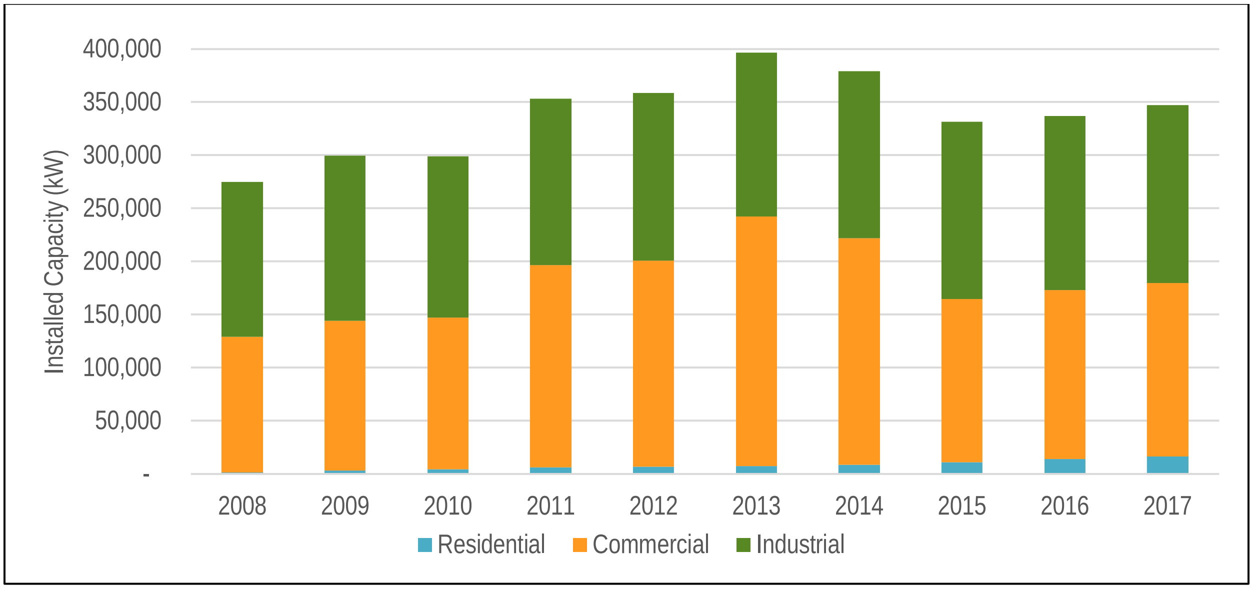


Figure 49 Cumulative Kilowatts of Installed DER Capacity, by Customer Class, 2008-2017[128]



Figures 50 and 51 show the installed capacity and number of DER for the state. The amount of capacity (kW) and total number of installations represented by each graph includes IOUs, municipal-owned utilities and cooperatives, data are organized according to the type of technology.

[127] This chart does not include power cooperative data.

[128] This chart does not include power cooperative data

Figure 50 Cumulative Kilowatts of Installed DER Capacity, by Technology Type, 2008-2017[129]

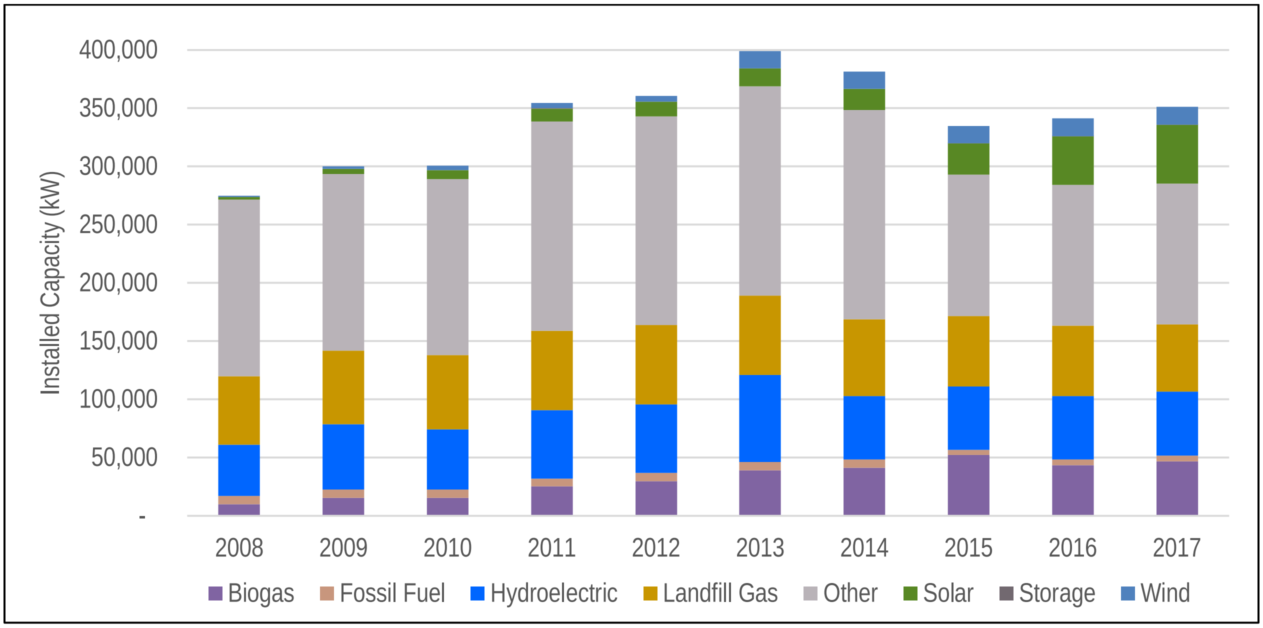
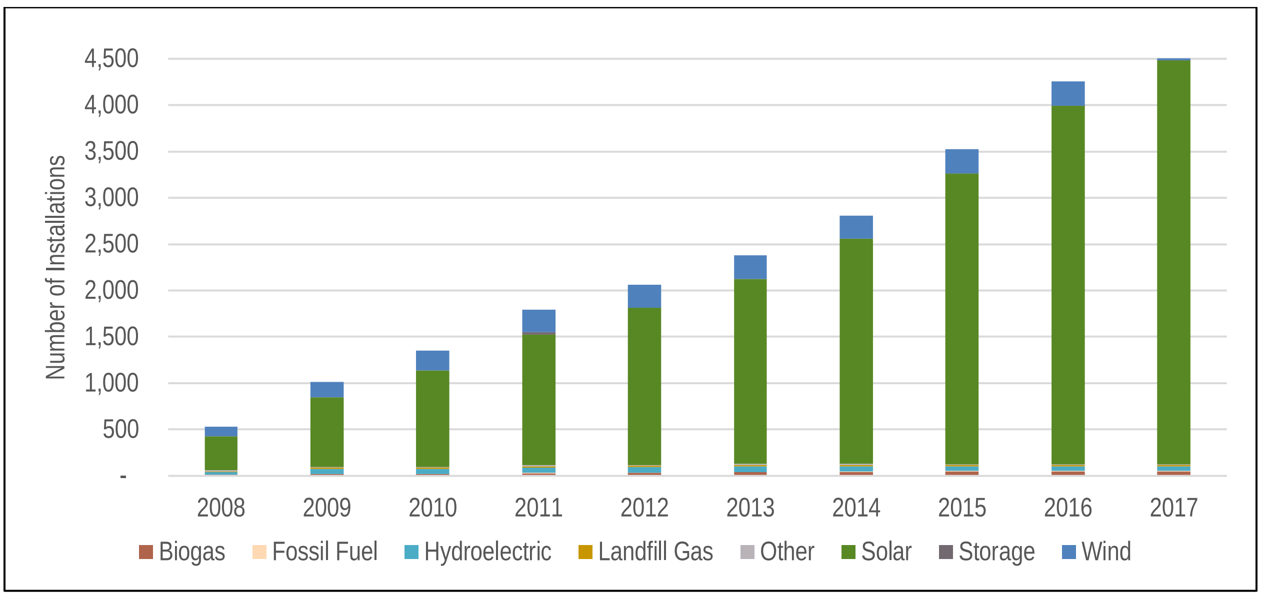


Figure 51 Cumulative Number of DER Installations, by Technology Type, 2008-2017[130]



Community Solar

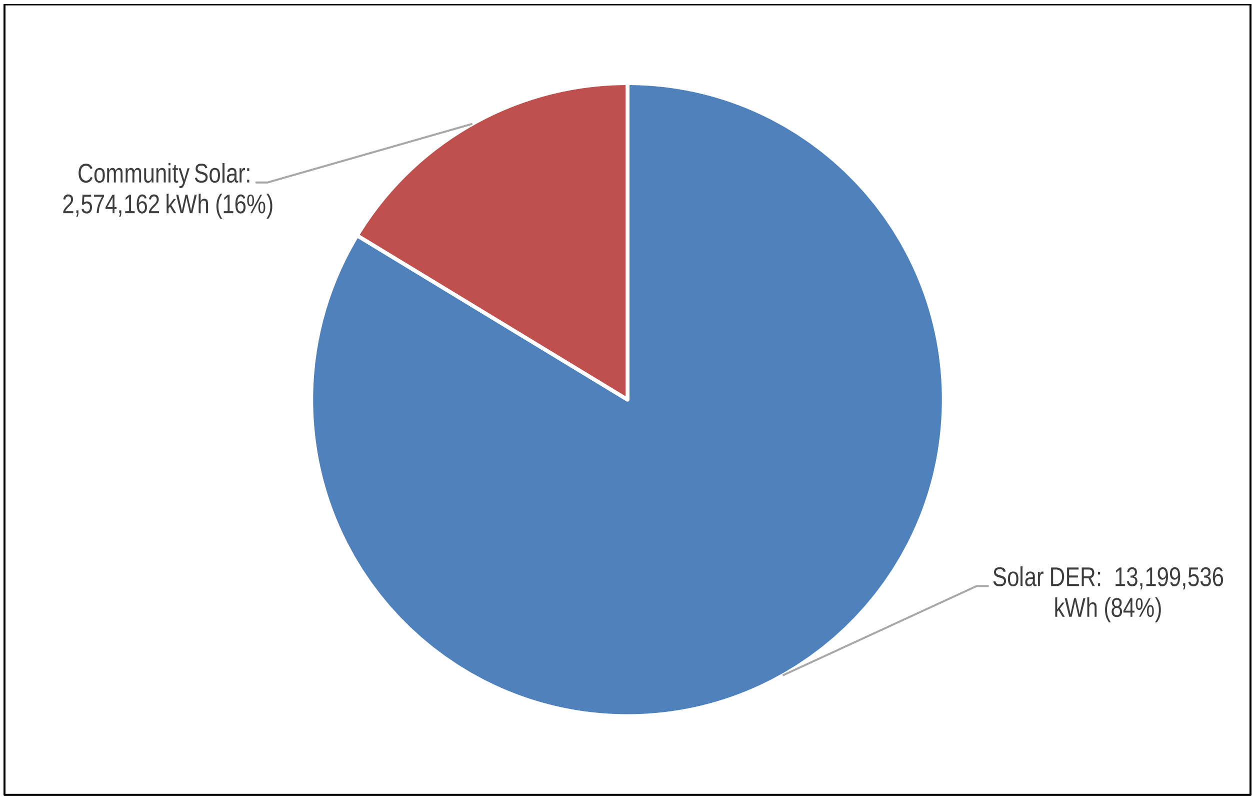
Community solar programs provide a unique opportunity for utilities to test new business models and products, while increasing deployment of solar energy. In addition, community solar programs

[129] This chart includes power cooperative data.

[130] This chart includes power cooperative data.

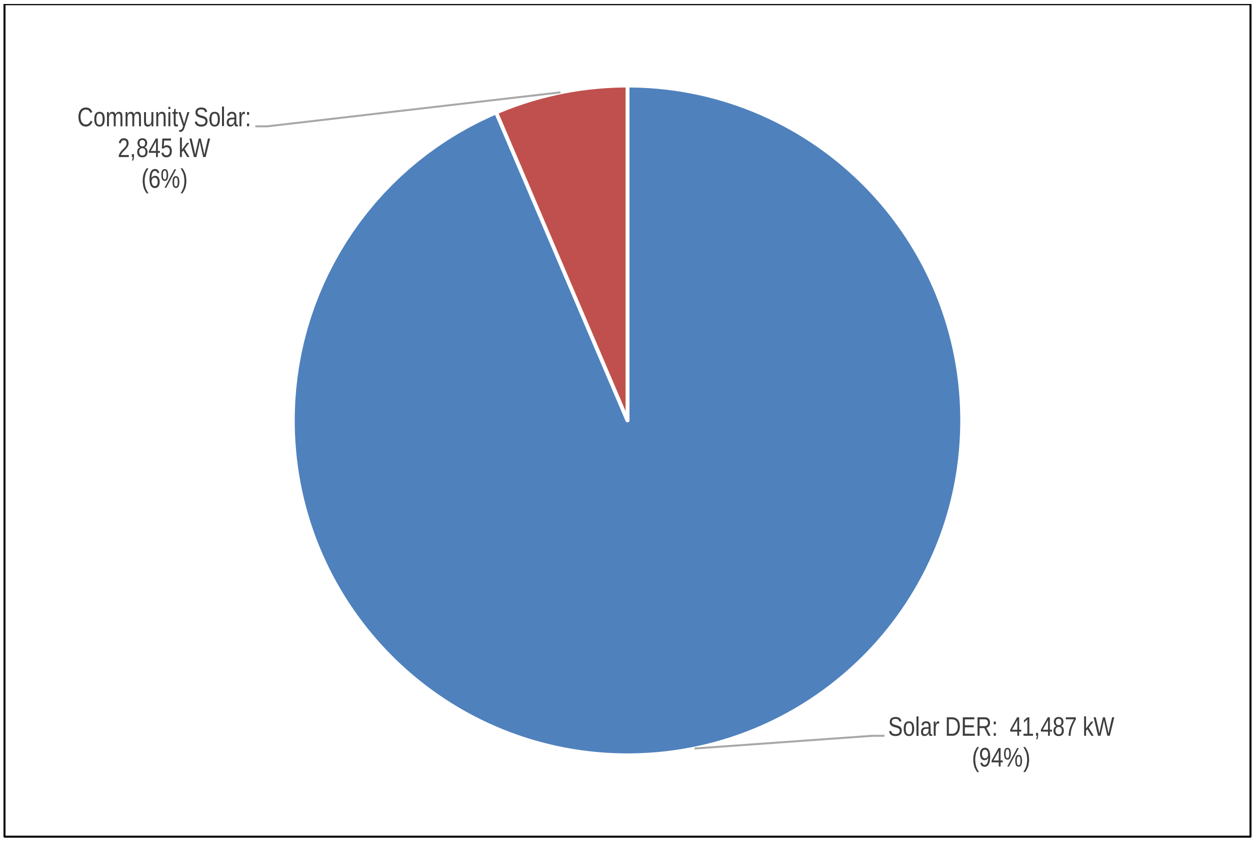
offer customers who may not have the ability to install rooftop solar with access to more renewable energy choices. Figures 52 and 53 show the generation and capacity, respectively, of community solar as a share of all solar DER reported by Wisconsin utilities.

Figure 52 Solar Energy Production (kWh), DER and Community Solar, 2016[131]



[131] Aggregated electricity provider data responses, docket 5-ES-109.

Figure 53 Solar Capacity (kW), DER and Community Solar DER, 2016[132]



In 2015, the Commission approved three community solar programs for NSPW, New Richmond Municipal Utility, and River Falls Municipal Utility. Under these programs, customers pay an upfront subscription fee to cover the cost of their share of an electricity provider-financed solar array. The utilities, leveraging their economies of scale, contract with third-party developers to construct and operate the solar arrays. In return for their subscription fees, customers receive a credit on their bills for each kWh produced by their share of the solar array. NSPW received Commission approval in 2017 to expand its offering to 3 MW and lowered the pricing for all community solar customers.

In 2016, the Commission approved a community solar program for MGE. Rather than acting as a purchasing agent for its customers, MGE added the community solar facility to its generation fleet. For a subscription fee of 10 percent of the share cost, subscribers can enter MGE's shared solar purchase program. The energy for the program comes from a dedicated PV array that MGE constructed in Middleton. Subscribers purchase their share's output at a levelized rate, locked in for 25 years. Unlike the other programs, MGE offers a utility-owned shared solar program, which allows the utility to add the community solar to its rate base and earn a return for its shareholders. MGE sold out all subscriptions to its program in only a few months.

[132] Aggregated electricity provider data responses, docket 5-ES-109.

All municipal and investor-owned electricity providers were surveyed about their current and future community solar projects. Although DPC is not regulated by the Commission, Commission staff also collected data from DPC on behalf of its members as part of the SEA.

Data collected for 2015 and 2016 are actual values. Due to the timing of the SEA data collection, data for 2017 represents partial year data for January through September. Data for years 2018 and 2019 are utility-supplied forecasted values.

At the end of 2016, three of the four Commission-regulated programs have installed the solar arrays and are generating power. However, only the municipal arrays were operating completely in 2016; the MGE array did not go online until December 2016. Therefore, production curve data is only available for the WPPI arrays (River Falls and New Richmond). In 2016, those arrays produced 636,484 kWh for a combined capacity factor of 14.5 percent. At 500 kW of nameplate capacity, these arrays contributed approximately 300 kW toward the WPPI system peak on August 3, 2016.

MGE and River Falls have fully-subscribed programs. MGE currently has a waiting list, and indicated in its last rate case that it would pursue a second phase of shared solar. NSPW is currently at an 88 percent subscription rate, which surpasses its threshold to begin construction of 2 MW of solar arrays, though it does not yet have any arrays constructed. River Falls took a different approach to its program. After an initial period of customer subscriptions, the city of River Falls bought the remaining shares and plans to incorporate the community solar shares in its tax-increment financing districts for commercial customers.

APPENDIX

Table A-1 Public Comments Received

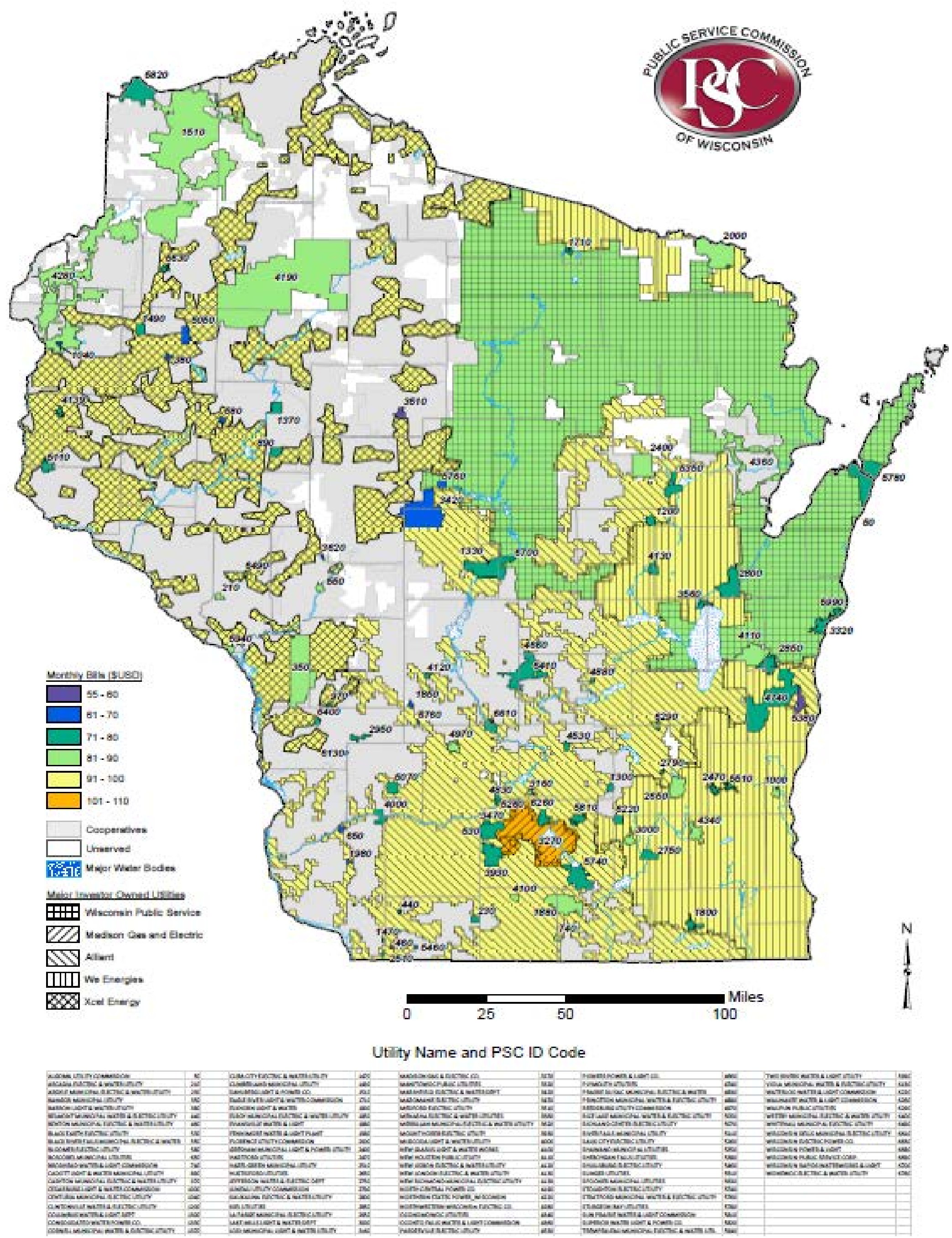
Commission Reference Number	Stakeholder Name	Commission Response
Comments Suggesting Specific Edits		
PSC REF#: 346556	ATC Comments on Draft SEA 2024	Some edits suggested by ATC for clarity and accuracy were incorporated into the final SEA.
PSC REF#: 347009	RENEW Wisconsin Comments on SEA 2024	Some edits suggested by RENEW for clarity and accuracy were incorporated into the final SEA.
Planning Reserve Margin, Rates and the Impact of Transmission Costs, and DER		
PSC REF#: 347034	CUB Comments on the Draft SEA 2024	The comments suggested that an integrated resource data gathering effort, associated with the SEA, may provide additional context to Commissioners during generation construction and rate case proceedings. The comments also suggested: • data collection changes to provide granularity of demand load control data, and that • DER represents a least-cost opportunity to leverage capacity requirements. The comments suggested that the context provided to the rates discussion by looking at ratepayer bills, while laudable, also demonstrates that the ways in which Wisconsinites have lowered their bills have a structural limit which cannot transcend the fact of higher rates. The Commission took these comments into consideration in preparation of the final SEA.
Discussion of Retail Choice		
PSC REF#: 346809	Comments on Draft SEA 2024 by TEPA and RESA	Commenters in this section discussed retail choice and advocated study and consideration of this approach in Wisconsin. The Commission previously evaluated retail choice in Docket 05-EI-114.

Planning Reserve Margin, Rates and the Impact of Transmission Costs, and DER, con't		
PSC REF#: 347010	ICG Comments Regarding the Draft Strategic Energy Assessment	The comments suggested that the changes in the PRM between the SEA2022 and SEA2024 bears additional explanation. In a discussion of rates, the commenters credited real-time rates as a positive driver of competitive rates, and focused on the role of pass-through transmission expenses, escrow accounts, and regional cost sharing, suggesting an expanded analysis of these impacts. The comments provided suggestions on: (a) presenting data according to local resource zones, (b) collecting additional information on forecasted capital expenditures, and (c) showing winter- and summer-peak data differently. The Commission took these comments into consideration in preparation of the final SEA.
PSC REF#: 347029	Fair Rates for Wisconsin's Dairyland comments on SEA	The comments noted the significant difference in the PRM from SEA2022 to SEA2024 as an indicator of the changes in baseload generation and to Wisconsin's historical status of being long on capacity, both resulting from retirements. The comments lauded the Commission for its analysis regarding rate drivers and affordability, and noted as CUB did, the demand control programs represent an opportunity to address capacity needs. The Commission took these comments into consideration in preparation of the final SEA.

Planning Reserve Margin, Rates and the Impact of Transmission Costs, and DER, con't		
PSC REF#: 347249	Public Comment by Jennifer Jones	Commenters in this section discussed a desire to see the SEA: (a) address cost-effective alternatives to transmission projects, (b) provide a different kind of analysis than that described in Wisconsin law, and (c) address the incorporation of DER as a demand resource for utilities. Comments in this section also discussed specific transmission projects. Commission consideration of this comment is more appropriate in the specific construction docket. The Commission took these comments into consideration in preparation of the final SEA.
PSC REF#: 347250	Public Comment by Radloff Group	
PSC REF#: 345144	Public Comment by Chris Klopp	
PSC REF#: 346675	Public Comment by Lila Zastrow-Dave Hendrickson	
Comments Received during the Public Hearing		
PSC REF#: 344948	David Stanfield, a citizen of Wisconsin John Romankiewicz, on behalf of the Sierra Club, John Muir Chapter Rob Danielson, on behalf of SOUL Wisconsin	The commenters at the hearing suggested that staff consider the following: • providing a break-out of debt from utility costs; • specifically addressing CO2, • vetting utility-provided demand forecasts for accuracy; • providing PRM analysis by LRZ and/or by utility instead of using an aggregate statewide approach; • using data sources other than EIA to provide a more accurate cost of utility-scale renewable energy; • analyzing DER costs relative to the cost of utility-scale generation; • discussing utilization rates of direct load control programs; and • breaking down rate driver details, especially transmission expenses. The Commission took these comments into consideration in preparation of the final SEA.

Other Comments		
PSC REF#: 346889	SEA Comment Letter – CONFIDENTIAL (REDACTED COPY) [filed by the Wisconsin Electric Power Company d.b.a. We Energies and the Wisconsin Public Service Corporation]	The comments addressed a confidential issue in the SEA data collection, and expressed support for the comments filed by the Wisconsin Utility Association. The Commission took these comments into consideration in preparation of the final SEA.
PSC REF#: 346857	Brief Comments on Draft SEA [filed by the Wisconsin Utilities Association]	The comments expressed an appreciation of the "Moving from Rates to Bills" section which provided background to rates section. The Commission took these comments into consideration in preparation of the final SEA.
PSC REF#: 347036	Customers First! Coalition Comments	The comments provided suggestions for future SEAs, including a suggestion to analyze the potential benefits to customers, utilities and the environment of electric vehicles and "efficient electrification." The Commission took these comments into consideration in preparation of the final SEA.

Figure A-1 2017 Average Residential Electric Monthly Bills, based on 650 kWh[133]



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133 https://psc.wi.gov/PublishingImages/Pages/ForConsumers/Maps/BillComp2017ResidentialMed.pdf

Table A-2 New Transmission Lines[1] (construction expected to start before December 31, 2024)

PSC Docket Number	Status	New Line or Rebuild/Upgrade[2]	Endpoints (Substations)	Voltage (kV)	Est. Cost (Millions)	Expected Construction	Expected In-Service	Substation Changes
American Transmission Company LLC (ATC)								
5-CE-146	Application Filed 4/30/18	New 125-mile 345 kV line	Cardinal-Hickory Creek, IA	345	492-543	Sep 19	Dec 23	Endpoint 2 will connect to the existing Salem-Hazelton 345kV line in Iowa.
137-CE-185	Application Withdrawn 1/17/18	New 2.8 mile 345 kV line	Arcadian/Pleasant Prairie-Zion Sub/Libertyville	345	54	Aug 18	Dec 21	New four position midpoint switching station Rosecrans
137-CE-187	Application Approved 1/2/18	Upgrade to 21.4 miles of 69 kV line	Caldron Falls-Goodman	69	28.2	Jan 19	Jun 20	
No Docket	Application Expected	New distribution substation	Northern Lights-Line 13898	138	26	Oct 17	Jun 20	New distribution substation
5-CE-149	Application Filed 1/31/18	New distribution substation	Juneautown Line 247K81	138	34.6	Oct 17	Jun 21	New distribution substation
No Docket	Application Expected	Convert 69 kV substations to 138 kV and a new 138 kV terminal at Pioneer	Bayport-Pioneer	138	53	Oct 17	Dec 21	Substation conversion from 69kV to 138kV
137-CE-188	Application Filed 1/26/18	New 1.5 mile 345 kV line	Pleasant Prairie-Racine	345	130	Oct 18	Dec 19	New Mt. Pleasant substation
Superior Water, Light and Power								
5820-CE-104	Application Approved 2/8/18	New 2.8 miles of 115 kV line	Nemadji-Enbridge	115	49.3	Jan 18	Dec 18	
Northern States Power Company-Wisconsin (NSPW)								
No Docket	Application Expected	Upgrade 63 miles of 345 kV line	King-Eau Claire	345	25.6	Jan 20	Dec 21	May require some substation equipment upgrades/replacements
No Docket	Application Expected	Upgrade 80 miles of 345 kV line	Eau Claire-Arpin	345	32.6	Jan 21	Dec 22	May require some substation equipment upgrades/replacements
No Docket	Application Expected	Upgrade 45 miles of 161 kV line	Eau Claire-Tremval	161	22	Jan 21	Dec 22	May require some substation equipment upgrades/replacements
No Docket	Application Expected	New 40 miles of 115 kV line	Bayfront-Norrie	115	51	Oct 20	Dec 22	Modifications to Saxon Pump substation will be required.

[1] Does not identify lines approved by the Commission after 4-26-18.

[2] Rebuilds and upgrades, as well as new lines, may require new ROW.

Source: Aggregated electricity provider data responses, docket 5-ES-109.

Table A-3 Customer-Owned Distributed Energy Resources by Customer Class—Investor-Owned and Municipal Utilities, 2008-2017 (continued on the next page)[134]

		Residential				Commercial			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	1,647	264	3,196	289,921	127,177	195	423,911	20,444,503
	Muni	36	6	3	224	135	23	42	12,738
	Total	1,683	270	3,199	290,145	127,313	218	423,954	20,457,241
2009	IOU	3,282	527	4,299	520,611	140,732	314	405,150	19,586,796
	Muni	111.7	23	24.635	4948	258.5	36	105.16	31547
	Total	3,394	550	4,323	525,559	140,990	350	405,255	19,618,343
2010	IOU	4,413	695	6,510	1,023,578	142,443	386	449,030	27,089,613
	Muni	221	46	112	26,091	343	46	218	65,353
	Total	4,633	741	6,621	1,049,669	142,786	432	449,248	27,154,966
2011	IOU	5,647	877	4,838	936,743	189,651	556	526,784	28,476,185
	Muni	276	58	163	40,427	1,042	68	320	75,136
	Total	5,923	935	5,002	977,170	190,693	624	527,104	28,551,321
2012	IOU	6,189	1,043	6,789	1,216,455	193,022	600	549,638	30,204,961
	Muni	328	70	234	59,332	1,114	78	473	98,528
	Total	6,517	1,113	7,023	1,275,787	194,136	678	550,111	30,303,489
2013	IOU	6,970	1,189	6,344	1,102,681	233,559	689	540,458	30,904,358
	Muni	521	104	310	80,854	1,146	83	520	94,531
	Total	7,491	1,293	6,654	1,183,535	234,705	772	540,977	30,998,889
2014	IOU	8,147	1,422	6,779	1,116,169	212,094	736	533,415	32,638,336
	Muni	696	132	452	110,569	1,207	89	573	103,029
	Total	8,843	1,554	7,231	1,226,738	213,301	825	533,988	32,741,365
2015	IOU	10,125	1,828	4,636	678,626	152,448	886	506,441	28,304,355
	Muni	837	161	670	142,662	1,331	99	604	113,013
	Total	10,961	1,989	5,306	821,288	153,779	985	507,045	28,417,368
2016	IOU	12,937	2,304	5,021	685,945	157,200	960	539,698	30,333,953
	Muni	1,044	189	732	143,523	2,219	112	628	111,473
	Total	13,980	2,493	5,754	829,468	159,419	1,072	540,326	30,445,426
2017[135]	IOU	15,141	2,671	5,297	587,933	160,333	1,022	373,839	20,831,252
	Muni	1,205	214	703	122,971	2,987	120	596	88,693
	Total	16,346	2,885	6,001	710,904	163,319	1,142	374,434	20,919,945
Total[136] 2008 - 2017				57,114	8,890,263			4,852,442	269,608,353

[134] This table does not include power cooperative data.

[135] 2017 data cover the period of January to September.

[136] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-3 (continued) Customer-Owned Distributed Energy Resources by Customer Class—Investor-Owned and Municipal Utilities, 2008-2017[137]

		Industrial				Total			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	145,891	15	33,840	551,615	274,715	474	460,947	21,286,039
	Muni	-	-	-	-	172	29	46	12,962
	Total	145,891	15	33,840	551,615	274,887	503	460,992	21,299,001
2009	IOU	155,291	18	80,607	1,264,993	299,305	859	490,055	21,372,400
	Muni	-	-	-	-	370	59	130	36,495
	Total	155,291	18	80,607	1,264,993	299,675	918	490,185	21,408,895
2010	IOU	151,535	23	53,632	3,255,515	298,391	1,104	509,171	31,368,706
	Muni	388	3	250	26,088	951	95	580	117,532
	Total	151,923	26	53,882	3,281,603	299,342	1,199	509,751	31,486,238
2011	IOU	156,068	26	71,140	4,625,792	351,366	1,459	602,762	34,038,720
	Muni	388	3	449	49,025	1,706	129	932	164,588
	Total	156,456	29	71,589	4,674,817	353,072	1,588	603,694	34,203,308
2012	IOU	157,663	29	74,011	5,075,484	356,874	1,672	630,439	36,496,900
	Muni	454	3	512	53,751	1,896	151	1,220	211,611
	Total	158,117	32	74,524	5,129,235	358,770	1,823	631,658	36,708,511
2013	IOU	154,163	29	77,883	4,148,546	394,692	1,907	624,685	36,155,585
	Muni	454	3	511	53,761	2,121	190	1,341	229,146
	Total	154,617	32	78,394	4,202,307	396,813	2,097	626,026	36,384,731
2014	IOU	156,237	30	61,851	4,109,130	376,478	2,188	602,045	37,863,635
	Muni	584	4	334	38,542	2,487	225	1,359	252,140
	Total	156,821	34	62,185	4,147,672	378,965	2,413	603,403	38,115,775
2015	IOU	166,324	60	40,120	2,589,095	328,898	2,774	551,196	31,572,076
	Muni	584	4	515	51,478	2,751	264	1,789	307,153
	Total	166,908	64	40,635	2,640,573	331,649	3,038	552,985	31,879,229
2016	IOU	163,013	87	58,410	3,245,515	333,149	3,351	603,129	34,265,413
	Muni	584	4	489	46,499	3,847	305	1,849	301,495
	Total	163,597	91	58,898	3,292,014	336,996	3,656	604,978	34,566,908
2017[138]	IOU	166,621	110	42,166	2,343,278	342,095	3,803	421,302	23,762,463
	Muni	683	5	393	39,123	4,875	339	1,692	250,787
	Total	167,304	115	42,559	2,382,401	346,969	4,142	422,994	24,013,250
Total[139] 2008 - 2017				597,112	31,567,230			5,506,667	310,065,846

[137] This table does not include power cooperative data.

[138] 2017 data cover the period of January to September.

[139] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-4 Customer-Owned Distributed Energy Resources by Installation Size—Investor-Owned Utilities, Municipal Utilities, and Cooperatives 2008-2017 (continued on the next page)[140]

		≤ 20 kW				> 20-200 kW			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	2,462	398	4,254	381,512	1,358	26	621	47,311
	Other	308	55	109	15,600	77	2	9	396
	Total	2,770	453	4,363	397,112	1,435	28	630	47,707
2009	IOU	5,209	754	5,852	681,751	1,858	38	704	47,790
	Other	819	150	227	31,962	172	5	39	9,276
	Total	6,028	904	6,079	713,713	2,030	43	743	57,066
2010	IOU	7,691	988	8,959	1,471,282	2,747	50	4,802	326,719
	Other	1,381	234	580	79,042	445	10	244	40,415
	Total	9,072	1,222	9,539	1,550,324	3,192	60	5,047	367,134
2011	IOU	10,212	1,286	7,577	1,446,190	4,480	96	5,938	392,883
	Other	1,844	310	924	111,479	841	19	597	65,949
	Total	12,056	1,596	8,500	1,557,669	5,320	115	6,536	458,832
2012	IOU	11,600	1,519	10,285	1,868,491	4,163	71	5,875	370,710
	Other	2,193	368	1,405	162,237	830	19	692	68,832
	Total	13,793	1,887	11,691	2,030,728	4,993	90	6,567	439,542
2013	IOU	13,579	1,739	10,205	1,740,586	4,460	79	6,908	410,563
	Other	2,677	450	1,150	168,556	945	23	794	69,455
	Total	16,256	2,189	11,355	1,909,142	5,405	102	7,702	480,018
2014	IOU	15,369	2,013	10,670	1,941,504	4,768	87	7,253	425,695
	Other	3,475	594	1,260	200,818	1,125	26	884	72,606
	Total	18,844	2,607	11,930	2,142,322	5,893	113	8,137	498,301
2015	IOU	16,893	2,522	9,915	1,478,422	10,025	160	6,498	536,334
	Other	4,397	720	1,626	244,478	1,130	26	909	74,308
	Total	21,290	3,242	11,541	1,722,900	11,155	186	7,408	610,642
2016	IOU	20,354	3,061	10,589	1,493,216	11,412	183	7,796	478,335
	Other	5,661	871	2,061	251,673	1,444	32	999	74,820
	Total	26,015	3,932	12,650	1,744,889	12,856	215	8,795	553,155
2017[141]	IOU	22,900	3,472	9,926	1,208,275	13,651	214	6,302	358,241
	Other	5,996	902	2,113	215,902	1,603	33	781	60,888
	Total	28,896	4,374	12,040	1,424,177	15,254	247	7,083	419,129
Total[142] 2008 - 2017				99,689	15,192,976			58,646	3,931,526

[140] Other is an aggregate of power cooperative and municipal utility data.

[141] 2017 data cover the period of January to September.

[142] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-4 (continued) Customer-Owned Distributed Energy Resources by Installation Size—Investor-Owned Utilities, Municipal Utilities, and Cooperatives, 2008-2017 (continued on the next page)[143]

		> 200-1,000 kW				> 1,000 - 15,000 kW			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	10,718	17	17,308	814,369	102,577	26	398,978	19,167,436
	Other	-	-	-	-	-	-	-	-
	Total	10,718	17	17,308	814,369	102,577	26	398,978	19,167,436
2009	IOU	15,991	28	19,317	892,857	118,647	32	401,688	18,021,440
	Other	-	-	-	-	-	-	-	-
	Total	15,991	28	19,317	892,857	118,647	32	401,688	18,021,440
2010	IOU	16,106	28	52,208	3,758,464	114,247	31	416,741	24,313,695
	Other	225	1	165	15,897	-	-	-	-
	Total	16,331	29	52,373	3,774,361	114,247	31	416,741	24,313,695
2011	IOU	18,109	33	61,864	4,748,743	132,965	37	495,572	25,611,387
	Other	550	2	238	23,056	-	-	-	-
	Total	18,659	35	62,102	4,771,799	132,965	37	495,572	25,611,387
2012	IOU	21,809	37	66,376	5,053,644	133,702	38	523,429	27,757,033
	Other	616	2	312	29,741	-	-	-	-
	Total	22,425	39	66,688	5,083,385	133,702	38	523,429	27,757,033
2013	IOU	23,099	40	83,305	6,278,910	147,354	41	507,243	26,745,499
	Other	616	2	288	27,427	-	-	-	-
	Total	23,715	42	83,593	6,306,337	147,354	41	507,243	26,745,499
2014	IOU	23,962	42	83,304	6,225,826	146,780	39	487,824	28,578,627
	Other	616	2	126	13,593	-	-	-	-
	Total	24,578	44	83,430	6,239,419	146,780	39	487,824	28,578,627
2015	IOU	33,602	52	79,498	4,853,711	159,378	37	455,139	24,699,131
	Other	616	2	265	24,678	-	-	-	-
	Total	34,218	54	79,763	4,878,389	159,378	37	455,139	24,699,131
2016	IOU	30,737	66	85,136	5,804,679	161,646	38	498,287	26,459,850
	Other	1,176	3	206	20,200	-	-	-	-
	Total	31,913	69	85,342	5,824,879	161,646	38	498,287	26,459,850
2017[144]	IOU	34,842	77	54,377	3,642,142	157,301	35	339,978	18,071,466
	Other	1,710	5	270	22,231	-	-	-	-
	Total	36,552	82	54,647	3,664,373	157,301	35	339,978	18,071,466
Total[145] 2008 - 2017				604,563	42,250,168			4,524,878	239,425,564

[143] Other is an aggregate of power cooperative and municipal utility data.

[144] 2017 data cover the period of January to September.

[145] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-4 (continued) Customer-Owned Distributed Energy Resources by Installation Size—Investor-Owned Utilities, Municipal Utilities, and Cooperatives, 2008-2017[146]

		> 15,000 kW				Total			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	157,600	7	39,787	875,411	274,715	474	460,947	21,286,039
	Other	-	-	-	-	385	57	118	15,996
	Total	157,600	7	39,787	875,411	275,100	531	461,065	21,302,035
2009	IOU	157,600	7	62,494	1,728,562	299,305	859	490,055	21,372,400
	Other	-	-	-	-	991	155	266	41,238
	Total	157,600	7	62,494	1,728,562	300,296	1,014	490,321	21,413,638
2010	IOU	157,600	7	26,461	1,498,546	298,391	1,104	509,171	31,368,706
	Other	-	-	-	-	2,051	245	989	135,354
	Total	157,600	7	26,461	1,498,546	300,442	1,349	510,161	31,504,060
2011	IOU	185,600	7	31,811	1,839,517	351,366	1,459	602,762	34,038,720
	Other	-	-	-	-	3,234	331	1,759	200,484
	Total	185,600	7	31,811	1,839,517	354,600	1,790	604,521	34,239,204
2012	IOU	185,600	7	24,473	1,447,022	356,874	1,672	630,439	36,496,900
	Other	-	-	-	-	3,638	389	2,409	260,810
	Total	185,600	7	24,473	1,447,022	360,512	2,061	632,848	36,757,710
2013	IOU	206,200	8	17,024	980,027	394,692	1,907	624,685	36,155,585
	Other	-	-	-	-	4,237	475	2,232	265,438
	Total	206,200	8	17,024	980,027	398,929	2,382	626,916	36,421,023
2014	IOU	185,600	7	12,994	691,983	376,478	2,188	602,045	37,863,635
	Other	-	-	-	-	5,216	622	2,270	287,017
	Total	185,600	7	12,994	691,983	381,694	2,810	604,315	38,150,652
2015	IOU	109,000	3	146	4,478	328,898	2,774	551,196	31,572,076
	Other	-	-	-	-	6,144	748	2,801	343,464
	Total	109,000	3	146	4,478	335,041	3,522	553,997	31,915,540
2016	IOU	109,000	3	1,322	29,333	333,149	3,351	603,129	34,265,413
	Other	-	-	-	-	8,281	906	3,266	346,693
	Total	109,000	3	1,322	29,333	341,430	4,257	606,395	34,612,106
2017[147]	IOU	113,400	5	10,719	482,339	342,095	3,803	421,302	23,762,463
	Other	-	-	-	-	9,309	940	3,165	299,021
	Total	113,400	5	10,719	482,339	351,403	4,743	424,467	24,061,484
Total[148] 2008 - 2017				227,230	9,577,218			5,515,006	310,377,452

[146] Other is an aggregate of power cooperative and municipal utility data.

[147] 2017 data cover the period of January to September.

[148] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-5 Customer-Owned Distributed Energy Resources by Technology Type—Investor-Owned Utilities, Municipal Utilities, and Cooperatives, 2008-2017 (continued on the next page)[149]

		Biogas				Fossil Fuel			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	9,888	12	16,894	932,361	6,996	3	-	-
	Other	-	-	-	-	-	-	-	-
	Total	9,888	12	16,894	932,361	6,996	3	-	-
2009	IOU	15,341	18	29,759	1,527,710	6,996	3	-	-
	Other	-	-	-	-	-	-	-	-
	Total	15,341	18	29,759	1,527,710	6,996	3	-	-
2010	IOU	15,601	18	50,739	4,178,489	6,996	3	2,182	143,494
	Other	-	-	-	-	-	-	-	-
	Total	15,601	18	50,739	4,178,489	6,996	3	2,182	143,494
2011	IOU	24,852	28	72,076	5,954,230	6,996	3	3,370	258,331
	Other	325	1	-	-	-	-	-	-
	Total	25,177	29	72,076	5,954,230	6,996	3	3,370	258,331
2012	IOU	29,409	33	94,919	7,882,943	6,996	3	26	1,345
	Total	325	1	-	-	-	-	-	-
	Total	29,734	34	94,919	7,882,943	6,996	3	26	1,345
2013	IOU	38,815	40	114,463	8,284,483	6,996	3	26	1,228
	Other	325	1	-	-	-	-	-	-
	Total	39,140	41	114,463	8,284,483	6,996	3	26	1,228
2014	IOU	40,874	42	115,701	9,788,693	6,996	3	29	1,262
	Other	455	2	-	-	-	-	-	-
	Total	41,329	44	115,701	9,788,693	6,996	3	29	1,262
2015	IOU	52,022	46	114,001	8,702,664	4,129	5	52	4,172
	Other	455	2	49	1,733	-	-	-	-
	Total	52,477	48	114,050	8,704,397	4,129	5	52	4,172
2016	IOU	43,182	46	116,853	9,645,262	4,599	5	154	5,212
	Other	455	2	89	3,029	-	-	-	-
	Total	43,637	48	116,942	9,648,291	4,599	5	154	5,212
2017[150]	IOU	46,342	47	88,138	6,937,399	4,599	5	27	897
	Other	455	2	32	1,104	435	1	0	17
	Total	46,797	49	88,170	6,938,503	5,034	6	28	914
Total[151] 2008 - 2017				813,713	63,840,100			5,866	415,958

[149] Other is an aggregate of power cooperative and municipal utility data.

[150] 2017 data cover the period of January to September.

[151] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-5 (continued) Customer-Owned Distributed Energy Resources by Technology Type—Investor-Owned Utilities, Municipal Utilities, and Cooperatives, 2008-2017 (continued on the next page)[152]

		Hydroelectric				Landfill Gas			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	44,077	22	23,003	933,636	59,081	12	374,294	18,028,282
	Other	1	1	0	4	-	-	-	-
	Total	44,078	23	23,003	933,640	59,081	12	374,294	18,028,282
2009	IOU	56,237	51	55,223	933,836	63,331	14	341,377	16,352,905
	Other	1	1	2	80	-	-	-	-
	Total	56,238	52	55,225	933,916	63,331	14	341,377	16,352,905
2010	IOU	51,857	52	64,278	3,581,029	63,331	14	351,232	20,290,272
	Other	1	1	1	92	-	-	-	-
	Total	51,858	53	64,280	3,581,121	63,331	14	351,232	20,290,272
2011	IOU	58,719	55	70,874	3,813,033	68,131	15	410,150	20,573,314
	Other	1	1	1	49	-	-	-	-
	Total	58,720	56	70,875	3,813,082	68,131	15	410,150	20,573,314
2012	IOU	58,719	55	63,520	3,250,108	68,131	15	429,944	21,911,164
	Other	19	2	2	144	-	-	-	-
	Total	58,738	57	63,522	3,250,252	68,131	15	429,944	21,911,164
2013	IOU	74,919	55	74,597	3,872,291	68,131	15	403,109	21,187,870
	Other	19	2	-	-	-	-	-	-
	Total	74,938	57	74,597	3,872,291	68,131	15	403,109	21,187,870
2014	IOU	54,549	53	74,467	3,521,485	66,131	14	383,097	21,923,884
	Other	19	2	-	-	-	-	-	-
	Total	54,568	55	74,467	3,521,485	66,131	14	383,097	21,923,884
2015	IOU	54,680	48	56,977	2,471,497	60,231	12	365,603	18,683,982
	Other	19	2	9	421	-	-	-	-
	Total	54,699	50	56,986	2,471,918	60,231	12	365,603	18,683,982
2016	IOU	54,680	48	84,124	3,383,361	60,231	12	384,258	19,168,829
	Other	20	2	15	715	-	-	-	-
	Total	54,700	50	84,140	3,384,076	60,231	12	384,258	19,168,829
2017[153]	IOU	54,680	48	57,398	2,238,784	57,786	11	257,092	12,455,824
	Other	20	2	23	1,162	-	-	-	-
	Total	54,700	50	57,421	2,239,946	57,786	11	257,092	12,455,824
Total[154] 2008 - 2017				624,515	28,001,727			3,700,156	190,576,326

[152] Other is an aggregate of power cooperative and municipal utility data.

[153] 2017 data cover the period of January to September.

[154] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-5 (continued) Customer-Owned Distributed Energy Resources by Technology Type—Investor-Owned Utilities, Municipal Utilities, and Cooperatives, 2008-2017 (continued on the next page)[155]

		Other				Solar			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	151,550	10	42,233	984,419	1,741	324	4,366	390,106
	Other	-	-	-	-	205	41	83	14,699
	Total	151,550	10	42,233	984,419	1,946	365	4,449	404,805
2009	IOU	151,550	10	57,519	1,847,395	3,888	637	5,980	699,307
	Other	-	-	-	-	589	117	213	39,204
	Total	151,550	10	57,519	1,847,395	4,477	754	6,193	738,511
2010	IOU	151,550	10	32,512	1,780,761	6,189	848	7,665	1,342,445
	Other	-	-	-	-	1,233	192	728	117,232
	Total	151,550	10	32,512	1,780,761	7,422	1,040	8,393	1,459,677
2011	IOU	179,675	11	39,058	2,053,757	8,916	1,137	6,428	1,302,262
	Other	-	-	-	-	1,795	270	1,147	153,474
	Total	179,675	11	39,058	2,053,757	10,711	1,407	7,575	1,455,736
2012	IOU	179,675	11	31,933	1,631,615	10,415	1,370	8,897	1,697,760
	Other	-	-	-	-	2,240	326	1,711	213,376
	Total	179,675	11	31,933	1,631,615	12,655	1,696	10,609	1,911,136
2013	IOU	179,675	11	22,702	1,140,586	12,311	1,586	8,691	1,554,918
	Other	-	-	-	-	2,803	410	1,485	217,008
	Total	179,675	11	22,702	1,140,586	15,114	1,996	10,176	1,771,926
2014	IOU	179,675	11	18,308	878,694	14,473	1,871	9,401	1,638,849
	Other	-	-	-	-	3,688	559	1,528	241,431
	Total	179,675	11	18,308	878,694	18,161	2,430	10,928	1,880,280
2015	IOU	121,266	10	3,500	85,279	22,470	2,453	9,572	1,432,408
	Other	-	-	-	-	4,628	685	2,004	295,298
	Total	121,266	10	3,500	85,279	27,097	3,138	11,576	1,727,706
2016	IOU	121,266	10	4,588	101,648	34,935	3,025	11,721	1,782,585
	Other	-	-	-	-	6,782	845	2,420	299,545
	Total	121,266	10	4,588	101,648	41,718	3,870	14,141	2,082,130
2017[156]	IOU	121,266	10	5,018	140,736	43,119	3,478	12,554	1,865,779
	Other	-	-	-	-	7,375	878	2,569	265,016
	Total	121,266	10	5,018	140,736	50,494	4,356	15,123	2,130,795
Total[157] 2008 - 2017				257,371	10,644,890			99,162	15,562,702

[155] Other is an aggregate of power cooperative and municipal utility data.

[156] 2017 data cover the period of January to September.

[157] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-5 (continued) Customer-Owned Distributed Energy Resources by Technology Type—Investor-Owned Utilities, Municipal Utilities, and Cooperatives, 2008-2017 (continued on the next page)[158]

		Storage				Wind			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	-	-	-	-	1,382	91	156	17,235
	Other	-	-	-	-	179	15	35	1,293
	Total	-	-	-	-	1,561	106	190	18,528
2009	IOU	-	-	-	-	1,962	126	197	11,247
	Other	-	-	-	-	401	37	51	1,954
	Total	-	-	-	-	2,363	163	248	13,201
2010	IOU	-	-	-	-	2,866	159	564	52,216
	Other	-	-	-	-	818	52	260	18,030
	Total	-	-	-	-	3,684	211	824	70,246
2011	IOU	730	34	11	1,759	3,347	176	796	82,034
	Other	-	-	-	-	1,114	59	611	46,961
	Total	730	34	11	1,759	4,460	235	1,407	128,995
2012	IOU	-	-	-	-	3,529	185	1,199	121,965
	Other	-	-	-	-	1,055	60	695	47,290
	Total	-	-	-	-	4,583	245	1,895	169,255
2013	IOU	-	-	-	-	13,845	197	1,096	114,209
	Other	-	-	-	-	1,091	62	747	48,430
	Total	-	-	-	-	14,935	259	1,843	162,639
2014	IOU	-	-	-	-	13,780	194	1,043	110,768
	Other	-	-	-	-	1,054	59	743	45,586
	Total	-	-	-	-	14,834	253	1,785	156,354
2015	IOU	13	1	-	-	14,087	199	1,492	192,074
	Other	-	-	-	-	1,042	59	738	46,012
	Total	13	1	-	-	15,129	258	2,231	238,086
2016	IOU	13	1	-	-	14,243	204	1,431	178,516
	Other	-	-	-	-	1,024	57	742	43,404
	Total	13	1	-	-	15,267	261	2,173	221,920
2017[159]	IOU	13	1	-	-	14,290	203	1,074	123,044
	Other	-	-	-	-	1,024	57	541	31,722
	Total	13	1	-	-	15,314	260	1,615	154,766
Total[160] 2008 - 2017				11	1,759			14,211	1,333,990

[158] Other is an aggregate of power cooperative and municipal utility data.

[159] 2017 data cover the period of January to September.

[160] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Table A-5 (continued) Customer-Owned Distributed Energy Resources by Technology Type—Investor-Owned Utilities, Municipal Utilities, and Cooperatives, 2008-2017[161]

		Total			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	274,715	474	460,947	21,286,039
	Other	385	57	118	15,996
	Total	275,100	531	461,065	21,302,035
2009	IOU	299,305	859	490,055	21,372,400
	Other	991	155	266	41,238
	Total	300,296	1,014	490,321	21,413,638
2010	IOU	298,391	1,104	509,171	31,368,706
	Other	2,051	245	989	135,354
	Total	300,442	1,349	510,161	31,504,060
2011	IOU	351,366	1,459	602,762	34,038,720
	Other	3,234	331	1,759	200,484
	Total	354,600	1,790	604,521	34,239,204
2012	IOU	356,874	1,672	630,439	36,496,900
	Other	3,638	389	2,409	260,810
	Total	360,512	2,061	632,848	36,757,710
2013	IOU	394,692	1,907	624,685	36,155,585
	Other	4,237	475	2,232	265,438
	Total	398,929	2,382	626,916	36,421,023
2014	IOU	376,478	2,188	602,045	37,863,635
	Other	5,216	622	2,270	287,017
	Total	381,694	2,810	604,315	38,150,652
2015	IOU	328,898	2,774	551,196	31,572,076
	Other	6,144	748	2,801	343,464
	Total	335,041	3,522	553,997	31,915,540
2016	IOU	333,149	3,351	603,129	34,265,413
	Other	8,281	906	3,266	346,693
	Total	341,430	4,257	606,395	34,612,106
2017[162]	IOU	342,095	3,803	421,302	23,762,463
	Other	9,309	940	3,165	299,021
	Total	351,403	4,743	424,467	24,061,484
Total[163] 2008 - 2017				5,515,006	310,377,452

[161] Other is an aggregate of power cooperative and municipal utility data.

[162] 2017 data cover the period of January to September.

[163] Totals for Installed Capacity and Number of Installations are not year-on-year cumulative, but represented by the total in 2017.

Acronyms

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

JOA	Joint Operating Agreement
kV	kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LMP	Locational Marginal Pricing
LMR	Load Modifying Resources
LOLE	Loss of load expectations
LRZ	Local Resource Zone
LSE	Load Serving Entity
LTRA	Long-Term Resource Assessment
MATS	Mercury and Air Toxics Standard
MEP	Market Efficiency Project
MGE	Madison Gas and Electric Company
MISO	Midcontinent Independent System Operator, Inc.
MTEP	MISO Transmission Expansion Plan
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NEV	Neutral-to-earth voltage
NO_X	Nitrogen oxides
NRC	Nuclear Regulatory Commission
NSPM	Northern States Power Company-Minnesota
NSPW	Northern States Power Company-Wisconsin
NWE	Northwestern Wisconsin Electric Company
OMS	Organization of MISO States
PPA	Purchased power agreements
PRB	Power River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PY	Planning Year
RER	Renewable Energy Rider
ROW	Right-of-way
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCPC	Supercritical pulverized coal

SCR	Selective catalytic reduction
SEA	Strategic Energy Assessment
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SWL&P	Superior Water, Light and Power Company
TMEP	Targeted Market Efficiency Projects
TOU	Time-of-Use
TRC	Total Resource Cost
UCAP	Unforced Capacity
VOC	Volatile organic compounds
WEC	Wisconsin Energy Corporation
WEM	Wisconsin Emergency Management
WEPCO	Wisconsin Electric Power Company
WG	Wisconsin Gas LLC
Wis. Admin. Code	Wisconsin Administrative Code
Wis. Stat.	Wisconsin Statutes
WP&L	Wisconsin Power and Light Company
WPPI	WPPI Energy
WPSC	Wisconsin Public Service Corporation
Xcel	Xcel Energy, Inc.

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