TO THE READER

This is the ninth 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 copy of the notice providing information on the hearing will be 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. It will be available on the Commission's website at least 30 days prior to the public hearing.

Public comments will be used to prepare the final SEA. The Commission encourages all interested persons to comment on the content of this report during the 90-day comment period, which begins with the mailing of this draft SEA. Questions regarding the process or requests for additional copies of the draft SEA may be directed to PSCSEA2022@wisconsin.gov. Questions from the legislature and the media may be directed to Elise Nelson at (608) 266-9600.

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STRATEGIC ENERGY ASSESSMENT

2016-2022 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:

- All large electric generating facilities for which an electricity provider or merchant plant developer plans to commence construction within seven years;
- All high-voltage transmission lines for which an electricity provider plans to commence construction within seven years;
- Any plans for assuring that there is an adequate ability to transfer electric power into or out of Wisconsin in a reliable manner;
- The projected demand for electric energy and the basis for determining the projected demand;
- Activities to discourage inefficient and excessive energy use;
- Existing and planned generation facilities that use renewable energy sources; and
- Regional and national policy initiatives that could have direct and material impacts on Wisconsin's energy supply, delivery, and rates.
- 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 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.

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 ninth SEA covers the years 2016 through 2022. During the past year, 11 large Wisconsin-based investor-owned utilities, cooperatives, municipal electric utilities, and other electricity and transmission providers submitted historic information regarding statewide demand, generation, out-of-state sales and purchases, transmission capacity, and energy efficiency efforts. In addition, these entities provided forecasted information through 2022.

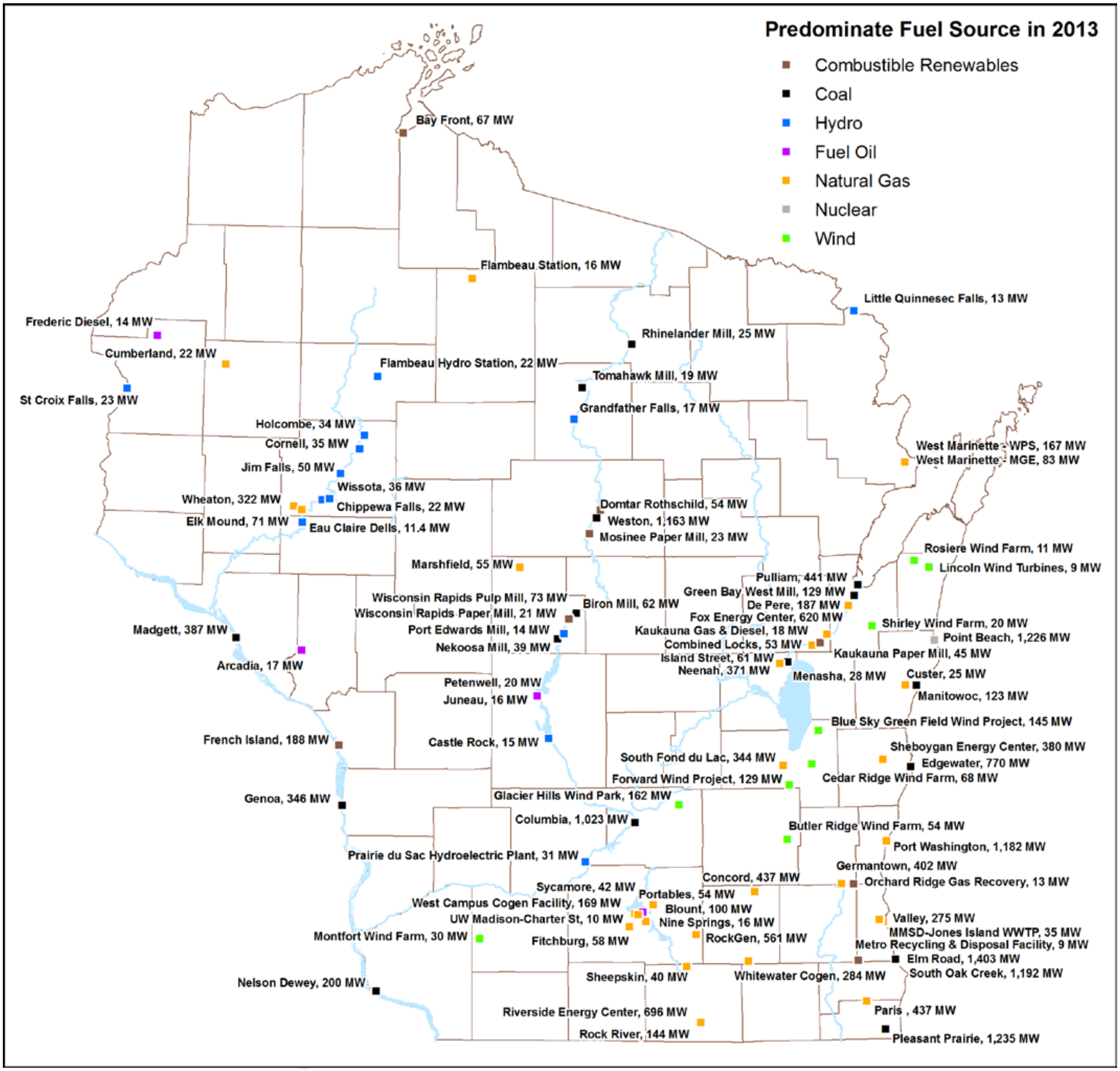
The SEA is an informational report that provides the public and stakeholders with information about relevant trends, facts, and issues affecting the state's electric industry. Under Wis. Stats. § 196.491(3)(dm), the SEA is not a prescriptive report, meaning that the ideas, facts, projects, and discussions 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 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 (MPU), 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), Wisconsin Public Power, Inc. (WPPI), and Wisconsin Public Service Corporation (WPSC).

DPC and WPPI provided data on behalf of their member cooperatives and municipal electricity providers. The other providers were required to include supply and demand data for any wholesale requirements that they have under contract. This action streamlined data reporting and reflected current market activities. Figure 1 shows existing generating facilities greater than nine MW.

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



EXECUTIVE SUMMARY

There are some notable differences in this SEA compared to prior SEAs. For example, data collection for this SEA included a survey of all municipal and investor-owned utilities specific to customer-owned generation, known as distributed energy resources (DER). DER is a growing trend across the country and in Wisconsin, and contributes to an electricity provider's demand profile. The overall volume of DER is expected to grow in the future.

There are also some regional and national trends and changes that are impacting Wisconsin. These so-called externalities are not regulated or controlled in Wisconsin. Specifically, in late 2015, the Environmental Protection Agency (EPA) promulgated new air pollution rules to regulate carbon emissions from electric generating units. Referred to as the "Clean Power Plan," (CPP) these rules require reductions in carbon dioxide (CO_2) emissions from existing power plants and establish emissions limits for any new power plants. Wisconsin, along with over 25 other states, challenged these regulations in federal court. The U.S. Supreme Court granted a stay of the rules while the litigation proceeds. The Governor of Wisconsin has directed that no further work be done to develop or promote the development of a state plan in response to these rules until after the outcome of the litigation is known. As a result, this SEA does not attempt to address any outcomes related to the regulation of carbon from electricity generating units.

Furthermore, the Midcontinent Independent Service Operator (MISO), through its role as a regional planning body, directly impacts how electricity is produced and transmitted in Wisconsin. MISO developed a new Aggregated Forecasted Supply and Demand calculation which impacts planning in Wisconsin. This calculation is used in this SEA.

ADEQUACY AND RELIABILITY OF WISCONSIN'S ELECTRIC SUPPLY

- Data collected for the purposes of this SEA indicate that Wisconsin's planning reserve margins are forecasted to remain above 14 percent through 2022. The planning reserve margin for the 2016-2022 period is between 14.2 and 17.5 percent.
- Wisconsin exceeds the 7.1 percent planning reserve requirement set by MISO for 2016.
- Electricity providers expect slow but continued growth in peak demand and estimate increases in non-coincident peaks to be between approximately 0.5 and 1.6 percent for the 2016 through 2022 time period.
- Wisconsin's primary electric generation fuel source continues to be coal with approximately 65 percent of energy generated in Wisconsin from coal-fired facilities in 2013.
- The shutdown of the Kewaunee nuclear facility and decreases in the cost of natural gas, among other factors, continue to change the generation mix proportions in the state.
- Wisconsin electric utilities estimate that they will retire approximately 520 MW of existing Wisconsin-based electric generation by 2020.
- Approximately 720 MW of new generation is expected to be added from 2016-2022.

TRANSMISSION SYSTEM PLANS, ISSUES, AND DEVELOPMENTS

- The MISO reliability footprint consists of 15 states and one Canadian Province. MISO's energy and operating reserves markets had gross annual charges of $37 billion in 2014.
- The most recent MISO transmission expansion planning (MTEP) process contains 357 new projects that total $2.64 billion in transmission facilities, in year-of-occurrence dollars.
- MISO conducts an annual Long-Term (10-year) Resource Assessment. Since resources are typically committed five years in advance, a planning gap often appears late in the analysis period. A planning gap occurs when the difference between planned and committed resources is less than any anticipated planning reserve margin.
- The Federal Energy Regulatory Commission's (FERC) Order 1000 requires coordination with neighboring regions, whether they are regional transmission organizations (RTOs) or transmission planning regions. The Commission continues to work with MISO and other states to fully participate in this and other interregional processes and studies.

RATES

- Since the last SEA, electricity rates have increased for all customer classes both in Wisconsin and the Midwest. The utility industry is a capital-intensive industry, and rate increases pay for investments in transmission, generation, and distribution facilities. This investment is necessary to replace aging facilities, comply with federal regulations, and develop new renewable energy resources. However, lower fuel and purchased power costs have helped to offset these increases.
- Although electricity rates continue to increase, customers can mitigate some of the impact of the increases on their individual bills through increased conservation and energy efficiency.
- The Commission continues to investigate ways to mitigate electric rate increases to ensure Wisconsin remains competitive in a global marketplace.
- EPA has promulgated several rules that further regulate emissions from electric generating facilities. These regulations, if implemented, will affect the mix of generation resources in Wisconsin and could result in higher costs for utilities and ratepayers.
- The Commission continues to monitor the implementation of EPA rules to ensure that electricity providers are pursuing cost-effective compliance strategies.
- For the first time, the Commission collected information from utilities about DER in Wisconsin. These data will provide the Commission and other stakeholders with better information about the effects of DER on the electric grid and their rate impacts going forward.

ENERGY EFFICIENCY AND RENEWABLE RESOURCES

- The Commission continues to review the funding and structure of the energy efficiency and renewable resource programs—known as Focus on Energy—paid for by Wisconsin ratepayers to ensure that the programs cost-effectively meet goals established under Wis. Stat. § 196.374.
- Wis. Stat. § 196.378 requires 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 2020.

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.

In preparing this assessment, the Commission relies on data submitted by the electricity providers for the SEA as well as other data collected by Commission staff, as noted.

Regional Bulk Power Market and Electric System Adequacy and Reliability

Forecasts indicate that Wisconsin will maintain an adequate and reliable electric supply with an acceptable planning reserve margin (PRM) through 2022. The PRM is calculated to reduce the probability of losing load during peak conditions. This is usually expressed as a percent of capacity greater than the forecasted demand.

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. Because PRM is relevant to many sections in the SEA, discussion on the topic is presented here to avoid duplication of information. The two PRM benchmarks, Wisconsin's and MISO's, are described below.

In Docket 5-EI-141, the Commission set a guideline of 14.5 percent (installed capacity rating) for the PRM. Table 1 shows that the 2016 Wisconsin PRM is 17.5 percent. This indicates that Wisconsin is forecasted to maintain an adequate and reliable electric supply, even with the preliminary, forecasted growth in summer peak demand. The PRM is expected to remain above 14 percent through 2022. Essentially, Wisconsin is experiencing a surplus of capacity. These generally higher PRMs are a result of a strong generation construction program beginning in the late 1990s, effective energy efficiency and conservation programs, and moderate demand growth.

As part of its annual transmission expansion planning, MISO conducts an analysis of expected planning reserve margins for its footprint. Wisconsin is part of the greater MISO market and transmission planning effort. Parts of Wisconsin are located in MISO's zones one and two.

The Commission currently requires that each electricity provider match loss of load expectation reliability criteria, as well as the planning reserve measurement process under Module E-1 of MISO's transmission tariff. For 2016, MISO requires 7.1 percent PRM[1] unforced capacity. Wisconsin electricity providers exceeded MISO's required PRM of 7.1 percent for the 2016-17 planning year. From the perspective of the MISO 2016 and 2020 load zone analysis and the 7-year analysis carried out in this SEA, there will be resource adequacy for Wisconsin for the planning period 2016 through 2022. Wisconsin is not unusual in this regard; other regions of the United States also have similar PRMs.

Table 1: Forecast Planning Reserve Margins from SEA (Percent)

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	Draft SEA 2016
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	17.5
2017							11.6	15.3	14.4
2018							13.3	13.7	14.2
2019								14.3	17.0
2020								13.8	16.1
2021									15.2
2022									14.2

Note: The SEA was expanded to cover seven years of forecast data in 2004; prior SEAs only examined two years.

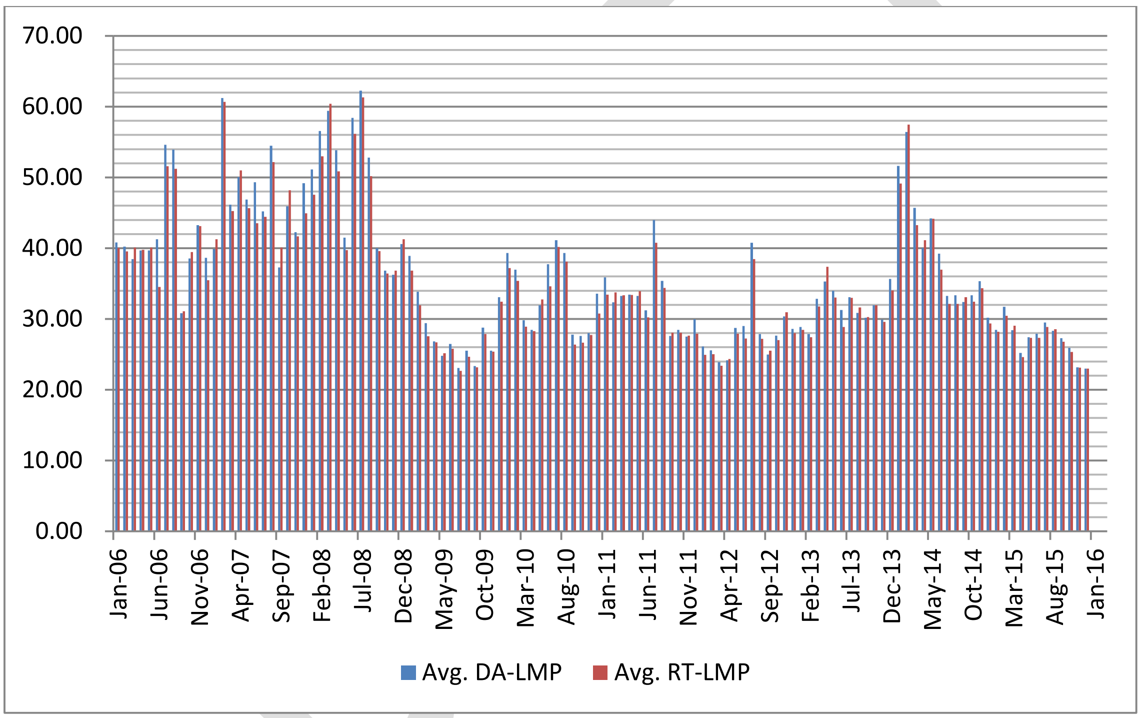
Source: Table 3 and previous SEA reports

[1] "Planning Year 2016-2017 Loss of Load Expectation Study Report," www.misoenergy.org.

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

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 Wisconsin electricity providers are part of MISO. For a broader view of the complete MISO wholesale energy 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 LMPs ($/MWh)



Source: Commission staff, using data from MISO portal.

A June 2015 report by MISO's independent market monitor (IMM), entitled "State of the Market 2014," provides evidence that MISO's wholesale energy markets were competitive with market clearing prices within 1.0 percent of the IMM's estimated reference-level marginal costs. The IMM also concluded that the marketplace experienced appropriate price convergence, with minor output withholding (only 0.6 percent of actual load) which could effectuate non-competitive prices.[2] The report indicated "market power mitigation measures were applied infrequently."[3]

[2] Potomac Economics, Dr. David Patton, *2014 State of the Market Report for the MISO Electricity Markets*, June 2015.
[3] Ibid.

The final topic in this section is an assessment of whether competitive markets[4] 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, 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. So, 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, as the implementation and effects that might occur in the MISO wholesale energy markets are not known. Economic theory dictates that if such a policy were already least cost, private business would have implemented such action already. Since public policy is the driver, prices are expected to increase for electricity. Increases in the price of electricity may change consumption and usage of electric energy as well. Dispatch of generator units will change, and preferred technologies will emerge. Basically, compliance costs will be incurred by all MISO market participants who are obligated to comply with EPA rules.

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 thereby maintaining sufficient capacity throughout the SEA assessment period. Regarding reasonable prices, the Commission reviews all purchase power contracts for public utilities during the formal rate case process.[5] 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. For these reasons, the Commission concludes that capacity and energy will continue to be available at a reasonable price.

Wisconsin currently meets its existing 10 percent renewable portfolio standard (RPS). By law, the Commission must ensure that electricity providers comply with the RPS in a cost-effective manner. Both requirements affect Wisconsin's optimal energy expansion path, and the RPS is considered in the Commission's analysis of proposed new generation resources.

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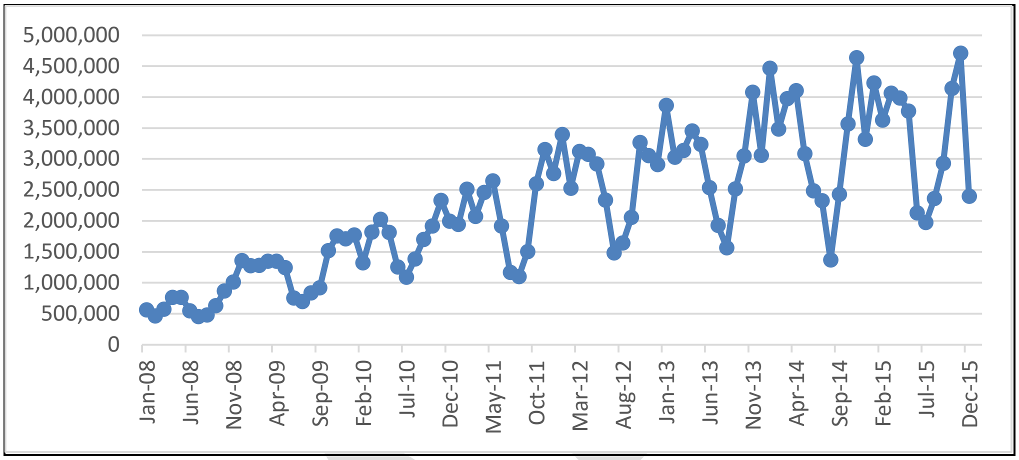
[4] Wis. Stat. § 196.491(2)(a)12 does not specifically identify what "effective competition" means. Since Wisconsin does not have retail competition, the Commission considers the impacts of the wholesale energy market operated by MISO. This does not indicate that the Commission believes that all markets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

[5] 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.

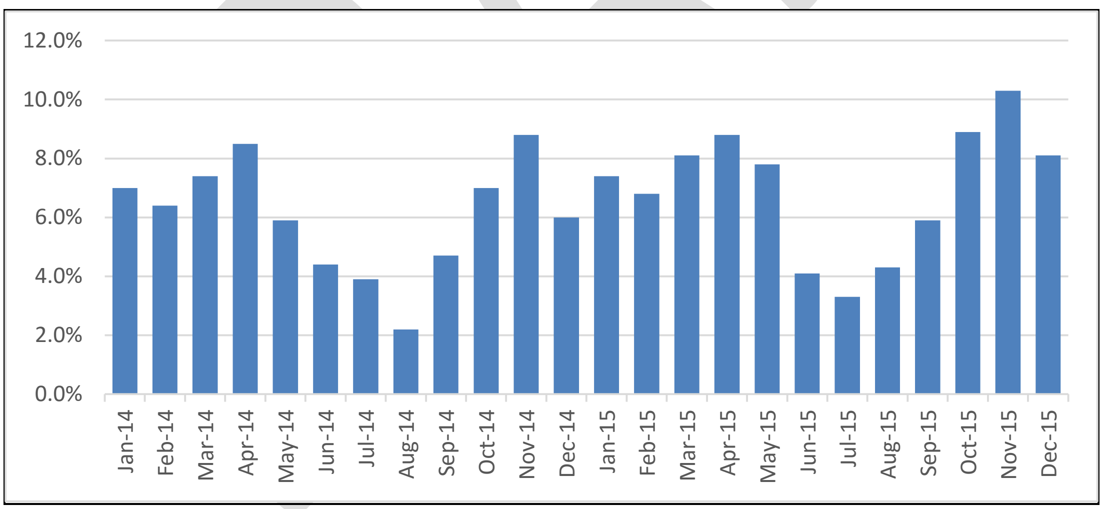
Wind energy accounts for most renewable energy available to Wisconsin. It is characterized by low marginal costs but intermittent availability. Figure 3 shows the growing presence of wind energy in the MISO footprint as well as its variability due to changes in seasonal weather. Figure 4 shows the percentage of energy in the MISO footprint coming from wind resources.

Figure 3: MISO Monthly Wind Generation in MWh



Source: www.misoenergy.org

Figure 4: Wind Energy as Percent of MISO Footprint Wide Energy 2014 –2015



Source: www.misoenergy.org

Utilities' Perspectives – Peak Demand and Supply

DEMAND

Demand is a measure of the instantaneous rate of electricity use measured in megawatts (MW). However, the volume of electricity consumed 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 higher in the summer, lowest in the spring and autumn "shoulder" months, and smaller peaks occur in the winter.

Table 2 shows the actual, aggregated peak electric demand and supply for Wisconsin electricity providers from 2013 through 2015. Wisconsin electricity providers have maintained sufficient reserves to meet the summer peak in recent years.

Table 2: Aggregated Historic Supply and Demand

Wisconsin Peak Electric Demand (MW)	**2013**	**2014**	**2015**
Date of Peak Load	July 18	July 22	August 14
Peak Load Data & Forecast (non-coincident)	13,752	12,608	12,588
Direct Load Control Program	(62)	(73)	(74)
Interruptible Load	(152)	(158)	0
Capacity Sales Incl. Reserves	847	803	772
Capacity Purchases Incl. Reserves	(250)	(250)	(250)
Miscellaneous Demand Factors	0	0	0
Adjusted Electric Demand	14,136	12,931	13,037
Electric Power Supply (MW)			
Owned Generating Capacity (in, or used, for Wis. cust.)	13,615	14,297	13,930
Merchant Power Plant Capacity Under Contract (in, or used, for Wis. cust.)	1,727	1,647	1,596
New Owned or Leased Capacity\Additions	550	45	44
Net Purchases W\O Reserves	119	(168)	148
Miscellaneous Supply Factors	(207)	(209)	(72)
Electric Power Supply	15,804	15,611	15,646
Transmission Data (MW)			
Resources Utilizing PJM/WUMS-MISO Interface	348	442	433

Source: Aggregated electricity provider data responses, docket 5-ES-108

Table 3 shows the forecasted aggregated peak electric demand and supply for the years 2016 through 2022. Beginning with this SEA, these data were collected in a revised format that is consistent with information reported to MISO. The data in Table 3 are consistent with data provided in previous SEAs, which predated the formation of MISO. The independent needs of some electricity providers may result in a need for new generation resources to be placed in service before 2022.

Table 3: Wisconsin Aggregated Forecasted Supply and Demand

	2016	2017	2018	2019	2020	2021	2022
Capacity (MW)	Unforced capacity capability (UCAP)[1]						
High Certainty Resources (not including registered behind the meter generation, below)	13,404	13,510	13,512	13,513	13,416	13,418	13,397
Low Certainty Resources	14	14	14	14	14	14	36
Behind the Meter (Receiving MISO capacity credit)	355	357	357	357	357	357	357
Demand Response Resources plus Registered Demand-Side Management	1,080	991	999	999	1,001	1,001	1,002
New Capacity	44	58	155	811	811	811	811
Local Resource Zone Internal Net Transfer-In	939	1,037	1,248	1,242	1,290	1,290	1,290
Net Imports	357	360	360	360	349	367	367
Retired	(164)	(164)	(499)	(640)	(621)	(633)	(634)
Net Capacity (MW)	16,029	16,163	16,145	16,655	16,616	16,625	16,625
Demand (MW)							
Full Responsibility Transactions (FRT)	259	(7)	(14)	(14)	(14)	(40)	(67)
Non-Coincident Load Serving Entity (LSE) Peak gross of Demand Response (DR)	14,424	14,646	14,648	14,754	14,840	14,931	15,040
Total Coincident Wisconsin LSE Peak with Zonal Peak gross of DR Net FRT	13,822	14,305	14,312	14,413	14,497	14,611	14,743
Weighted Derived Zonal Coincident Factor	0.9762	0.9763	0.9761	0.9760	0.9760	0.9759	0.9758
Total Coincident Wisconsin LSE Peak with MISO Peak gross of DR Net FRT	13,645	14,125	14,133	14,234	14,317	14,430	14,562
MISO Coincident Factor	0.9639	0.9640	0.9639	0.9638	0.9638	0.9638	0.9638
Reserve Requirement (MW)							
Local Clearing Requirement	11,479	11,711	11,806	11,877	11,930	12,060	12,212
Planning Reserve Requirement (UCAP)	14,613	15,127	15,136	15,245	15,334	15,455	15,596
Resources above Local Clearing Requirement	4,550	4,452	4,339	4,778	4,686	4,564	4,413
Resource above Planning Reserve Requirement	1,415	1,036	1,009	1,410	1,283	1,170	1,029
Planning Reserve Margin[2] (%)	17.47%	14.43%	14.24%	17.00%	16.06%	15.21%	14.17%

[1] UCAP refers to the generator tested capacity multiplied by (1 - Equivalent Generator's Forced Outage Rate).
[2] MISO's required UCAP PRM of 7.1% per LOLE study is only required for the next planning year; 2016-2017 for this assessment.

Source: Aggregated electricity provider data responses, docket 5-ES-108

Table 4 shows historic monthly peaks since 2003 and forecasted non-coincident monthly peak demand, in MW.[6] 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 Table 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.

[6] These are electricity provider forecasts; Commission staff does not do an independent demand or energy forecast.

Table 4: Monthly Non-Coincident Peak Demands, MW

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	10,686	10,182	9,719	9,170	10,221	11,936	14,347	14,162	13,427	9,646	9,814	10,896
2014	11,300	10,656	10,271	9,150	10,116	11,793	13,289	12,270	11,254	9,339	10,402	10,515
2015	11,048	10,668	10,110	9,014	9,849	11,153	12,787	13,246	12,623			
Forecasted:												
2015										9,929	10,321	11,000
2016	11,026	10,718	10,240	9,632	10,646	12,462	14,579	14,171	12,589	10,047	10,422	11,103
2017	11,111	10,814	10,327	9,718	10,770	13,572	14,708	14,294	12,697	10,140	10,515	11,196
2018	11,204	10,900	10,399	9,787	10,853	13,669	14,816	14,401	12,790	10,242	10,606	11,294
2019	11,316	10,997	10,491	10,077	10,956	13,795	14,941	14,530	12,912	10,315	10,679	11,377
2020	11,379	11,080	10,554	9,934	11,034	13,881	15,024	14,619	12,988	10,371	10,739	11,436
2021	11,440	11,117	10,611	9,989	11,104	13,975	15,122	14,704	13,059	10,420	10,805	11,490
2022	11,497	11,174	10,651	10,059	11,157	14,046	15,220	14,749	13,167	10,472	10,830	11,579

Source: Aggregated electricity provider data responses, docket 5-ES-108

Typically, as shown in Table 4, the maximum non-coincident peak demand is highest in the summer (June-August), with a smaller peak in the winter (December-February). Electricity providers expect this general pattern of winter and summer peaks to continue into the future. While actual demand remains weather-dependent, the non-coincident peak demand is expected to increase by approximately 0.5 to 1.6 percent annually from 2016 to 2022. The large increase from 2015 to 2016 is attributable to less extreme temperatures in 2015. The non-coincident monthly peak demand forecast provided in this SEA is similar to what was forecast in the last SEA, docket 5-ES-107.

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 demand for electricity outpaced available generation, these programs have been used to assure a balance between demand and available supply.[7]

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, 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 5.0 percent of projected electric generating capacity in Wisconsin in 2022. 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 2013 through 2015, up to 74 MW of direct load control were called upon, which is approximately half of the load available. Data on the amount of load actually interrupted under interruptible tariffs is not available. The change in the relative size of MWs in each column has to do with the newer reliability definitions used in the MISO reliability assessment.

[7] 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

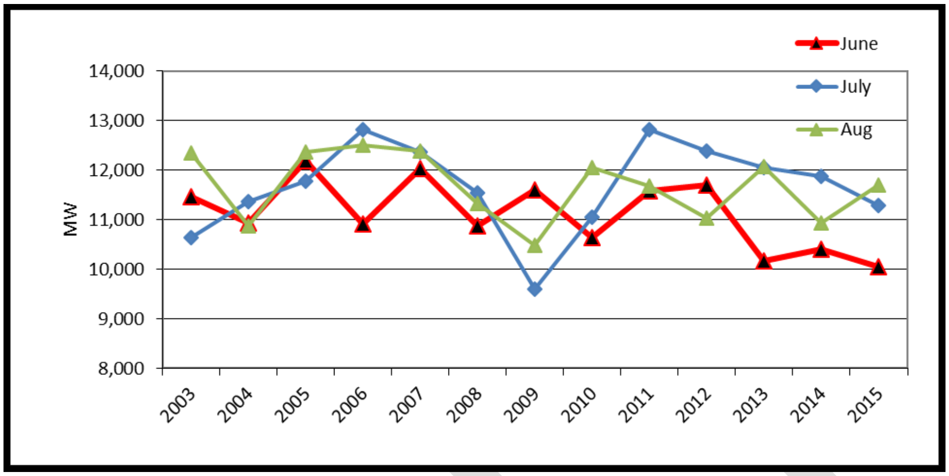
Year	Direct Load Control (MW)	Interruptible Load (MW)
Historical		
2003	186	554
2004	193	629
2005	225	693
2006	282	830
2007	246	776
2008	222	707
2009	170	597
2010	202	689
2011	230	842
2012	203	632
2013	144	667
2014	130	598
2015	131	734
Forecasted		
2016	51	907
2017	49	821
2018	48	830
2019	45	832
2020	44	836
2021	43	838
2022	41	840

Source: Aggregated electricity provider responses and previous SEA reports

SUMMER PEAK DEMAND

Figure 5 shows the maximum summer peak demand (June, July, and August) since 2003 on ATC's transmission system, which serves a majority of the load in Wisconsin. The summer peak is dependent on temperature and humidity, as these weather conditions affect air conditioner load. Data shown in Figure 5 are actual peak demand and are not weather-normalized. Figure 5 indicates that summer peak demand, while variable, has not increased over the past 10 years. Coupled with the information in Table 5, it appears that direct load control and interruptible tariff programs reduce peak demand for electricity providers served by ATC.

Figure 5: Monthly Summer Coincident Peak Demand – ATC[4]

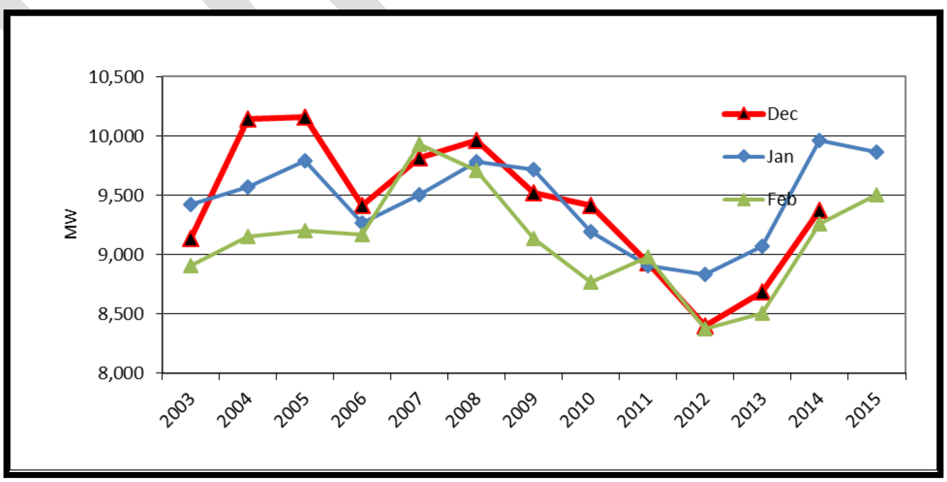


Source: ATC Hourly Load Data from http://www.atcllc.com/oasis-directory/

WINTER PEAK DEMAND

Figure 6 shows the maximum winter peak demand (December, January, and February) on ATC's transmission system since 2003. Historically, the maximum winter peak occurred in December due to holiday lighting. But due to more efficient LED holiday lighting, in recent years the winter peak has occurred in January. The sharp increase in 2014 is attributable to an unusually cold winter. In general, the winter peak is approximately 80 to 90 percent of the summer peak for Wisconsin electricity providers.

Figure 6: Monthly Winter Coincident Peak Demand – ATC[8]



Source: ATC Hourly Load Data from http://www.atcllc.com/oasis-directory/

[8] 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.

Peak Supply Conditions – Generation and Transmission

Planned capacity additions and retirements expected by 2022 are described in the Appendix of this report. Table A-1 shows new generation facilities and upgrades, Table A-2 describes new transmission lines, and Table A-3 lists planned retirements.

CURRENT GENERATION FLEET

Figure 7 shows the in-state generation resources that were operated by electricity providers as of January 2016. The totals indicate in-service nameplate and uprate capacity (MW) by fuel source. Approximately 46 percent of Wisconsin's nameplate capacity is coal-fired, with natural gas combustion turbine and combined cycle facilities providing more than 36 percent of Wisconsin's nameplate capacity. The generation capacity fuel mix in Wisconsin is generally unchanged since the last SEA.

Figure 7: Wisconsin Electricity Generation Capacity by Fuel Source, January 2016 (MW)

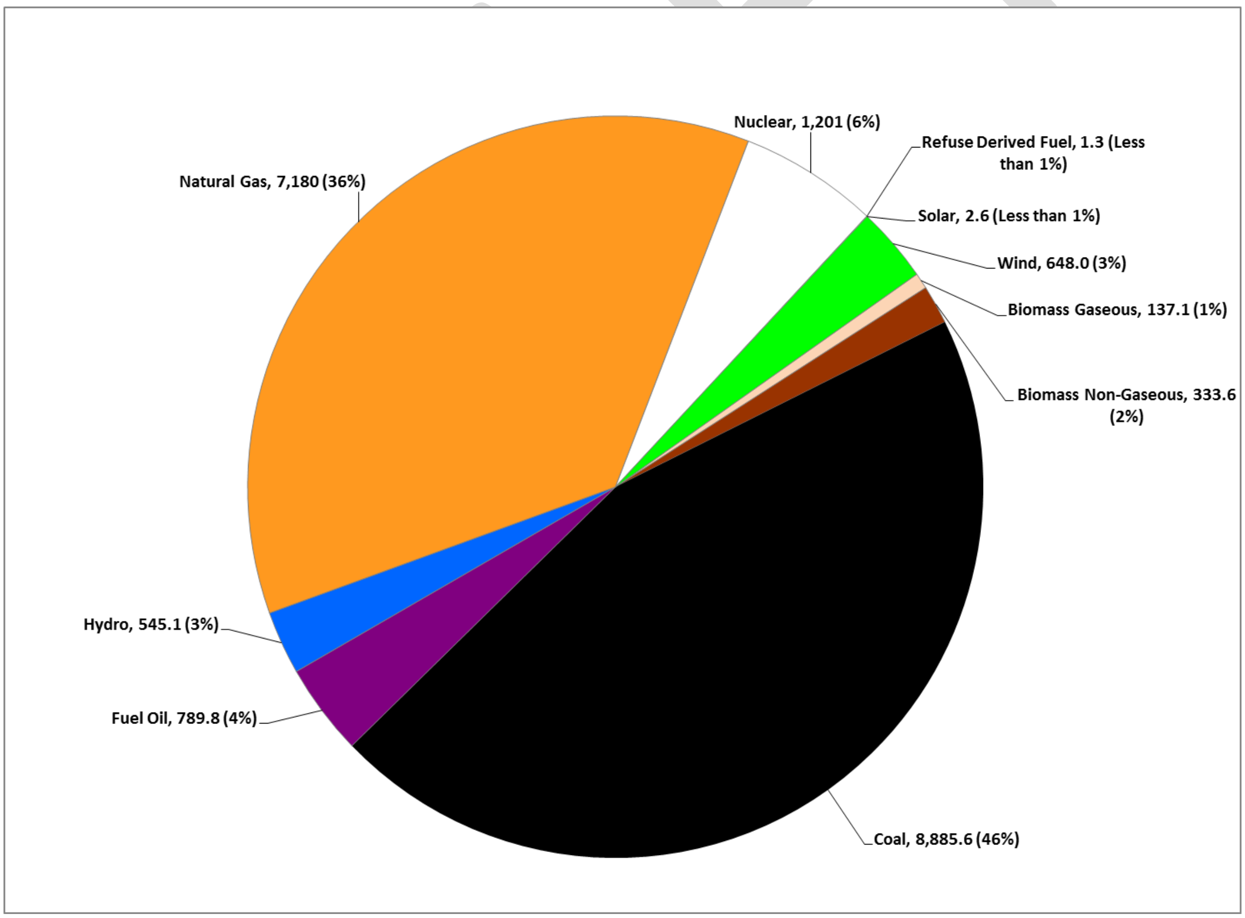
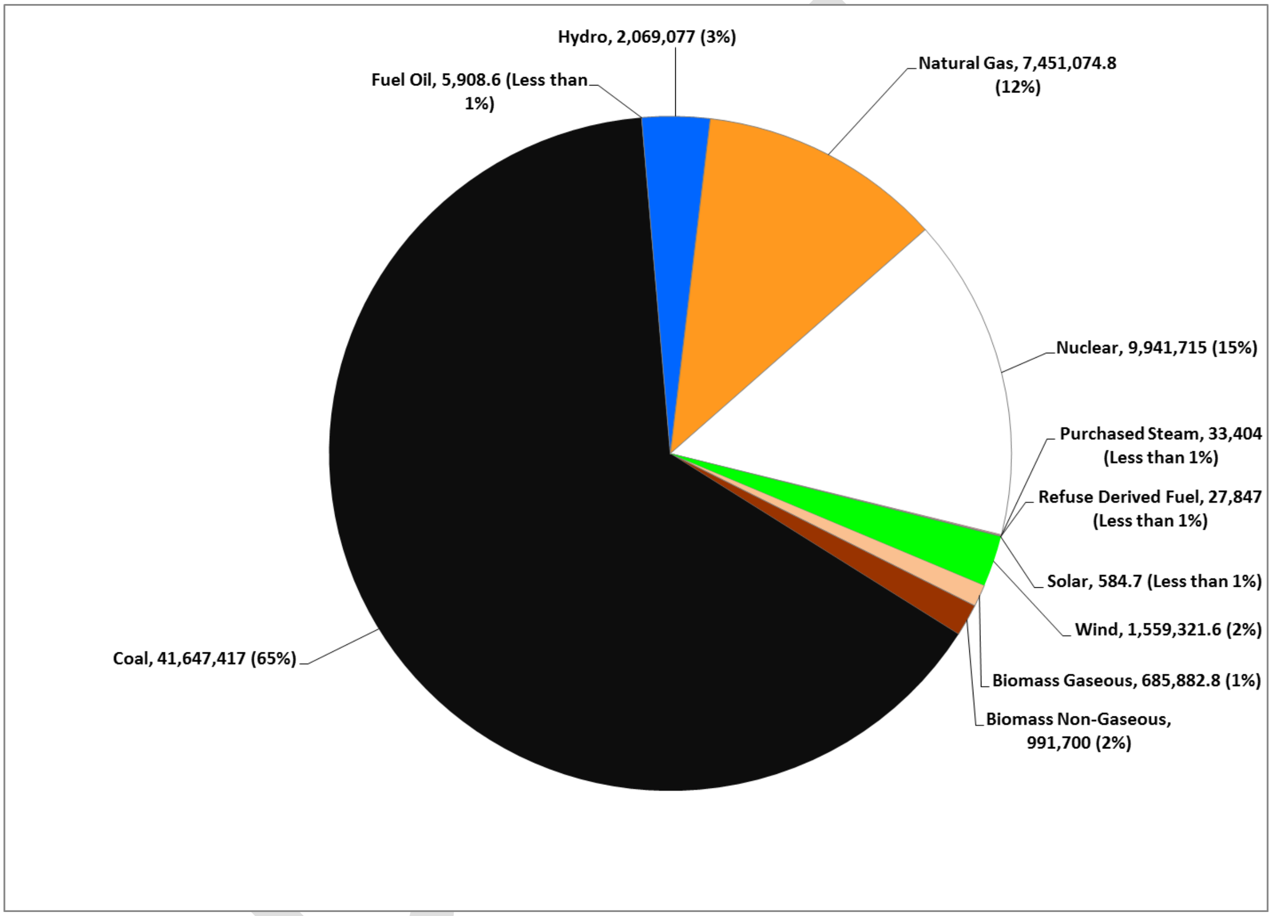


Figure 8 shows the actual electricity generated by in-state generating units operated by electricity providers in 2013 (the Commission expects to have 2014 data in time for the Final SEA). Approximately 65 percent of the electricity was supplied by coal-fired units, and 12 percent was supplied by natural gas. The percentage of electricity generated by nuclear plants decreased from 18 percent in 2012 to 15 percent in 2013. The relative changes in electricity generated since the last SEA are largely the result of the decommissioning of the Kewaunee nuclear plant.

Figure 8: Wisconsin Electricity Generated by Fuel Source, 2013 (MWh)



NEW GENERATION

Since the last SEA, Wisconsin electricity providers added relatively little new generation capacity. During this time period, electricity providers experienced slow demand growth and adequate PRM. However, with Dominion's 2013 decision to close the (556 MW) Kewaunee nuclear plant and the pending retirements of several smaller and older coal facilities, electricity providers expect a combined need for an additional 200-700 MW of capacity and energy by 2020.

A number of new generation projects have been 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-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. 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 70 MW of capacity during this SEA period as a result of upgrades to existing electric generating facilities. The upgrades are shown in the Appendix, Table A-1.

- On May 1, 2015, WP&L submitted an application with the Commission for authority to construct a nominal 700 MW natural gas-fired, combined-cycle electric generating facility at its existing Riverside site in the Town of Beloit, Wisconsin, docket 6680-CE-176. If authorized, WP&L expects the proposed Riverside unit to begin operation in 2020.

- DPC stated it will likely need to build a natural gas-fired, combined-cycle electric generating facility in the 2022-2023 time frame.

EMISSION CONTROL PROJECTS

In general, Wisconsin electricity providers operate a modern generation fleet with environmental controls that meet or exceed pollution control requirements. Nonetheless, Wisconsin electricity providers continue to face the task of updating existing facilities to comply with federal regulations. Between 2000 and 2013, Wisconsin electricity providers invested $184 million in efficiency upgrades and just over $3 billion in pollution control equipment at existing plants. Table 6 shows the current status of known emission control projects at Wisconsin's power plants as of January 2016.

Table 6: Major Emissions Control Projects* at Wisconsin Electricity Provider's Power Plants

Unit Name	Electricity Provider Owner	Project Status	Type of Emission Control**	Year of Commercial Operation	Estimated Cost (in $million)
Edgewater 5	WP&L	Under Construction	FGD	1985	$440.0
Columbia 2	WP&L/WPSC/ MGE	Under Construction	SCR	1978	$150.0
Weston 3***	WPSC	Under Construction	FGD (ReAct)	1981	$415.0
John P. Madgett	DPC	Under Construction	SCR	1979	$120.0
				Total	$1,125.0

*Major emissions control projects only include projects over $25 million. Table does not include lower capital cost projects such as combustion control projects for NO_x, and activated carbon control projects for mercury since these actions do not reach the threshold dollar amount required for a Certificate of Authority (CA) from the Commission. However, these lower cost projects will also increase plant operations and maintenance costs.
**Selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are methods of chemically converting NO_x emissions into other substances. Flue gas desulfurization (FGD) refers to methods of chemically transforming SO_2 emissions into other substances. All are chemical methods of converting air pollutants to more benign and/or manageable substances.
***Weston 3 ReACT costs have been updated to the latest estimates provided by WPSC. The $415 million includes the estimated $70 million cost over-run that is an issue in PSC Docket 6690-UR-124.

PLANNED RETIREMENTS

Wisconsin electricity providers face a constant challenge of 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 2022, Wisconsin's electricity providers estimate they will retire approximately 520 MW of existing Wisconsin based electric generation. Additional information about planned retirements is included in the Appendix, Table A-3.

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 above 100 kilovolts (kV) on which electricity providers propose to begin construction before 2022, subject to Commission approval. "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 three transmission owners in the state: ATC, DPC, and NSPW.

In addition to approving new transmission construction, the Commission approves the rebuilding or upgrading 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.

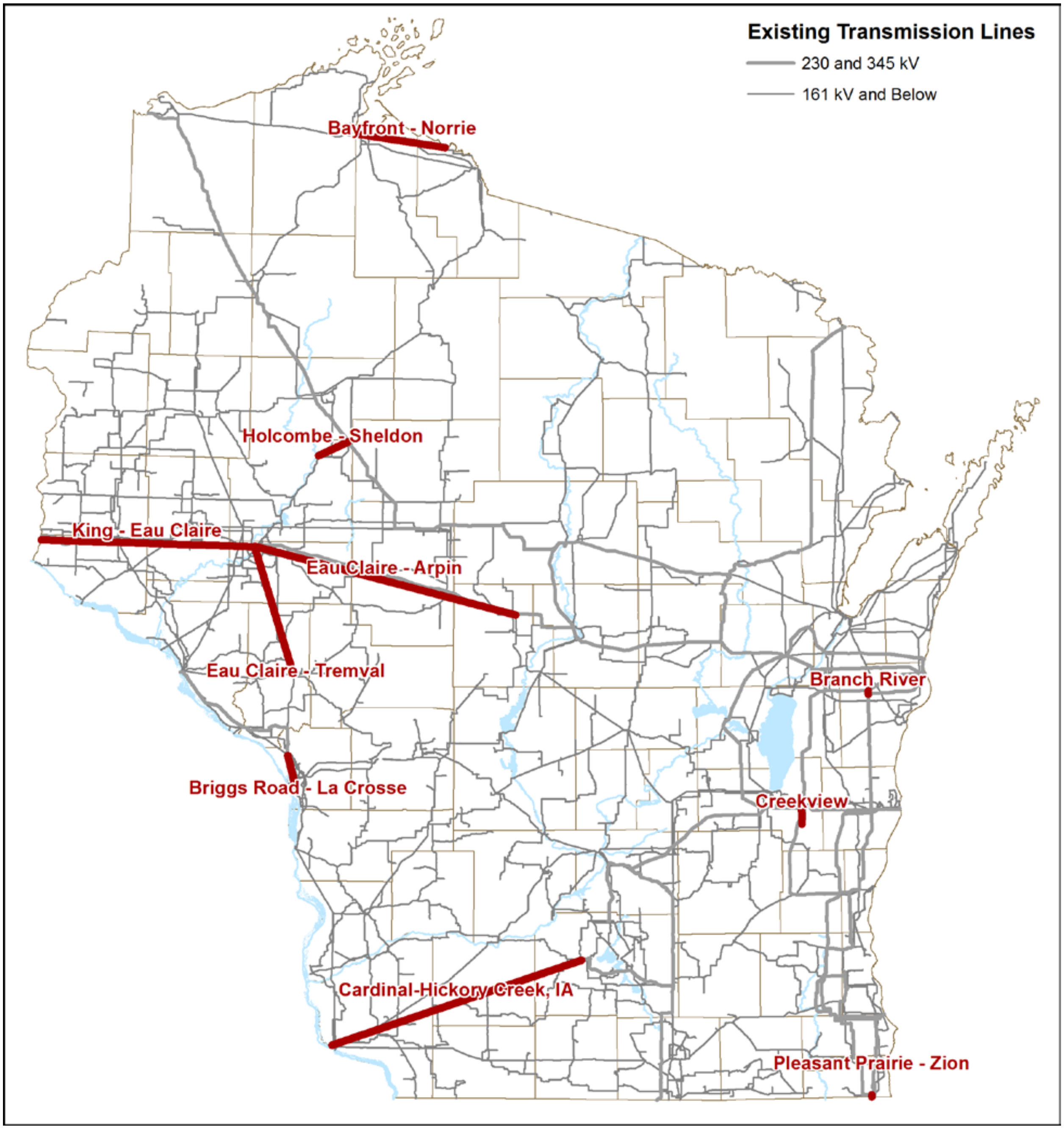
Both rebuilding and upgrading may require new, taller structures. New ROW may also be needed if the new structures require a wider ROW, or if the line route requires relocation to reduce environmental impacts. Either way, rebuilt or upgraded transmission lines usually need significantly less new ROW 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;
- Maintenance of system operational security for 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. As a consequence, 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 in providing adequate, reliable service to customers.
Table A-2 in the Appendix list projects in Wisconsin on which construction is expected to start by 2022, subject to approval by the Commission. Figure 9 depicts the projects.

Figure 9: Major Transmission Projects for which Construction is Expected to Begin Between 2016-2022



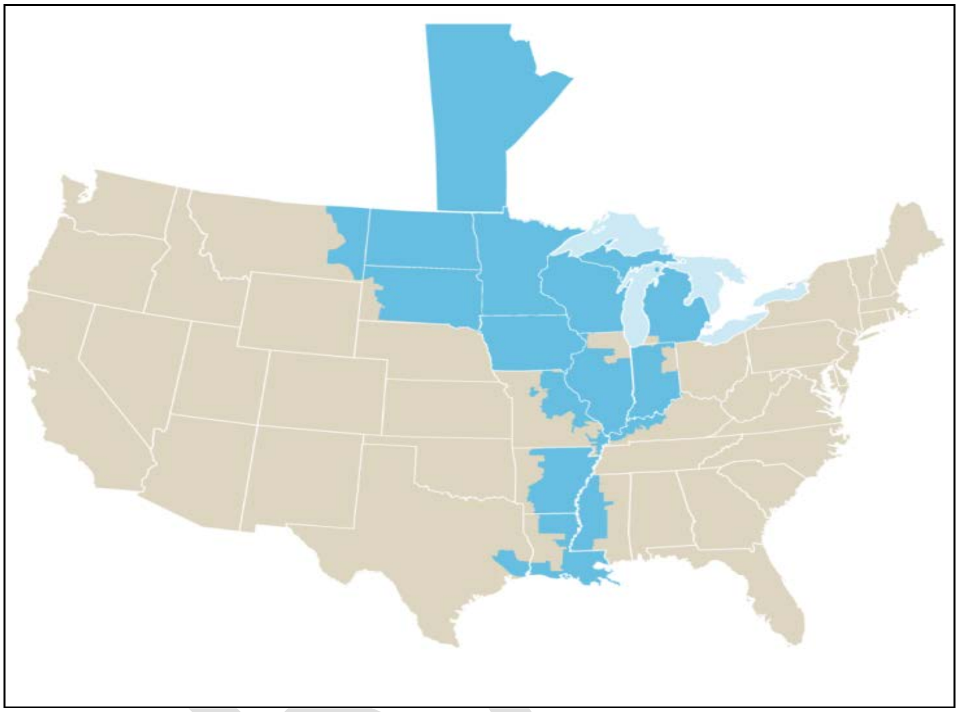
Source: Electricity provider data responses, docket 5-ES-108. Proposed transmission projects are graphic representations and do not reflect actual routes.

Transmission Planning in the Midcontinent

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

North American Electric Reliability Corporation (NERC) Reliability Coordinator for the areas located in the MISO footprint. As shown in Figure 10, MISO covers 15 states and one Canadian Province. The real-time market footprint is approximately the same footprint.

Figure 10: MISO Reliability Footprint



Source: www.misoenergy.org

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. As the NERC Reliability Coordinator, MISO controls reliability operations for approximately 195,231 MW of generation capacity, with a peak load of approximately 133,181 MW. There are 425 market participants serving approximately 42 million people. MISO's operations team performs a "what-if" contingency analysis every five minutes for 8,300 potential contingencies.

MISO TRANSMISSION PLANNING – OBJECTIVES AND SCOPE[9]

The MISO Transmission Expansion Plan (MTEP) process is a collaborative process among MISO planning staff and stakeholders that is 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. MTEP15, which was approved in December 2015, is the 12th edition of the process.

[9] This section of the SEA relies significantly on documents produced and made available from MISO, and used with permission.

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.[10] 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 purpose of OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, FERC, other relevant government entities, and state commissions as appropriate.

MISO TRANSMISSION EXPANSION PLAN 2015 OVERVIEW AND SUMMARY

MTEP15 contains 357 new projects throughout the MISO footprint that total an incremental $2.64 billion in transmission facilities. The following is a summary of the four categories of projects:[11]

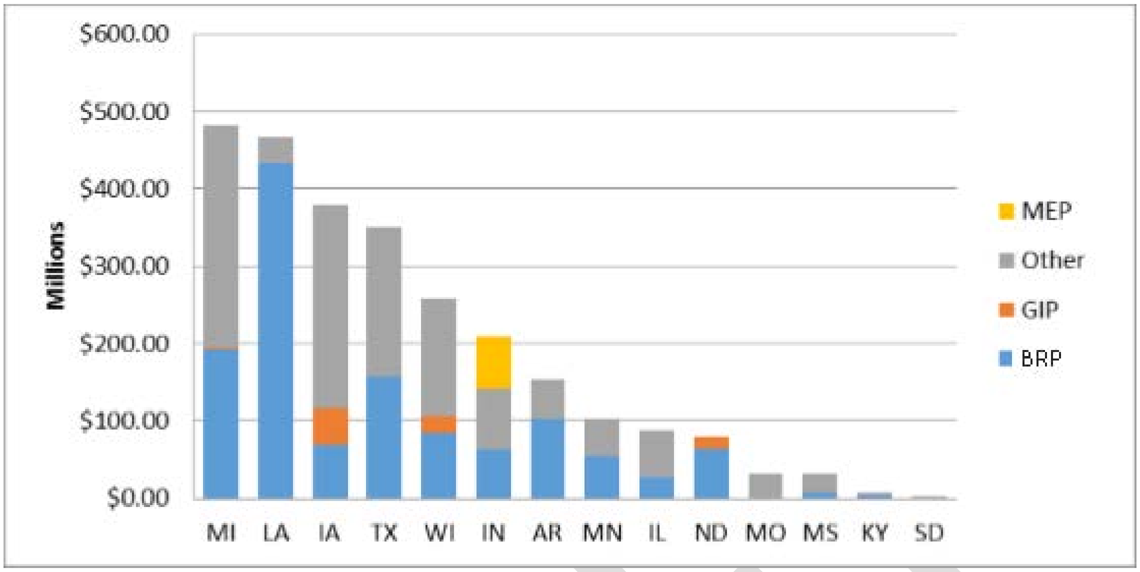
- Baseline Reliability Projects (BRP) – projects required to meet NERC reliability standards – 92 projects; $1.3 billion;
- Generator Interconnection Projects (GIP) – projects required to reliably connect new generation to the transmission grid – 13 projects; $85.2 million;
- Market Efficiency Projects (MEP) – projects that have a benefit to cost ratio greater than 1.0 for the purpose of reducing the market congestion pricing component – 1 project; $67 million; and
- Other Projects – wide range of maintenance projects and lower voltage projects, such as those designed to provide local economic benefit – 251 projects; $1.2 billion.

The new MTEP15 Appendix A projects are primarily located in 14 states. Some projects are in multiple states, but the dollar amount is aggregated to the primary state. Figure 11 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 MTEP15 Appendix A.

[10] 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.

[11] These projects 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.

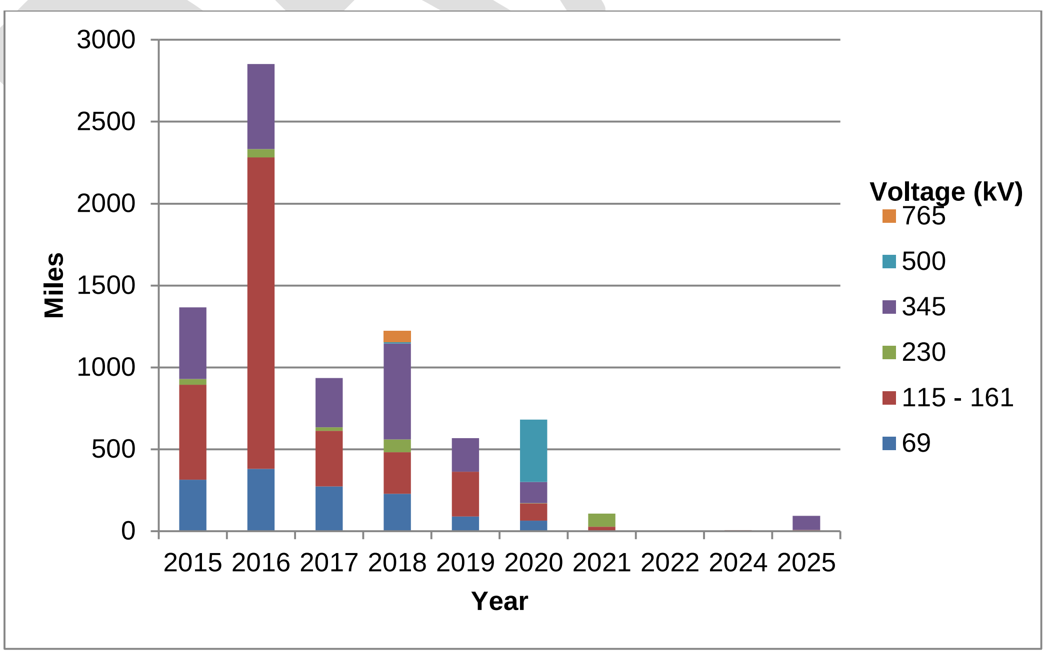
Figure 11: New MTEP15 Appendix A Projects Categorized by State



Source: www.misoenergy.org

Approximately 66,500 miles of existing transmission lines are located in the MISO area. Within the 10-year planning horizon approximately 7,900 miles of new or upgraded transmission lines are envisioned. Of the upcoming planned projects, 4,800 miles of upgraded transmission lines are on existing corridors, and 3,100 miles of new transmission lines are planned on new corridors. Figure 12 shows the mileage by voltage and MTEP planning year.

Figure 12: New or Upgraded Line Mileage by Voltage Class (kV) through 2025



Source: www.misoenergy.org

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 LTRA is conducted in conjunction with the annual NERC LTRA. The most recent MISO LTRA shows that planned new resources out to 2020 are 2,600 MW. After 2020, a planning gap begins; this is the expected result of a 10-year survey. 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. Ninety-one percent of the MISO load is served by LSEs with 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 7 shows the results of the planning survey.

Table 7: MISO Planning Year Reserve Margin Survey Results (Installed Capacity (ICAP), Gigawatts)

In GW (ICAP)	PY 2016/17	PY 2017/18	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26
(+) Existing Resources	151.9	151.5	151.2	150.5	150.4	150.4	150.4	150.4	150.4	150.4
(+) New Resources	0.7	2.1	2.1	2.5	2.6	2.6	2.6	2.6	2.6	2.6
(+) Imports	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
(-) Exports	3.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
(-) Low Certainty Resources	0.6	0.5	1.1	1.0	2.3	3.0	3.7	4.4	5.7	8.6
(-) Transfer Limited	3.4	3.0	2.6	1.9	1.6	1.4	1.2	1.0	0.8	0.6
Available Resources	149.1	151.5	151.1	151.5	150.5	150.1	149.6	149.1	148.0	145.3
Demand	128.9	130.4	131.2	132.4	133.3	134.1	134.9	135.9	136.6	137.7
PRMR	147.3	149.0	150.0	151.3	152.3	153.2	154.2	155.3	156.2	157.4
PRMR Shortfall	1.7	2.6	1.1	0.2	-1.8	-3.2	-4.6	-6.2	-8.2	-12.2
Reserve Margin Percent (%)	15.6%	16.3%	15.1%	14.5%	13.0%	11.9%	10.9%	9.7%	8.3%	5.5%

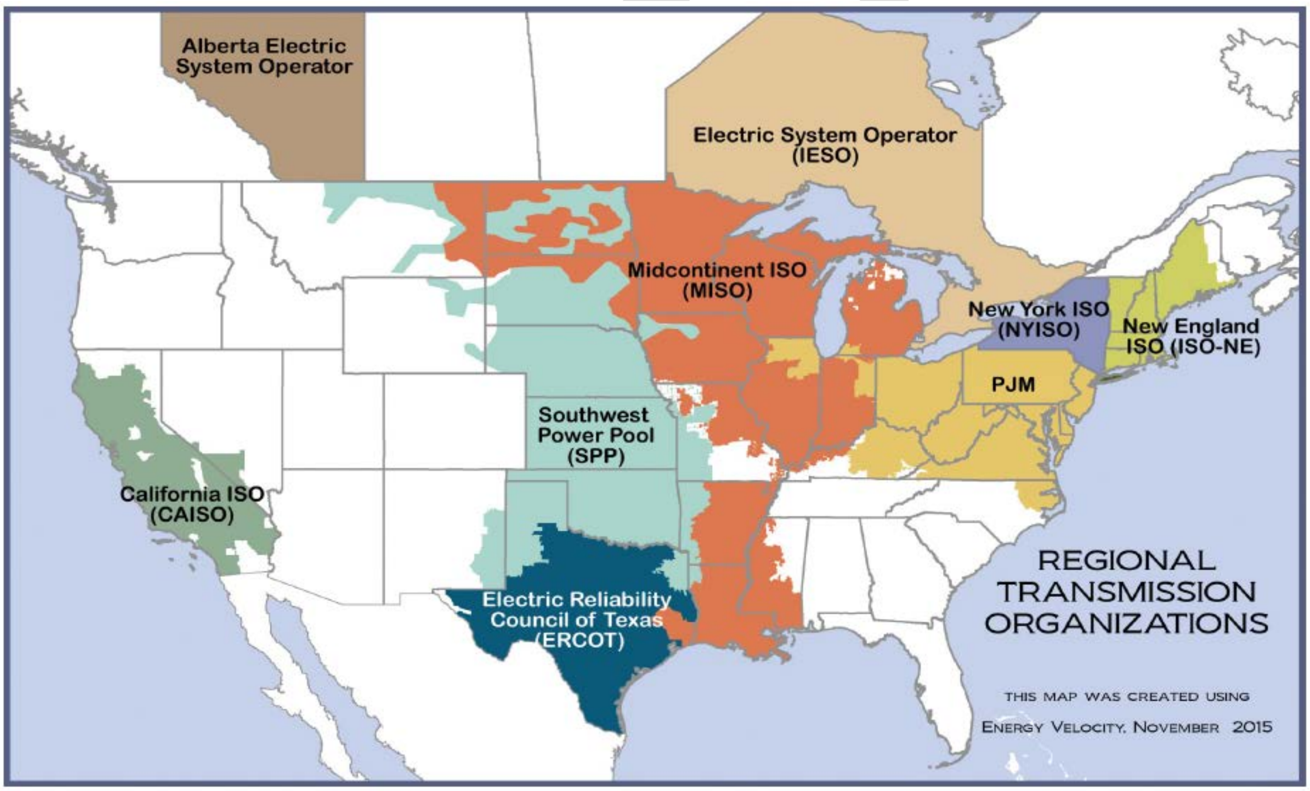
Source: www.misoenergy.org

In coordination with neighboring Reliability Coordinators, MISO also conducts seasonal assessments based on capacity resource capability, forced outage rates, and expected loads. Based on past winter experiences, MISO is planning to formalize the winter period with a modified operational reserve requirement, which would consider planned, scheduled generator maintenance. The goal is to manage risk with a short term MW reserve margin in the Local Resource Zones (LRZ). This operating, seasonal, risk management reserve is not the same metric used in the annual Planning Reserve Margin, which is based primarily on the summer period.

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 both regions with cost-effective measures to address market issues, reliability or other expansion plans. Figure 13 illustrates the major interregional planning entities.

Figure 13: Interregional Planning Entities



Source: http://www.ferc.gov/

MISO and PJM in 2015 worked together on FERC Order 1000 compliance, a Quick Hits study (small-scale and relatively simple analysis), and other targeted studies. The Quick Hits Study examined 39 market to market flowgates with $408 million of congestion. The MISO-PJM Interregional Planning Stakeholder Advisory Committee identified two projects to address market reliability and pricing issues. One 161 kV project was placed into service, and the other 138 kV project was not pursued due to uncertain congestion patterns. The Quick Hits study will be completed in the first quarter of 2016, and MISO and PJM will create a new set of projects to study that will include a two-year evaluation cycle.

MISO and the Southwest Power Pool (SPP) have a Coordinated System Plan to evaluate market seams issues (where service territory of MISO is electrically interconnected with other grid operators). Three projects to address market seams issues with SPP have been identified for consideration. The projects are at 345 kV, 138 kV and 115 kV totaling approximately $165 million.

A collaborative study effort between MISO and the Electric Reliability Council of Texas (ERCOT) began in 2015. The ERCOT region is the portion of the state of Texas that is not in the MISO and SPP footprints (see Figure 13). The goal of the study is to help understand each system's transmission issues. The primary objectives of the study include providing: transfer capability from ERCOT into MISO South Load pockets, congestion relief in MISO and ERCOT, and enhancement of system diversity through the study of load patterns and generation diversity. The study was presented to ERCOT stakeholders in November 2015 and to MISO stakeholders in December 2015. A joint kick-off meeting was held in January 2016 and model building will begin immediately. This study effort is in the preliminary phase, and a timeframe has not been determined.

RATES

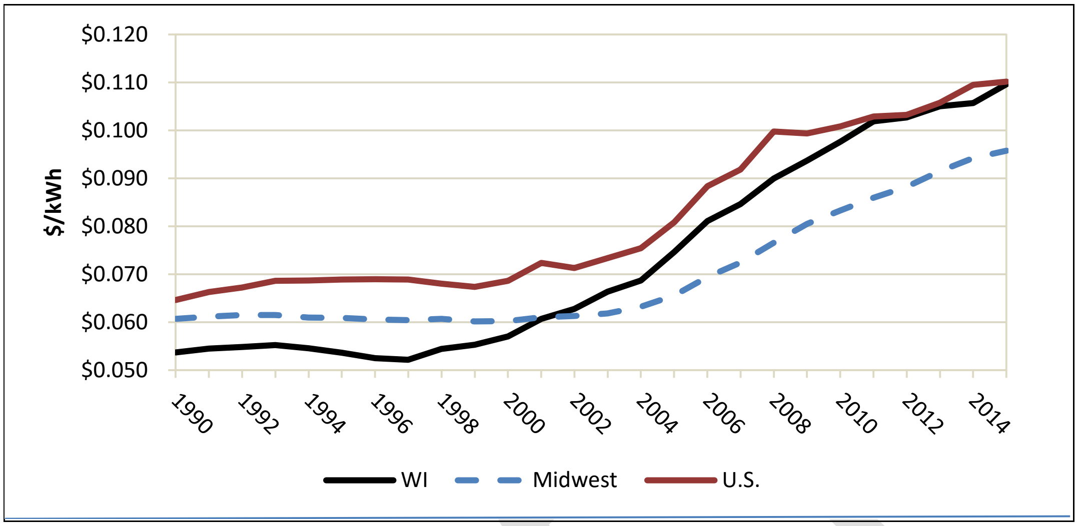
Direct rate comparisons among states and regions are increasingly difficult to make due to the complexities of energy regulation and the energy market in general. Rates can vary widely based on factors such as whether a state is in a construction cycle for generating facilities or transmission infrastructure. Rates are also influenced by various regulatory rate structures utilized in the Midwest. Wisconsin has several vertically integrated utilities with regulated retail rates and a stand-alone transmission company, while other states, such as Illinois, use a partially deregulated retail rate structure. How a state and its electricity providers 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 have an effect on rates as well.

Investment in New Generation and Transmission

Beginning in the late 1990s, Wisconsin entered a construction cycle with significant investment in electric generation and transmission facilities. This construction cycle continued for over two decades, and utilities are now recovering associated construction costs in rates. As shown in Figure 14, the levelized cost of energy has increased since 2002 through the United States.[12] To ensure that Wisconsin ratepayers benefit from this additional capacity, the Commission will continue to evaluate and promote the potential for selling energy into the MISO market. Revenue from selling excess energy or capacity is returned to retail customers through the Commission's rate setting process.

[12] Source: U.S. Department of Energy, Energy Information Agency, Monthly Electric Utility Sales and Revenue Data (Form EIA-826), October 29, 2015. All values prior to 2014 are based on final EIA data. The 2014 and 2015 values are based on preliminary EIA data. The 2015 values are year-to date through August 2015. 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.

Figure 14: Wisconsin, Midwest and U.S. Average Residential Utility Rates 1990-2015



Source: U.S. Department of Energy, Energy Information Agency

INVESTMENT IN GENERATION AND POLLUTANT EMISSION CONTROLS

Since 2000, Wisconsin generation owners have spent approximately $3 billion on emission control upgrades. Many of these projects were the result of Consent Decrees that the electricity providers entered into with EPA. Wisconsin generators continue to face the task of updating their existing coal facilities to comply with federal emissions requirements, and meeting these requirements may increase rates and bills. The amount of criteria pollutants, (CO, lead, NOx, particulate matter, ozone, and SOx, mercury, and CO_2) are continually being reduced. The following list summarizes the rules that could 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 in 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 of 2016, a request to stay the MATS rule was rejected by the U.S. Supreme Court. Compliance with the MATS Rule was required by April 16, 2015, and all large units in Wisconsin already have controls in place for compliance. A few smaller units have received an extension and will complete the work by April 2016.

- 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. 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.

- EPA Cross State Air Pollution Rule (CSAPR) – This rule continues to be modified and challenged since its introduction as Clean Air Interstate Rule in 2005, and Clean Air Transport Rule in 2010. CSAPR was finalized July 6, 2011, but implementation of the rule, like its predecessor rules, has been affected by a number of challenges, court actions, and changes. The rule is designed to address: sulfur dioxide (SO2) and nitrogen oxides (NOx) 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 November 16, 2015, EPA proposed an update to the rule that would require reductions beginning in 2017 of summertime NOx emissions from power plants in 23 states in the eastern U.S. The comment period on the CSAPR Update Rule closed February 1, 2016, with the Commission, Wisconsin Department of Natural Resources, and various electricity providers challenging several aspects of the proposed rule.

- Clean Power Plan (CPP) for Existing Power Plants – On October 23, 2015, EPA published the CPP final rule on greenhouse gas regulation for existing power plants under section 111(d) of the CAA. The rule requires Wisconsin generators to reduce carbon dioxide emissions by 34 percent by 2030, and would have significant impacts on utility operations and the generating mix in the state. This rule is being challenged in federal court by Wisconsin and over 25 other states, and a stay of the rule was issued by the U.S. Supreme Court on February 9, 2016. The Governor of Wisconsin issued an Executive Order on February 15, 2016, that prohibits any state agency, department, or commission from developing or promoting the development of a state plan in response to the finalization of the 111(d) rule until the expiration of the stay issued by the Supreme Court.

- Carbon Pollution Standard for new power plants under Section 111, CAA – On August 3, 2015, EPA published rules on greenhouse gas regulations and CO_2 rules for new, modified and reconstructed sources by establishing standards under section 111(b) of the Clean Air Act (CAA). The rule limits carbon emissions from new power plants, as opposed to existing plants, under utility new source performance standards. The regulation mandates that all future coal plants may emit no more than 1,100 pounds of CO_2 per MWh. New coal power plants, with either integrated gasification combined cycle (IGCC) or supercritical pulverized coal (SCPC) carbon capture technology, must incorporate the carbon limit into the design of the plant. No electric generating plants in the U.S., either IGCC or SCPC, currently employ CO_2 capture technology.

- Clean Water Act, Section 316(b) for Cooling Water Intake Structures – CWA 316(b) – 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 over 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 that have 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.

- Effluent Limitations Guidelines (ELG) – On September 30, 2015, EPA finalized a rule revising regulations for steam-powered electric generating plants. EPA promulgated the Steam Electric Power Generating effluent guidelines and standards (40 CFR Part 423) in 1974, and amended the regulation in 1977, 1978, 1980, and 1982. In April 2013, EPA initiated a rulemaking proceeding aimed at further curbing the discharge of toxic pollutants into waterways from wastewater discharges laced with heavy metals and other toxins from coal-fired and certain other power plants, particularly for pollutants such as mercury, arsenic, lead, and selenium. Plants below 50 MW do not fall under this regulation.

- 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 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.

The exact magnitude and timing of generation retirements, and the degree to which they will affect Wisconsin (and other states) retail rates is highly uncertain. The Commission will continue to monitor these rules.

RATE TRENDS AMONG CUSTOMER CLASSES

According to the U.S. Energy Information Administration's (EIA) September 2015, Electric Power Monthly report, the U.S. average electricity rates in the residential class increased; whereas the rates for the commercial and industrial classes decreased. The trend in Wisconsin rates generally matched those in surrounding states.

Table 8 through Table 11 summarize average rates for residential, commercial, industrial, and all sectors in the Midwest and the country. [13]

Table 8: Residential Average Rates in the Midwest and U.S. (in cents)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Illinois	8.32	8.41	10.15	11.12	11.33	11.54	11.86	11.49	10.67	12.04	12.45
Indiana	7.57	8.28	8.32	8.97	9.58	9.67	10.14	10.61	11.06	11.56	11.16
Iowa	9.25	9.62	9.44	9.55	10.08	10.47	10.50	10.81	11.08	11.24	12.12
Michigan	8.36	9.74	10.18	10.71	11.62	12.43	13.25	14.09	14.61	14.49	14.36
Minnesota	8.26	8.66	9.17	9.77	10.08	10.61	10.99	11.36	11.84	12.06	12.33
Missouri	7.04	7.37	7.62	8.04	8.57	9.07	9.71	10.06	10.61	10.72	11.05
Ohio	8.52	9.36	9.58	10.13	10.75	11.35	11.45	11.77	12.04	12.59	12.64
Wisconsin	9.66	10.52	10.87	11.55	11.95	12.67	13.05	13.21	13.57	13.72	14.42
Midwest	8.07	8.55	8.89	9.39	9.88	10.35	10.77	11.16	11.43	11.77	12.06
U.S. Average	9.47	10.30	10.73	11.57	11.66	11.88	12.19	12.40	12.65	13.13	13.32

Table 9: Commercial Average Rates in the Midwest and U.S. (in cents)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Illinois	7.73	7.92	8.57	9.24	9.05	8.86	8.63	7.99	8.14	9.33	8.90
Indiana	6.57	7.21	7.28	7.81	8.32	8.38	8.78	9.15	9.60	9.96	9.60
Iowa	6.93	7.26	7.08	7.17	7.55	7.89	7.84	7.97	8.42	8.67	9.27
Michigan	7.83	8.50	8.77	9.16	9.23	9.81	10.32	10.91	11.05	10.86	10.64
Minnesota	6.56	6.98	7.46	7.86	7.91	8.36	8.62	8.82	9.41	9.84	9.56
Missouri	5.86	6.00	6.26	6.56	6.91	7.42	7.96	8.12	8.74	8.85	9.05
Ohio	7.93	8.44	8.67	9.23	9.66	9.74	9.63	9.48	9.35	9.83	9.96
Wisconsin	7.65	8.36	8.70	9.27	9.56	9.97	10.42	10.50	10.74	10.77	11.06
Midwest	6.82	7.21	7.43	7.85	8.11	8.42	8.69	8.89	9.22	9.55	9.56
U.S. Average	8.31	9.07	9.32	10.10	9.97	10.14	10.36	10.36	10.61	11.02	11.01

[13] Source: U.S. Department of Energy, Energy Information Agency, Monthly Electric Utility Sales and Revenue Data (Form EIA-826), October 29, 2015. All values prior to 2014 are based on final EIA data. The 2014 and 2015 values are based on preliminary EIA data. The 2015 values are year-to date through August 2015. 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.

Table 10: Industrial Average Rates in the Midwest and U.S. (in cents)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Illinois	4.61	4.69	6.61	7.33	7.01	6.81	6.42	5.80	5.94	7.14	6.36
Indiana	4.42	4.95	4.89	5.47	5.81	5.87	6.17	6.34	6.70	6.97	6.70
Iowa	4.56	4.91	4.73	4.80	5.26	5.35	5.20	5.28	5.62	5.70	6.06
Michigan	5.32	6.04	6.47	6.72	6.99	7.08	7.31	7.62	7.71	7.67	7.25
Minnesota	5.01	5.28	5.68	5.86	6.26	6.28	6.46	6.53	6.97	6.72	7.14
Missouri	4.51	4.55	4.75	4.91	5.43	5.49	5.84	5.88	6.28	6.33	6.29
Ohio	5.10	5.61	5.76	6.20	6.73	6.40	6.11	6.25	6.22	6.77	6.92
Wisconsin	5.38	5.85	6.16	6.50	6.73	6.84	7.32	7.34	7.39	7.51	7.81
Midwest	4.78	5.12	5.44	5.79	6.08	6.18	6.36	6.51	6.81	7.05	7.09
U.S. Average	6.14	6.96	7.14	7.88	7.59	7.64	7.75	7.67	7.85	8.14	8.02

Table 11: All Sectors Average Rates in the Midwest and U.S. (in cents)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Illinois	6.91	7.03	8.45	9.22	9.15	9.10	8.96	8.39	8.25	9.49	9.27
Indiana	5.88	6.46	6.50	7.09	7.62	7.67	8.00	8.29	8.73	9.06	8.82
Iowa	6.65	6.97	6.80	6.88	7.36	7.63	7.54	7.67	8.05	8.14	8.65
Michigan	7.21	8.11	8.51	8.91	9.39	9.86	10.37	10.94	11.19	11.02	10.87
Minnesota	6.59	6.95	7.41	7.78	8.14	8.39	8.64	8.84	9.40	9.51	9.71
Missouri	6.06	6.23	6.49	6.81	7.32	7.71	8.23	8.42	8.99	9.09	9.35
Ohio	7.06	7.70	7.90	8.39	9.02	9.13	9.01	9.11	9.19	9.72	9.92
Wisconsin	7.47	8.11	8.47	9.00	9.37	9.77	10.20	10.27	10.50	10.57	10.97
Midwest	6.56	6.95	7.24	7.66	8.05	8.33	8.60	8.82	9.15	9.42	9.58
U.S. Average	8.09	8.84	9.19	9.98	9.94	10.08	10.29	10.32	10.58	10.95	11.02

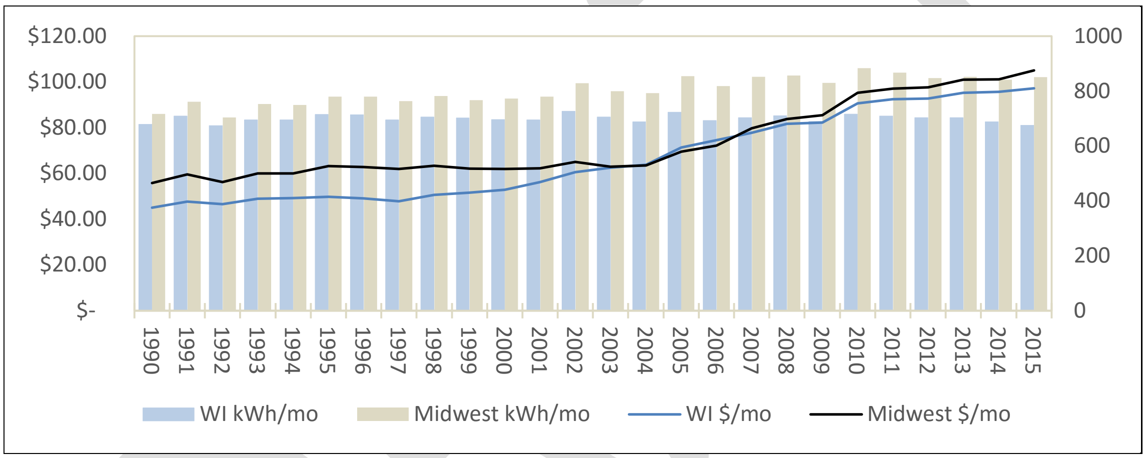
Fuel prices and purchased power cost increases, generation and transmission construction costs, and lost sales as a result of the recession are the significant drivers of recent rate increases. Increases to customers' bills can be mitigated to some extent with energy conservation and efficiency. For example, energy efficiency and conservation programs such as the statewide Focus on Energy program have helped keep average Wisconsin residential usage flat over the last two decades. Additionally, despite slightly higher than average electric rates, Wisconsin residential customers have the fourth smallest monthly electric bill when compared to Midwestern states. The average Wisconsin residential customer's monthly bill has consistently fallen at or below the Midwest average. These trends can be seen in Table 12 and Figure 15.[14]

[14] Source: U.S. Department of Energy, Energy Information Agency, Monthly Electric Utility Sales and Revenue Data (Form EIA-826), October 29, 2015. All values prior to 2014 are based on final EIA numbers. EIA adjusts monthly data to annual data based the annual totals for Form EIA-826 data by State and end-use- sector which is compared to the corresponding Form EIA-861 values for sales and revenue. The ratio for these two values in each case is then used to adjust each corresponding monthly value. www.eia.gov/electricity/monthly/pdf/technotes.pdf. Prior to 2007 EIA did not include customer counts for the adjusted monthly data. When calculating the values in Table 12 and Figure 15, the adjusted monthly values were excluded from data prior to 2008.

Table 12: Average Residential Monthly Electricity Cost (in $)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Illinois	65.43	61.92	81.76	84.63	82.04	92.03	90.79	87.20	80.57	84.85	93.36
Indiana	75.56	78.96	83.34	91.94	94.30	101.79	103.54	104.93	110.44	112.44	113.77
Iowa	76.73	77.19	77.63	83.94	86.25	95.19	93.94	94.50	100.30	99.15	104.05
Michigan	60.43	68.16	70.36	71.58	74.69	84.82	90.63	95.50	96.95	94.46	95.60
Minnesota	63.68	66.58	71.95	79.55	80.48	86.19	89.14	90.06	96.51	96.14	94.85
Missouri	75.86	75.71	83.00	87.83	90.66	104.66	108.38	107.80	121.98	114.47	121.34
Ohio	77.34	82.16	89.38	91.50	93.65	105.29	104.86	105.23	107.07	111.25	117.34
Wisconsin	71.26	74.60	77.73	81.71	82.28	90.59	92.39	92.79	95.21	95.61	97.17
Midwest	69.50	72.17	79.69	83.79	85.41	95.24	97.10	97.68	100.95	101.09	105.01
U.S. Average	84.91	90.42	95.84	103.63	104.52	110.55	110.14	107.28	111.08	113.61	118.32

Figure 15: Average Residential Monthly Cost and Electricity Consumption in Wisconsin and the Midwest 1990-2015



Source: U.S. Department of Energy, Energy Information Agency

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 investor-owned utilities (IOU) and municipal electricity providers have mandatory or optional TOU rates for all customer classes. Innovative retail rate options provide opportunities for Wisconsin businesses to control their energy costs while contributing to economic growth in the state. For example, the Commission recently approved innovative rate programs that are intended to promote increased economic development for WEPCO and WPSC commercial, industrial, and institutional customers. These real-time tariff pricing options allow customers with increased load to pay market rates for the increase in load, rather than tariff rates. Typically, these customers can sign-up for four-year contracts. During 2010-2011, the Commission also approved an economic development rate program (EDR) for WP&L and in 2015, approved an EDR tariff for WEPCO. In addition, any sale of surplus energy to out-of-state utilities has the potential to help lower rates in Wisconsin.

Another area of innovation since the last SEA has been an increasing interest in community solar programs. 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. These programs provide an opportunity for utilities to test new business models and products, while providing customers who may not have the ability to install rooftop solar with an opportunity to participate in a solar project.

DISTRIBUTED ENERGY RESOURCES

In recent years, DER has become an issue in rate proceedings before the Commission. Because DER is a growing resource in Wisconsin, an inventory of DER resources was conducted for the first time as part of this SEA to provide the Commission and other stakeholders with better information going forward. 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 spans the period January 2008 through September 2015. The following discussion and figures summarize the results of the DER inventory. Complete summary data can be found in the Appendix of this report.

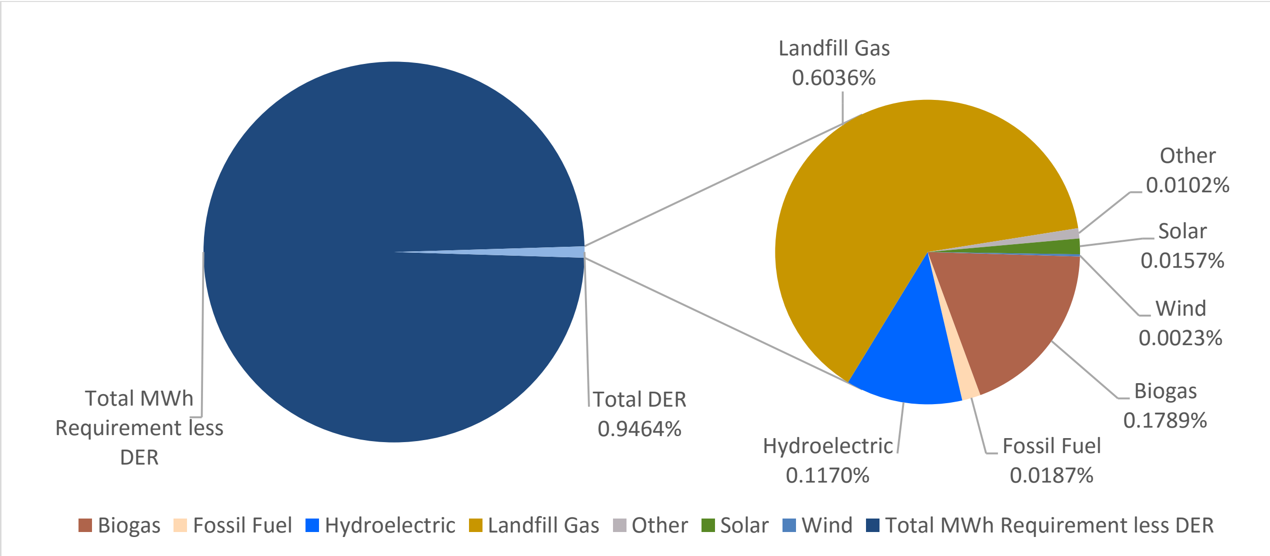
Data for DER are organized according to capacity, number of installations, and the value and amount of energy delivered to the electricity provider. Not every installation delivers energy to the electricity provider. For some installations, all energy is used on-site at the owner's location, and no "excess"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

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

All DER figures shown in the SEA, with the exception of Figure 17, do not include power 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. DER data reported for power cooperatives are shown in the Appendix.

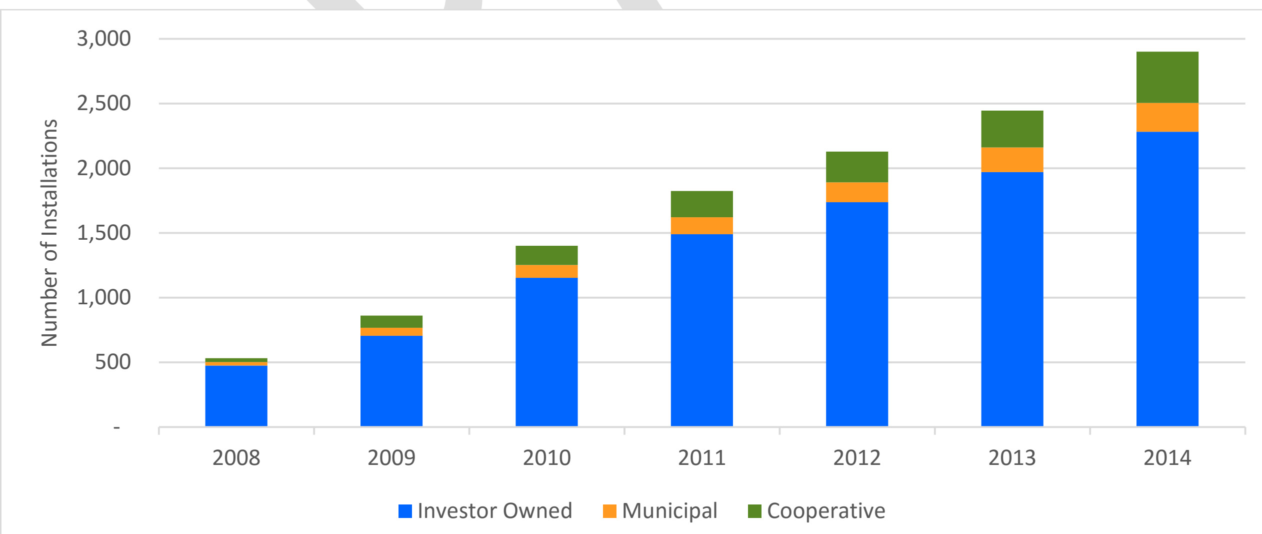
Figure 16 provides context for the magnitude of energy generated by customer-owned DER. The dark blue in the pie chart on the left shows the amount of energy provided to all customers. This energy comes from: purchase power agreements with independent power producers, purchases from the regional energy market, electricity provider-owned generation units, 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 16: Electricity Provider DER Energy Purchases as a Percent of Total Electricity Provider Energy Requirements, 2014



DER is a statewide development in Wisconsin. Seventy-five percent of the state's 12 IOUs, and 66 percent of the municipal electricity providers report at least one DER installation in their service territory.

Figure 17: Total Number of DER Installations, by Type of Electricity Provider



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 solar installations (Figure 21) the amount of solar capacity is less significant when considering capacity of all DER installations (Figure 18). While residential customers own a significant number of installations (Figure 22), the bulk of the capacity is owned by commercial and industrial customers (Figure 19).

Figures 18 through 20 show the installed capacity of DER around the state. The amount of capacity (KW) represented by each graph is the same. Data are organized according to the type of technology (Figure 18), by the type of customer class (Figure 19) and by the size (capacity) of individual installations (Figure 20).

Figure 18: Cumulative Kilowatts of Installed DER Capacity, by Technology Type, 2008-2015

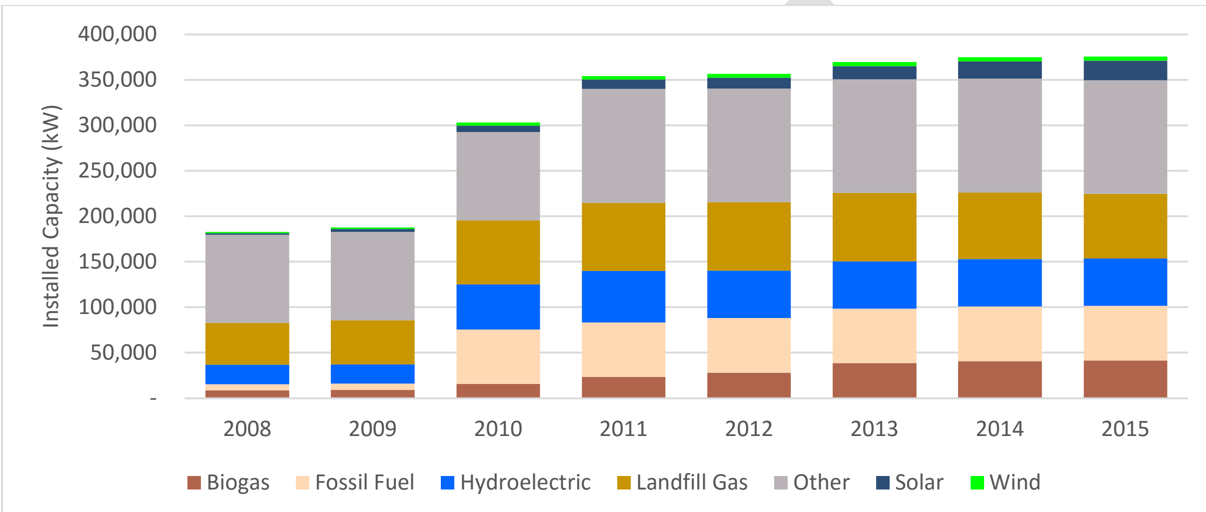
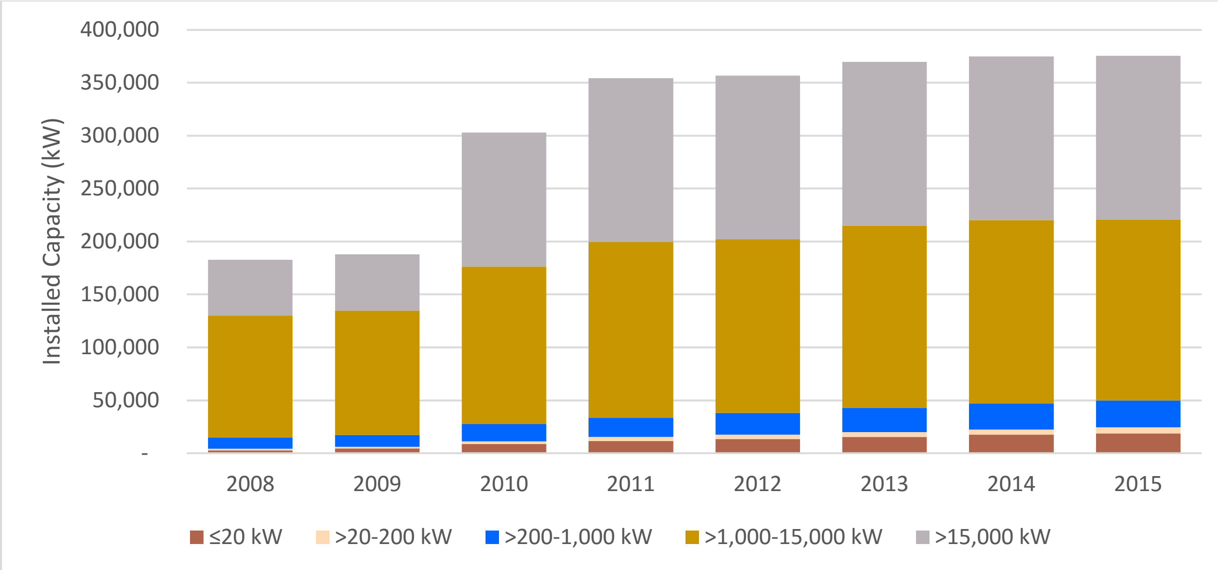


Figure 19: Cumulative Kilowatts of Installed DER Capacity, by Customer Class, 2008-2015

Figure 20: Cumulative Kilowatts of Installed DER Capacity, by Installation Size, 2008-2015



Figures 21 through 23 show the total number of installations of DER around the state. The number of installations represented by the figures is the same. Data are organized by type of technology (Figure 21), Customer Class (Figure 22) and by size (capacity) of individual installations (Figure 23).

Figure 21: Cumulative Number of DER Installations, by Technology Type, 2008-2015

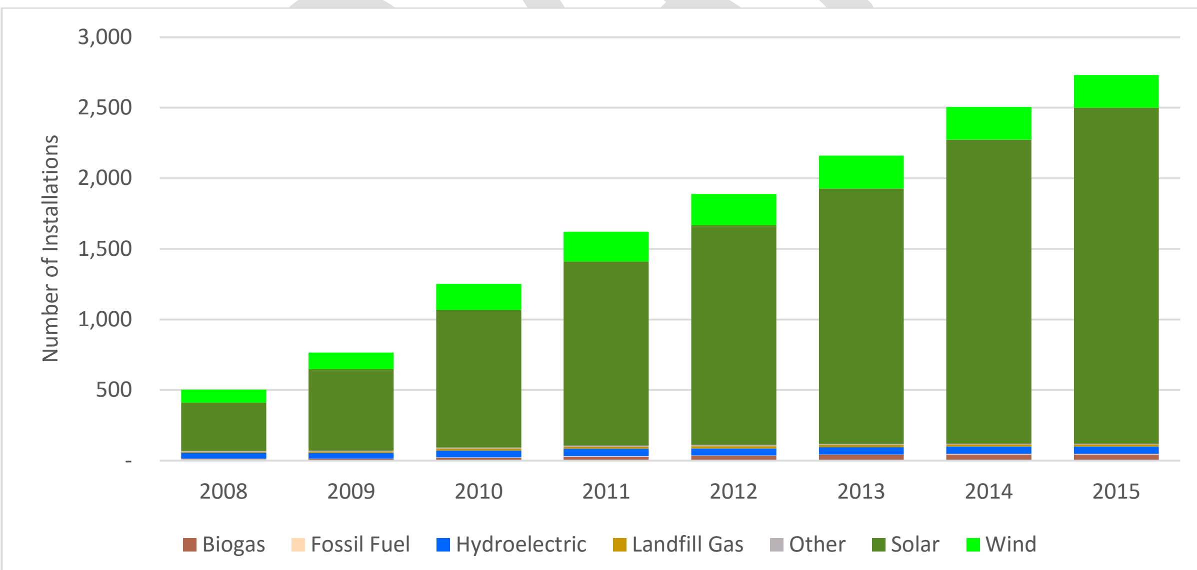


Figure 22: Cumulative Number of DER Installations, by Customer Class, 2008-2015

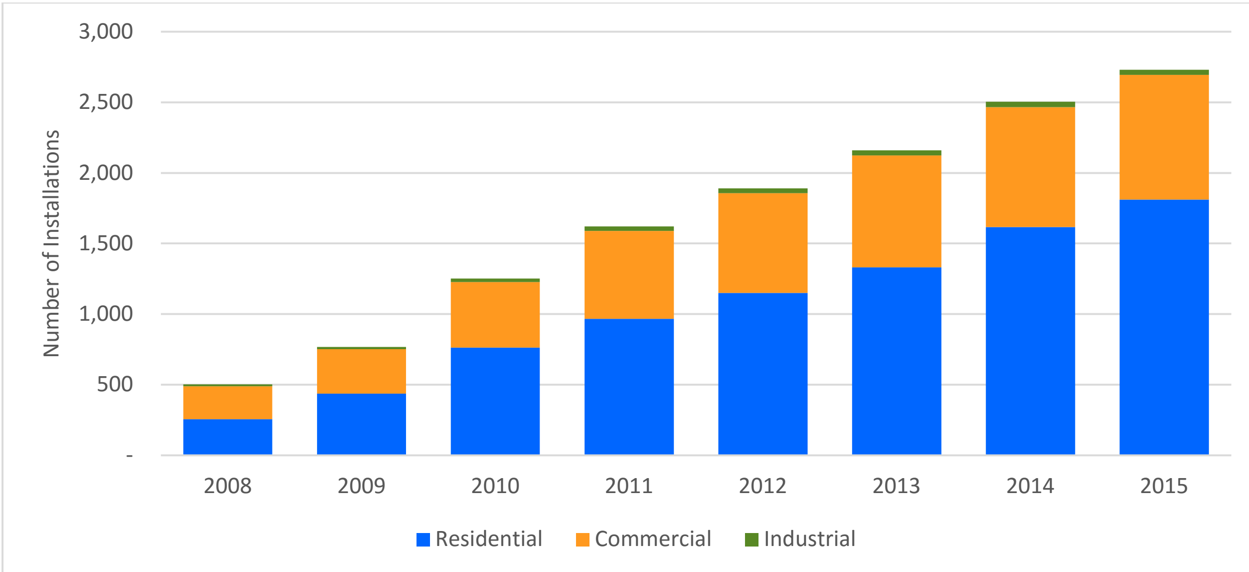
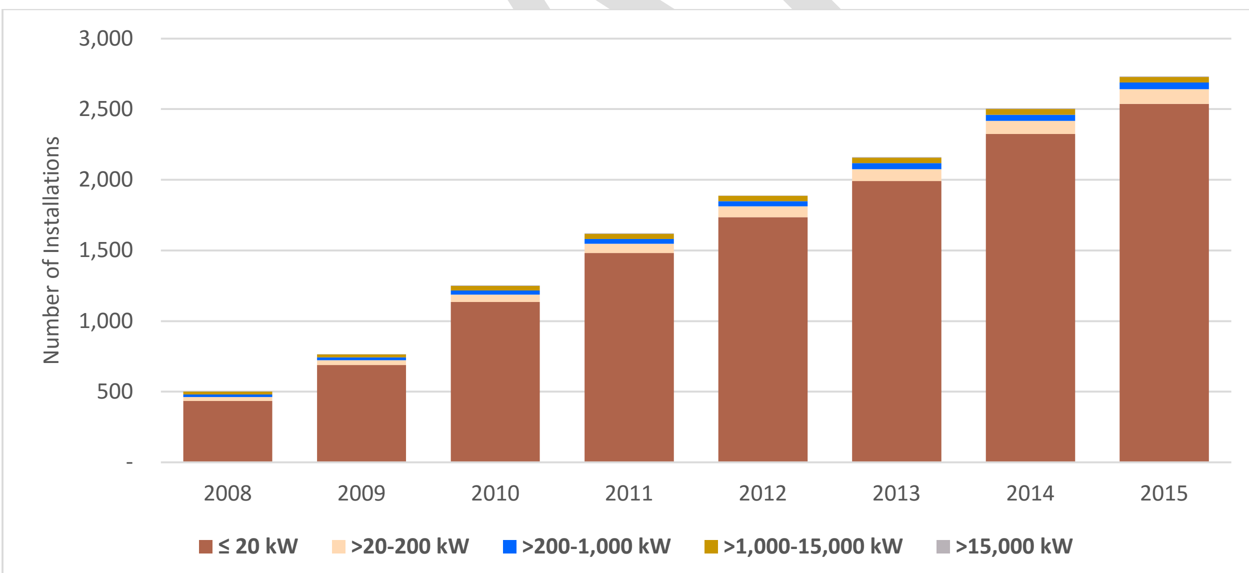


Figure 23: Cumulative Number of DER Installations, by Installation Size, 2008-2015



ENERGY EFFICIENCY AND RENEWABLE RESOURCES

Energy Efficiency

STATUS OF ENERGY EFFICIENCY EFFORTS

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 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 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 2015, 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.[15]

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 four-year basis, preceded by a quadrennial planning process the Commission conducts to review program goals, policies, and priorities. The first quadrennial planning process was completed in 2010, and set electric and natural gas savings goals to be achieved during the four-year period between 2011 and 2014. Chicago Bridge and Iron (CB&I) was selected to serve as Focus program administrator from 2011 through 2014, under a performance contract which provided financial incentives for exceeding the Commission's savings goals. The second quadrennial planning process was completed in the summer of 2014 and set updated savings goals for the 2015-2018 period and extending CB&I's contract.

Energy efficiency expenditures 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 cost-effectiveness and take the persistence of the measures into consideration. For 2014, Cadmus's program cost-benefit analysis concluded that for every dollar spent, the program achieved $3.33 in lifecycle benefits.[16] In order to realize energy savings on the electric side, it cost an average of 1.25 cents per kilowatt-hour (cost of conserved energy). These

[15] 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 Wisconsin Stat. § 196.374.
[16] Focus reports cost-effectiveness based on a modified 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 2014, the program evaluator's expanded TRC analysis found that Focus created economic benefits of $756 million and achieved $6.66 in benefits for every $1 in costs.

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.

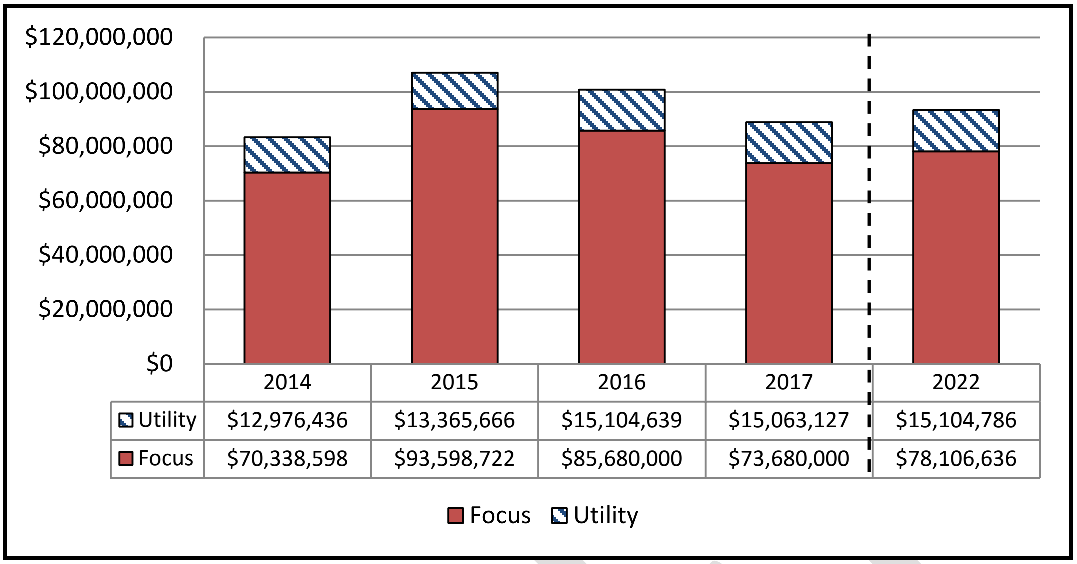
As shown in Figure 24, projected Focus expenditures on electric energy efficiency increase in 2015 and 2016, before returning closer to 2014 levels in 2017. This temporary increase reflects the Commission's decision in the 2014 quadrennial planning process to spend Focus funds unspent during the 2011-14 quadrennium during 2015 and 2016. The Commission has also specified certain programs to which funding would be allocated, including strategic energy management for large customers, biodigesters on small- and mid-sized farms, and a pilot smart thermostat program. The projections are based on budgeted figures, but program tracking to date suggests that some of those Commission-ordered programs may not use all allocated funding. If that occurs, unspent funds may be allocated in 2017 and 2018 and would cause an increase in funding levels in those years above current projections. Spending projections in 2022 reflect a limited increase from actual 2014 and projected 2017 levels, based on the projections of some utilities that their Focus contributions will gradually increase throughout the analysis period.

As shown in Figures 25 and 26, Focus savings do not increase as much as expenditures in 2015 and 2016. This reflects the Commission's recognition that several of the programs to which it allocated surplus funds are "pilot" efforts intended to explore new technologies and program approaches, rather than to maximize savings achievement. Projected savings still increase from 2014 to 2015, as the Commission set higher savings goals under the 2015-18 program administration contract. Projected savings undergo a comparable increase between 2017 and 2022, on the assumption that savings goals will continue to increase under the 2019-2022 program administration contract.

While Focus accounts for the largest share of energy efficiency activity in the state, MGE, SWL&P, WEPCO, WP&L, WPSC, NSPW, WPPI, and DPC all provide additional energy efficiency services. Some of the expenditures for these electricity provider energy efficiency services include educational and behavior-based activities that do not have quantifiable savings. Figures 24 through 26 provide forecasts through 2022 in terms of expenditures and first-year annual energy and demand savings.[17] All utilities expect that funding levels and savings achieved will remain steady throughout the period. This level of activity is much lower than the years immediately before 2014, when higher savings and spending levels were driven by stipulated programs in the WPSC territory that ended in 2013.

[17] Does not include persistent savings that occur multiple years after measures are installed.

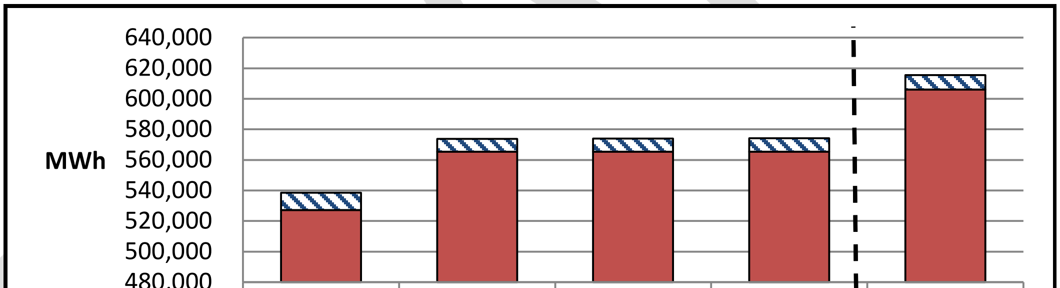
Figure 24: Annual Electric Energy Efficiency Expenditures (2014-2022)



	2014	2015	2016	2017	2022
Utility	$12,976,436	$13,365,666	$15,104,639	$15,063,127	$15,104,786
Focus	$70,338,598	$93,598,722	$85,680,000	$73,680,000	$78,106,636

Sources: Aggregated electricity provider data responses, docket 5-ES-108; Focus on Energy 2014 Evaluation Report; Focus on Energy 2015-18 Program Administration Contract.

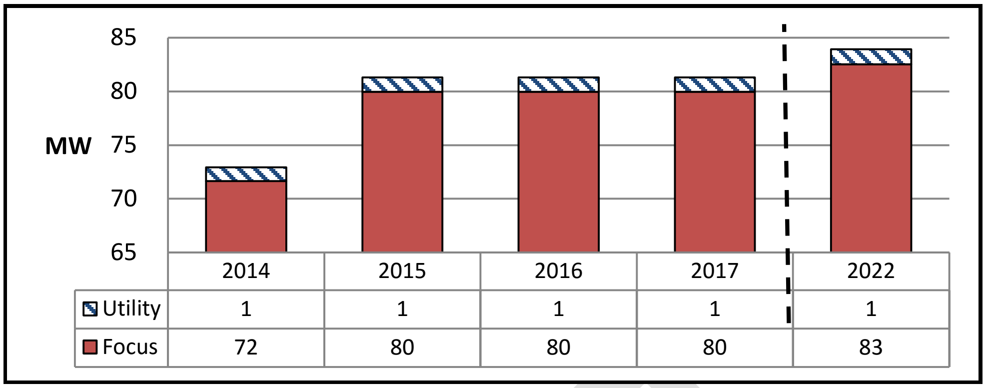
Figure 25: First-Year Annual Energy Savings (2014-2022)



	2014	2015	2016	2017	2022
Utility	11,212	8,497	8,647	8,847	9,357
Focus	527,283	565,373	565,373	565,373	606,215

Sources: Aggregated electricity provider data responses, docket 5-ES-108; Focus on Energy 2014 Evaluation Report; Focus on Energy 2015-18 Program Administration Contract.

Figure 26: First-Year Annual Demand Savings (2014-2022)



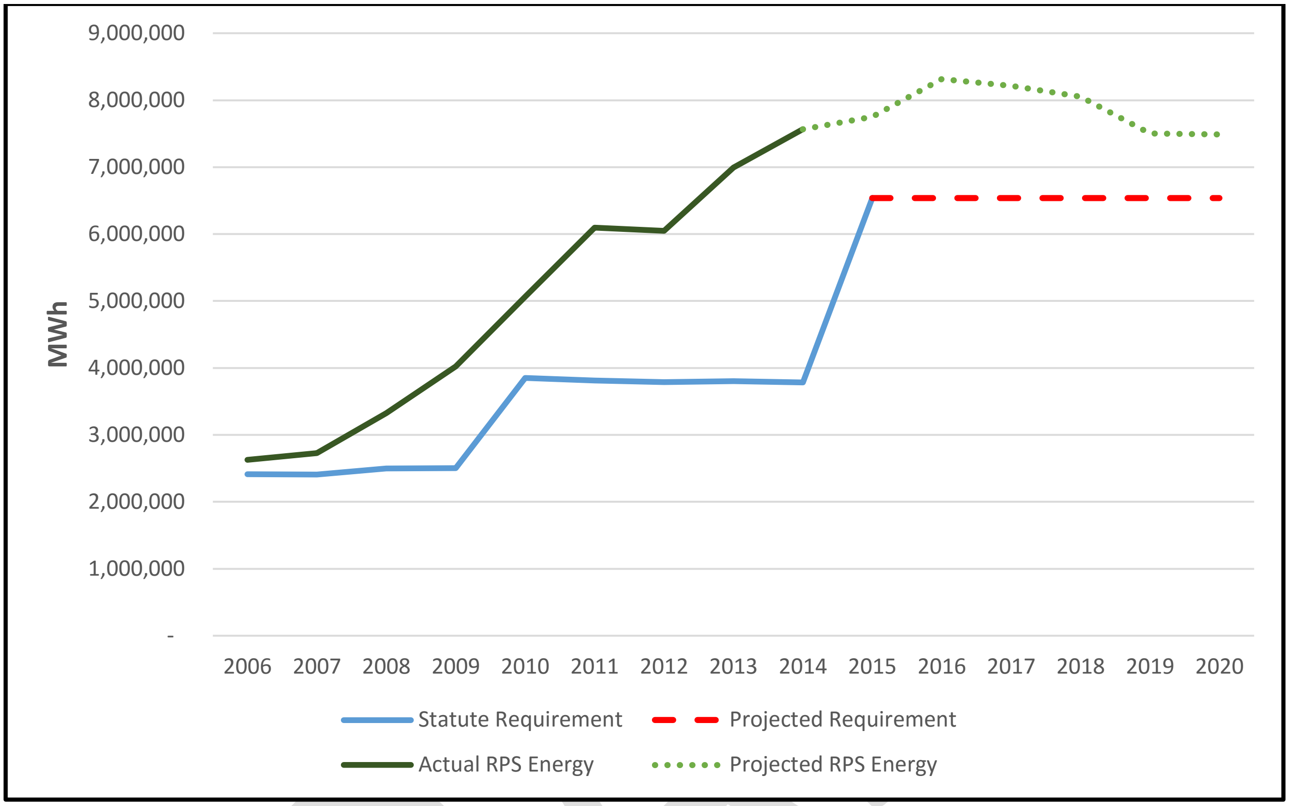
	2014	2015	2016	2017	2022
Utility	1	1	1	1	1
Focus	72	80	80	80	83

Source: Aggregated electricity provider data responses, docket 5-ES-108; Focus on Energy 2014 Evaluation Report; Focus on Energy 2015-18 Program Administration Contract.

RENEWABLE RESOURCES

The primary driver for renewable resource development by Wisconsin electricity providers is the RPS. The RPS requires electricity providers to increase their individual 2001-2003 average renewable baseline percentages by two percent by 2010, and by a total of six percent above their baselines by 2015. These electricity provider requirements then support the RPS statewide goal to achieve 10 percent of all electricity provided to Wisconsin retail customers to come from renewable resources by 2015. The statewide goal was met in 2013 and 2014, and projections show this goal will be met through at least 2020. As shown in Figure 27, electricity providers are expected to procure about eight million MWh from renewable resources annually.

Figure 27: Statewide RPS Renewable Retail Sales (Actual vs. Required, 2006-2020)*



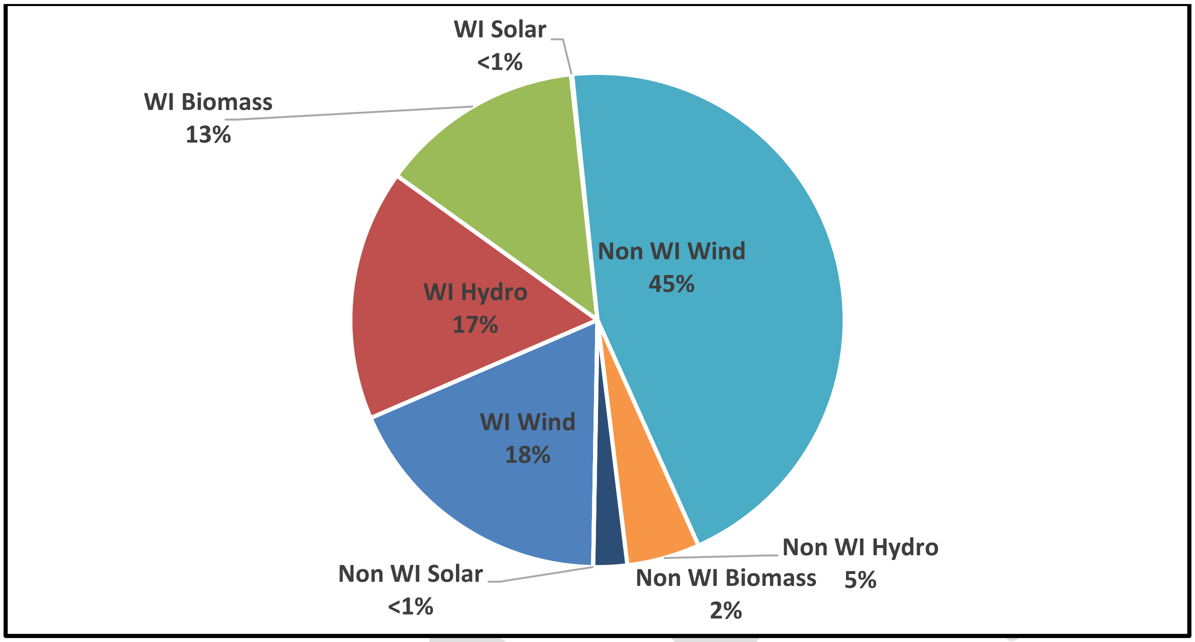
* Projection out to 2020 based on 0 percent energy growth.
Source: Commission Staff 2014 RPS Compliance Memorandum (PSC REF#: 271802)

Electricity providers have reasons to procure renewable resources beyond their RPS requirements. Most of them have voluntary "Green Pricing Programs," in which customers can choose to pay a premium for renewable energy. These programs require the electricity providers to either build new renewable facilities or contract with independent facility owners to meet their customers' demand. In addition to these voluntary programs, electricity providers cite other reasons for increasing renewable resource production, such as hedging against market and fuel prices, customer interest in community-based renewable facilities, and further resource diversification.

Figures 28 and 29 present renewable statistics for resource type and location for 2014, as well as resource development from 2010 to 2014.

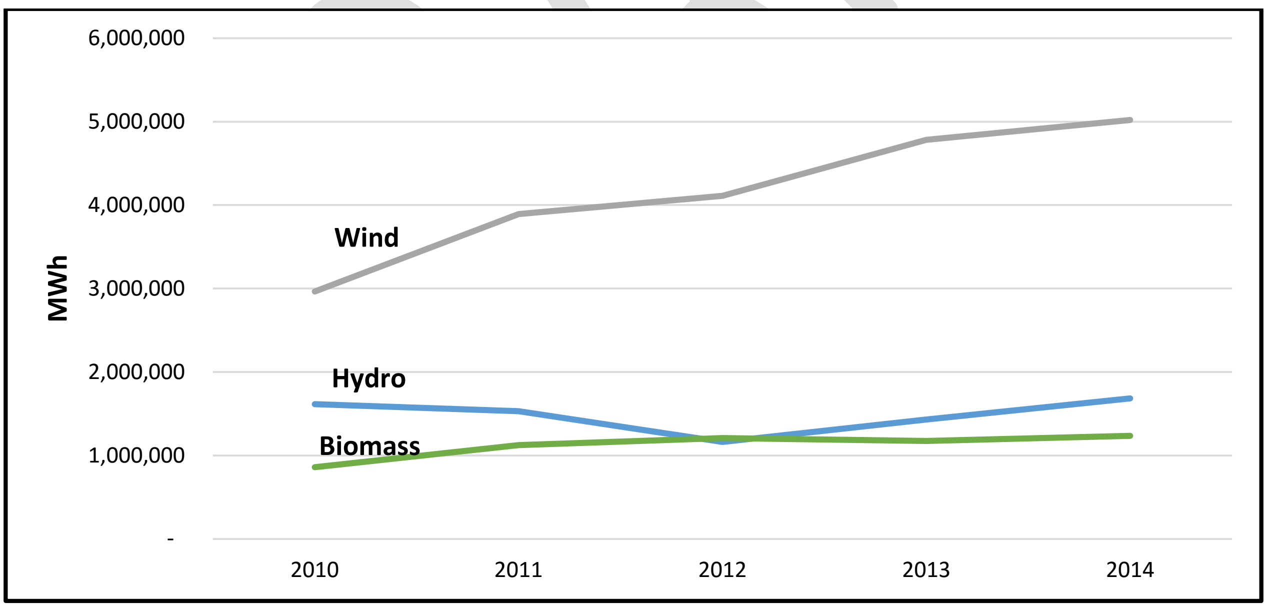
Figure 28 shows that in 2014 almost two-thirds of renewable resources serving Wisconsin retail customers came from wind. Most of these wind facilities are located in states west of Wisconsin. Figure 29 shows that wind procurement by Wisconsin electricity providers escalated over 2010-2014 period, while biomass and hydro resources stayed relatively constant.

Figure 28: 2014 Renewable Sales by Resource and Location - Percent of Total Renewable Sales



Source: Commission Staff 2014 RPS Compliance Memorandum (PSC REF#: 271802)

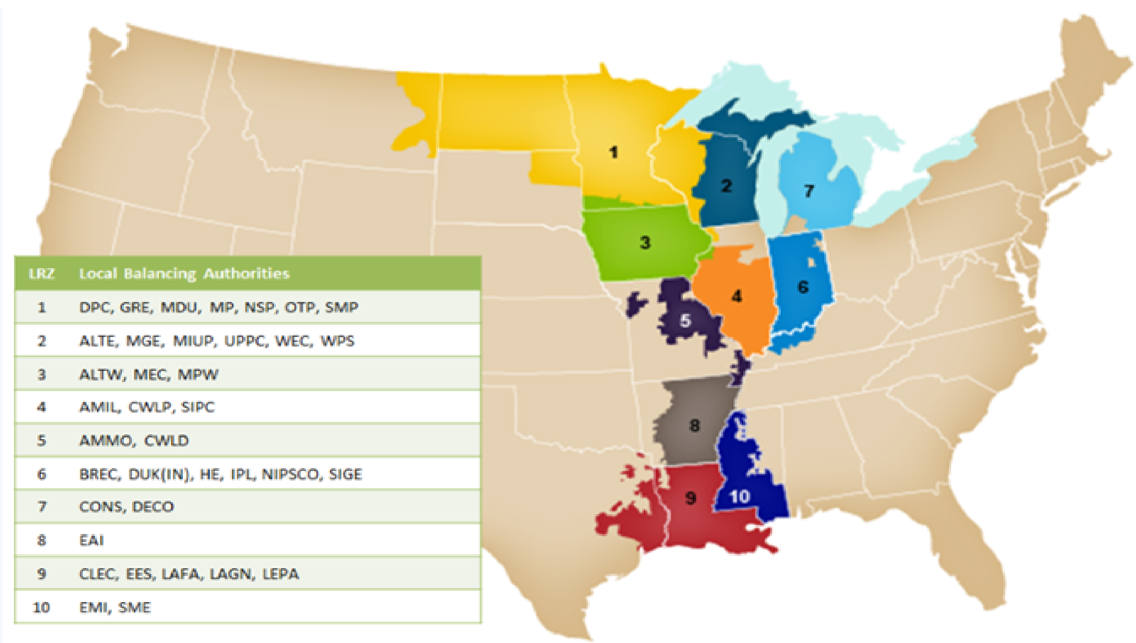
Figure 29: Wisconsin Electricity Provider Retail Sales by Renewable Resource (2010-2014)



Source: Commission Staff 2014 RPS Compliance Memorandum (PSC REF#: 271802)

In the Midwest region, new wind capacity additions have led to instantaneous, system-wide wind output records in MISO occurring on a fairly regular basis. MISO achieved a new system wind output record of 12.7 GW on January 27, 2016 (overall system load peaked at 98.2 GW on January 19, 2016, but the average load for the month was 78.5 GW[18]). Figure 30 shows the distribution of wind capacity throughout MISO, as well as the average Effective Load Carrying Capacity (ELCC) percentage per MISO LRZ. The ELCC percentages are established through annual MISO planning studies, and determine the capacity credit that wind facilities receive through MISO's capacity construct. On an average system wide basis, the 2016-2017 planning-year study found wind facilities performing at 15.6 percent of actual output per rated nameplate capacity during the coincident summer peak (a hot afternoon typically in July or August). This means of the 14,732 MW of installed wind capacity in MISO, about 2,300 MW of actual output is expected during the peak. According to the distribution per MISO zone, most wind facilities in MISO are sited in the states of Iowa, Minnesota and North Dakota. Lower Michigan, MISO Zone 7, also has more than 1,400 MW of wind facilities.

Figure 30: MISO Local Resource Zones (LRZ) And Distribution of Wind Capacity



Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Registered Max (MW)	14,732	4,315	627	7,379	644	282	1,486	0	0	0
UCAP (MW)	2,292	813	87	1,042	80	27	244	0	0	0
ELCC %	15.6%	18.8%	13.8%	14.1%	12.4%	9.6%	16.4%	0.0%	0.0%	0.0%
Wind CPnode Count	196	69	10	81	8	4	24	0	0	0

Source: MISO Report – Planning Year 2016-2017 Wind Capacity Credit, p.4:
(https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf)

[18] Source: MISO Informational Forum Presentation, February 23, 2016.

SUMMARY

Wisconsin's planning reserve margins are 14.2 percent or higher through 2022. If these forecasts hold true, Wisconsin will surpass the 7.1 percent unforced capacity requirement set by MISO (for 2016-2017). In future years, the utilities will monitor and meet the MISO planning reserve margin for the next planning year.

This SEA has shown that Wisconsin utilities continue to forecast annual load growth to be approximately 0.5-1.6 percent through 2022. Wisconsin's predominate energy source is coal, which accounted for approximately 65 percent in 2013. Nuclear made up the next largest share Wisconsin's energy mix, followed by natural gas, which made up 12 percent.

For MISO's planning horizon of 10 years, MISO envisions approximately 7,900 miles of new or upgraded transmission lines during that time period; 61 percent will be upgrades on existing corridors, and 39 percent will be new transmission lines on new corridors. MISO has been monitoring and studying potential impacts of environmental regulations on resource adequacy and anticipates a planning gap beginning in 2020. The Commission will continue to work with MISO, OMS, and other stakeholders on regional and interregional transmission planning.

Direct rate comparisons among states and regions are difficult because of the complexities of energy regulation and the energy market in general. While Wisconsin's rates are higher than many other states in the Midwest, the Commission noted that in a comparison of average residential bills, the average Wisconsin residential customer's monthly bill has consistently fallen at or below the Midwest average. The Commission also continues to explore innovative retail rate options for Wisconsin businesses to control their energy costs while contributing to economic growth in the state.

Customer-owned DER has been an issue in rate proceedings before the Commission. While DER represents approximately 1.0 percent of the energy requirement, the Commission will continue to monitor the use and impacts of DER. An inventory of DER resources was conducted for the first time as part of this SEA in order to provide the Commission and stakeholders better data regarding this issue going forward. The data collected spans the period January 2008 through September 2015.

Wisconsin continues to be a leader through its statewide energy efficiency program, Focus on Energy. As of 2015, all IOUs and municipal electric utilities, as well as 11 of the 24 electric cooperatives in the state, are participants in the Focus program. All electricity providers have been compliant with their RPS requirements through 2015. Going forward, electricity providers in Wisconsin are well-positioned to meet future RPS requirements.

APPENDIX

Table A-1: New Electricity Provider-Owned or Leased Generation Capacity, 2016-2022[1]

Year	Type of Load Served	Capacity (MW) [2]	Name	New or Existing Site	Owner/ Leaser	Fuel	Location (County: Locality)	PSC Status & Docket #
2016	Base	9	Twin Falls	Existing upgrade	WEPCO	Hydro		
2018	Intermediate	60	Port Washington	Existing upgrade	WEPCO	Nat. Gas	City of Port Washington	
2019	Intermediate	650	Riverside	New	WP&L	Nat. Gas	Town of Beloit	6680-CE-176
2022-2023	Peaking/Intermittent	N/A	DPC combined cycle	N/A	DPC	Nat. Gas	N/A	N/A

[1]NSPW stated its intent to add new generation in 2015, 2016 and 2019. These plants are not expected to be constructed in Wisconsin and are not included in this table.
[2] Nameplate MW shown.
Source: Data provided by utilities.

Table A-2: New Transmission Lines[1] (construction expected to start before 12-31-2022)

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)								
No Docket	Application Expected	New 109-mile 345 kV line	Cardinal-Hickory Creek, IA	345	436	Sep-19	Dec-20	Endpoint 2 will connect to the existing Salem-Hazelton 345kV line in Iowa.
No Docket	Application Expected	2.8 miles of new 345kV line	Arcadian/Pleasant Prairie-Zion Sub/Libertyville	345	54	Aug-18	Dec-20	New four position midpoint switching station[5]
Dairyland Power Cooperative (DPC)								
No Docket Expected		New 8.6 miles of 161kV line	La Crosse-Briggs Road	161	12	Oct-16	Nov-16	
Northern States Power Company-Wisconsin (NSPW)								
No Docket	Application Expected	Upgrade 63 miles of 345kV line	King-Eau Claire	345	25.6	Jan-19	Dec-20	May require some substation equipment upgrades/replacements.
No Docket	Application Expected	Upgrade 80 miles of 345kV line	Eau Claire-Arpin	345	32.3	Jan-19	Dec-20	May require some substation equipment upgrades/replacements.
No Docket	Application Expected	Upgrade 45 miles of 161kV line	Eau Claire-Tremval	161	39.3	Jan-21	Dec-23	May require some substation equipment upgrades/replacements.
No Docket	Application Expected	Upgrade 11 miles of 161kV line	Briggs Road-La Crosse	161	12	Jan-20	Dec-21	May require some substation equipment upgrades/replacements.
No Docket	Application Expected	New 40 miles of 115kV line	Bayfront-Norrie	115	51	Oct-19	Dec-21	Modifications to Saxon Pump substation will be required.
No Docket	Application Expected	New 0.6 miles of 345/115kV line	Holcombe-Sheldon	345/115	14	Oct-16	Dec-18	Includes a new Pershing substation.

[1]Does not include lines approved by the Commission.
[2]Rebuilds and upgrades, as well as new lines, may require new right-of-way.
[3]New distribution substation (Endpoint 1) will be interconnected with circuit X-97, Cedar Ridge-Kettle Moraine-Mullet River.
[4]Switching station will be interconnected with circuit 111, Point Beach-Sheboygan Energy Center, and circuit 121, Point Beach-Forest Junction.
[5]Southeast Wisconsin-Northeastern Illinois Interface Project - New switching station (yet to be formally named) will be interconnected with ATC circuit PLPL81, Pleasant Prairie to Arcadian, and ComEd circuit 2224, Zion Station to Libertyville.
Source: Data provided by utilities.

Table A-3: Retired Electricity Provider-Owned or Leased Generation Capacity: 2016-2022[1]

Year	Name	Owner/ Leaser	Type of Load Served	Capacity (MW)[2]	Fuel	Location
2016	Milwaukee County	WEPCO	Peaking	6	Nat. Gas	Milwaukee, WI
2018	Edgewater 4	WP&L/WPSC	Base	320	Coal	Sheboygan, WI
2018	Flambeau 1	NSPW	Peaking	12	Nat. Gas	Park Falls, WI
2020	Rock River 3,4,5,6	WP&L	Peaking	26,15,51,52	Nat. Gas	Beloit, WI
2020	Sheepskin 1	WP&L	Peaking	39	Nat. Gas	Beloit, WI

[1]NSPW stated its intent to retire generation in 2015, 2017, and 2020. These plants are not located in Wisconsin and are not included in this table.
[2]Capacity listed is the summer net-accredited capacity.

Table A-4: Customer Owned Distributed Energy Resources by Customer Class--Investor Owned and Municipal Utilities, 2008-2015 (continued on the next page)[19]

		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	1,200	249	3,183	290,307	108,489	211	322,436	17,492,880
	Muni	36	6	3	224	136	23	42	-
	Total	1,237	255	3,186	290,531	108,625	234	322,479	17,492,880
2009	IOU	2,135	414	4,134	502,101	111,705	277	277,723	15,799,314
	Muni	116	23	25	4,927	269	37	105	2,082
	Total	2,251	437	4,159	507,029	111,974	314	277,828	15,801,395
2010	IOU	4,168	714	5,522	947,501	170,680	419	450,100	27,165,619
	Muni	228	49	112	26,082	333	46	218	12,604
	Total	4,396	763	5,634	973,584	171,013	465	450,318	27,178,223
2011	IOU	5,432	907	4,383	887,473	208,765	556	526,888	28,470,158
	Muni	280	60	164	40,406	670	67	312	22,162
	Total	5,712	967	4,546	927,879	209,434	623	527,200	28,492,320
2012	IOU	6,475	1,078	5,919	1,128,617	209,040	629	548,686	30,207,008
	Muni	328	71	247	59,688	742	78	450	31,440
	Total	6,803	1,149	6,166	1,188,305	209,781	707	549,136	30,238,448
2013	IOU	7,255	1,226	5,720	1,035,859	216,793	712	536,944	30,732,041
	Muni	521	104	335	80,549	785	83	502	34,298
	Total	7,776	1,330	6,055	1,116,408	217,578	795	537,446	30,766,340
2014	IOU	8,552	1,487	6,099	1,057,305	215,644	763	516,522	31,819,995
	Muni	688	130	467	108,320	834	87	559	37,348
	Total	9,241	1,617	6,566	1,165,624	216,478	850	517,081	31,857,343
2015	IOU	9,740	1,671	5,392	861,292	214,912	790	393,930	23,247,393
	Muni	756	140	451	101,258	929	93	427	28,587
	Total	10,497	1,811	5,843	962,550	215,842	883	394,358	23,275,980
Total 2008 - 2015				42,154	7,131,910			3,575,845	205,102,929

[19] [i]Data collected for the period of January 2008 through September 2015. All DER tables shown in Appendix A, with the exception of Table A-4, include power cooperative data. Dairyland Power Cooperative, the state's generation and transmission cooperative, submits data on behalf of its members but was unable to provide customer class information due to the varied ways cooperatives classify customers. In addition, Dairyland Power Cooperative was unable to provide DER data for 2015.

Table A-4 (continued): Customer Owned Distributed Energy Resources by Customer Class—Investor Owned and Municipal Utilities, 2008-2015

		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	72,924	14	1,060	54,726	182,613	474	326,679	17,837,913
	Muni	-	-	-	-	172	29	46	224
	Total	72,924	14	1,060	54,726	182,785	503	326,725	17,838,137
2009	IOU	73,524	15	3,441	91,871	187,365	706	285,299	16,393,286
	Muni	-	-	-	-	384	60	130	7,009
	Total	73,524	15	3,441	91,871	187,749	766	285,428	16,400,296
2010	IOU	127,154	21	53,443	3,242,131	302,002	1,154	509,066	31,355,251
	Muni	388	3	250	19,275	949	98	580	57,962
	Total	127,542	24	53,693	3,261,406	302,951	1,252	509,645	31,413,213
2011	IOU	138,357	28	70,826	4,615,709	352,554	1,491	602,097	33,973,339
	Muni	713	4	449	30,866	1,663	131	924	93,434
	Total	139,070	32	71,275	4,646,574	354,217	1,622	603,021	34,066,773
2012	IOU	139,319	30	78,709	5,122,321	354,834	1,737	633,314	36,457,946
	Muni	779	4	513	38,318	1,849	153	1,210	129,447
	Total	140,098	34	79,222	5,160,640	356,682	1,890	634,524	36,587,393
2013	IOU	143,419	32	84,950	4,195,362	367,468	1,970	627,614	35,963,262
	Muni	779	4	511	37,082	2,085	191	1,348	151,930
	Total	144,198	36	85,461	4,232,445	369,552	2,161	628,962	36,115,192
2014	IOU	148,208	33	76,710	4,539,061	372,405	2,283	599,331	37,416,361
	Muni	909	5	334	22,358	2,431	222	1,360	168,025
	Total	149,117	38	77,044	4,561,418	374,836	2,505	600,690	37,584,386
2015	IOU	148,208	33	55,685	3,606,854	372,861	2,494	455,007	27,715,539
	Muni	909	5	389	27,979	2,595	238	1,267	157,824
	Total	149,117	38	56,074	3,634,833	375,456	2,732	456,274	27,873,363
Total 2008 - 2015				427,270	25,643,913			4,045,270	237,878,751

Table A-5: Customer Owned Distributed Energy Resources by Installation Size—Investor Owned Utilities, Municipal Utilities and Cooperatives, 2008-2015 (continued on the next page)

		≤ 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	2,663	407	4,269	391,838	1,389	26	338	30,077
	Muni	133	28	46	224	39	1	-	-
	Coop	176	27	63	2,640	38	1	9	396
	Total	2,972	462	4,378	394,703	1,465	28	347	30,473
2009	IOU	4,263	632	5,641	693,356	1,540	31	371	40,247
	Muni	277	57	100	7,009	107	3	30	-
	Coop	556	94	128	4,506	65	2	9	240
	Total	5,096	783	5,868	704,870	1,713	36	410	40,487
2010	IOU	8,222	1,043	8,869	1,460,453	2,325	48	3,654	239,803
	Muni	453	92	237	38,148	270	5	178	3,917
	Coop	925	145	343	15,298	175	5	67	2,526
	Total	9,601	1,280	9,449	1,513,898	2,771	58	3,898	246,246
2011	IOU	10,940	1,359	7,450	1,432,229	3,289	60	4,298	273,363
	Muni	693	122	341	58,558	420	7	345	11,820
	Coop	1,182	192	575	24,897	347	10	252	11,001
	Total	12,814	1,673	8,366	1,515,685	4,056	77	4,895	296,184
2012	IOU	12,371	1,591	10,054	1,839,731	3,884	70	4,691	290,887
	Muni	812	144	490	86,250	420	7	408	13,457
	Coop	1,406	228	905	37,869	336	10	285	11,187
	Total	14,589	1,963	11,449	1,963,849	4,641	87	5,383	315,531
2013	IOU	14,330	1,809	9,944	1,706,059	4,216	78	5,518	316,444
	Muni	1,048	182	576	108,050	420	7	484	16,434
	Coop	1,665	271	580	24,399	451	14	310	11,895
	Total	17,043	2,262	11,100	1,838,508	5,088	99	6,311	344,772
2014	IOU	16,211	2,113	10,361	1,907,036	4,483	83	5,752	320,682
	Muni	1,265	212	733	137,852	550	8	500	16,576
	Coop	2,228	381	528	20,503	502	16	384	14,376
	Total	19,704	2,706	11,622	2,065,391	5,536	107	6,636	351,635
2015	IOU	17,217	2,310	9,096	1,431,054	5,356	96	4,328	239,763
	Muni	1,429	228	670	124,478	550	8	364	11,530
	Coop	-	-	-	-	-	-	-	-
	Total	18,645	2,538	9,766	1,555,532	5,907	104	4,692	251,293
Total 2008 - 2015				71,998	11,552,436			32,572	1,876,621

Table A-5 (continued): Customer Owned Distributed Energy Resources by Installation Size—Investor Owned Utilities, Municipal Utilities and Cooperatives, 2008-2015 (continued on the next page)

		> 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	10,466	18	7,185	478,329	115,096	21	307,880	16,559,147
	Muni	-	-	-	-	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	10,466	18	7,185	478,329	115,096	21	307,880	16,559,147
2009	IOU	11,066	19	8,028	595,086	117,496	22	260,368	14,480,713
	Muni	-	-	-	-	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	11,066	19	8,028	595,086	117,496	22	260,368	14,480,713
2010	IOU	15,906	28	53,341	3,842,754	148,948	31	416,741	24,313,695
	Muni	225	1	165	15,897	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	16,131	29	53,505	3,858,651	148,948	31	416,741	24,313,695
2011	IOU	17,659	32	62,966	4,816,843	166,066	36	495,572	25,611,386
	Muni	550	2	238	23,056	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	18,209	34	63,205	4,839,898	166,066	36	495,572	25,611,386
2012	IOU	19,976	35	71,909	5,483,576	164,003	37	522,186	27,396,730
	Muni	616	2	312	29,741	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	20,592	37	72,221	5,513,317	164,003	37	522,186	27,396,730
2013	IOU	22,266	39	88,559	6,677,513	172,055	40	506,570	26,283,219
	Muni	616	2	288	27,447	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	22,882	41	88,847	6,704,960	172,055	40	506,570	26,283,219
2014	IOU	23,629	42	87,649	6,550,578	173,481	41	482,575	27,946,082
	Muni	616	2	127	13,597	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	24,245	44	87,776	6,564,174	173,481	41	482,575	27,946,082
2015	IOU	24,607	44	70,943	5,308,438	171,081	40	369,955	20,707,544
	Muni	616	2	234	21,816	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	25,223	46	71,177	5,330,254	171,081	40	369,955	20,707,544
Total 2008 - 2015				451,944	33,884,669			3,361,847	183,298,517

Table A-5 (continued): Customer Owned Distributed Energy Resources by Installation Size—Investor Owned Utilities, Municipal Utilities and Cooperatives, 2008-2015

		> 1,000 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	53,000	2	7,007	378,522	182,614	474	326,679	17,837,914
	Muni	-	-	-	-	172	29	46	224
	Coop	-	-	-	-	214	28	72	3,037
	Total	53,000	2	7,007	378,522	182,999	531	326,797	17,841,174
2009	IOU	53,000	2	10,891	583,885	187,365	706	285,299	16,393,286
	Muni	-	-	-	-	384	60	130	7,009
	Coop	-	-	-	-	621	96	136	4,745
	Total	53,000	2	10,891	583,885	188,370	862	285,565	16,405,041
2010	IOU	126,600	4	26,461	1,498,546	302,002	1,154	509,066	31,355,251
	Muni	-	-	-	-	949	98	580	57,962
	Coop	-	-	-	-	1,100	150	410	17,824
	Total	126,600	4	26,461	1,498,546	304,051	1,402	510,055	31,431,036
2011	IOU	154,600	4	31,811	1,839,518	352,554	1,491	602,097	33,973,339
	Muni	-	-	-	-	1,663	131	924	93,434
	Coop	-	-	-	-	1,528	202	827	35,898
	Total	154,600	4	31,811	1,839,518	355,745	1,824	603,848	34,102,671
2012	IOU	154,600	4	24,473	1,447,022	354,834	1,737	633,314	36,457,946
	Muni	-	-	-	-	1,849	153	1,210	129,447
	Coop	-	-	-	-	1,742	238	1,190	49,056
	Total	154,600	4	24,473	1,447,022	358,425	2,128	635,713	36,636,449
2013	IOU	154,600	4	17,024	980,027	367,467	1,970	627,614	35,963,262
	Muni	-	-	-	-	2,085	191	1,348	151,930
	Coop	-	-	-	-	2,116	285	890	36,294
	Total	154,600	4	17,024	980,027	371,668	2,446	629,852	36,151,486
2014	IOU	154,600	4	12,994	691,983	372,405	2,283	599,331	37,416,361
	Muni	-	-	-	-	2,432	222	1,360	168,025
	Coop	-	-	-	-	2,730	397	912	34,879
	Total	154,600	4	12,994	691,983	377,566	2,902	601,602	37,619,265
2015	IOU	154,600	4	685	28,590	372,861	2,494	455,007	27,715,390
	Muni	-	-	-	-	2,595	238	1,267	157,824
	Coop	-	-	-	-	-	-	-	-
	Total	154,600	4	685	28,590	375,456	2,732	456,274	27,873,214
Total 2008 - 2015				131,346	7,448,092			4,049,706	238,060,336

Table A-6: Customer Owned Distributed Energy Resources by Technology Type—Investor Owned Utilities, Municipal Utilities and Cooperatives, 2008-2015 (continued on the next page)[20]

		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	8,471	10	8,498	640,433	6,996	3	-	-
	Muni	-	-	-	-	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	8,471	10	8,498	640,433	6,996	3	-	-
2009	IOU	9,071	11	12,215	1,042,236	6,996	3	-	-
	Muni	-	-	-	-	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	9,071	11	12,215	1,042,236	6,996	3	-	-
2010	IOU	15,601	18	50,739	4,178,490	59,996	4	28,464	1,629,338
	Muni	-	-	-	-	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	15,601	18	50,739	4,178,490	59,996	4	28,464	1,629,338
2011	IOU	23,002	26	71,546	5,907,018	59,996	4	34,340	2,060,016
	Muni	325	1	-	-	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	23,327	27	71,546	5,907,018	59,996	4	34,340	2,060,016
2012	IOU	27,776	31	94,810	7,874,207	59,996	4	23,690	1,427,269
	Muni	325	1	-	-	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	28,101	32	94,810	7,874,207	59,996	4	23,690	1,427,269
2013	IOU	38,178	39	112,657	8,129,280	59,996	4	15,584	924,348
	Muni	325	1	0	20	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	38,503	40	112,657	8,129,300	59,996	4	15,584	924,348
2014	IOU	40,237	41	113,582	9,606,484	59,996	4	11,841	640,342
	Muni	455	2	0	4	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	40,692	43	113,582	9,606,488	59,996	4	11,841	640,342
2015	IOU	41,000	42	105,471	9,021,927	59,996	4	75	3,594
	Muni	455	2	19	679	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	41,455	44	105,490	9,022,606	59,996	4	75	3,594
Total 2008 - 2015				569,537	46,400,776			113,994	6,684,907

[20] Several municipal utilities have entered into solar purchased power agreements (PPA) with their wholesale energy provider. DER tables shown in Appendix A include the total megawatt hours of energy purchased through the PPAs, but the monetary value of the purchased power is excluded because PPA contract rates are confidential.

Table A-6 (continued): Customer Owned Distributed Energy Resources by Technology Type—Investor Owned Utilities, Municipal Utilities and Cooperatives, 2008-2015 (continued on the next page)

		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	21,137	41	13,183	728,154	46,150	8	290,899	15,570,643
	Muni	-	-	-	-	-	-	-	-
	Coop	1	1	0	5	-	-	-	-
	Total	21,138	42	13,183	728,159	46,150	8	290,899	15,570,643
2009	IOU	21,137	41	14,246	680,410	48,550	9	239,739	13,226,381
	Muni	-	-	-	-	-	-	-	-
	Coop	1	1	2	80	-	-	-	-
	Total	21,138	42	14,248	680,490	48,550	9	239,739	13,226,381
2010	IOU	49,607	49	64,271	3,581,030	70,382	14	351,232	20,290,272
	Muni	-	-	-	-	-	-	-	-
	Coop	1	1	1	92	-	-	-	-
	Total	49,608	50	64,272	3,581,122	70,382	14	351,232	20,290,272
2011	IOU	56,469	52	70,886	3,813,032	75,182	15	410,150	20,573,314
	Muni	-	-	-	-	-	-	-	-
	Coop	1	1	1	50	-	-	-	-
	Total	56,470	53	70,887	3,813,081	75,182	15	410,150	20,573,314
2012	IOU	52,069	51	66,781	3,250,109	75,182	15	429,944	21,911,164
	Muni	-	-	-	-	-	-	-	-
	Coop	19	2	2	-	-	-	-	-
	Total	52,088	53	66,783	3,250,109	75,182	15	429,944	21,911,164
2013	IOU	52,069	51	79,697	3,872,291	75,182	15	403,109	21,187,870
	Muni	-	-	-	-	-	-	-	-
	Coop	19	2	-	-	-	-	-	-
	Total	52,088	53	79,697	3,872,291	75,182	15	403,109	21,187,870
2014	IOU	52,299	52	74,273	3,293,819	73,182	14	383,097	21,923,884
	Muni	-	-	-	-	-	-	-	-
	Coop	19	2	-	-	-	-	-	-
	Total	52,318	54	74,273	3,293,819	73,182	14	383,097	21,923,884
2015	IOU	52,299	52	52,670	2,148,854	70,782	13	285,294	15,104,769
	Muni	-	-	-	-	-	-	-	-
	Coop	-	-	-	-	-	-	-	-
	Total	52,299	52	52,670	2,148,854	70,782	13	285,294	15,104,769
Total 2008 - 2015				436,013	21,367,925			2,793,464	149,788,297

Table A-6 (continued): Customer Owned Distributed Energy Resources by Technology Type—Investor Owned Utilities, Municipal Utilities and Cooperatives, 2008-2015 (continued on the next page)

		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	96,900	7	9,641	490,799	1,659	314	4,385	400,617
	Muni	-	-	-	-	150	27	42	-
	Coop	-	-	-	-	55	14	41	1,962
	Total	96,900	7	9,641	490,799	1,865	355	4,469	402,579
2009	IOU	96,900	7	13,225	724,235	2,977	519	5,778	709,993
	Muni	-	-	-	-	353	57	122	6,483
	Coop	-	-	-	-	250	61	91	3,236
	Total	96,900	7	13,225	724,235	3,580	637	5,991	719,712
2010	IOU	96,900	7	6,229	294,917	6,368	882	7,569	1,328,187
	Muni	-	-	-	-	754	93	480	53,153
	Coop	-	-	-	-	496	103	248	10,783
	Total	96,900	7	6,229	294,917	7,619	1,078	8,297	1,392,123
2011	IOU	125,025	8	8,087	252,072	9,226	1,186	6,295	1,284,948
	Muni	-	-	-	-	914	119	646	80,043
	Coop	-	-	-	-	858	153	493	20,436
	Total	125,025	8	8,087	252,072	10,997	1,458	7,434	1,385,427
2012	IOU	125,025	8	8,269	205,691	10,944	1,417	8,659	1,666,508
	Muni	-	-	-	-	1,099	141	878	113,536
	Coop	-	-	-	-	1,114	187	823	33,109
	Total	125,025	8	8,269	205,691	13,157	1,745	10,360	1,813,153
2013	IOU	125,025	8	7,144	217,466	12,860	1,631	8,367	1,517,312
	Muni	-	-	-	-	1,325	178	929	133,831
	Coop	-	-	-	-	1,461	233	562	22,620
	Total	125,025	8	7,144	217,466	15,646	2,042	9,858	1,673,763
2014	IOU	125,025	8	6,496	239,614	17,498	1,945	9,030	1,601,297
	Muni	-	-	-	-	1,542	208	929	149,712
	Coop	-	-	-	-	2,111	348	600	23,785
	Total	125,025	8	6,496	239,614	21,151	2,501	10,558	1,774,794
2015	IOU	125,025	8	2,611	67,224	19,582	2,155	8,208	1,296,988
	Muni	-	-	-	-	1,706	224	968	144,815
	Coop	-	-	-	-	-	-	-	-
	Total	125,025	8	2,611	67,224	21,287	2,379	9,175	1,441,803
Total 2008 - 2015				61,703	2,492,018			66,143	10,603,354

Table A-6 (continued): Customer Owned Distributed Energy Resources by Technology Type—Investor Owned Utilities, Municipal Utilities and Cooperatives, 2008-2015 (continued on the next page)

		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	-	-	-	-	1,300	91	72	7,267
	Muni	-	-	-	-	22	2	3	224
	Coop	-	-	-	-	157	13	31	1,070
	Total	-	-	-	-	1,479	106	107	8,561
2009	IOU	-	-	-	-	1,734	116	95	10,033
	Muni	-	-	-	-	32	3	8	526
	Coop	-	-	-	-	370	34	43	1,429
	Total	-	-	-	-	2,135	153	146	11,988
2010	IOU	-	-	-	-	3,147	180	561	53,017
	Muni	-	-	-	-	195	5	99	4,808
	Coop	-	-	-	-	604	46	161	6,949
	Total	-	-	-	-	3,945	231	821	64,774
2011	IOU	-	-	-	-	3,654	200	793	82,941
	Muni	-	-	-	-	425	11	278	13,391
	Coop	-	-	-	-	670	48	333	15,412
	Total	-	-	-	-	4,748	259	1,404	111,744
2012	IOU	-	-	-	-	3,842	211	1,161	122,998
	Muni	-	-	-	-	425	11	332	15,911
	Coop	-	-	-	-	610	49	364	15,947
	Total	-	-	-	-	4,876	271	1,857	154,856
2013	IOU	-	-	-	-	4,157	222	1,055	114,696
	Muni	-	-	-	-	435	12	418	18,079
	Coop	-	-	-	-	636	50	329	13,674
	Total	-	-	-	-	5,228	284	1,802	146,449
2014	IOU	-	-	-	-	4,168	219	1,012	110,920
	Muni	-	-	-	-	435	12	431	18,310
	Coop	-	-	-	-	600	47	312	11,094
	Total	-	-	-	-	5,202	278	1,755	140,324
2015	IOU	-	-	-	-	4,178	220	680	72,034
	Muni	-	-	-	-	435	12	280	12,330
	Coop	-	-	-	-	-	-	-	-
	Total	-	-	-	-	4,612	232	960	84,364
Total 2008 - 2015				-	-			8,853	723,059

Table A-6 (continued): Customer Owned Distributed Energy Resources by Technology Type—Investor Owned Utilities, Municipal Utilities and Cooperatives, 2008-2015

		Total			
Year	Utility Type	Installed Capacity (kW)	Number of Installations	Amount of Purchases (MWh)	Value of Purchases ($)
2008	IOU	182,614	474	326,679	17,837,914
	Muni	172	29	46	224
	Coop	214	28	72	3,037
	Total	182,999	531	326,797	17,841,174
2009	IOU	187,365	706	285,299	16,393,286
	Muni	384	60	130	7,009
	Coop	621	96	136	4,745
	Total	188,370	862	285,565	16,405,041
2010	IOU	302,002	1,154	509,066	31,355,251
	Muni	949	98	580	57,962
	Coop	1,100	150	410	17,824
	Total	304,051	1,402	510,055	31,431,036
2011	IOU	352,554	1,491	602,097	33,973,339
	Muni	1,663	131	924	93,434
	Coop	1,528	202	827	35,898
	Total	355,745	1,824	603,848	34,102,671
2012	IOU	354,834	1,737	633,314	36,457,946
	Muni	1,849	153	1,210	129,447
	Coop	1,742	238	1,190	49,056
	Total	358,425	2,128	635,713	36,636,449
2013	IOU	367,467	1,970	627,614	35,963,262
	Muni	2,085	191	1,348	151,930
	Coop	2,116	285	890	36,294
	Total	371,668	2,446	629,852	36,151,486
2014	IOU	372,405	2,283	599,331	37,416,361
	Muni	2,432	222	1,360	168,025
	Coop	2,730	397	912	34,879
	Total	377,566	2,902	601,602	37,619,265
2015	IOU	372,861	2,494	455,007	27,715,390
	Muni	2,595	238	1,267	157,824
	Coop	-	-	-	-
	Total	375,456	2,732	456,274	27,873,214
Total 2008 - 2015				4,049,706	238,060,336

Acronyms

§	Section
ATC	American Transmission Company LLC
BRP	Baseline Reliability Project
CA	Certificate of Authority
CAA	Clean Air Act
Cadmus	Cadmus Group
CB&I	Chicago Bridge and Iron
Commission	Public Service Commission of Wisconsin
CO_2	Carbon Dioxide
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CSAPR	Cross State Air Pollution Rule
DER	Distributed Energy Resources
DPC	Dairyland Power Cooperative
EDR	Economic Development Rate
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capacity
ELG	Effluent Limitations Guideline
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
Focus	Focus on Energy
GIP	Generator Interconnection Project
GLU	Great Lakes Utilities
GW	Gigawatt
IGCC	Integrated Gasification Combined Cycle
IMM	Independent market monitor
IOU	Investor-owned utility
kV	kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LMP	Locational Marginal Pricing
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.
MPU	Manitowoc Public Utilities
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
NO_x	Nitric oxides
NRC	Nuclear Regulatory Commission
NSPM	Northern States Power-Minnesota
NSPW	Northern States Power-Wisconsin
OMS	Organization of MISO states
ROW	Right of way
RPS	Renewable portfolio standard
RTO	Regional Transmission Organization
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
TOU	Time-of-Use
WEC	Wisconsin Energy Corporation
WEPCO	Wisconsin Electric Power Company
Wis. Stat.	Wisconsin Statutes
WP&L	Wisconsin Power and Light Company
WPPI	Wisconsin Public Power, Inc.
WPSC	Wisconsin Public Service Corporation
Xcel	Xcel Energy, Inc.