PUBLIC SERVICE COMMISSION OF WISCONSIN

FINAL

STRATEGIC ENERGY ASSESSMENT

ENERGY 2020

610 NORTH WHITNEY WAY
MADISON, WISCONSIN

OCTOBER 2014
DOCKET 5-ES-107

TO THE READER

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

UNDERSTANDING THE SEA – KEY TIPS AND PROCESSES

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

The Commission is required to hold a public hearing before issuing the final SEA. A public hearing was held on July 15, 2014, and a copy of the notice providing information on the hearing is available for review on the Commission's website at: http://psc.wi.gov.

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

Public comments have been used to prepare the final SEA. Questions regarding the final SEA or requests for additional copies of the final SEA may be directed to Amy Pepin at (608) 267-7972. Questions from the legislature and the media may be directed to Nathan Conrad at (608) 266-9600.

Public Service Commission of Wisconsin
Phone (608) 266-5481 ● Fax (608) 266-3957 ● TTY (608) 267-1479
Email: pscrecs@wisconsin.gov
Home Page: http://psc.wi.gov

Table of Contents

STRATEGIC ENERGY ASSESSMENT

2014-2020 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 identify and describe:

- All large electric generating facilities for which an electric utility or merchant plant developer plans to commence construction within seven years;
- All high-voltage transmission lines for which an electric utility 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 SEA is required by statute to assess:

- 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 comments. After hearing(s) 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 eighth SEA covers the years 2014 through 2020. During the past year, eleven large Wisconsin-based investor-owned utilities, cooperatives, municipal electric companies, 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 2020.

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. 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.[1] Should a specific topic warrant further attention with the intent of Commission action, the Commission must take additional steps as authorized by law.[2]

[1] Wis. Stat. § 196.491(3)(dm)
[2] Some stakeholders have indicated in the past, as well as during the comment period for this SEA that they would prefer that the Commission institute a statewide integrated resource planning process rather than the existing SEA approach.

EXECUTIVE SUMMARY

DEMAND AND SUPPLY OF ELECTRICITY

- Recent economic conditions, in addition to efficiency and conservation gains, have translated into lower peak demand growth in Wisconsin. Wisconsin utilities forecast between 0.5 percent and 1.2 percent annual load growth through 2020. This is similar to the 1.0 percent forecast from the last SEA.
- Wisconsin's primary energy source is coal.
- The increased shift to natural gas in Wisconsin, and the recent shutdown of the Kewaunee nuclear facility, continues to change the generation mix proportions in the state.
- Based on Wisconsin specific data collected for the purposes of producing this SEA, the Commission does not expect a shortfall for Wisconsin. The Midcontinent Independent System Operator (MISO) and the Organization of MISO States (OMS) continue to discuss resource adequacy surveys in the MISO footprint.

TRANSMISSION SYSTEM PLANS, ISSUES, AND DEVELOPMENTS

- The MISO reliability footprint expanded in 2013 with the integration of parts of the states of Arkansas, Mississippi, Louisiana, and Texas.
- The most recent MISO transmission expansion planning (MTEP) process contains 317 new projects that total $1.48 billion in transmission facilities.
- The Federal Energy Regulatory Commission (FERC) issued Order 1000 on July 21, 2011, to restructure FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. MISO's initial FERC compliance filing was made on October 25, 2012, and MISO's interregional and regional compliance filings were made in July 2013. The U.S. Court of Appeals for the D.C. Circuit upheld Order 1000 on August 15, 2014. The Commission will continue to work with MISO and other states to fully participate in this process.

MARKET ANALYSIS AND PLANNING RESERVE MARGINS

- Commission data collected for the purposes of this SEA indicate that Wisconsin's planning reserve margins are forecasted to remain above 13.7 percent through 2020. The planning reserve margin for the 2015-2016 period is between 17.3 and 18.9 percent.
- Wisconsin easily meets the 14.8-15 percent requirement set by the Midcontinent Independent System Operator (MISO) for 2014-2016.

RATES

- Energy rates continue to increase across customer classes both in Wisconsin and the Midwest. Rate increases are generally driven by sales decline, transmission, generation, distribution and renewable investments, increased federal regulation of pollutants, fuel price volatility and purchased power costs, as well as the high fixed-cost nature of the utility business. Some of these increases, however, have been, and are expected to continue to be, offset by the lower cost of natural gas.
- Rate increases can be frustrating for Wisconsin consumers who undertake efforts to conserve energy. Proactive customers can mitigate some bill impacts from rate increases with energy conservation and energy efficiency.
- The Commission continues to investigate ways to mitigate energy rate increases to ensure Wisconsin remains competitive in a global marketplace.
- The Commission will continue to monitor developments with the implementation of EPA rules and their impacts on ratepayers and utilities, including the costs associated with compressed compliance periods for EPA rules, such as the Cross State Air Pollution rule and the initiatives under 111(b) and (d) under the Clean Air Act to curb carbon emissions. Wisconsin utilities may have to respond with new or retrofitted generation facilities that meet all emission restrictions, and the Commission will give these impacts careful consideration when reviewing upcoming rate and construction cases.

ENERGY EFFICIENCY AND RENEWABLE RESOURCES

- The Commission continues to work on examining the funding and structure of the energy efficiency and renewable resource programs in Wisconsin under Wis. Stat. § 196.374. The Commission will continue to pursue cost-effective strategies to meet energy efficiency and renewable resource program goals as set forth in that statute.
- State law requires Wisconsin's electric providers to sell a certain percentage of renewable energy. [3] Approximately 10 percent of all electricity sales in Wisconsin must be from renewable resources by 2015. Wisconsin surpassed the 10 percent standard for the first time in 2013. All electric providers and aggregators were Renewable Portfolio Standard (RPS) compliant as of the latest full data year on this topic (2013), and just under 10.8 percent of all electrical energy sold in Wisconsin, including RPS and voluntary green pricing retail sales, was generated from renewable resources.

[3] Wis. Stat. § 196.378(2).

ELECTRIC DEMAND AND SUPPLY CONDITIONS IN WISCONSIN

Overview

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 greater than five megawatts (MW) in Wisconsin. Figure 1 shows generators greater than nine MW. Electricity providers also include those entities providing retail electric service or that self-generate electricity for internal use with any excess sold to a public utility.

Entities that submitted demand and supply data for this SEA include: American Transmission Company LLC (ATC), Great Lakes Utilities (GLU), Madison Gas and Electric Company (MGE), Manitowoc Public Utilities (MPU), Northern States Power-Wisconsin (NSPW) (d/b/a Xcel Energy, Inc. (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), and Wisconsin Public Service Corporation (WPSC).

These providers were required to include supply and demand data for any wholesale requirements that they may have under contract. This action streamlined data reporting and reflected current market activities. Demand and supply data were also provided by Dairyland Power Cooperative (DPC) and Wisconsin Public Power, Inc. (WPPI) on behalf of their member cooperatives and municipal utilities.

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

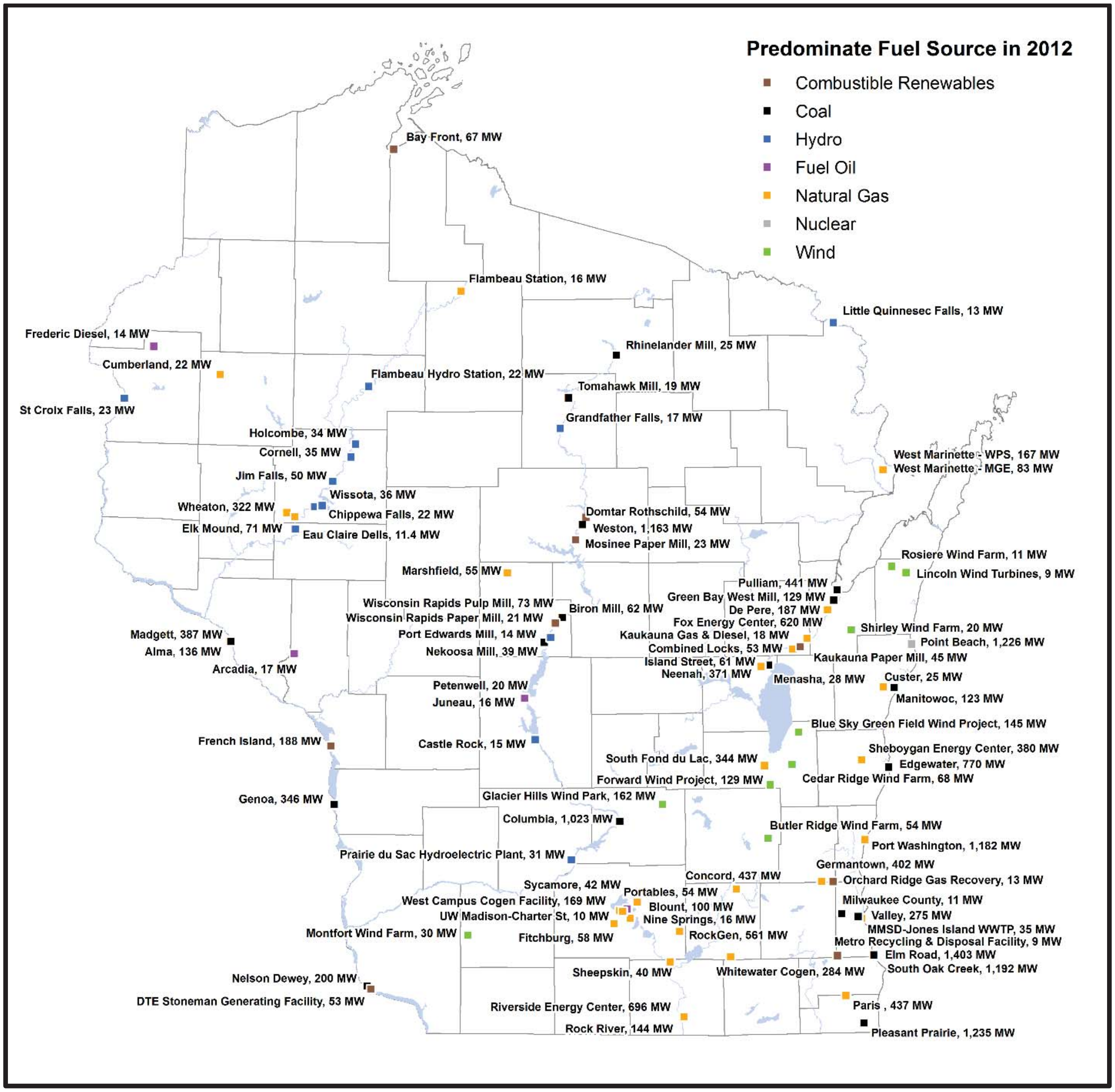


Table 1 shows the aggregated responses of the entities providing data for this SEA. The current planning reserve margin requirement for the MISO footprint is, after factoring in diversity factors, 14.8 to 15.0 percent for each load serving entity and is sufficient by MISO's standards to meet demand while maintaining reliability for the 2014-2016 period. Data for later years should be considered preliminary, because of the longer-term outlook and the very nature of contracting for supply arrangements. Wisconsin easily meets the MISO requirement for 2014-2016.

Table 1: Aggregated Responses of Entities Providing Data for this SEA

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
						Forecasted Planning Values				
Wisconsin Peak Electric Demand (MW)										
Date of Peak Load	July 20	July 17	July 18							
Peak Load Data & Forecast (non-coincident)	14,910	15,121	14,550	14,449	14,660	14,784	14,919	14,998	15,069	15,162
Direct Load Control Program	(108)	(84)	(65)	(135)	(136)	(137)	(137)	(138)	(138)	(139)
Interruptible Load	(179)	(188)	(287)	(620)	(661)	(657)	(658)	(660)	(661)	(663)
Capacity Sales Incl. Reserves	897	1092	841	797	758	750	660	656	656	656
Capacity Purchases Incl. Reserves	(604)	(663)	(614)	(555)	(462)	(452)	(327)	(327)	(327)	(327)
Miscellaneous Demand Factors	(127)	(121)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Adjusted Electric Demand	14,789	15,158	14,420	13,931	14,154	14,282	14,451	14,524	14,593	14,684
Electric Power Supply (MW)										
Owned Generating Capacity (in, or used, for Wis. cust.)	13,770	13,694	14,020	14,828	14,883	14,697	14,446	14,612	14,555	14,717
Merchant Power Plant Capacity Under Contract (in, or used, for Wis. cust.)	3,466	3,477	1,934	1,660	1,660	1,662	1,656	1,571	1,565	1,565
New Owned or Leased Capacity\Additions	53	77	630	129	139	138	129	129	791	129
Net Purchases W\O Reserves	(1,026)	(893)	(61)	104	369	522	436	393	287	288
Miscellaneous Supply Factors	(324)	(841)	37	65	(216)	(273)	(2)	(189)	(522)	15
Electric Power Supply	15,940	15,514	16,560	16,786	16,835	16,747	16,665	16,516	16,676	16,714
Calculated Data										
Planning Reserve Margin				20.5%	18.9%	17.3%	15.3%	13.7%	14.3%	13.8%
Transmission Data (MW)										
Resources Utilizing PJM/WUMS-MISO Interface	161	185	235	235	235	235	235	150	150	150

Source: Aggregated utility data responses, docket 5-ES-107

The examination of both peak demand figures for the recent past, and reserve margin forecasts in the future, confirms that Wisconsin has largely operated with a healthy level of reserves during the summer peak in recent history and is expected to continue to do so into the near future. Reserve margin forecasts are expected to remain above 13.7 percent through 2020. While some utilities have sufficient reserves beyond 2020, the independent needs of other utilities may result in proposals to build new generation to be in service before 2020.

Utilities' Perspectives – Peak Demand and Supply

DEMAND

The Commission compiled substantial information on peak electric demand and energy use for this report. Demand is a measure of instantaneous use measured in megawatts (MW). Energy is a measure of electricity volume used in megawatt hours (MWh) over a period of time. 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 a morning and an evening peak. Over the course of a year, demand for electricity is higher in the summer, lowest in the spring and autumn "shoulder" months, and a smaller peak occurs in the winter. Table 2 shows historic monthly peaks since 2003 and forecasted monthly peaks.

The peak load data presented in Table 1 and Table 2 do not necessarily show the same MW because different utilities may have different months in which their highest peak occurs. Table 1 shows the total of each utility's maximum peak within the year; Table 2 shows the maximum within a month.

Table 2: Assessment of Electric Demand and Supply Conditions—Monthly Non-Coincident Peak Demands, MW

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
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	10,897	10,391	9,937	9,480	10,420	12,183	14,576	14,377	12,681			
Forecasted:												
2013										10,251	10,356	11,013
2014	10,896	10,669	10,171	9,639	10,444	13,192	14,407	13,994	12,458	10,100	10,410	10,976
2015	10,989	10,779	10,276	9,764	10,586	13,366	14,589	14,170	12,619	10,235	10,547	11,115
2016	11,122	10,777	10,390	9,859	10,675	13,480	14,713	14,294	12,722	10,320	10,636	11,205
2017	11,218	10,967	10,484	9,955	10,778	13,605	14,848	14,426	12,836	10,413	10,731	11,305
2018	11,268	11,012	10,532	10,000	10,829	13,675	14,925	14,504	12,903	10,461	10,782	11,361
2019	11,316	11,090	10,574	10,041	10,871	13,735	14,998	14,580	12,967	10,503	10,824	11,403
2020	11,383	11,032	10,637	10,105	10,941	13,825	15,092	14,675	13,050	10,561	10,890	11,475

Source: Aggregated utility data responses, docket 5-ES-107

Using the projections provided by the entities submitting data for this SEA, this pattern of winter and summer peaks is expected to continue into the future. While actual demand will remain dependent upon weather, the overall statewide trend is expected to show continued growth in peak demand.

Utilities estimate increases in non-coincident peaks to be between approximately 0.5 and 1.2 percent. Non-coincident peak refers to the sum of two or more peak loads on a system that do not occur in the same time interval. The current SEA shows similar forecasts for peak demand growth as the last SEA, docket 5-ES-106.[4]

Programs to Control Peak Electric Demand

Wisconsin utilities have two forms of peak load management: direct load control and interruptible load. Peak load management involves removing load from the system at times when utility 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. In recent years, 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.[5]

Direct load management gives utilities the ability to take electric demand, such as residential air conditioners, off the system. When utilities implement direct load control, affected customers who volunteered to participate in the program receive a credit on their utility bill. Prior SEAs and Table 1 show that direct load control has been used sparingly. From 2011 through 2013, up to 108 MW of direct load control were called upon. As shown in Table 3, the MW of direct load control available to utilities is much greater than what was called upon.

Table 3: 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	147	614
Forecasted		
2014	135	620
2015	136	661
2016	137	657
2017	137	658
2018	138	660
2019	138	661
2020	139	663

Source: Aggregated utility responses and previous SEA reports

[4] These are utility forecasts; Commission staff does not do an independent demand or energy forecast.
[5] This is a general summary of how peak load management is used, though different utilities address the issue differently.

The second form of load management is the use of interruptible load for industrial customers. An industrial customer choosing an interruptible load tariff receives a lower electric energy rate in cents per kilowatt-hour (kWh) by agreeing that load may be interrupted during periods of peak demand on the system. A utility will notify an industrial customer on an interruptible load tariff that its load will be taken off the system at a specific time. Again, the actual MW of load that is interrupted in a given year is less than the MW of load that is covered by interruptible tariffs.

In any given year, the need to utilize this form of load control will depend upon generation supply that is available on the days when peak demand happens or when available generation is tight due to planned or unexpected (forced) outages. If the available tariffs are fully subscribed, by 2020 these programs would represent approximately 5.0 percent of projected electric power supply in Wisconsin. Historically, these numbers have been closer to 3.5 percent.

Peak Supply Conditions – Generation and Transmission

As indicated in Table 4, the 2015 planning reserve margin in Wisconsin is 18.9 percent. Even with the growth in peak summer demand indicated by the utilities through 2020, planning reserve margins are expected to be above 13.7 percent. In future years, the utilities will monitor and meet the MISO planning reserve margin for the following planning year.

Table 4: 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
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
2017							11.6	15.3
2018							13.3	13.7
2019								14.3
2020								13.8

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

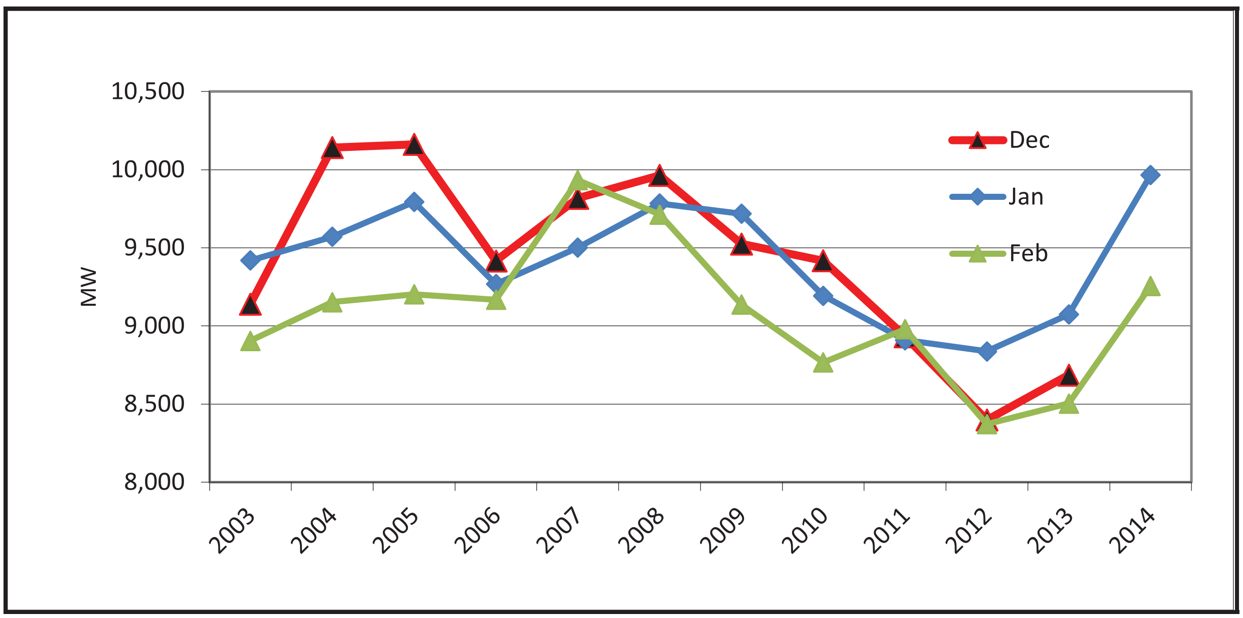
Source: Table 1 and previous SEA reports

In Appendix A of this report, Table A-1 shows new generation facilities and upgrades expected to be in operation or under construction by 2020. Table A-2 describes new transmission lines, and Table A-3 in Appendix A includes the utilities' listed retirements.

WINTER PEAK LOAD

Figure 2 shows the American Transmission Company (ATC) winter peaks since 2003 for the months of December, January, and February. December typically had been the winter peak because of Christmas and other holiday lighting. The winter peak declined since 2003 until Tuesday, January 7, 2014, when a new peak was reached due to unusually cold weather. The January 2014 peak was 1,000 MW more than the winter peak in 2013. Winter peak is usually 80-90 percent of the summer peak for Wisconsin utilities.

Figure 2: Monthly Winter Peaks – ATC[6]



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

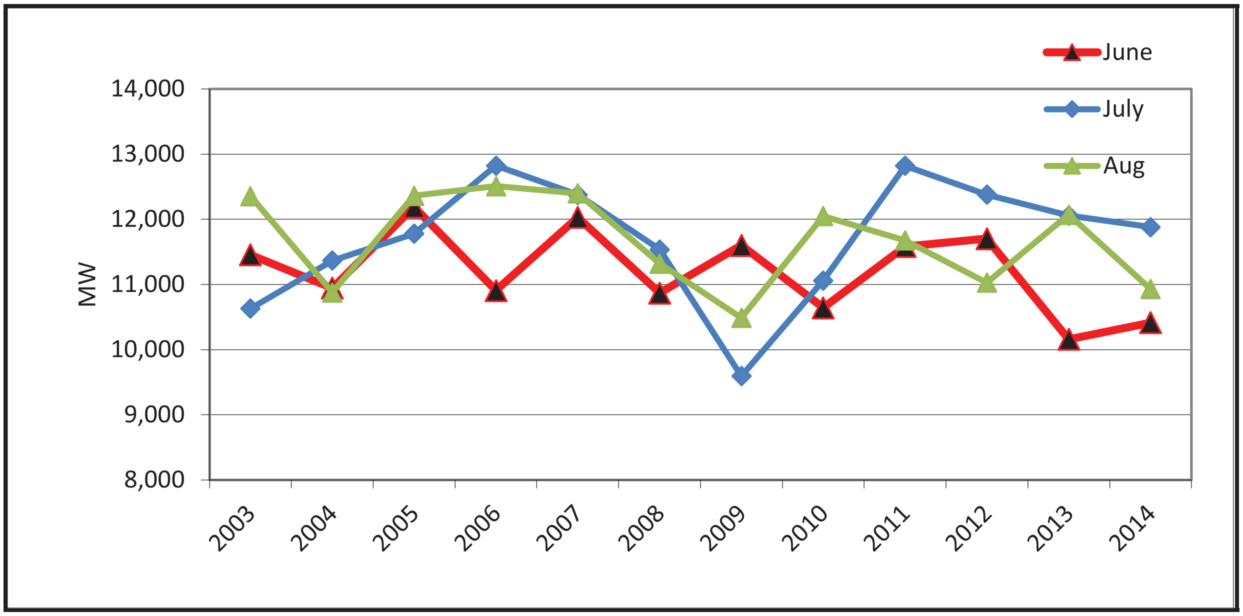
SUMMER PEAK LOAD

Figure 3 shows the ATC summer peaks since 2003 for the months of June, July, and August. The over 10 years of data summarized in the figure indicate that the Maximum Peak Demand is flat. The actual peak in the summer is temperature and humidity dependent, as these weather conditions affect air

[6] ATC Disclaimer: This load is the total of daily/hourly loads provided by MG&E, UPPCo, We Energies, WPPI, WP&L, and WPS. The load excludes any duplication of load reported between the entities. These values are not updated for load adjustments that occur over time.

conditioner load. This appears to indicate direct load control and interruptible load conservation have an effect on peak demand for the ATC utilities. Load management programs for DPC and Xcel are not reflected in the peak data. If peak data were analyzed from DPC and Xcel, it is expected that similar variations in annual peaks would occur, along with some dampening of the higher peaks due to load management activities of both DPC and Xcel and the geographic diversity of their territories.

Figure 3: Monthly Summer Peaks – ATC[4]



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

CURRENT GENERATION FLEET

Figure 4 and Figure 5 indicate the mix of generation available to Wisconsin utilities for the current SEA. Roughly 45 percent of Wisconsin's nameplate capacity is available through coal, with natural gas combustion turbine and combined cycle facilities providing over 35 percent of Wisconsin's nameplate capacity. The increased presence of renewable projects in Wisconsin, the shutdown of the Kewaunee nuclear plant, and the increased use of natural gas as a fuel source continues to change generation mix proportions in the state.

Figure 4: Wisconsin Generation Capacity by Fuel, January 2014 – includes generating units operated by IOUs, cooperatives, municipals, non-utilities, and merchants; total in service nameplate and uprate capacity (MW)

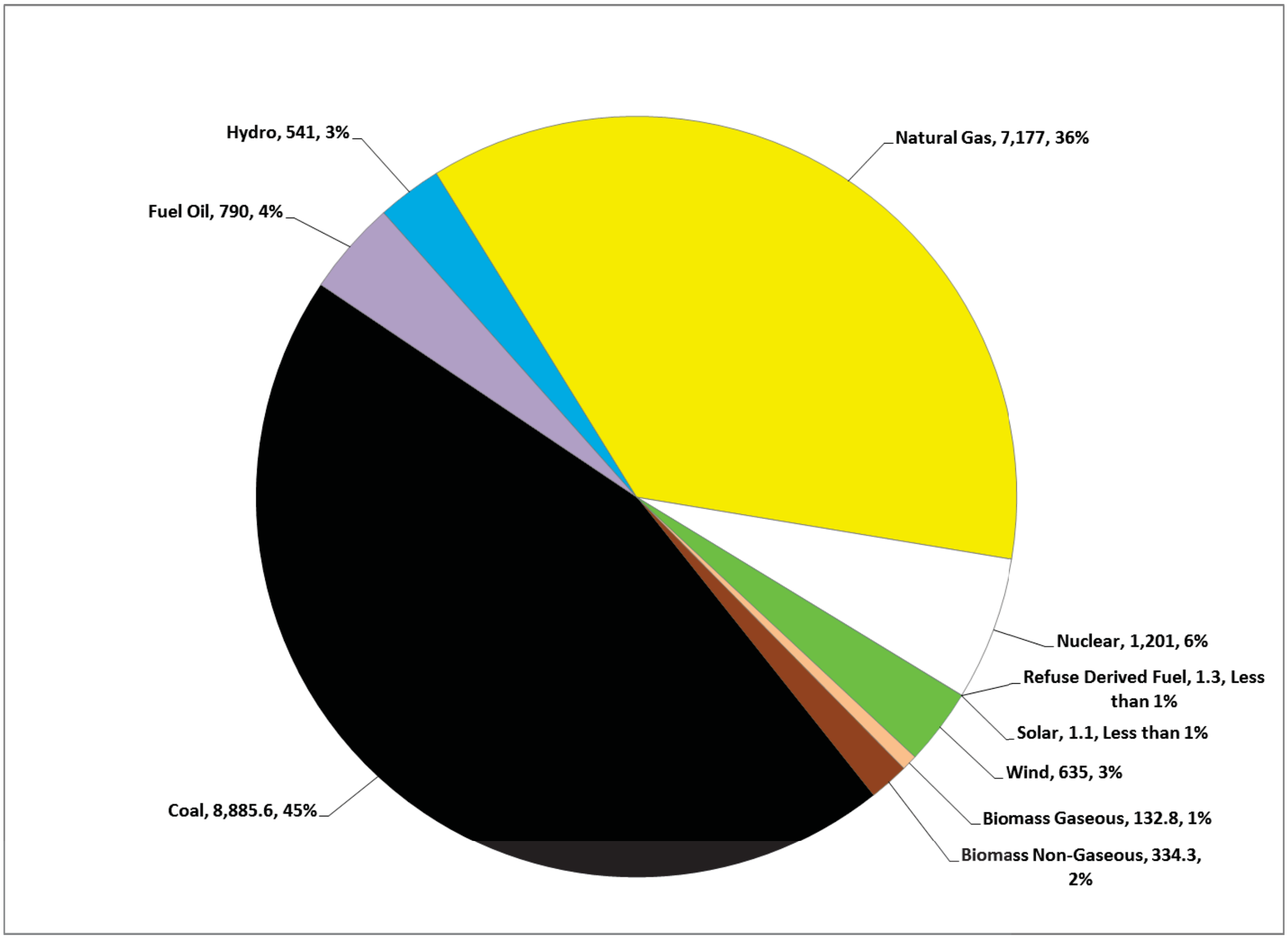
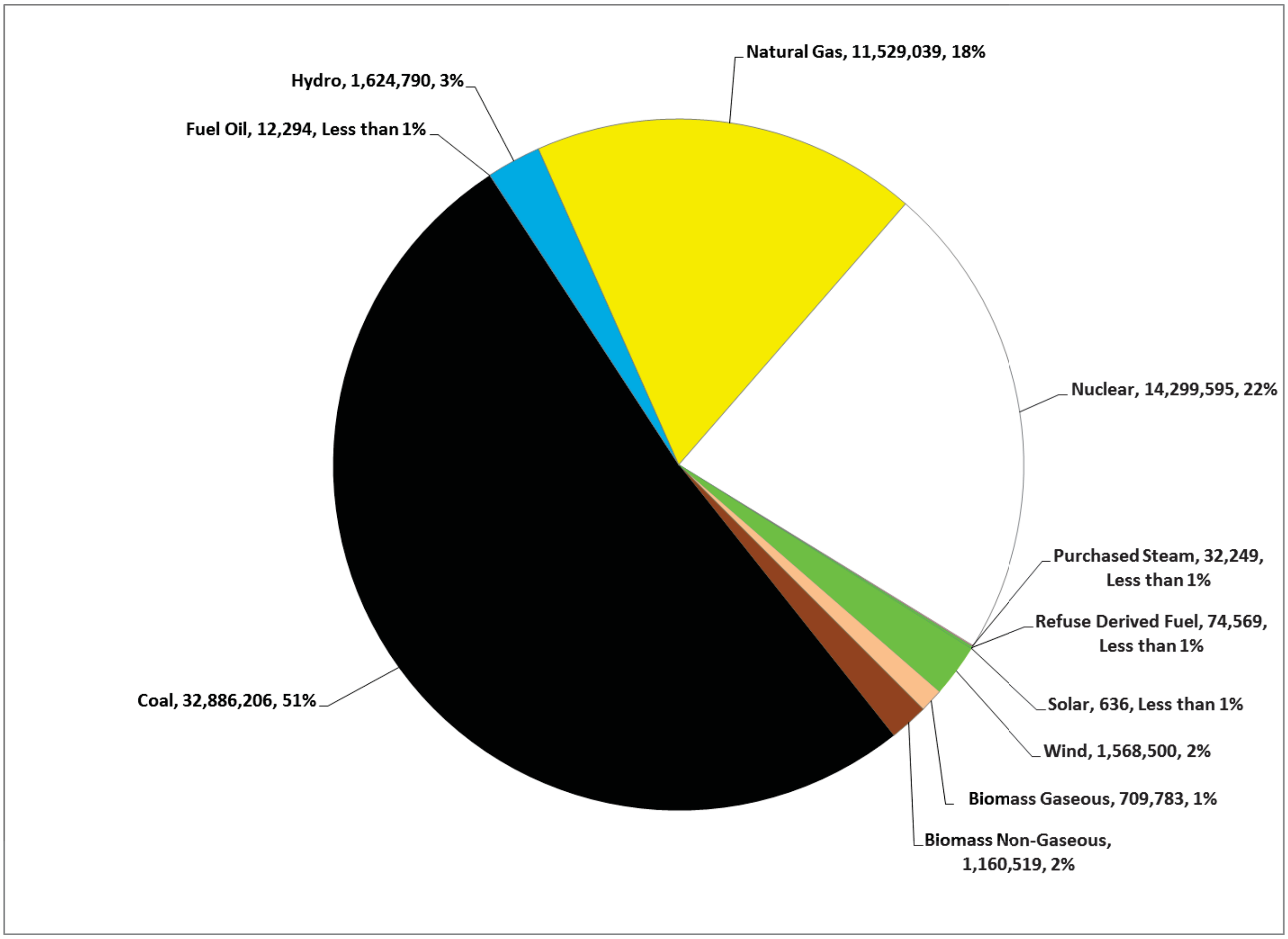


Figure 5 depicts actual generation by fuel from 2012. Approximately 50 percent of generation is supplied from coal, compared to 63 percent in 2010, and slightly less than 20 percent of actual generation comes via natural gas sources. Hydro resources for 2012 are lower than historical averages due to the lack of rainfall in 2012. It should be noted that while the nuclear capacity shown in Figure 4 includes Point Beach only, the nuclear generation depicted in Figure 5 includes Point Beach and Kewaunee.

Figure 5: Wisconsin Energy Generated by Fuel, 2012 – includes generating units operated by IOUs, cooperatives, municipals, non-utilities, and merchants (MWh)



NEW GENERATION[7]

Between the beginning of 2012 and this SEA, little new generation capacity for Wisconsin utilities has been brought into service. The one unit that became operational during that time was the Rothschild biomass facility, which began commercial operation in November 2013. The current SEA indicates new planned generation is in the form of additional combined cycle capacity after 2016.

Wisconsin utilities have prioritized generation construction and enjoy a healthy planning reserve margin and adequate capacity. They continue to balance newly added capacity against an economic downturn and subsequent slowing of energy demand growth. With Dominion's decision to close the Kewaunee nuclear plant and the pending retirements of several smaller and older coal facilities, a combined need for additional

[7] As noted in the introduction of this SEA, identification in the SEA of any application pending before the Commission or applications that the Commission anticipates receiving in the near future should not be construed as any indication of the Commission's potential approval or denial of those applications.

contracts and/or generation of 200-600 MW will appear beginning in 2016 and extending into 2019 for some Wisconsin utilities. These utilities are in the process of formulating their plans, to be approved by the Commission, to meet their upcoming capacity and energy requirements.

EMISSION CONTROL AND GENERATION FACILITY UPGRADES

Wisconsin generators continue to face the task of updating their current coal facilities to comply with federal emissions requirements. Table 5 indicates the current status of completed and expected major emission control projects at Wisconsin's power plants as of January 2014.

Table 5: Major Emissions Control Projects* at Wisconsin Utilities' Power Plants

Unit Name	Utility Owner	Project Status	Type of Emission Control**	Year of Commercial Operation	Estimated Cost (in $million)
Pleasant Prairie 2	WE	Complete	SCR	1985	$72.5
Pleasant Prairie 1 & 2	WE	Complete	SCR/FGD	1981-1985	$291.4
Oak Creek 5	WE	Complete	SCR/FGD	1959	$830.0
Oak Creek 6	WE	Complete	SCR/FGD	1961	Included in above
Oak Creek 7	WE	Complete	SCR/FGD	1965	Included in above
Oak Creek 8	WE	Complete	SCR/FGD	1967	Included in above
Edgewater 5	WP&L	Complete	SCR	1985	$153.9
Edgewater 5	WP&L	Under Construction	FGD	1985	$440.0
Columbia 1	WP&L/WPSC/ MGE	Under Construction	FGD	1975	$627.0
Columbia 2	WP&L/WPSC/ MGE	Under Construction	FGD	1978	Included in above
Columbia 2	WP&L/WPSC/ MGE	Application Received	SCR	1978	$150.0
Weston 3	WPSC	Complete	Baghouse	1982	$26.0
Weston 3***	WPSC	Under Construction	FGD (ReAct)	1981	$345.0
Presque Isle Units 5-9****	WEPCO	Approved/ Pending	Air Quality Control System	1974-1979	TBD
John P. Madgett	DPC	Complete	Bag House	1979	$50.0
John P. Madgett	DPC	Under Construction	SCR	1979	$92.0
John P. Madgett	DPC	Under Construction	DSI/PACI	1979	$25.0
Genoa #3	DPC	Complete	Bag House	1969	$50.0
Genoa #3	DPC	Complete	Dry Scrubber	1969	$75.0
				Total	$3,227.8

*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 WPS.
****Presque Isle docket 6630-BS-100 was approved on June 21, 2013. The docket was subsequently reopened after WEPCO announced its desire to suspend operations at Presque Isle. The approved cost was $130-$140 million in exchange for receiving approximately a one-third undivided ownership interest in Presque Isle Power Plant. WEPCO and Wolverine subsequently cancelled their Joint Agreement, and the continued operation of Presque Isle is now under review.

In December 2005, the Nuclear Regulatory Commission (NRC) granted a license extension to Point Beach Nuclear Power Plant Units 1 and 2, which authorizes the Point Beach facility to operate until at least 2030. The Kewaunee Nuclear Power Plant was granted a license extension in February 2011, which authorized it to operate until at least 2033. In May of 2013, the Kewaunee Nuclear Power Plant owner, Dominion, shut down the plant due to economic concerns.

THE GENERATION PICTURE

Wisconsin finished a cycle (during the late 1990's and early 2000's) of building new generation capacity in order to adequately address past capacity limitations and installing emission controls on large coal fired units. Wisconsin utilities face an ongoing challenge – compliance plans to meet new EPA rules. Within this challenge lies a potential opportunity for Wisconsin to work with other states on a coordinated compliance plan that sets a reasonable timeline for meeting EPA requirements while minimizing customer costs. Since Wisconsin has mostly completed its construction cycle, newer units in Wisconsin have a benefit over generation located in other parts of the MISO footprint because these Wisconsin units have environmental controls that likely will be in compliance with imminent EPA requirements. We do not know how anticipated carbon regulations will affect this situation. Other states may not be as well positioned with their capacity mix in the near future, and Wisconsin utilities may increasingly serve as energy exporters if other states become capacity strapped in the next few years. MISO has expressed concern over capacity shortfalls in the MISO footprint. Decisions of retirement, mothballing, emission retrofits, or new generation in the MISO footprint are discussed within several forums at MISO and the Organization of MISO States (OMS). Nonetheless, additional analysis is needed to identify realistic assumptions about the benefits that may flow to ratepayers from this capacity and energy.

Wisconsin utilities generate a strong majority of our state's daily electricity. Depending on the exact compliance rules implemented as part of EPA's environmental regulation, Wisconsin utilities may have to respond with new or retrofitted generation facilities that meet all the emission restrictions to continue operation.

TRANSMISSION SYSTEM PLANS, ISSUES, AND DEVELOPMENTS

Locations and Descriptions of Proposed Transmission Projects

By state statute, this SEA is required to report all transmission lines designed to operate at voltages above 100 kilovolts (kV) on which transmission providers propose to begin construction before 2020, subject to Commission approval. ATC, a stand-alone transmission company created in 2001 and the largest transmission provider in Wisconsin, provided data for this SEA together with DPC and Xcel, which are the other transmission owners in Wisconsin. "Construction" refers to building new lines, rebuilding existing lines, or upgrading existing lines.

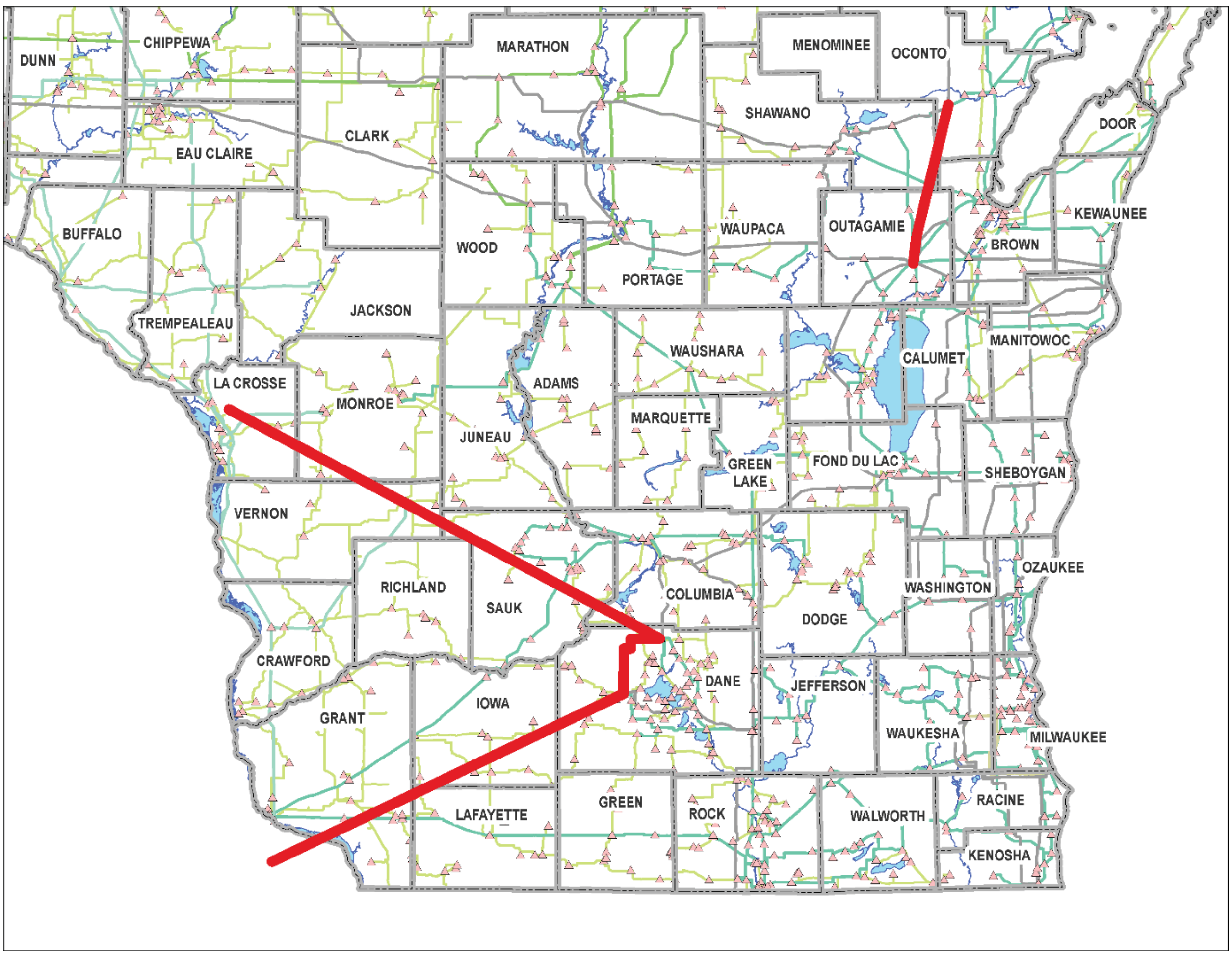
Beyond new construction, the Commission oversees rebuilding or upgrading existing lines, which may also require new structures or new right-of-way (ROW). To rebuild a line means to modify or replace an existing line; in other words, to keep it at the same voltage and improve its capacity to carry power through new hardware or design. To upgrade an electric line means to modify or replace an existing line, but at a higher voltage. An upgrade also improves the line's capacity to carry power. Both rebuilding and upgrading may require some (or many) 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 may include one or more of the following:

- 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 needed increased capacity of existing transmission lines;
- Aging of existing facilities that has resulted in reduced reliability due to poor condition;
- Maintenance of system operational security for the loss of one or more transmission or generation elements;
- Increased power transfer capability or access;
- Increased access to support the use of renewable energy;
- Improved economics or increased market efficiency in the markets;
- Generation interconnection agreements and transmission service requirements for proposed (or approved) new power plants;
- Maintenance and assurance of local reliability when older generation is retired; and
- Maintenance of transmission system reliability and performance.

In general, the higher a line's voltage, the more power it can carry and the fewer losses occur. As a consequence, the higher voltage transmission lines are important in delivering large amounts of power on a regional basis, and the lower voltage lines primarily deliver power over a more limited area. 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 Appendix A shows new electric transmission lines on which construction is expected to start by 2020 in Wisconsin if approved by the Commission. Three ATC 345 kV projects are shown in Figure 6: Badger Coulee: La Crosse area-North Madison-Cardinal; Cardinal Bluffs: Dubuque County area-Cardina; and Bay Lake: North Appleton-Morgan.

Figure 6: Illustration of Extra High Voltage Transmission Project Applications Filed or Expected by Commission

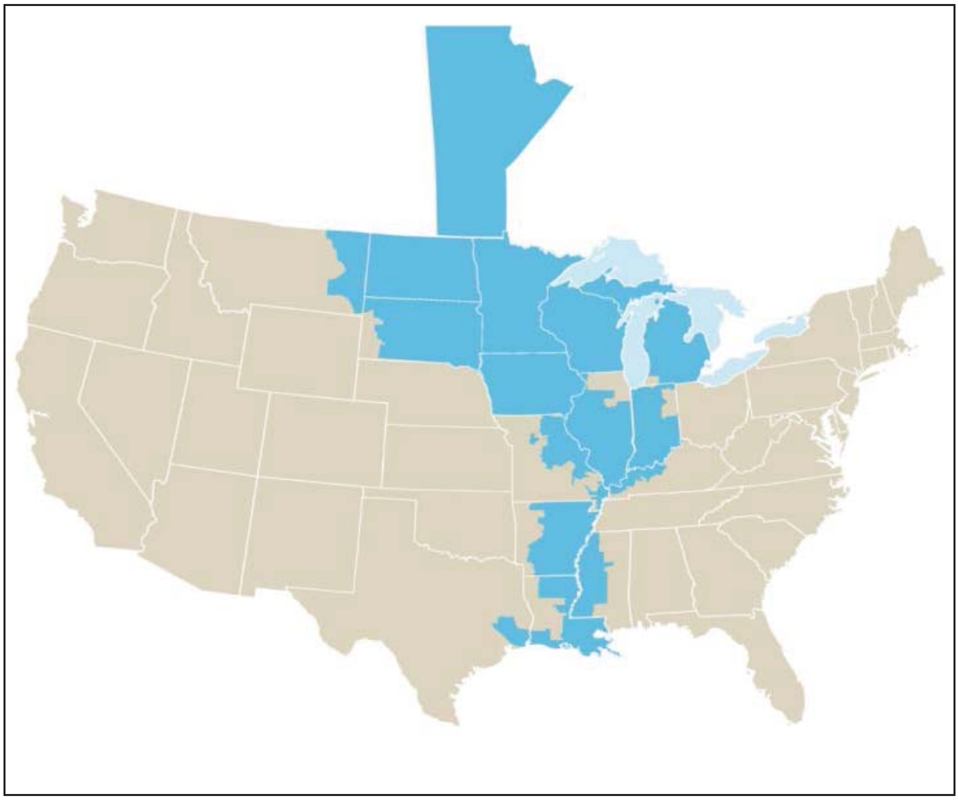


Source: Recreated from ATC 10-Year Transmission System Assessment, September 2013, pp. 22-23. Proposed transmission projects are graphic representations and do not reflect actual routes.

Transmission Planning in the Midcontinent

The Midcontinent Independent System Operator (MISO) is a not-for-profit, member-based organization that administers a wholesale electricity market and is the NERC (North American Electric Reliability Corporation) Reliability Coordinator for the MISO footprint. As shown in Figure 7, the MISO reliability footprint consists of 15 states and one Canadian Province. The footprint expanded in 2013 with the integration of parts of the states of Arkansas, Mississippi, Louisiana, and Texas.

Figure 7: MISO Reliability Footprint



Source: www.misoenergy.org

MISO has functional control of the region's bulk electric system, including both transmission planning and generation dispatch. MISO controls reliability operations (engineering aspects) for approximately 196,824 MW of generation capacity in a reliability footprint with a peak load of approximately 133,368 MW. The energy and operating reserves markets had gross annual charges of $18.4 billion in 2012 for 526 Terawatt hours in annual billing. Membership in MISO includes 46 transmission owners and 97 non-transmission owners. The total membership area includes 65,787 miles of transmission lines and 43,656 network buses. MISO's operations team performs a "what-if" contingency analysis every four minutes for 11,500 potential contingencies.

MISO TRANSMISSION PLANNING – OBJECTIVES AND SCOPE[8]

The MISO transmission expansion planning (MTEP) process, a collaborative process among MISO planning staff and stakeholders, is an ongoing comprehensive expansion plan that is designed to ensure the reliable

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

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. MTEP13 is the 10th edition of the process. The six MISO planning principles are as follows:

- Make the benefits of a competitive energy market available to customers by providing access to the lowest possible energy costs;
- Provide a transmission infrastructure that safeguards local and regional reliability;
- Support state and federal renewable energy objectives by planning for access to all such resources (e.g. wind, biomass, demand-side management);
- Create a cost allocation mechanism to ensure costs are allocated roughly commensurate with expected benefits;
- Develop a transmission system scenario model and make it available to state and federal energy policy makers to provide context and information regarding potential policy choices; and
- Coordinate transmission planning with neighboring planning regions to support more efficient and cost-effective solutions.

The MTEP process provides an annual report which identifies a number of transmission projects that are being planned or alternatives being considered. The planning process is conducted at many different levels, including special task forces, work groups, sub-committees, and, finally, the Advisory Committee.[9] 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, the Federal Energy Regulatory Commission (FERC), other relevant government entities, and state commissions as appropriate.

INVESTMENT OVERVIEW AND SUMMARY

MTEP13 contains 317 new projects that total an incremental $1.48 billion in transmission facilities. The following is a summary of the three categories of projects:[10]

- Baseline Reliability Projects (BRP) – projects required to meet North American Electric Reliability Corporation (NERC) reliability standards – 79 projects; $372 million;
- Generator Interconnection Projects (GIP) – projects required to reliably connect new generation to the transmission grid – 3 projects; $15 million; and

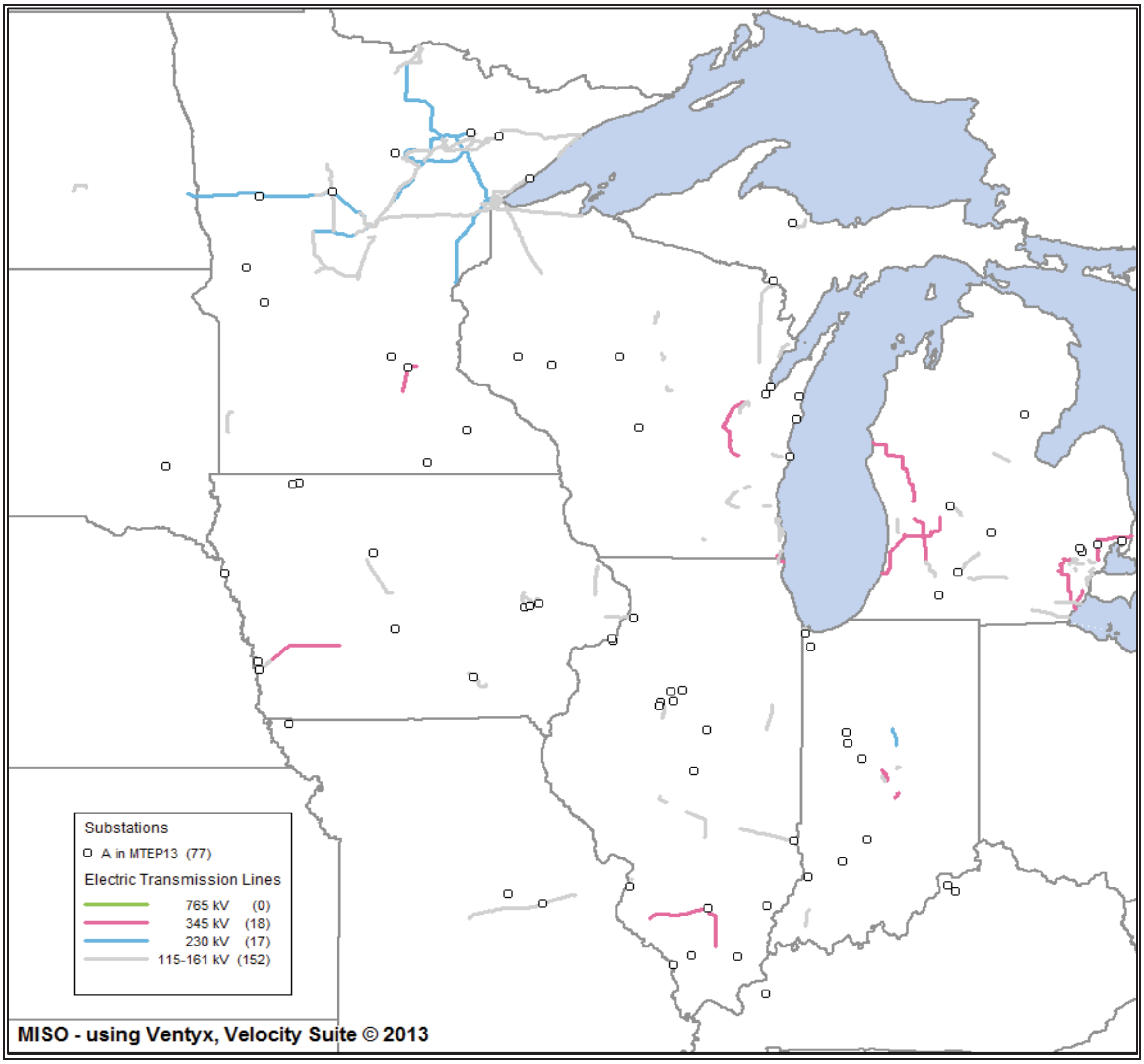
[9] The Advisory Committee is a forum for its members to be apprised of MISO's activities and to provide information and advice to the management and Board of Directors of MISO on policy matters of concern to the Advisory Committee, or its constituent stakeholder groups. Neither the Advisory Committee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

[10] These projects have been approved by MISO, but have not received Commission approval. Cost allocation of the projects is controlled by federal tariffs which vary by category.

- Other Projects – wide range of maintenance projects and lower voltage projects, such as those designed to provide local economic benefit – 235 projects; $1.1 billion.

Figure 8 is for illustration purposes only to show the location of new transmission and substation projects approved in MTEP13 but does not include all projects. The details of all the approved projects can be found in MTEP 13 Appendix A.

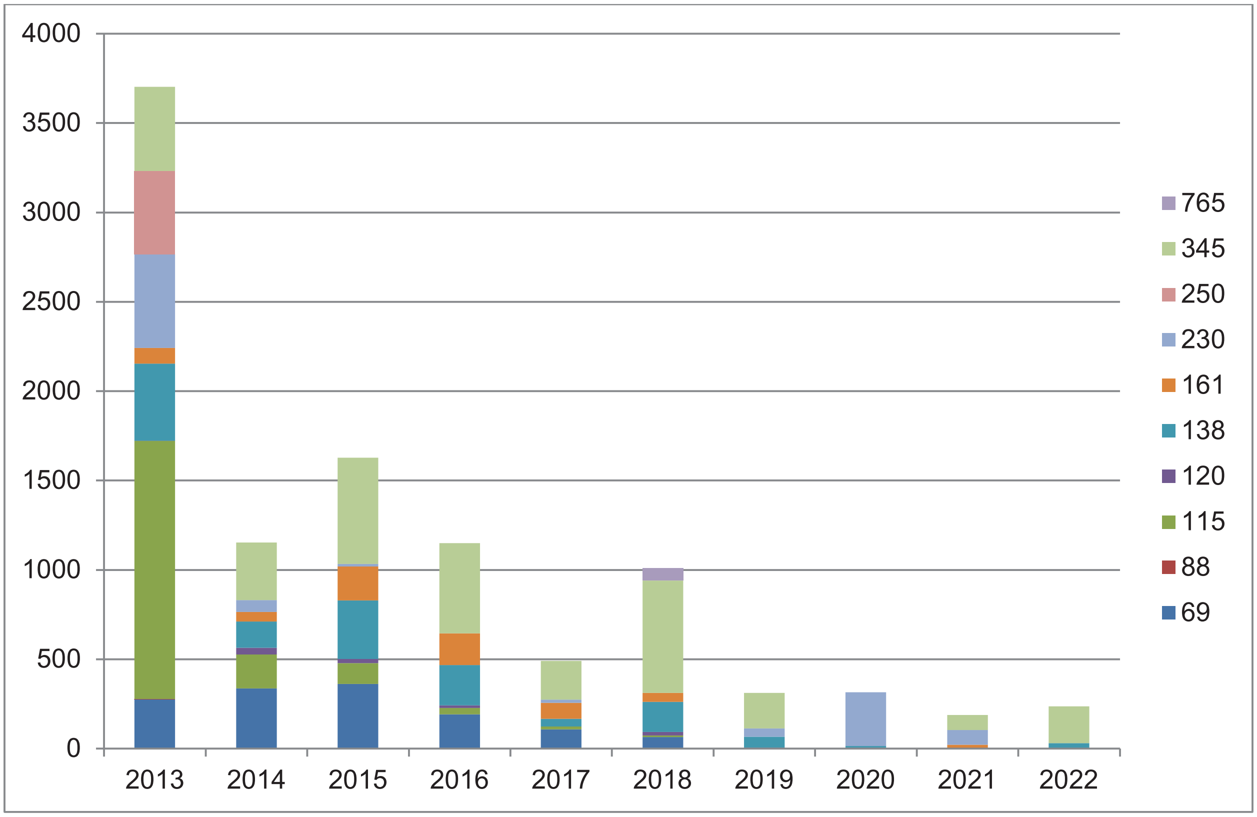
Figure 8: Map of New MTEP13 Appendix A Projects



Source: www.misoenergy.org

The planning horizon is 10 years, and there are approximately 10,442 miles of new or upgraded transmission lines envisioned for that time period. Before the southern region integration, the MISO transmission footprint consisted of approximately 49,500 miles. Of the upcoming planned projects, 6,548 miles of upgraded transmission lines are on existing corridors, and 3,894 miles of new transmission lines are planned on new corridors. Figure 9 shows the mileage by voltage class and MTEP planning year.

Figure 9: New or Upgraded Line Mileage by Voltage Class (kV) through 2022

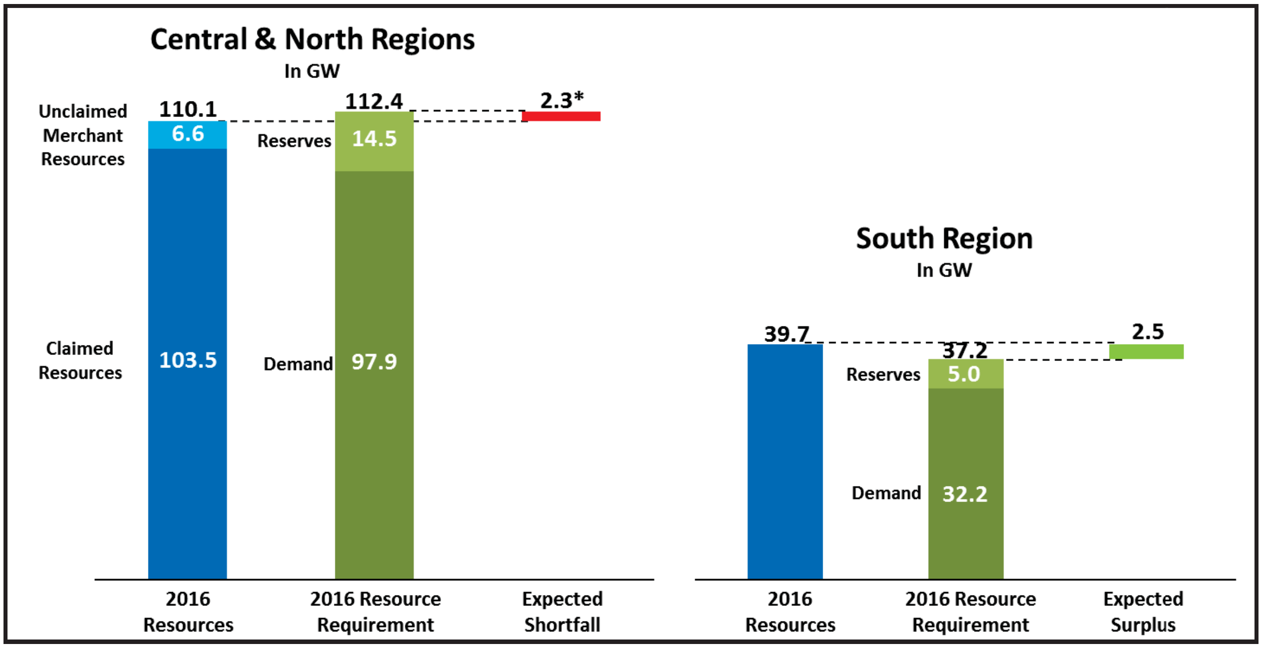


Source: www.misoenergy.org

LONG TERM RESOURCE ASSESSMENT

MISO has been monitoring and studying potential impacts of a variety of state and federal regulations on resource adequacy since 2011. MISO collected confidential information from generation owners for an EPA compliance survey and for a long-term reliability assessment with load serving entities (LSE) in conjunction with the Organization of MISO States (OMS). The LSE survey continues to be reviewed for updates. The MISO projected planning reserve requirement is about 14.8 percent. Results that MISO released in June 2014 indicated a potential 2.3 GW reserve shortfall for the Central and North Regions and an expected 2.5 GW surplus for the South Region, beginning in 2016. This indicates the complete MISO footprint is close to the targeted planning reserve level. The ability of the individual Local Resource Zones to provide or receive capacity is being monitored. Data gathered from Wisconsin entities for the purposes of this SEA show that Wisconsin is not likely to have a shortfall. Figure 10 illustrates the relative relationships of the regions concerning their resources, demand and reserve requirement.

Figure 10: MISO Resource Adequacy Forecast – as of June 2, 2014



*A shortfall figure means that the probability of a loss of load event increases. A 2.3 GW shortfall would result in a 12.5 percent PRM, resulting in approximately a .2 day/year probability of a loss of load event.
Source: www.misoenergy.org

The MISO/OMS survey is a work in progress, with several measures being investigated in order to ensure adequate resources are available to all of the local planning zones. Some of MISO's next steps to expand available resources include:

- Evaluate potential solutions to capacity resources that are limited by energy only interconnection service;
- Establish more specific availability and use conditions for load modifying resources;
- Establish South to Central/North capacity transfer limits and respective conditions;
- Eliminate barriers to efficient capacity transactions across seams; and
- Continue to refine and standardize the survey process to improve transparency.

NORTHERN AREA STUDY & MANITOBA WIND SYNERGY STUDY

The Northern Area Study (NAS) was a regional assessment that originated from two situations: the Blackout of the Upper Peninsula of Michigan in 2011, and the proposal by Manitoba Hydro for injection of new hydro generation into the MISO footprint for energy and to complement MISO's wind resources. The NAS included both economic and reliability components in the analysis. The analysis found that there was no large-scale transmission expansion in the Dakotas, Minnesota, Wisconsin and Michigan areas that was cost-effective from a market production cost standpoint under the business as usual scenario. Various stakeholders suggested to MISO 38 different transmission options for evaluation. The

NAS did find some economic benefit to some incremental transmission from Manitoba Hydro for new incremental generation.

The Manitoba Hydro Wind Synergy Study provided an assessment of what impact approximately 2,000 MW of new Canadian hydro generation would have in the MISO market by supplementing the variability of wind on different time scales. This included a bidirectional tie back to Canada. The study found that substantial benefits could be realized by adding a 500 kV tie from Canada south of Winnipeg to north eastern Minnesota or to western Minnesota/Fargo North Dakota. This project is being evaluated in MTEP14.

FEDERAL ENERGY REGULATORY COMMISSION (FERC ORDER 1000)

FERC issued Order 1000 on July 21, 2011, to reform FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. FERC subsequently issued a clarification Order 1000-A that made additional policy changes affecting transmission projects which are cost shared across the MISO footprint.

MISO believes it is mostly compliant with FERC Orders 1000 and 1000-A. MISO's initial FERC compliance filing was made on October 25, 2012. MISO's Interregional Compliance Filings were made on July 10, 2013, and the Regional Compliance Filing was made July 22, 2013. Beginning in 2013, states have a recognized role in MISO transmission planning. The Organization of MISO States (OMS) has a more clearly defined role in the MISO transmission planning process. Individual states will continue to have input through their need certification process and their involvement with OMS.

FERC Orders 1000 and 1000-A specifically require:

- Public utility transmission providers participate in a regional transmission planning process to produce regional plans;
- Local and regional transmission planning processes consider state and federal public policy requirements; and
- Public utility transmission providers coordinate with neighboring regions to determine whether more efficient or cost-effective solutions are available for their needs.

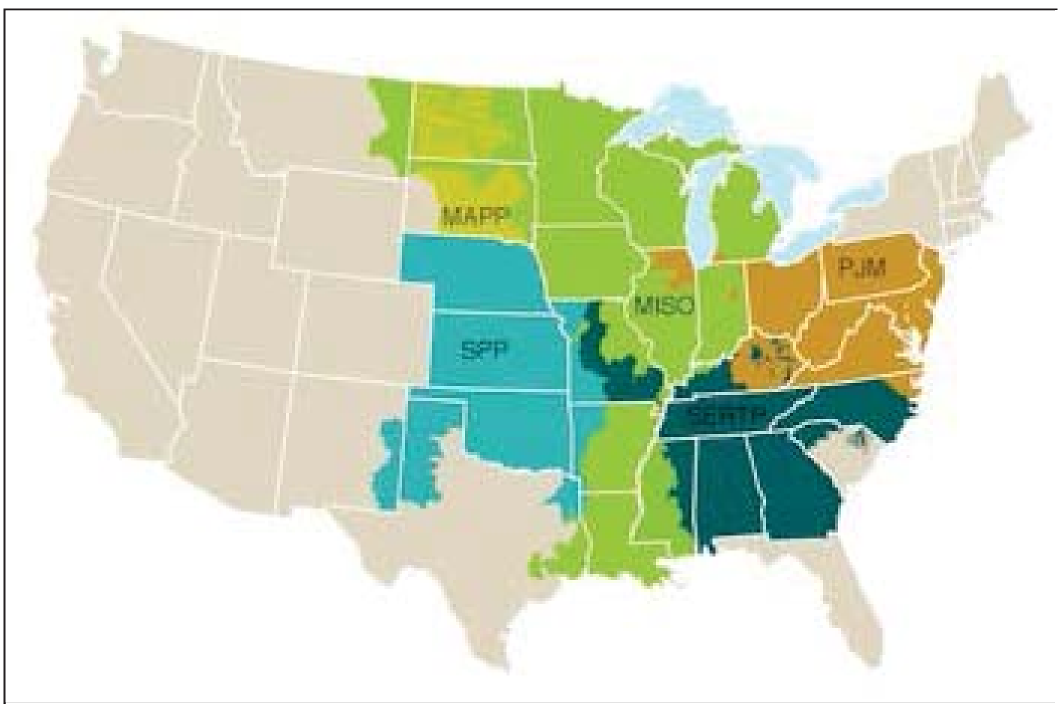
FERC Orders 1000 and 1000-A establish cost allocation principles for regional and interregional transmission facilities as well as for any transmission project that is cost-shared. The allocated costs should generally be commensurate with established benefits. Different types of transmission facilities can have different allocation methods. FERC issued a subsequent clarification order, 1000-B, on October 18, 2012, that affirms the requirements of Orders 1000 and 1000-A, including that each utility transmission provider must participate in a regional planning process. Furthermore, Order 1000-B affirms that transmission facilities located in two neighboring transmission planning regions be jointly evaluated by the two regions in the interregional transmission coordination process.

A key item that has emerged with FERC Order 1000 is the removal of any federal rights of first refusal from FERC-approved tariffs and agreements for transmission projects that are cost-shared. Essentially, the FERC orders require that any cost-shared project be subject to competitive evaluation in order to reduce costs to ratepayers. In MISO's October 2012 draft-tariff wording, transmission projects that are Market Efficiency Projects or Multi Value Projects will now have to participate in a developer selection process by MISO.

Because FERC requires projects that are cost-shared to be subject to competitive bidding, MISO is proposing that cost shared Baseline Reliability Projects no longer be cost-shared, and that the incumbent utility have the sole right to build any reliability projects. That is, there would be no competitive bidding. The elimination of cost-sharing for large baseline reliability projects is a controversial policy issue and has created discrepancies for cross-border transmission planning. Within MISO, most transmission-owning utilities support the MISO-proposed change, as they want to ensure that some projects will remain within their sole-construction jurisdiction. The U.S. Court of Appeals for the D.C. Circuit upheld Order 1000 on August 15, 2014.

Figure 11 shows the major interregional planning entities. Southern region transmission and load has recently merged into the MISO footprint.

Figure 11: Interregional Planning Entities



Source: www.misoenergy.org

MARKET ANALYSIS AND PLANNING RESERVE MARGIN FORECASTS

This section provides an assessment of Wisconsin's electric industry as it addresses four of the topics mandated by law. Wisconsin Stat. § 196.491(2)(a) specifically requires the SEA to assess: (1) the extent to which the regional bulk power market is contributing to the adequacy and reliability of the state's electrical supply; (2) the adequacy and reliability of purchased generation capacity and energy to serve the needs of the public; (3) the extent to which effective competition is contributing to a reliable, low cost, and environmentally sound source of electricity for the public; and (4) whether sufficient electric capacity and energy will be available to the public at a reasonable price. The following sections address these concerns. The analysis incorporates data submitted by the electricity providers for the SEA and other data collected by Commission staff.

Extent to which Regional Bulk Power Market Contributes to Adequacy and Reliability of Wisconsin's Electric Supply

Adequacy and reliability are expected to remain satisfactory with an acceptable planning reserve margin forecast through 2020. This assumes that retirements associated with the implementation of various EPA air and water quality rules do not force dramatic fossil fuel plant closings in Wisconsin or elsewhere. Data in this SEA show that planning reserves are expected to be at least 13.7 percent for the 2014-2020 time period, but other factors subsequent to the initial data presented here may change the margin. It should be noted that this forecast is predicated on load serving entities entering into additional contracts and/or generation of 200-600 MW beginning in 2016 and extending into 2019 for some, but not all, of the Wisconsin utilities.

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 the year ahead (14.8-15 percent for 2014-2016). Planning reserve margins in later years are often finalized through capacity purchases made a short time ahead of any shortfall. Planning reserve data filed in this SEA actually show that Wisconsin in the near term is experiencing a surplus, with expected planning reserve margins exceeding 17 percent. The generally high reserve margins can be linked to a strong construction program from 2000 to 2010, effective energy efficiency and conservation programs, and moderate demand growth.

Sufficient capacity is only part of the equation. Getting power from the generation source to customers is the other part. The current state of Wisconsin's transmission system was addressed in the previous section of this SEA, and it showed that the transmission system is able to deliver capacity and energy to customers without unusually large amounts of congestion or electricity losses.

Adequacy and Reliability of Purchased Generation Capacity and Energy to Serve Public Needs

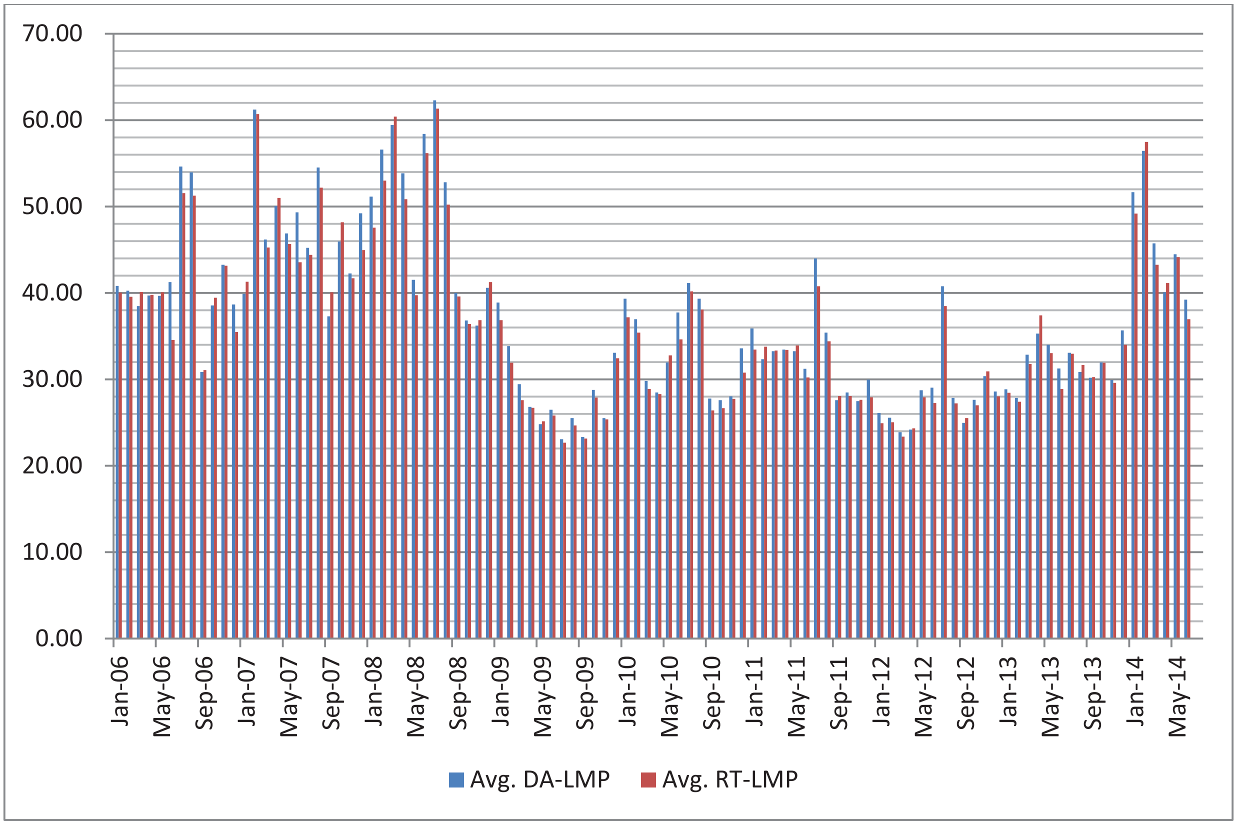
Generation capacity and energy may be purchased from facilities located within or outside of Wisconsin. Given the current surplus in Wisconsin's generating capacity, it is unlikely that new purchased power capacity agreements will be required in the near future. Currently, there seems to be an adequate and reliable supply of purchased generation and energy to serve the public's needs. This changes, however, in 2016-2019 when WP&L and WPS may require new generation, either owned or under contract. The Commission expects these utilities to use a robust Request for Proposal process for purchased capacity as part of any application to build utility-owned assets. In addition, due to compliance with the Renewable Portfolio Standard (RPS), purchases of renewable energy via purchase power agreements may still be required.

Extent to which Effective Competition Contributes to a Reliable, Low Cost, and Environmentally Sound Electricity Source[11]

The issue of reliability has been addressed in previous sections of this report. This section focuses on low cost and environmentally sound requirements for energy, found in Wisconsin statutes. 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 utilities are part of MISO. For a broader view of the complete MISO wholesale energy market, Figure 12 displays wholesale energy market prices in MISO since the start of the first year of the market beginning in 2006.

Figure 12: MISO System-wide Average Monthly Day-Ahead and Real-Time LMPs

[11] 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."



Source: Commission staff, using data from MISO portal.

A report by MISO's independent market monitor (IMM), entitled "State of the Market 2013," published in June 2014, provides evidence that MISO's wholesale energy markets were competitive with market clearing prices within 1.70 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 0.1 percent of actual load) which could effectuate non-competitive prices.[12]

The final topic in this section is an assessment of whether competitive markets 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, 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.

The EPA has promulgated rules that regulate utility emissions of a number of pollutants such as sulfur dioxide (SO2), nitrogen oxide (NOX), particulate matter and mercury. The Commission is also in the process of working with other states and interested stakeholders in our region on compliance with 111(d) regulations under the

[12] Potomac Economics, Dr. David Patton, *2013 State of the Market Report for the MISO Electricity Markets*, June 2014.

Clean Air Act. On June 2, 2014, the EPA proposed a draft rule designed to reduce CO2 emissions from the existing fleet of electric generating units by 30 percent from 2005 levels. The overall goal is achieved through standards developed for each state. Each state has a different goal based on the application of a formula using “building blocks” to determine a state reduction capability. The Building Blocks include:
BLOCK 1: Improve efficiency of existing coal plants;
BLOCK 2: Increase reliance on combined cycle gas units;
BLOCK 3: Expand use of renewable resources and sustain nuclear power production; and
BLOCK 4: Expand use of demand-side energy efficiency.

The plan establishes a compliance time period, with a final target in 2030. The rule identifies a variety of ways to meet the targets, including the building blocks, as well as through interstate cooperation. Compliance costs will be incurred by all MISO market participants who are obligated to comply with these EPA rules.

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

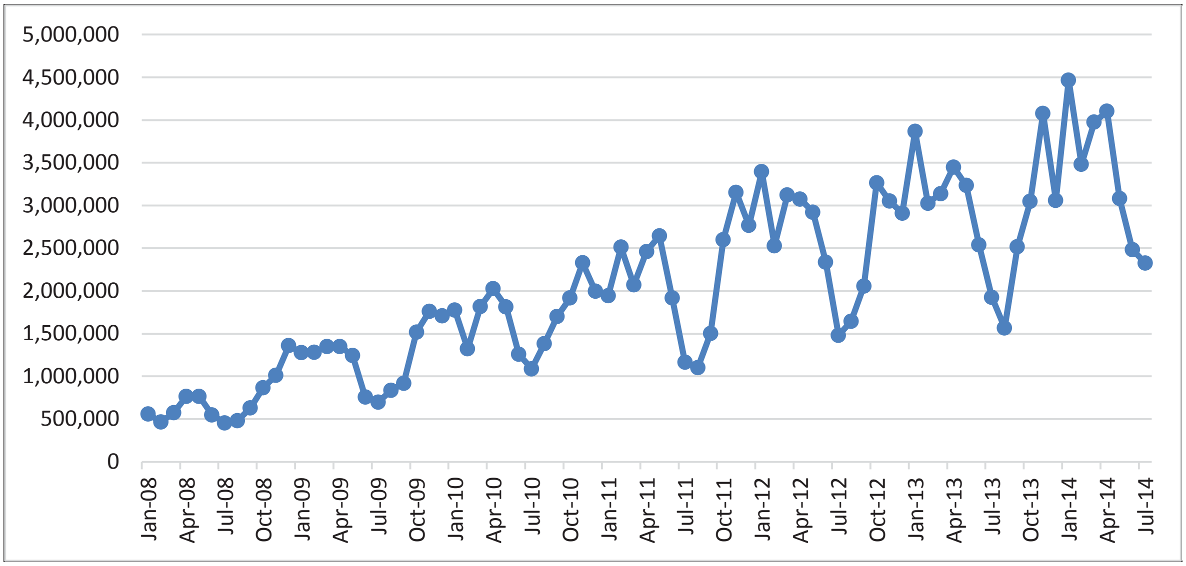
As noted in Table 1, planning reserve margins are projected to be at least 13.7 percent through 2020. The magnitude and the mix of new electric generation appear to answer the statutory concern about sufficient capacity in the affirmative. Wisconsin’s electric generation supply future appears sufficient.

In regard to the finding on reasonable price, the Commission reviews all purchase power contracts for public utilities either during the formal rate case process or, if asked, rules on them before implementation, such as during a construction case.[13] As for units that are constructed, the Commission reviews and makes sure that costs associated with 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.

The state has implemented an RPS that requires 10 percent of energy must come from defined renewable energy resources by the year 2015. This requirement affects Wisconsin’s optimal energy expansion path. Wind energy has accounted for most of the utilities’ renewable energy. Wind energy has low marginal costs of generation, but it has intermittent availability. Figure 13 displays the growing presence of wind energy in the MISO footprint as well its variability due to changes in seasonal weather. During the public comment phase for this SEA, some noted that wind generation falls off significantly during the summer months of July and August. This can be especially true during a heat storm when a large high pressure unit sets in with little storm activity or cool fronts such that the wind breeze is too slight to ramp up a wind turbine. Also of note is that during late fall to early spring when weather fronts are more actively crossing the MISO footprint, wind generation picks up noticeably.

[13] 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.

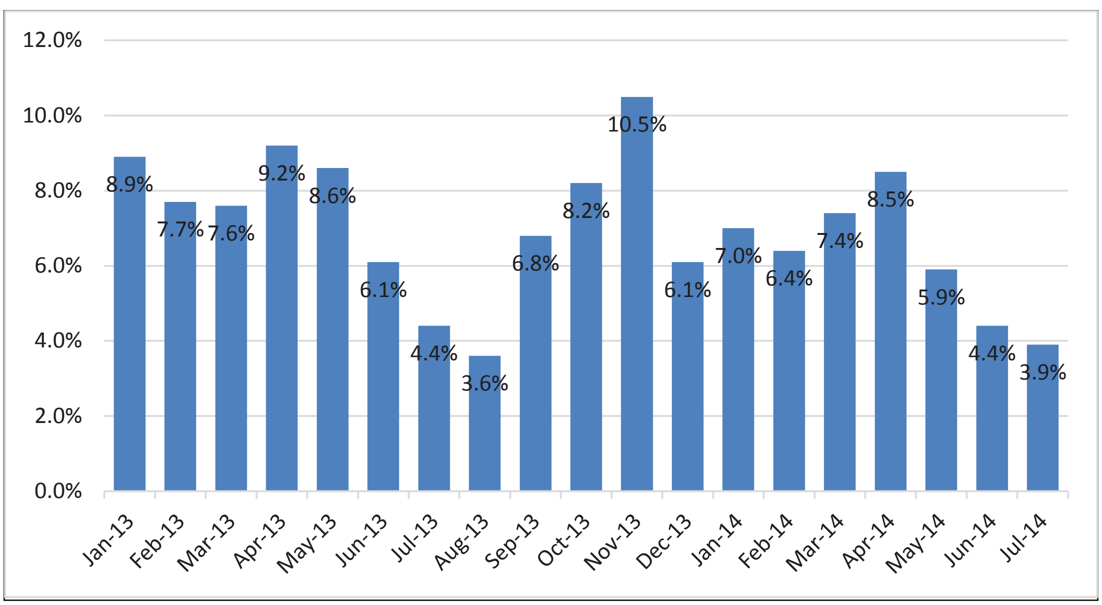
Figure 13: Monthly Wind Generation in MISO



Source: www.misoenergy.org

The Commission will continue to carefully weigh the need for new capacity, as well as the optimal generation mix. By law, the Commission must also ensure that Wisconsin utilities comply with the state RPS in a cost effective manner. Figure 14 shows the percentage of energy in the MISO footprint coming from wind resources in 2013.

Figure 14: Wind Energy as Percent of MISO Footprint Wide Energy 2013 – June 2014



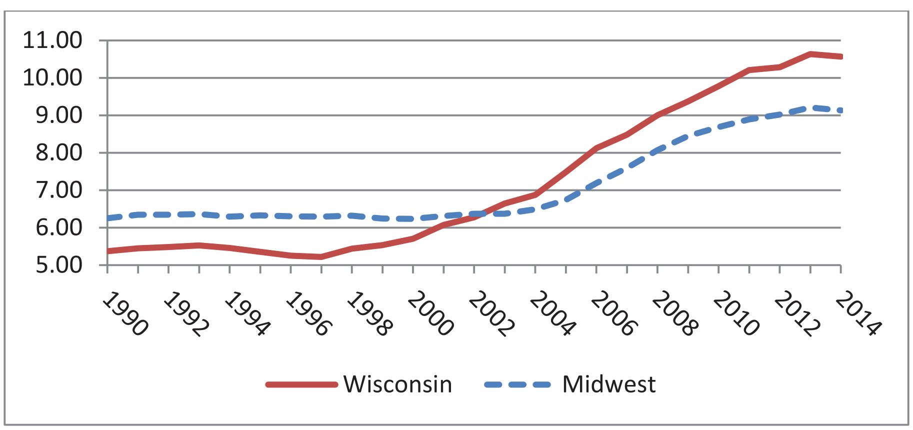
Source: www.misoenergy.org

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 utilities handle the accounting behind the rate setting process – for example, if cost deferrals are being approved – 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.

Wisconsin remains ahead of many other states with respect to its investment in new electric generation and transmission facilities needed to address future service reliability, and it is well positioned in the near future to meet its energy demand needs. Wisconsin entered a construction cycle earlier than other states in the Midwest partly because its economy was stronger than in surrounding states. This required generation plants and transmission facilities to be constructed beginning in the late 1990s and continuing through recent years for which utilities now seek to obtain cost recovery. Although subject to future EPA carbon constraints, Wisconsin's current fleet of coal plants are well positioned to produce favorable energy sales into the MISO market which will benefit Wisconsin's ratepayers. As noted in Figure 15, the recent construction cycle has had rate impacts on customers in Wisconsin. 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. Selling excess energy or capacity is returned to retail customers in the Commission's rate setting process.

Figure 15: Average Rates in Wisconsin and the Midwest[14] 1990-2014



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

[14] 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. 2014 values are year-to-date.

Wisconsin remains ahead of many other states with respect to its investment in emission controls as well. This too, has impacted rates. Emission control and generation facility upgrades were discussed earlier in this report. Many of these projects were a result of Consent Decrees that the utilities entered into with EPA. Approximately $3 billion has or will be spent on these emission control upgrades since 2000.

Wisconsin generators continue to face the task of updating their current coal facilities to comply with federal emissions requirements. Recently promulgated rules such as the EPA Cross State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standard (MATS) rule that were until recently under appeal, and proposed federal environmental regulations, such as the Cooling Water Intake, greenhouse gas regulations, including revised and new rules on carbon emissions, and revised SO2 standards, will likely increase utility rates and bills. MISO estimates 10 gigawatts (GW) of coal units (as of 4th quarter 2013) in the MISO footprint could be retired in 2014-2015 due in part to increased federal regulations. The exact magnitude and timing of these costs, and the degree to which they will affect Wisconsin (and other states) retail rates is highly uncertain. The Commission will continue to monitor this evolving situation.

Several of the environmental laws are under review and/or being challenged at the time of this writing. These challenges and/or delays have led to considerable uncertainty for generating units. The following list summarizes the rules that are either under review by a court, have had a court ruling issued or are awaiting further action by the EPA.

- Mercury and Air Toxics Standard (MATS) – April 24, 2013: EPA published the final version of the MATS rule. From June 25 to August 26, 2013, EPA solicited comments for additional input on specific issues raised during the initial public comment period related to periods of startup and shutdown. The MATS rule was appealed (White Stallion Energy Center LLC v. EPA) to the U.S. Court of Appeals for the D.C. Circuit, but the U.S. Court of Appeals for the D.C. Circuit upheld the MATS rule in a decision on April 15, 2014.

- EPA Cross State Air Pollution Rule (CSAPR) – August 21, 2012: The U.S. Court of Appeals for the District of Columbia Circuit ruled in a 2-1 decision (EME Homer City Generation, L.P v. EPA) that EPA exceeded its statutory authority with CSAPR. CSAPR was finalized in July 2011 and replaced the Clean Air Transport Rule, signed on July 6, 2010, which was challenged as not strict enough. The U.S. Supreme court overturned on April 29, 2014, an appeal of the CSAPR regulations.

- EPA rules on greenhouse gas regulations and development of carbon dioxide (CO2) rules for existing power plants under section 111(d) of the Clean Air Act are under development by the EPA. In September 2013, the EPA issued a series of questions to states for a response. The Commission worked with the Wisconsin Department of Natural Resources, the State Energy Office, and stakeholders to evaluate issues related to developing CO2 requirements for power plants and issued those comments to EPA on December 13, 2013. State of Wisconsin comments that were submitted concluded with: "…assuming EPA decides to move forward with the development of Best System of Emission Reduction guidelines under section 111(d) of the Clean Air Act, the State of Wisconsin recommends a regulatory structure that allows states to balance carbon reductions with minimal cost to consumers." After reviewing comments from across the country, EPA issued draft rules in June 2014 that would require Wisconsin to reduce its carbon emissions per MWh generated by approximately one-third by the year 2030. The draft rules set goals for Wisconsin and other states by assuming they could make five key changes: improving heat rates; increasing the dispatch of natural gas combined cycle units; maintaining the use of nuclear plants at risk of retirement; increasing the use of renewable sources; and increasing savings from energy efficiency. The draft rules are intended to allow states flexibility on their plan for meeting the carbon goal, which could include choosing the relative level of investment in each of the practices described above or using other verifiable methods for reducing emissions. The draft rule would also allow a variation for compliance in limiting overall CO2 emissions from electric generation sources. The Commission is working with other involved stakeholders to evaluate the draft rules and issue comments to EPA in October 2014. EPA intends to finalize rules in June 2015; as currently drafted, the rules would require states to submit implementation plans for achieving their emissions reductions goals in 2016, with the potential for extensions on the final plan until 2017 or 2018. It is expected, however, that the final rules will receive multiple legal challenges once they are issued.

- EPA rules on greenhouse gas regulations and development of carbon dioxide (CO2) rules for new, modified and reconstructed sources by establishing standards under section 111(b) of the Clean Air Act – January 9, 2014: EPA published its proposed rule to limit carbon emissions from new power plants under Utility New Source Performance Standards (NSPS). New coal power plants, with either IGCC or SCPC, carbon capture technology must be incorporated into the design of the plant; it is not a matter of simply adding a piece of equipment later. No electric generating plants in the U.S., either IGCC or SCPC, currently employ carbon dioxide capture technology. Comments on the proposed rule were due to EPA by March 10, 2014. The regulation mandates that all future coal plants can emit just 1,100 pounds of carbon dioxide per megawatt-hour. On June 23, 2014, the U.S. Supreme Court upheld the majority of EPA's proposed greenhouse gas regulations. The EPA is expected to issue final rules in January 2015.

- Cooling Water Intake Structures – CWA 316(b) – May 19, 2014: EPA finalized rules for cooling water intake structures under section 316(b) of the Clean Water Act. The rule was published in August, 2014, with an effective date of October 14, 2014. Three lawsuits were filed the week of September 1, 2014, and there may be additional legal challenges coming. 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 technology available 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 Guidelines – 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, the EPA initiated a rulemaking proceeding aimed at further curbing of 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. On June 7, 2013, the EPA published the proposed rules that would create tighter standards for pollutants such as mercury, arsenic, lead and selenium. Plants below 50 MW will not fall under this regulation. The public comment period on the proposal closed on September 20, 2013. The EPA is reviewing public comments and is required to release a final standard by September 30, 2015.

- Coal Ash – EPA believes additional coal ash specific federal regulations are necessary to ensure the safe management of coal ash that is disposed in surface impoundments and landfills. EPA proposes to ensure the safe disposal and management of coal ash from coal-fired power plants under the nation's primary law for regulating solid waste, the Resource Conservation and Recovery Act (RCRA). The EPA put forward two proposals that reflect different approaches to managing the disposal of coal ash and invited public comments on these two options. The comment period closed on September 3, 2013. The EPA has agreed to take final action on the rule by December 19, 2014, pursuant to a consent decree signed in January 2014.

According to the U.S. Energy Information Administration's (EIA) reported 2013 and 2014 Q1 sales and revenue information in its Electric Power Monthly report, the U.S. average rates in the residential, commercial, and industrial classes all increased in the past year. The trend in Wisconsin rates generally matched its surrounding environment. Table 6 – Table 9 summarize average rates for residential, commercial, industrial, and all sectors in the Midwest and the country.

Table 6: Residential Average Rates in the Midwest and U.S. (in cents)[15]

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Illinois	8.37	8.34	8.42	10.12	11.07	11.27	11.52	11.78	11.38	10.25	10.92
Indiana	7.30	7.50	8.22	8.26	8.87	9.50	9.56	10.06	10.53	10.84	11.07

[15] Source: U.S. Department of Energy, Energy Information Agency, Monthly Electric Utility Sales and Revenue Data (Form EIA-826), August 14, 2014. 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. 2014 values are through May 2014.

Iowa	8.96	9.27	9.63	9.45	9.49	9.99	10.42	10.46	10.82	11.15	10.90
Michigan	8.33	8.40	9.77	10.21	10.75	11.60	12.46	13.27	14.13	14.59	14.30
Minnesota	7.92	8.28	8.70	9.18	9.74	10.04	10.59	10.96	11.35	11.94	11.79
Missouri	6.97	7.08	7.44	7.69	8.00	8.54	9.08	9.75	10.17	10.52	10.03
Ohio	8.45	8.51	9.34	9.57	10.06	10.67	11.32	11.42	11.76	11.91	11.78
Wisconsin	9.07	9.66	10.51	10.87	11.51	11.94	12.65	13.02	13.19	13.70	13.59
Midwest	8.04	8.19	8.78	9.24	9.78	10.29	10.78	11.19	11.54	11.62	11.22
U.S. Average	8.95	9.45	10.40	10.65	11.26	11.51	11.54	11.72	11.88	12.12	12.87

Table 7: Commercial Average Rates in the Midwest and U.S. (in cents)[15]

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Illinois	7.54	7.75	7.95	8.57	11.79	8.99	8.88	8.64	7.99	7.88	8.66
Indiana	6.31	6.57	7.21	7.29	7.82	8.32	8.38	8.77	9.14	9.48	9.74
Iowa	6.75	6.95	7.29	7.11	7.18	7.55	7.91	7.85	8.01	8.47	8.42
Michigan	7.57	7.84	8.51	8.77	9.20	9.24	9.81	10.33	10.93	11.07	10.84
Minnesota	6.31	6.59	7.02	7.48	7.88	7.92	8.38	8.63	8.84	9.53	9.47
Missouri	5.80	5.92	6.08	6.34	6.61	6.96	7.50	8.04	8.20	8.72	8.22
Ohio	7.75	7.93	8.44	8.67	9.22	9.65	9.73	9.63	9.47	9.38	9.64
Wisconsin	7.24	7.67	8.37	8.71	9.28	9.57	9.98	10.42	10.51	10.84	10.70
Midwest	6.98	7.20	7.62	7.91	8.84	8.57	8.83	9.05	9.11	9.31	9.23
U.S. Average	8.17	8.67	9.46	9.65	10.36	10.17	10.19	10.23	10.09	10.29	10.95

Table 8: Industrial Average Rates in the Midwest and U.S. (in cents)[15]

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Illinois	4.65	4.61	4.69	6.61	4.54	6.84	6.82	6.42	5.80	5.73	6.39
Indiana	4.13	4.42	4.95	4.89	5.46	5.81	5.87	6.17	6.34	6.59	6.78
Iowa	4.33	4.56	4.92	4.74	4.81	5.27	5.36	5.21	5.30	5.66	5.62
Michigan	4.92	5.32	6.05	6.47	6.74	6.99	7.08	7.32	7.62	7.78	7.73
Minnesota	4.63	5.02	5.29	5.69	5.87	6.26	6.29	6.47	6.54	7.06	7.06
Missouri	4.62	4.54	4.58	4.76	4.92	5.42	5.50	5.85	5.89	6.14	5.69
Ohio	4.89	5.10	5.61	5.76	6.19	6.71	6.40	6.12	6.24	6.10	6.56
Wisconsin	4.93	5.39	5.85	6.16	6.51	6.73	6.85	7.33	7.34	7.54	7.52
Midwest	4.63	4.86	5.24	5.66	5.65	6.32	6.33	6.39	6.44	6.58	6.86
U.S. Average	5.25	5.73	6.16	6.39	6.83	6.81	6.77	6.82	6.67	6.82	8.12

Table 9: All Sectors Average Rates in the Midwest and U.S. (in cents)[15]

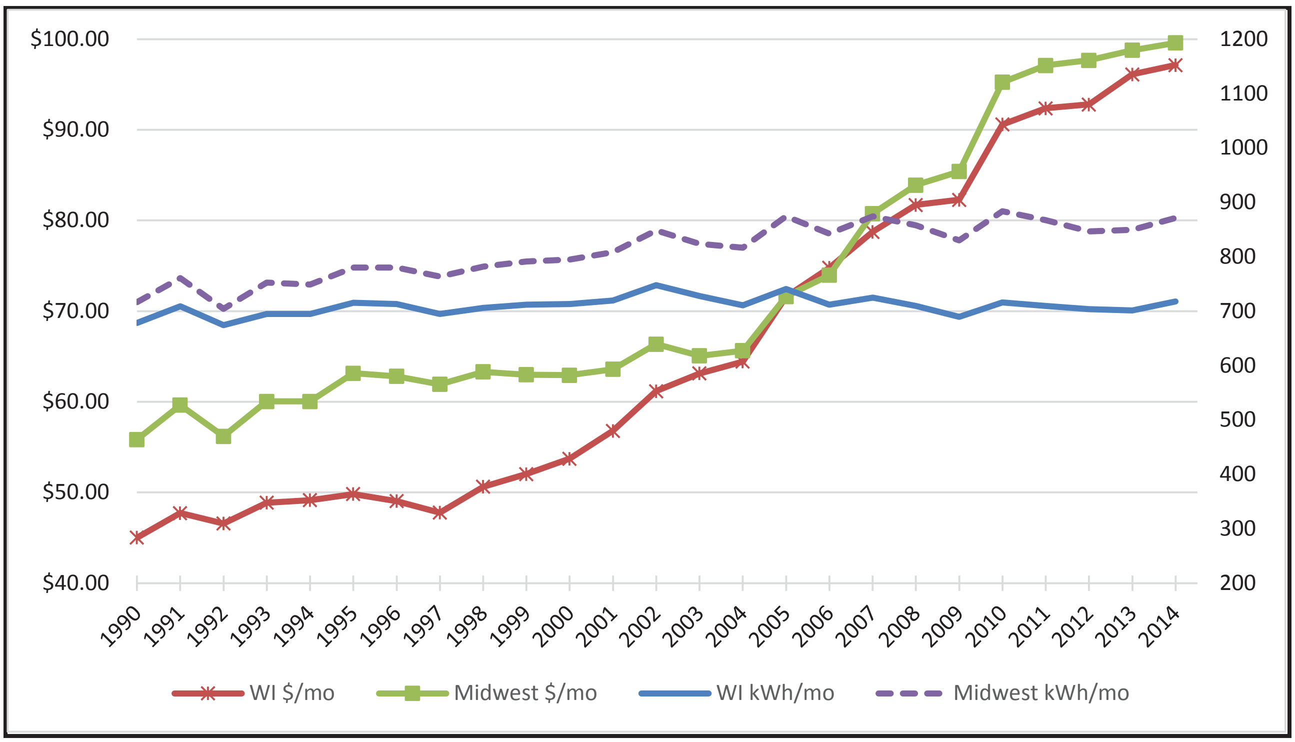
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Illinois	6.80	6.95	7.07	8.46	9.26	9.08	9.13	8.97	8.40	7.99	8.66
Indiana	5.58	5.88	6.46	6.50	7.09	7.62	7.67	8.01	8.29	8.63	8.84
Iowa	6.40	6.69	7.01	6.83	6.89	7.37	7.66	7.56	7.71	8.12	8.00
Michigan	6.94	7.23	8.14	8.53	8.94	9.40	9.88	10.40	10.98	11.26	11.02
Minnesota	6.24	6.61	6.98	7.44	7.79	8.14	8.41	8.65	8.86	9.52	9.51
Missouri	6.07	6.13	6.30	6.56	6.84	7.35	7.78	8.32	8.53	8.96	8.46
Ohio	6.89	7.08	7.71	7.91	8.39	9.01	9.14	9.03	9.12	9.16	9.39
Wisconsin	6.88	7.48	8.13	8.48	9.00	9.38	9.78	10.21	10.28	10.64	10.57
Midwest	6.49	6.74	7.19	7.60	8.07	8.45	8.69	8.89	9.02	9.21	9.13
U.S. Average	7.61	8.14	8.90	9.13	9.74	9.82	9.83	9.90	9.84	10.08	10.86

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 third smallest monthly electric bill when compared to neighboring 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 10 and Figure 16.

Table 10: Average Residential Monthly Electricity Cost (in $)[15]

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Illinois	61.61	67.47	64.85	80.01	84.62	82.04	92.03	90.80	87.20	77.75	79.70
Indiana	71.49	78.13	81.65	87.44	91.94	94.30	101.79	103.54	104.93	108.18	114.97
Iowa	73.32	80.61	81.52	83.65	83.94	86.25	95.19	93.94	94.50	100.60	100.06
Michigan	54.10	58.99	65.55	70.02	71.58	74.69	84.82	90.63	95.50	97.76	94.30
Minnesota	61.40	67.82	70.85	76.40	79.55	80.48	86.19	89.14	90.06	96.22	98.50
Missouri	70.98	78.02	79.48	86.22	87.83	90.66	104.66	108.39	107.80	112.57	108.40
Ohio	73.35	78.48	81.78	88.60	91.50	93.66	105.33	104.86	105.23	106.08	109.57
Wisconsin	64.44	71.60	74.79	78.75	81.71	82.28	90.59	92.39	92.79	96.12	97.15
Midwest	65.65	71.62	73.98	80.77	83.91	85.41	95.25	97.10	97.68	98.79	99.60
U.S. Average	81.10	88.60	95.66	99.70	103.67	104.52	110.55	110.14	107.28	106.24	109.44

Figure 16: Average Residential Monthly Bills & Electricity Usage in Wisconsin and Midwest 1990-2014



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

Additionally, 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 a customer with increased load to pay market rates for the increase in load, rather than tariff rates; a customer can sign up for a four-year contract. During 2010-2011, the Commission also approved an economic development rate program for WP&L. In addition, any selling of surplus energy to out of state utilities has the potential to help lower rates in Wisconsin.[16]

[16] Several stakeholders commented during the public comment period of the SEA that the Commission should include in the SEA a comprehensive analysis of rate impacts. While the SEA provides general information about rates and impacts and Commission activities and involvement in addressing these issues, specific analyses are conducted during utility rate case dockets and through Commission involvement in utility construction cases and in other forums, such as the MISO transmission planning processes.

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 install measures that reduce energy use. In 1999, state legislation established a statewide electric and natural gas energy efficiency program. This statewide energy efficiency program, called Focus on Energy (Focus), is administered by a third party. 2005 Wisconsin Act 141 made a number of statutory changes, including the repeal and recreation of Wis. Stat. § 196.374. These changes included moving the oversight of Focus from the Department of Administration to the Commission, and requiring investor-owned utilities (IOU) to levy an energy tax to fund Focus at a level of 1.2 percent of annual operating revenues.[17][18] Municipal and cooperative electric utilities 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 program. As of 2013, 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 utilities run voluntary energy efficiency programs within their service territories that provide additional benefits to their customers beyond what Focus offers.[19]

Wisconsin Stat. § 196.374(3) requires the Commission to conduct an extensive review of the Focus program every four years, referred to as the quadrennial planning process. The first quadrennial planning process was completed in 2010 and covered the period 2011 through 2014. The second quadrennial planning process was completed the summer of 2014 and will cover the period 2015 through 2018. During this review, goals and priorities were reassessed. Chicago Bridge and Iron (CB&I), the current Focus on Energy Program Administrator, is expected to continue in that role in the next quadrennium.[20]

Energy efficiency expenditures often result in energy savings that persist for multiple years in the future. Independent program evaluators report on cost-effectiveness and take the persistence of the measures

[17] Wisconsin Stat. § 196.374(3)(b)2., as created by 2005 Wisconsin Act 141, provided the opportunity for the Commission to request a higher energy tax. The Joint Committee on Finance approved, based on the Commission's recommendation, a higher energy tax, including $120 million for 2011. However, 2011 Wisconsin Act 32 amended Wis. Stat. § 196.374(3)(b)2. to remove the opportunity to set this higher energy tax and returned it to 1.2 percent of IOU operating revenues for 2012 and beyond.

[18] Commissioner Callisto disagrees with the terminology "energy tax" in reference to Focus funding. He states the following: Incorporating the phraseology "tax" in reference to the Focus program is inaccurate and inconsistent with 2005 Wisconsin Act 141, which privatized Focus funding and removed it from the state budget. The authors of Act 141 did not intend to create new or increased "taxes," and there is no legitimate reason for the Commission to now revise that history. Doing so only politicizes what is otherwise a purely factual document.

[19] A voluntary energy efficiency program is run by the utility with funding that is above and beyond what the utility is required to collect pursuant to Wisconsin Stat. § 196.374 as described above.

[20] As of the date of this SEA, contract negotiations are underway between the Statewide Energy Efficiency and Renewable Energy Administration and CB&I to extend CB&I's contract for the next quadrennium.

into consideration. For 2013, the program evaluator for Focus conducted a cost-benefit analysis, and concluded that for every dollar spent, societal benefits valued at $3.41 are achieved.[21] In order to realize energy savings on the electric side, it cost an average of 1.5 cents per kilowatt-hour (Cost of Conserved Energy). Only savings that the evaluator attributes to Focus program implementation are counted in these analyses. 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.

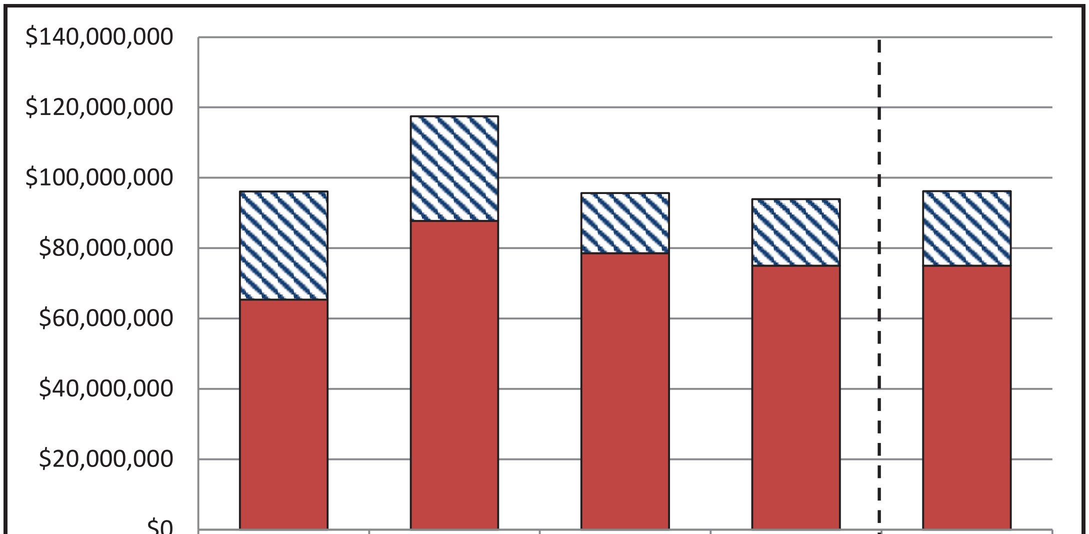
Focus spending in 2013 was substantially higher than in 2012 because there were unspent dollars in 2012 carried over into 2013. 2012 spending was impacted by the final steps in the transition to a new program administrator, new program implementers and new program designs. 2014 Focus expenditures are anticipated to decrease from 2013 expenditures as carry-over dollars from previous years will largely have been spent in 2013. Over 2015-2020, expenditures are held constant as reductions in energy use and increased rates have had opposing effects on utility operating revenues. In the second quadrennial planning process, the Commission set annual energy and demand goals for the quadrennium at 15 percent above expected achievement over the first quadrennium. Energy and demand achievement forecasts for 2015 through 2020 are held constant at one-fourth of the four-year goals set in the second quadrennial process.

Given the large scale of Focus and utility energy efficiency expenditures, when forecasting energy and demand savings it is essential to include program savings from both utility and statewide expenditures. As part of this SEA, a forecast of energy and demand savings was prepared by Commission staff for utility energy efficiency expenditures. MGE, SWL&P, WEPCO, WP&L, WPSC, NSPW, WPPI, and DPC all provide additional energy efficiency services. Some of the expenditures for these utility energy efficiency services include educational and behavior-based activities that do not have quantifiable savings. Figures 17, 18, and 19 provide forecasts through 2020 in terms of expenditures and first-year annual energy and demand savings.[22]

Voluntary utility energy efficiency expenditures experienced a decrease in program size in 2014. After 2013, the WPSC territory-wide energy efficiency programs ended, explaining most of the large drop in utility expenditures. Inflation counts for the slight rebound in utility expenditures after 2014.

[21] Focus evaluates the program using both a modified total resource cost (TRC) test and an expanded TRC test. The modified TRC test takes into account energy savings and avoided emissions of regulated air pollutants, and it showed for 2013 a benefit/cost of 3.41/1.00.
[22] Does not include persistent savings that occur multiple years after measures are installed.

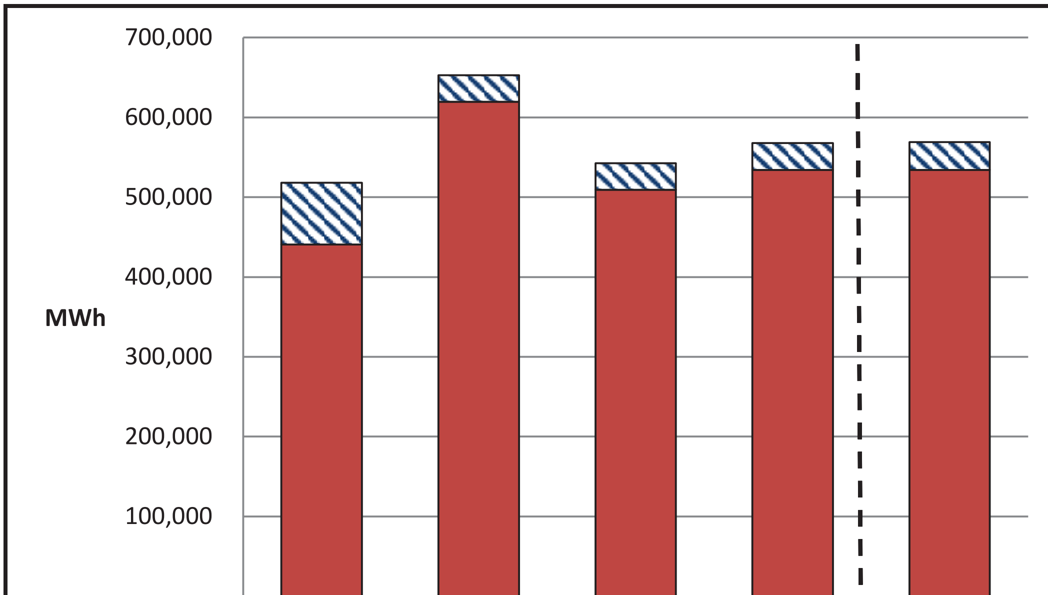
Figure 17: Annual Energy Efficiency Expenditures (2012-2020)



	2012	2013	2014	2015	2020
Utility	$30,799,781	$29,729,629	$17,120,146	$19,002,832	$21,243,747
Focus	$65,344,178	$87,792,174	$78,570,892	$74,970,891	$74,970,891

Source: Aggregated utility data responses, docket 5-ES-107; Focus on Energy 2013 Annual Report

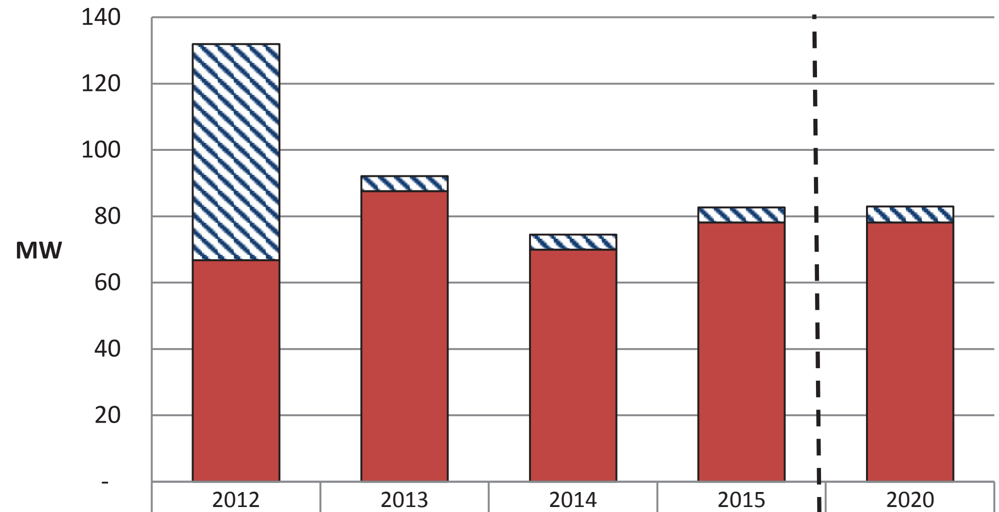
Figure 18: First-Year Annual Energy Savings (2012-2020)



	2012	2013	2014	2015	2020
Utility	77,603	33,250	33,460	33,674	34,791
Focus	440,600	619,418	509,217	534,286	534,286

Source: Aggregated utility data responses, docket 5-ES-107; Focus on Energy 2013 Annual Report

Figure 19: First-Year Annual Demand Savings (2012-2020)



	2012	2013	2014	2015	2020
Utility	65	5	5	5	5
Focus	67	88	70	78	78

Source: Aggregated utility data responses, docket 5-ES-107; Focus on Energy 2013 Annual Report

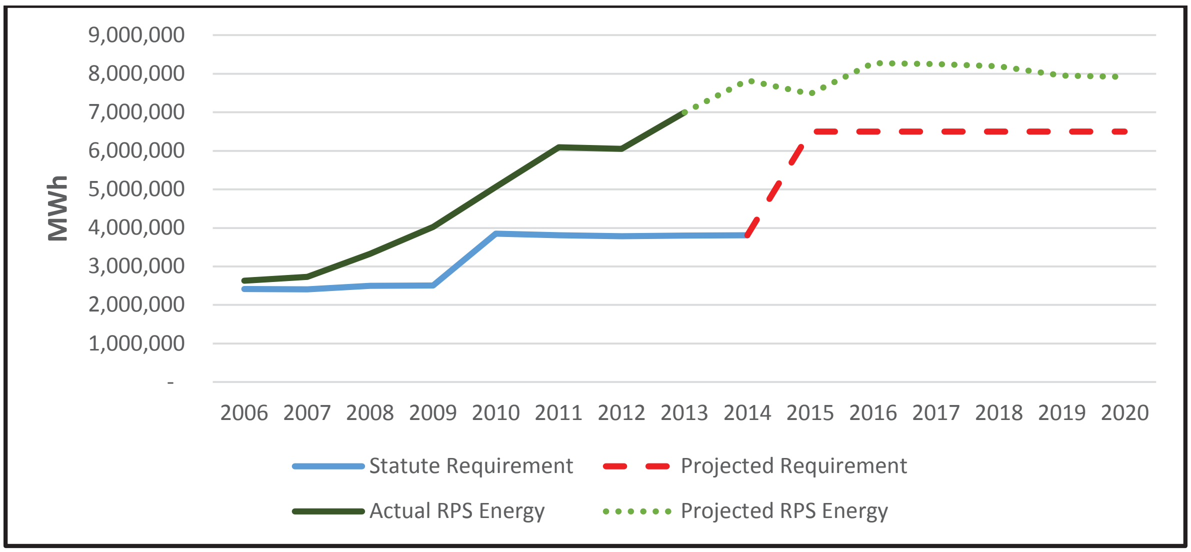
The large decrease in utility energy and demand savings is a result of WPSC reporting no energy and demand savings after 2012. In a joint agreement with the Citizens Utility Board which was approved by the Commission, WPSC implemented additional energy efficiency programs in its service territory. Enhanced Energy Efficiency programs that leverage Focus services to increase participation were available territory-wide. Because these Enhanced Energy Efficiency programs combined Focus and WPSC incentives, the energy and demand savings from these territory-wide programs are reported in Focus achievement. In addition to the territory-wide programs, in three pilot communities WPSC provided residential energy efficiency programs designed to engage customers with energy use information, as well as technologies such as in-home monitors and energy management devices that allow customers to view and better control their own energy use over time. Customers in the WPSC community pilot programs had the option of participating in Time-of-Use (TOU) rate structures that are based on the time of day and season of the year. While in two of the pilot communities customers had to opt in to the TOU rate, in the third community pilot customers were defaulted to the TOU rate but were allowed to opt out of the rate. These community pilot programs were discontinued on December 31, 2012 (PSC REF #: 194023).

RENEWABLE RESOURCES

The Wisconsin Renewable Portfolio Standard (RPS) requires all Wisconsin electric providers to procure increasing amounts of electricity from renewable resources for retail electric sales through 2015. The RPS generally requires electric 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.[23] This 2015 level must then be sustained by electric providers thereafter. Aside from electric provider requirements, the statewide goal of the RPS is to achieve 10 percent of all electricity provided to Wisconsin retail customers to come from renewable resources by 2015.

All electric providers have been compliant with their RPS requirements through 2013, and have more than doubled statewide total retail sales from renewable resources over the 2006-2013 time period; from about 2.6 MWh in 2006 to just under 7 million MWh in 2013. The statewide aggregate of actual RPS renewable energy sales in relation to RPS requirements is reflected in Figure 20. As of 2013, just under 10.8 percent of all electrical energy sold in Wisconsin, including RPS and voluntary green pricing retail sales, was generated from renewable resources. As a result, 2013 marks the first year the 10 percent statewide goal was achieved – two years ahead of schedule.

Figure 20: Statewide RPS Renewable Retail Sales (Actual vs. Required, 2006-2020)*



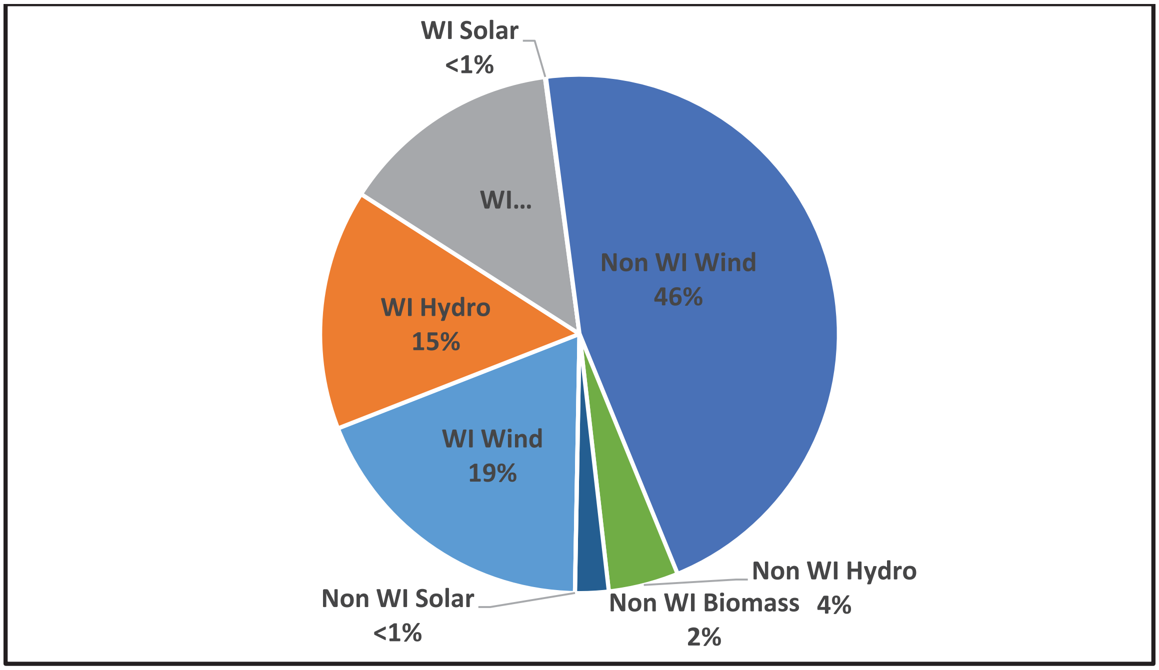
* Projection out to 2020 based on 0 percent energy growth.
Source: Commission Staff 2013 RPS Compliance Memorandum (PSC REF#: 206461)

Going forward, electric providers are well-positioned to meet future RPS requirements through owned generation and procurement practices. The 50 MW Rothschild Biomass Cogeneration Plant was placed in service near the end of 2013, and will add a significant amount of generation to WEPCO's renewable portfolio.

[23] 2013 Wisconsin Act 290 relieves four small utilities (Centuria Municipal Electric Utility, Consolidated Water Power Company, North Central Power Company, and Northwestern Wisconsin Electric Company) from meeting the 2015 renewable portfolio standard, provided they meet the 2010 renewable portfolio standard. The rationale is that these four utilities had a very high percentage of renewables in their energy mix when the statewide 10 percent by 2015 standard was created, meaning that even if they achieve the 2010 standard and no more, their renewable portfolio will still be higher than every other utility's 2015 standard. This will save their ratepayers money and not punish them for being early adopters of renewable energy.

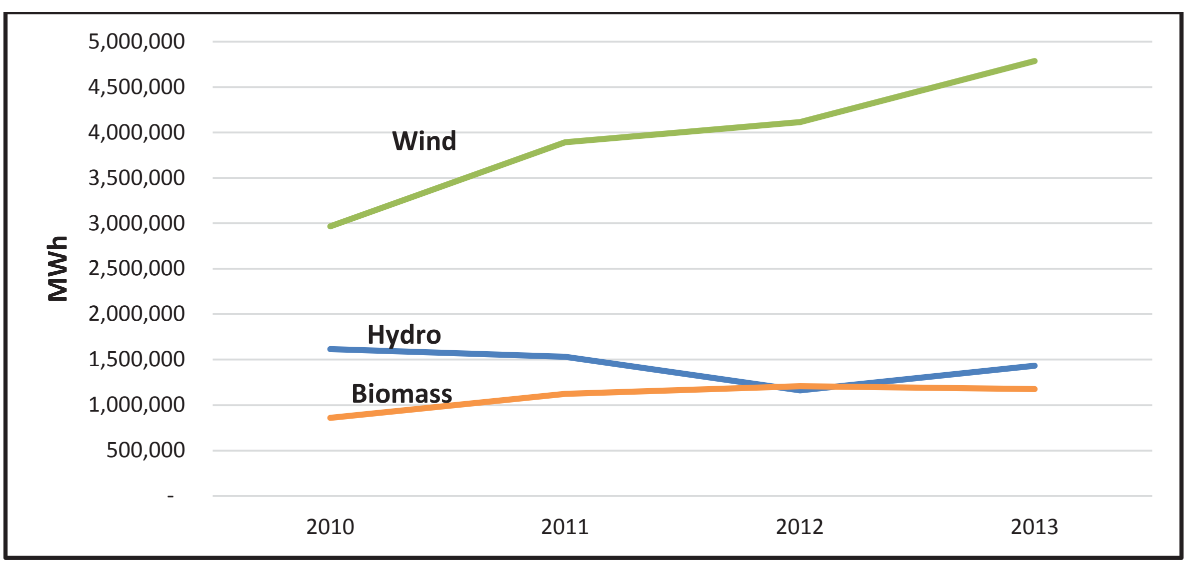
Statewide, Wisconsin's electric providers achieve about half of their RPS requirements from renewable resources located in the state. Figure 21 and Figure 22 depict 2012 Wisconsin and non-Wisconsin renewable resources and the recent trend in renewable resource growth, respectively.

Figure 21: 2013 Renewable Sales by Resource and Location - Percent of Total Renewable Sales



Source: Commission Staff 2013 RPS Compliance Memorandum (PSC REF#: 206461)

Figure 22: Wisconsin Utility Retail Sales by Renewable Resource (2010-2013)



Source: Commission Staff 2013 RPS Compliance Memorandum (PSC REF#: 206461)

SUMMARY

This SEA has shown that Wisconsin utilities continue to forecast annual load growth to be approximately 0.5-1.2 percent through 2020. Wisconsin's predominate energy source is still coal. In the last SEA, coal accounted for 63 percent of Wisconsin's energy mix, and in this current SEA, it is 51 percent. Natural gas's share of Wisconsin's energy mix has doubled since the last SEA, from 9 percent to approximately 18 percent currently. The rest of Wisconsin's energy mix remains similar to the last SEA that was completed in 2012.

For MISO's planning horizon of 10 years, MISO envisions approximately 10,442 miles of new or upgraded transmission lines during that time period; 63 percent will be upgrades on existing corridors, and 37 percent will be new transmission lines on new corridors. MISO has been monitoring and studying potential impacts of regulations on resource adequacy and anticipates a potential shortfall beginning in 2016. The Commission will continue to work with MISO, OMS, and other stakeholders on regional and interregional transmission planning.

Wisconsin's planning reserve margins are 15.3 percent or higher through 2017. If these forecasts hold true, Wisconsin will surpass the 14.8-15 percent requirement set by MISO (for 2014-2016). In future years, the utilities will monitor and meet the MISO planning reserve margin for the next planning year.

Direct rate comparisons among states and regions are difficult because of the complexities of energy regulation and the energy market in general. While Wisconsin remains ahead of 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 innovate retail rate options for Wisconsin businesses to control their energy costs while contributing to economic growth in the state.

Wisconsin continues to be a leader through its statewide energy efficiency program, Focus on Energy. As of 2013, 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 electric providers have been compliant with their RPS requirements through 2013 and have more than doubled statewide total retail sales from renewable resources over 2006-2013. Going forward, electric providers in Wisconsin are well-positioned to meet future RPS requirements.

APPENDIX A

Table A-1: New Utility-Owned or Leased Generation Capacity, 2014-2020[1]

Year	Type of Load Served	Capacity (MW)[2]	Name	New or Existing Site	Owner/ Leaser	Fuel	Location (County: Locality)	PSC Status & Docket #
2019	Base/Intermediate	294	WPS CC (Base)	New	WPSC	Nat. Gas	N/A	N/A
2019	Peaking	85	WPS CC (Duct Fire)	New	WPSC	Nat. Gas	N/A	N/A
2019	Intermediate	200-600	YTD	New	WP&L	Nat. Gas	N/A	N/A
2018-2020	Base	3.7, 3.4 upgrade	Columbia 1,2	Existing	WP&L	Coal	Portage, WI	?
N/A	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. These plants are not expected to be constructed in Wisconsin and are not included in this table. WPSC stated that Weston 2 will be converted from coal to natural gas in 2015. Since this is not a new plant, it is not included in this table.

[2] Nameplate MW shown.

Source: Data provided by utilities.

Table A-2: New Transmission Lines[1] (on which construction expected to start before 12-31-2020)

PSC Docket Number	Status	New Line or Rebuild/Upgrade[2]	Endpoints (Substations)	County	Voltage (kV)	Est. Cost (Millions)	Expected Construction	Expected In-Service	Substation Changes
American Transmission Company LLC (ATC)									
137-CE-164	Application Expected	New 110-mile 345 kV line	Cardinal, Dubuque, IA	Dane, Green, Iowa, Lafayette, Grant[3]	345	436	Sep-19	Dec-20	Line termination at Cardinal Substation
137-CE-166	Application Pending	New 45 mile 345 kV line and 45 miles of 138 kV line[3]	N. Appleton - Morgan	Brown, Outagamie, Oconto, Marinette, and Shawano	345/138	307-327	Jun-17	May-19	Expansion of existing substation[5]
05-CE-142	Application pending	New 160-180 mile 345 kV line	Cardinal-N.Madison-Briggs Road	Columbia, Dane, Jackson, Juneau, La Crosse, Monroe, Sauk, Trempealeau, Vernon[3]	345	539-580	Jul-16	Dec-18	Endpoint 2 will connect with the NSPW Briggs Road Substation in the La Crosse Area. Substation expansions at Briggs Road and Cardinal
137-CE-167	Application Expected	25 miles new 138 kV, rebuild 14 miles 138 kV, new 69 kV and rebuild 5 miles 69 kV	Spring Valley, N. Lake Geneva	Kenosha, Walworth	138	86	Jul-17	Mar-20	New intermediate 138/69 kV Substation near Twin Lakes, 138 kV bus at Spring Valley
137-CE-177	Application Expected	New 6 miles 138kV line	Creekview, Circuit X-96 or X-97	Fond du Lac	138	16	Oct-16	Jan-17	New WEPCO Creekview Substation
137-CE-176	Application Expected	New 1.0 mile 345kV line and 1.25 mile 138kV line	Branch River, Circuit 111 and 121	Manitowoc	345	25	Oct-16	Dec-18	New Branch River Switching Substation
No Docket Assigned	Application Expected	Rebuild 12 miles of 138kV line	North Appleton, Butte des Morts	Outagamie, Winnebago	138	14	Oct-16	Dec-17	
No Docket Assigned	Application Expected	Rebuild 14.3 miles of 138kV line	St. Martin, Edgewood, Mukwonago	Waukesha	138	19	Oct-16	Dec-17	
No Docket Assigned	Application Expected	Rebuild 12.9 miles of 138kV line	Oak Creek, Hayes	Milwaukee, Racine	138	14	2018	2019	
Dairyland Power Cooperative (DPC)									
No Docket Expected		Rebuild 13.3 mile 161kV line	Briggs Rd, Marshland		161	13		Fall 2015	
No Docket Expected		Rebuild .94 mile 161kV line	Alma, Cap X		161	1.2		2016	
No Docket Expected		Rebuild 9.1 mile 161 kV line	LaCrosse, Briggs Rd		161	11.7		2016	
Northern States Power Company-Wisconsin (NSPW)									
05-CE-142	Application pending	New 160-180 mile 345 kV line	Cardinal-N.Madison-Briggs Road		345	167	Jul-15	Dec-18	Badger Coulee Line
No Docket		New 40 miles of 115/88 kV line	Bay Front-Iron Wood	Ashland, Bayfield	115/88	51	Jan-17	Dec-19	Saxon Pump sub
No Docket		New 70 miles of 115 kV line	Iron River - Bay Front	Ashland, Bayfield	115	55	Jun-16	Jun-18	Construction of two new substations. Some existing substation modifications may be required. Project plans are not yet final.
No Docket		New 8 mile 161kV line	Jim Falls, Hydro Lane		161	7.5	Oct-13	Dec-13	

[1]Does not include lines approved by the Commission.

[2]Rebuilds and upgrades, as well as new lines, may require new right-of-way.

Source: Data provided by utilities.

Table A-3: Retired Utility-Owned or Leased Generation Capacity: 2015-2019[1]

Year	Name	Owner/ Leaser	Type of Load Served	Capacity (MW)[2]	Fuel	Location
2015	Edgewater 3	WP&L	Base	54.9	Coal	Sheboygan, WI
2015	Nelson Dewey 1,2	WP&L	Base	107, 104	Coal	Cassville, WI
2015	Alma 4,5	DPC	Intermediate	49, 76	Coal	Alma, WI
2015	Weston 1	WPSC	Peaking	57	Coal	Wausau, WI
2015	Pulliam 5,6	WPSC	Peaking	49, 65	Coal	Green Bay, WI
2018	Edgewater 4	WP&L/WPSC	Base	320	Coal	Sheboygan, WI
2018	Flambeau 1	NSPW	Peaking	12	Nat. Gas	Park Falls, 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.

Source: Data provided by utilities.

Acronyms

§	Section
AC	Alternating Current
ART	Advanced renewable tariffs
ATC	American Transmission Company LLC
CA	Certificate of Authority
Commission	Public Service Commission of Wisconsin
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
DATC	Duke Energy and ATC joint venture
DC	Direct Current
DOE	U.S. Department of Energy
DPC	Dairyland Power Cooperative
EHV	Extra High Voltage
EIA	U.S. Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States' Planning Council
EPA	U.S. Environmental Protection Agency
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
Focus	Focus on Energy
GLU	Great Lakes Utilities
IMM	Independent market monitor
IOU	Investor-owned utility
kV	kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LMP	Locational Marginal Pricing
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
NERC	North American Electric Reliability Corporation
NO_x	Nitric oxides
NRC	Nuclear Regulatory Commission
NSPW	Northern States Power-Wisconsin
OMS	Organization of MISO states
PMU	Phasor measurement units
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
SWL&P	Superior Water, Light and Power Company
TOU	Time-of-Use
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.