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September 30, 2010

Ms. Mary Jo Kunkle  
Executive Secretary  
Michigan Public Service Commission  
6545 Mercantile Way, Ste 7  
Lansing, MI 48911

Re: 2011 PSCR Plan  
MPSC Case No. U-16424

Dear Ms. Kunkle:

Enclosed please find the: (i) Application; (ii) Testimony and Exhibits (A-1 through A-11) of Thomas P. Lorden; and (iii) Testimony and Exhibits (A-12 through A-15 with A-13 and A-14 being partially redacted) of Jeff Knitter on behalf of Wisconsin Electric Power Company.

Additionally, a marked-up Notice of Hearing is being e-mailed to Cathy Bowers ([bowersc1@michigan.gov](mailto:bowersc1@michigan.gov)) and Gloria Jones ([jonesgl@michigan.gov](mailto:jonesgl@michigan.gov)).

If you have any questions, please kindly advise.

Very truly yours,

Miller, Canfield, Paddock and Stone, P.L.C.

By: \_\_\_\_\_  
Ronald W. Bloomberg

RWB/cla  
Enclosures

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

\_\_\_\_\_  
In the matter of the application of )  
WISCONSIN ELECTRIC POWER COMPANY )  
d/b/a We Energies for approval of a power )  
supply cost recovery plan and authorization ) Case No. U-16424  
of monthly power supply cost recovery factors )  
for the calendar year 2011 )  
\_\_\_\_\_

**APPLICATION**

WISCONSIN ELECTRIC POWER COMPANY d/b/a We Energies (“Wisconsin Electric” or the “Company”) applies for approval, pursuant to 1982 PA 304 (“Act 304”) of its Power Supply Cost Recovery (“PSCR”) plan and five-year forecast and for authority to implement PSCR factors for the calendar year 2011. In support thereof, Wisconsin Electric respectfully represents to the Michigan Public Service Commission (“Commission”) as follows:

1. Wisconsin Electric is a public service corporation organized under the laws of Wisconsin with its principal offices located in Milwaukee, Wisconsin, and is engaged primarily in public utility operations. Wisconsin Electric is also authorized to do business in Michigan and provides retail electric service to the public in service areas located in the Upper Peninsula, including the Counties of Alger, Baraga, Delta, Dickinson, Gogebic, Houghton, Iron, Marquette, Menominee and Ontonagon.
2. Wisconsin Electric’s retail electric business in Michigan is subject to the Commission’s jurisdiction pursuant to 1909 PA 106 as amended, MCL 460.551

et seq.; 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; and 1939 PA 3, as amended, MCL 460.1 et seq.

3. Incorporated in Wisconsin Electric's rate schedules is a PSCR clause as authorized by the Commission pursuant to Section 6j(2) of Act 304 in its Opinion and Order, dated March 20, 1984, in Case No. U-7635.
4. Pursuant to Section 6j(3) of Act 304, Wisconsin Electric seeks to implement its PSCR clause for the calendar year of 2011 by filing its 2011 PSCR plan and factors, together with its five-year forecast, contemporaneously with this application. Wisconsin Electric is seeking approval of maximum authorized PSCR factors of \$0.00538/kWh to be implemented on customer's bills for the calendar months of January 2011 through December 2011. The proposed factor is calculated based upon: (i) the cost base of power supply included in base rates of \$40.54 per MWh at the customer level; (ii) a 2011 PSCR factor of \$0.00305/kWh; and (iii) a prior year reconciliation surcharge of \$0.00233/kWh. The 2011 PSCR plan and factors and the five-year forecast are described in and supported by the testimony and exhibits of Thomas P. Lorden and Jeff Knitter.
5. Wisconsin Electric represents that its proposed 2011 PSCR plan and factors and five-year forecast are reasonable, prudent and in the public interest.

WHEREFORE, Wisconsin Electric prays that this Commission:

1. Make and issue a Notice of Hearing, and after notice of hearing;
2. Determine that decisions underlying Wisconsin Electric's PSCR plan are reasonable and prudent;
3. Approve the PSCR plan as proposed by Wisconsin Electric;
4. Approve the twelve monthly PSCR factors of \$0.00538 per kWh based upon: (i) a current base cost of power supply included in base rates of \$40.54 per MWh at customer level; (ii) a proposed 2011 PSCR factor of \$0.00305/kWh; and (iii) the prior year reconciliation surcharge of \$0.00233/kWh;
5. Determine that the decisions underlying the five-year forecast are reasonable and prudent; and
6. Grant Wisconsin Electric such other and further authority as may be lawful and proper.

Respectfully submitted,  
WISCONSIN ELECTRIC POWER COMPANY  
d/b/a We Energies

Dated: September 30, 2010

By: \_\_\_\_\_  
Ronald W. Bloomberg (P30011)  
Sherri A. Wellman (P38989)  
MILLER, CANFIELD, PADDOCK  
AND STONE, P.L.C.  
One Michigan Avenue, Suite 900  
Lansing, MI 48933  
(517) 487-2070

S T A T E   O F   M I C H I G A N  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of )  
**WISCONSIN ELECTRIC POWER COMPANY** )  
d/b/a We Energies for approval of a power )  
supply cost recovery plan and authorization ) Case No. U-16424  
of monthly power supply cost recovery factors )  
for the calendar year 2011 )

DIRECT TESTIMONY OF THOMAS P. LORDEN

ON BEHALF OF

WISCONSIN ELECTRIC POWER COMPANY

September, 2010

**WISCONSIN ELECTRIC POWER COMPANY****Before the Michigan Public Service Commission****Direct Testimony of Thomas P. Lorden**

1 Q. Please state your name and business address.

2 A. Thomas P. Lorden, 231 West Michigan Street, Milwaukee,  
3 Wisconsin 53203.

4 Q. What is your present employment?

5 A. I am employed by Wisconsin Electric Power Company, d/b/a We  
6 Energies ("Wisconsin Electric" or "Company") as a Senior  
7 Project Specialist in the Regulatory Affairs and Policy  
8 Department. In this position, I am responsible for fuel  
9 filing and reporting to the various regulatory agencies.

10 Q. Please describe your qualifications and background.

11 A. I earned a Bachelor of Arts Degree in Business Administration  
12 from Marquette University with a specialization in finance in  
13 1980.

14 I joined Wisconsin Electric in 1968. From 1968 to 1975, I  
15 worked in the Plant Accounting Division. From 1975 until  
16 1980, I held various positions in the Load Research area of  
17 the Corporate Planning Department.

18 From 1980 to 1998, I was in the Rates Section. While in  
19 the Rates Section, I was involved in the development of  
20 numerous cost-of-service studies to support the Company's rate  
21 and regulatory needs. In my previous position, as Team Leader

1 for Fossil Fuel, Nuclear and Purchase Power Accounting, I was  
2 responsible for fuel accounting and reporting. I have  
3 previously testified before the Michigan Public Service  
4 Commission ("MPSC" or "Commission") on cost-of-service in Case  
5 Nos.U-7592, U-10000 and U-10183. I have also provided  
6 testimony for the 2010 Power Supply Cost Recovery ("PSCR")  
7 plan in Case No.U-16034, 2009 PSCR reconciliation in Case  
8 No.U-15664-R, 2009 PSCR plan in Case No.U-15664, 2008 PSCR  
9 reconciliation in Case No.U-15404-R, 2008 PSCR plan in Case  
10 No.U-15404, 2007 PSCR reconciliation in Case No.U-15007-R,  
11 2007 PSCR Plan in Case No.U-15007, 2006 PSCR reconciliation in  
12 Case No.U-14707-R, 2006 PSCR plan in Case No.U-14707, 2005  
13 PSCR reconciliation in Case No.U-14264-R, 2005 PSCR plan in  
14 Case No.U-14264, 2004 PSCR reconciliation in Case No.U-13907-  
15 R, 2004 PSCR plan in Case No.U-13907, 2003 PSCR plan in Case  
16 No.U-13556, 2003 PSCR reconciliation in Case No.U-13556-R,  
17 2002 PSCR plan in Case No.U-13107, 2002 PSCR reconciliation in  
18 Case No.U-13107-R, 2001 PSCR plan in Case No.U-12615, 2001  
19 PSCR reconciliation in Case No.U-12615-R, the 1995 PSCR plan  
20 in Case No.U-10707 and the 1994 PSCR reconciliation in Case  
21 No.U-10428-R.

22 Q. What is the purpose of your testimony in this proceeding?

23 A. The purpose of my testimony is to develop the PSCR factors for  
24 the period covered by the Company's 2011 PSCR plan. To do  
25 this, I developed the average power supply costs using the  
26 projected costs for January through December, 2011. The

1 factors were calculated using the base power supply costs from  
2 the generation and purchased power requirements and costs as  
3 ordered by the Commission in its Opinion and Order issued in  
4 Case No. U-15981, on July 1, 2010.

5 Q. Are you sponsoring any exhibits in this proceeding?

6 A. Yes, I am sponsoring Exhibits A-1 (TPL-1) through A-11 (TPL-  
7 11). These exhibits relate to the Company's forecast of  
8 electric sales, procurement of fossil fuels, projected fuel  
9 costs, the operation of the Company's generating units and the  
10 estimates of purchased power and energy interchange for the  
11 year 2011 and for the forecast period of 2012 through 2015.

12 Q. Were these exhibits prepared by you or under your direction and  
13 supervision?

14 A. Yes.

15 **OVERVIEW**

16 Q. Could you provide an overview of the process by which fuel and  
17 purchase power expenses are projected?

18 A. Yes. The process can be divided into three distinct steps.

19 Q. Please describe the first step.

20 A. The process begins by forecasting the electrical energy and  
21 demand requirements of Wisconsin Electric customers. This  
22 work is performed by the Forecasting Team of the Finance  
23 Department using econometric modeling and time trending.

24 Q. Please describe the second step.

25 A. The second step is to project the operation of the generating  
26 system needed to meet the forecasted energy and demand

1 requirements. This work is performed by the Planning Section  
2 of Wholesale Energy & Fuels Department ("WEAF") using a  
3 production cost model. Both the quantities of fossil fuel  
4 burned and the amounts of power purchased and energy  
5 interchanged are projected in this step.

6 Q. Please describe the third step.

7 A. The third step is to project the delivered cost of fossil  
8 fuels required by the above fuel consumption projection. This  
9 work is performed by WEAF. Due to the relationships between  
10 quantity of fuel delivered and the price of fuel delivered,  
11 there may be several iterations performed between steps two  
12 and three.

### 13 SALES FORECASTS

14 Q. Please discuss each of these three general steps in more  
15 detail, beginning with the forecast of energy and demand  
16 requirements for the period 2011 through 2015.

17 A. The forecast was developed in the third quarter of 2010 using  
18 historical sales and weather data through May 2010 and  
19 forecasts of economic and demographic activity issued in June  
20 2010.

21 Q. Would you please describe the steps involved in the  
22 development of the energy forecast?

23 A. The first and most fundamental step in the process is the  
24 development of the billing month or "billed" forecasts for  
25 each of the customer segments or "sectors" served. In this  
26 step, monthly historical sales as maintained in our billing

1 system are statistically related to economic, demographic,  
2 weather-related, and time-dependent variables, using a  
3 technique generally referred to as regression analysis.

4 Regression analysis quantifies the relationships between sales  
5 and these other variables, collectively referred to as driving  
6 variables or "drivers", into regression coefficients.

7 Forecast values of the drivers supplied by a vendor (Moody's  
8 Economy.com or MEDC) are then multiplied by the regression  
9 coefficients to project sales into the forecast period. The  
10 three largest sectors are the residential, commercial, and  
11 industrial sectors; customers are classified as commercial and  
12 industrial based on their Standard Industrial Classification  
13 (SIC) codes. The smaller sectors include street lighting and  
14 other retail or "Public Authority", municipal, and firm sales  
15 under contracts to other utilities.

16  
17 In the second step, the monthly billed sector forecasts are  
18 aggregated by broad rate class and jurisdiction, and then  
19 disaggregated into specific rate schedules based on historical  
20 relationships and observable trends. In some cases, sectors  
21 and rate classes coincide, e.g. residential sectors sales are  
22 the same as residential rate class sales (although the WI  
23 jurisdiction has a Farm rate class which is generally included  
24 under the Residential rate classification). This is not the  
25 case with the commercial and industrial sectors. The  
26 commercial sector, which includes customers groups like

1 Retail, Office, and Healthcare, consists of both General  
2 Secondary (sometimes called Small Commercial and Industrial or  
3 Small C&I) and General Primary (or Large Commercial and  
4 Industrial or Large C&I) customers. In terms of Company-wide  
5 energy sales, roughly 75% of commercial sector sales falls  
6 into the General Secondary rate class, and the remainder falls  
7 into the General Primary class. The industrial sector, which  
8 includes customers in Mining (SIC 10) and manufacturers of  
9 durable goods (like Primary Metals or SIC 33) and non-durable  
10 goods (like Paper and Allied Products or SIC 26), also  
11 consists of both General Secondary and General Primary  
12 customers. The Company-wide rate class mix for the industrial  
13 sector reflects the energy-intensive nature of the processes  
14 in which these customers are engaged; roughly 75% of  
15 industrial energy sales (excluding sales to two very large  
16 industrial customers) fall into the General Primary rate class  
17 and the remainder falls in to the General Secondary rate  
18 class.

19  
20 The third major step in the forecast process is the conversion  
21 of billing month or billed sales to calendar month sales.  
22 This step is necessary because the periods for which  
23 particular customers are billed do not generally coincide with  
24 calendar months. By examining historical billing patterns and  
25 their relationships with the calendar, estimates are made  
26 which essentially allocate the billed energy to specific

1 calendar periods. For example, a customer may be billed on or  
2 around the tenth day of each calendar month. That customer's  
3 consumption for a given billing month, therefore, must be  
4 allocated to two calendar months. Calendar month sales  
5 consequently are composed of a billed portion and an  
6 "unbilled" portion. The convention used in calculating  
7 calendar or "booked" sales is described as follows:

$$\begin{aligned} 8 & \\ 9 & \quad \text{Current period booked} = \text{current period billed} \\ 10 & \quad \quad \quad + \text{Current period unbilled} \\ 11 & \quad \quad \quad - \quad \text{Prior period unbilled.} \\ 12 & \end{aligned}$$

13 Over an extended period, the difference between the two  
14 unbilled quantities becomes small relative to the billed  
15 quantity, so billed sales and booked sales tend to converge.  
16 On a month-to-month basis, however, consumption can shift  
17 substantially, especially if weather or the customers'  
18 operations are particularly volatile. Furthermore, booked  
19 sales are generally regarded as more relevant for revenue  
20 calculations and financial reporting, and operational planning  
21 is also calendar-oriented, so this conversion process is  
22 essential.

23 The fourth step, which incorporates the impacts of expanded  
24 energy efficiency efforts, is new to the forecast process.  
25 The booked sales forecast, as originally developed, implicitly  
26 includes the impacts of prior years' conservation/energy

1 efficiency measures i.e., those which are embedded in the  
2 historical sales. However, the expanded level of effort, such  
3 as that mandated by Michigan's RPS statute, PA 295 of 2008, is  
4 not included, either explicitly or implicitly, in this initial  
5 forecast. For 2012 through 2015, however, the energy  
6 forecasts for only the Residential and General Secondary rate  
7 classes are reduced by the incremental difference between the  
8 impact of measures already implemented and the impact of  
9 future programs. These incremental differences are further  
10 reduced each year by a factor that accounts for the  
11 persistence of these energy savings over time. These  
12 reductions align the forecast with the RPS statute. For 2011,  
13 the energy forecast for Residential and General Secondary rate  
14 classes has not been adjusted for the effects of expanded  
15 energy efficiency efforts.

16 In the fifth step of the process, distribution loss factors  
17 are applied which convert booked / calendar month sales to  
18 transmission level and transmission loss factors are  
19 subsequently applied to reach generation level. Transmission  
20 level sales are required for fuel and purchased power  
21 planning. Generation level sales are used in the forecast of  
22 peak demand, which is needed for capacity planning. The  
23 distribution loss factors were initially developed in a study  
24 completed in 2005 and are specific to rate schedule,  
25 jurisdiction, and serving voltage. Transmission losses are  
26 set at 1.84%, based upon MISO convention.

1 Q. What are the drivers of the billed sector forecasts?

2 A. The residential sector forecast is a product of separate  
3 forecasts of customers and use per customer. The residential  
4 customer forecast is based on the historical relationship  
5 between changes in the housing stock in the WI and MI counties  
6 in our service territory and the number of customers we serve  
7 in those counties. The use per customer forecast is based  
8 largely on weather (heating degree days base 65 or "HDD65" and  
9 a residential cumulative temperature humidity index or "CTHI")  
10 a time-trend variable which simulates recent historical  
11 changes in weather-adjusted use and disposable personal  
12 income. The commercial sector forecast is driven primarily by  
13 weather (heating degree days base 50 and commercial CTHI) and  
14 employment in commercial businesses such as Hospitality,  
15 Trade, and Professional and Business Services. The industrial  
16 sector forecast is driven primarily by an index of  
17 manufacturing industrial production (IPX) and by information  
18 acquired by our Customer Relations personnel in consultation  
19 with specific customers regarding their expectations for  
20 future operations. Municipal sales are forecast based on  
21 trends in recent historical usage and contract length. Street  
22 lighting and other retail usage changes is relatively  
23 constant, so historical usage is used as its forecast. The  
24 forecasts for firm sales under contract to other utilities are  
25 based on contract terms and expectations of market conditions.

1 Q. Would you please describe the steps involved in the  
2 development of the net native system peak demand forecast?

3 A. There are eight major steps in the development of the forecast  
4 of monthly net native system peak demand.

5  
6 The first step is to update the historical values of  
7 native system peak demand (excluding the Empire and  
8 Tilden mine load) before load management.

9  
10 The second step is to update the monthly historical and  
11 forecast values for average weather and peak producing  
12 weather.

13  
14 The third step is to update the monthly historical and  
15 forecast values of non-mine native system energy.

16  
17 The fourth step is updating the historical and forecast  
18 values for residential and farm customers and the  
19 saturation rates for central air conditioners, room air  
20 conditioners, and electric space heating.

21  
22 The fifth step is to project the cooling load factor  
23 (CLF), which quantifies the load response to summer  
24 weather and the projected number of air conditioners  
25 determined in the fourth step and the weather determined  
26 in the second step

27  
28 The sixth step is the regression of monthly peak load  
29 from the first step and non-mine native system energy  
30 (step 3), weather (step 2), cooling load (step 5), and  
31 binary variables to account for (December) holiday usage,  
32 and public appeals for energy conservation.

33  
34 The seventh step involves examining the residual values  
35 of the regression equations to determine if any monthly  
36 patterns are evident and if so, to estimate their values  
37 and adjust the forecast values from the sixth step  
38 accordingly.

39  
40 The eighth step is to add the monthly (negative) amounts  
41 of Empire and Tilden curtailable load and the (negative)  
42 amounts from the other interruptible and curtailable  
43 customers and direct load control of air conditioners.  
44 This results in the monthly forecast of net native system  
45 peak demand.

46  
47

1 Q. Are you sponsoring any exhibits relating to the sales forecast  
2 portion of your testimony?

3 A. Yes. I am sponsoring Exhibits A-1 (TPL-1) and A-2 (TPL-2)  
4 which were prepared under my direction.

5 Q. What does Exhibit A-1 (TPL-1) show?

6 A. The System's Energy forecasts for 2011-2015 along with the  
7 System Native Peak Demand are presented in Exhibit A-1 (TPL-  
8 1).

9 Q. Have you included a forecast for electricity requirements for  
10 2011-2015 in the Company's Michigan service territory?

11 A. Yes. The Michigan service territory's sales are presented in  
12 Exhibit A-2 (TPL-2). This exhibit is based upon the Company  
13 forecast methodologies discussed previously.

14 Q. Are there any noteworthy differences between the historical  
15 consumption patterns of Wisconsin Electric's Michigan  
16 customers and the patterns reflected in 2011-2015?

17 A. Yes, there are several differences. First, an industrial  
18 customer is expecting to cease operations by the end of 2010,  
19 reducing its monthly purchases from Wisconsin Electric to zero  
20 from approximately 3,000 to 4,000 MWh in recent years.

21 Second, two municipal customer contracts expire during the  
22 second quarter of 2011, reducing Wisconsin Electric's monthly  
23 municipal sales in Michigan by a similar amount. Later in  
24 2011, a second industrial customer is expected to begin  
25 supplying itself with the majority of its energy requirements,  
26 reducing Wisconsin Electric's sales by 15,000 to 20,000 MWh

1 per month. Fourth, the resources of one of the two very large  
2 industrial customer's (mentioned earlier) are expected to be  
3 depleted by the end of 2014. The shutdown of that operation  
4 is expected to reduce Wisconsin Electric's sales by  
5 approximately 75,000 MWh per month beginning in 2015.

6 Q. Do you consider these forecasts to be reasonable?

7 A. Yes.

8 **OPERATION OF GENERATING SYSTEM**

9 Q. You previously stated that the second general step in the  
10 process of projecting fuel costs is to project the operation of  
11 the generating system needed to meet the forecasted energy and  
12 demand requirements. Could you describe this step in more  
13 detail?

14 A. WEAFF staff reviews the projected system demand and energy and  
15 evaluates the adequacy of the Company's generation resources.  
16 Factors that are incorporated in the plan for meeting customer  
17 load include: (1) generating unit operating characteristics,  
18 fuel costs, planned outage schedules, (2) firm transmission  
19 availability and (3) projections of energy costs from Midwest  
20 Independent System Operator ("MISO"). WEAFF staff then  
21 establishes the most economic energy mix of system generation  
22 and purchased power to adequately meet load projections  
23 consistent with reasonable levels of system reliability. In  
24 addition, the Company operates a steam utility system in  
25 downtown Milwaukee. Steam is supplied to the system from the  
26 Valley Power Plant. Fuel costs applicable to the steam utility

1 are calculated on a cost per million BTU basis. The allocation  
2 of the costs from the electric utility to the steam utility is  
3 provided as the Steam Transfer Credit. Similarly, the Company  
4 operates a steam and chilled water system at the Milwaukee  
5 County Grounds. This is a steam utility power plant, which  
6 also produces electric power for our system. Fuel costs  
7 applicable to the electric utility are calculated on a cost per  
8 million BTU basis. The allocation of the costs from the steam  
9 utility to the electric utility is provided as the Electric  
10 Transfer Debit.

11 Q. Are you sponsoring any exhibits as part of your testimony on  
12 forecasted system generation and purchased power?

13 A. Yes. I am sponsoring Exhibits A-3 (TPL-3) through A-8 (TPL-8).

14 Q. Were these exhibits prepared by you or under your direction?

15 A. Yes.

16 Q. Please identify and describe Exhibit A-3 (TPL-3).

17 A. Exhibit A-3 (TPL-3) indicates the projected monthly output and  
18 fuel cost for each generating facility on the Wisconsin  
19 Electric system.

20 Q. Please identify and describe Exhibit A-4 (TPL-4).

21 A. Exhibit A-4 (TPL-4) shows the monthly summary of projected  
22 megawatt hour production and fuel consumption and cost by  
23 various fuel types as well as the summary of these factors for  
24 the year 2011.

25 Q. Please identify and describe Exhibit A-5 (TPL-5).

1 A. Exhibit A-5 (TPL-5) indicates the forecast of annual  
2 interchange energy purchases and sales for the years 2011  
3 through 2015.

4 Q. Do you consider these exhibits to represent a reasonable  
5 forecast for 2011 through 2015?

6 A. Yes, I do. The forecast techniques are those utilized in  
7 planning and budgeting the Company's operations and utilize up-  
8 to-date assumptions and data. Results were reviewed and deemed  
9 reasonable by WEAFF staff and me.

10 Q. Returning to Exhibit A-5 (TPL-5) please describe the terms  
11 "Firm Purchases - Specific", "Renewable Energy - Other", "Act  
12 295 - Renewable Energy Plan", "Net Purchases from MISO Market",  
13 "NextEra Energy Point Beach, LLC."

14 A. The term "Firm Purchases - Specific" refers to signed contracts  
15 in place in the designated years for power purchases from  
16 others. More detail on these contracts is provided in Mr.  
17 Knitter's Exhibit A-13 (PDS-2).

18 The term "Renewable Energy - Other" refers to the purchase of  
19 energy which comes from natural resources that do not diminish  
20 with use—they are naturally and continually replenished and  
21 includes purchase from Customer-owned generation.

22 The term "Act 295 - Renewable Energy Plan" refers to renewable  
23 energy built or purchased used to meet the Renewable Portfolio  
24 Standards of Michigan's 2008 Public Act 295. This plan was  
25 approved in Case No.U-15812.

1 The term "Net Purchases from MISO Market" refers to energy  
2 purchased from the MISO energy market on an hourly basis.

3 "NextEra Energy Point Beach, LLC" (formerly FPL Energy Point  
4 Beach, LLC) refers to the purchased power contract for the  
5 output from the Point Beach power plant that was approved by  
6 the MPSC in Case No. U-15220 on September 25, 2007.

7 Q. Does the Company contemplate any firm purchases or sales  
8 involving capacity charges for periods in excess of six months?

9 A. Yes. Mr. Knitter's testimony and exhibits provide support for  
10 the capacity purchases and the firm sales of capacity.

11 Q. Have you provided the Company's capacity plan for the period  
12 2011-2015?

13 A. Yes. Exhibit A-8 (TPL-8) shows the calculation of the  
14 Company's capacity requirement for the years 2011-2015.

15 Q. Are there any additions or retirements of Company generation  
16 scheduled for 2011?

17 A. Yes. Mr. Knitter's testimony provides detail of the changes to  
18 the Company's generation assets affecting the 2011 PSCR plan.

19 Q. Does the Company plan any generating unit outages of more than  
20 90 days in duration during 2011?

21 A. Yes. During the Spring of 2011 the Company has scheduled a 13-  
22 week outage for one half of the generating capacity of unit 1  
23 at Germantown Generating Station for combustion unit inspection  
24 and engine overhaul. The Company has also scheduled a 12-week  
25 (84 days) full unit outage of unit 1 at the Paris Generating  
26 Station in the Spring of 2011 for generator inspection and

1 overhaul. Both units are expected to return to full service in  
2 May 2011. Combustion turbine equipment manufacturers recommend  
3 inspections and overhauls of units based on the accumulation of  
4 unit equivalent operating hours ("EOH"). The Company schedules  
5 a major overhaul, including generator inspection, on its  
6 combustion turbines every 24,000 EOH, or before seven years  
7 based on these recommendations.

8 Q. Were these outages caused or prolonged as a result of the  
9 Company's negligence or mismanagement?

10 A. No.

11 Q. Do the exhibits which you are sponsoring reflect the cost of  
12 sulfur dioxide ("SO2") emission allowances or fuel handling and  
13 ash disposal costs?

14 A. The exhibits include SO2 allowances estimated at less than  
15 \$1,000 for 2011. The exhibits do not include the cost of fuel  
16 handling and ash disposal.

17 Q. Please describe briefly the procedure by which the forecasts  
18 and projections identified in Exhibits A-3 (TPL-3) through A-6  
19 (TPL-6) are prepared.

20 A. WEAFF distributes the generation requirements among the various  
21 power plants on an economic loading basis utilizing computer  
22 programs which consider such factors as firm purchase or sale  
23 commitments, scheduled outages, forced outage experience,  
24 estimates of MISO energy market activity, additions or  
25 subtractions of generating resources, unit heat rate, estimated  
26 fuel costs, etc. As the computer program determines generation

1 requirements on an economic dispatch basis, under normal  
2 forecasted conditions, it does not address the extent to which  
3 plants may be operated on other basis, such as meeting  
4 reliability requirements under actual conditions.

5 Q. Please identify and describe Exhibit A-6 (TPL-6).

6 A. Exhibit A-6 (TPL-6) indicates for each of the years 2011  
7 through 2015 the anticipated output of the Company's generating  
8 plants, fuel usage and fuel cost, anticipated interchanges and  
9 associated costs.

10 **RENEWABLE ENERGY**

11 Q. Please describe the background of Wisconsin Electric treatment  
12 of renewable energy costs in this PSCR plan proceeding.

13 A. In prior PSCR cases, Wisconsin Electric has included renewable  
14 energy and the cost of renewable energy purchases in its PSCR  
15 plan and costs. These costs include energy purchased from  
16 customers under Customer-owned generation tariffs, such as  
17 rate schedule CGS2 and CGS1. As with all other PSCR energy  
18 and costs, the cost of renewable energy purchases has been  
19 included in the determination of the average system-wide power  
20 supply costs used to calculate PSCR costs for Michigan. In  
21 all these proceedings, Wisconsin Electric has presented or  
22 proffered testimony that such costs were reasonably and  
23 prudently incurred. In each case, the Commission order has  
24 approved the PSCR costs which included the costs of such  
25 renewable energy.

1 In Case No.U-15981, Wisconsin Electric's most recent Michigan  
2 rate case, the Mines argued that the Commission should exclude  
3 from the revenue deficiency used to calculate base rates the  
4 costs of all renewables other than approved in Wisconsin  
5 Electric's Michigan renewable energy plan case, Case No. U-  
6 15812 and recovered via Wisconsin Electric's Michigan  
7 renewable energy surcharge. In response, Wisconsin Electric  
8 argued that all its renewable energy costs were incurred  
9 pursuant to reasonable and prudent management and should be  
10 included in determining revenue requirements except to the  
11 extent such costs were recovered via the Michigan renewable  
12 energy surcharge. The Commission's July 1, 2010 Order, pages  
13 39-40, stated:

14 While the Commission continues to believe that  
15 system-wide costs provide the most appropriate basis  
16 for determining the Michigan revenue deficiency, the  
17 Commission also believes that the Michigan RPS  
18 requirement must be recognized. In light of the  
19 approval of WEPCo's Michigan-specific surcharge, the  
20 Commission is not persuaded that costs related to  
21 compliance with Wisconsin's RPS should continue to  
22 be included in Michigan's revenue requirement. Act  
23 295 changed the regulatory landscape in Michigan.  
24 Pursuant to the Commission's order in Case No.U-  
25 15812, WEPCo is currently collecting its incremental  
26 cost of compliance with the Michigan RPS. The  
27 Commission agrees with the utility that all of its  
28 reasonable and prudent power supply costs are  
29 recoverable in a PSCR proceeding. The Mines  
30 projected \$5.389 million in Wisconsin RPS costs  
31 assigned to Michigan ratepayers. Exhibit MIN-79  
32 shows this to be made up of capital expenditures,  
33 O&M expenses, and power supply costs. Factoring in  
34 the impact of the sales forecasts adopted in this  
35 order, and subtracting the costs subject to the  
36 PSCR, the Commission finds that the amount assigned  
37 to Michigan ratepayers would be \$4.011 million.  
38 WEPCo's Michigan revenue requirement should be

1 reduced by \$4.011 million in costs related to  
2 compliance with the Wisconsin RPS. However, WEPCo  
3 is free to present evidence on these costs in its  
4 PSCR and RPS reconciliation proceedings. (Emphasis  
5 added)  
6

7 The amounts removed from the revenue requirement calculation  
8 upon which base rates were set were the investments in, and O&M  
9 costs related to, all the Company's hydro and wind generating  
10 stations.

11 Q. Please describe each Customer-owned generation tariff.

12 A. The CGS2 tariff is for generators that are rated at 20 kW or  
13 less. The Company purchases output in excess of the customers'  
14 needs from these small generators. There are approximately 90  
15 customers on this tariff generating power from wind, hydro,  
16 methane and other sources. The energy purchased from them at  
17 the COGS2 rate represents less than 0.1% of system  
18 requirements.

19 The CGS1 tariff is for generators that are rated over 20 kW.  
20 This tariff consists of a variety of mid-size to larger  
21 customer-owned generation systems ranging in size from about  
22 100 kW to over 10 MW. Purchases of output from these customers  
23 are made using the CGS1 rate negotiated contracts. The sources  
24 of energy for these generators include landfill gas, wind,  
25 hydro, agricultural waste and municipal waste. In aggregate,  
26 these purchases represent less than 1% of the system  
27 requirements.

28 Q. Are the renewable energy purchases for the "Energy for  
29 Tomorrow" program included in this case?

1 A. No, the purchase of renewable energy for use by customers that  
2 are participating in the Company's experimental "Energy for  
3 Tomorrow" program, which was approved by the Commission, on  
4 November 16, 1999, in Case No. U-12099, are not included in  
5 this case. The incremental cost of renewable energy is charged  
6 directly to the customers on the program as a rider.

7 Q. How have you addressed the costs of Renewable Energy - Other  
8 purchases in this 2011 PSCR plan in light of the Commission's  
9 ruling?

10 A. With regards to the cost of Renewable Energy - Other  
11 purchases, the Commission did not remove such costs from the  
12 revenue requirement used to determine base rates and the cost  
13 of power supply included in base rates. Rather it stated that  
14 Wisconsin Electric is free to present evidence on such costs  
15 in its PSCR proceedings. Also, the Commission Order stated  
16 that all power supply costs reasonably and prudently incurred  
17 are recoverable in PSCR proceedings and that determining the  
18 amount of such costs on a system-wide basis is most  
19 appropriate.

20 Therefore, Wisconsin Electric has included both the quantity  
21 and cost on a system-wide basis of its Renewable Energy -  
22 Other purchases in its 2011 PSCR plan. These purchases were  
23 made pursuant to reasonable and prudent management policy and  
24 applicable requirements, including the provisions of tariffs  
25 approved by the PSCW and by the Commission. The inclusion of  
26 these purchases in the PSCR plan and calculation of the PSCR

1 factor is consistent with the methodology uniformly used by  
2 the Commission in calculating average PSCR costs and factors  
3 on a system-wide basis. Determining average PSCR costs on  
4 this basis, and then applying these average costs to Michigan  
5 power supply consumption does not result in having the cost of  
6 power supply consumed in Wisconsin paid by Michigan customers.  
7 If the Commission were to remove the renewable energy from the  
8 plan, the PSCR plan would have to be revised to reflect the  
9 cost of to replace this energy.

10 Q. Please explain "ACT 295 - Renewable Energy Plan" as shown on  
11 Exhibit A-7 (TPL-7).

12 A. "ACT 295 - Renewable Energy Plan" refers to the new renewables  
13 Wisconsin Electric is acquiring to meet its obligation  
14 (subject to the statutory cap on renewable energy surcharges)  
15 under the Michigan RPS. Only the incremental cost (i.e.,  
16 above the transfer price) of these renewables is recoverable  
17 through the renewable energy surcharge. The transfer price  
18 was established as part of Wisconsin Electric's renewable  
19 energy plan in Case No.U-15812. For Wisconsin Electric to  
20 recover the full cost of these renewables reasonably and  
21 prudently obtained to meet the Michigan RPS, Wisconsin  
22 Electric must recover both the transfer price portion of the  
23 costs through its PSCR mechanism and the incremental costs  
24 through the renewable energy surcharge.

25 Q. Please explain "Wind & Hydro Repl Power" as shown on Exhibit  
26 A-7 (TPL-7).

- 1 A. As discussed above, the July 1, 2010 Order in Case No. U-15981  
2 removed the cost of hydro and wind generation from base rates.  
3 Consistent with the exclusion of these generation costs from  
4 Michigan rates, the Company began, effective July 1, 2010, by  
5 removing the wind and hydro generation from the calculation of  
6 its PSCR costs for Michigan and replacing it with purchased  
7 power, the cost of which was calculated by multiplying the  
8 excluded generation times the MISO energy price on an hourly  
9 basis.
- 10 Q. What is the cost related to the hydro and wind replacement  
11 power cost in 2011?
- 12 A. The hydro and wind replacement power cost for 2011 is  
13 \$27,858,068 or an average of \$31.34/MWh on a system-wide  
14 basis.
- 15 Q. How does this cost compare to the cost of hydro and wind plant  
16 and O&M expense that was excluded from base rates?
- 17 A. In 2011, for sales subject to PSCR, the replacement power cost  
18 amounts to \$2.431 million compared to \$4.011 million that was  
19 excluded from base rates.
- 20 Q. Do you believe this methodology for determining the impact on  
21 PSCR costs of excluding the generation and cost of hydro and  
22 wind plants from Michigan base rates is reasonable?
- 23 A. Yes. It would be unreasonable to include the generation from  
24 these plants in the calculation of the PSCR costs and factors  
25 while denying Wisconsin Electric an opportunity to recover the  
26 costs of the plants used to generate it. If such generation

1 and costs are excluded from the PSCR calculations, that  
2 generation must come from another source, and the MISO energy  
3 price is a reasonable representation of the marginal cost of  
4 obtaining this replacement energy. Although one might argue  
5 that the cost of this replacement energy should be directly  
6 assigned to Michigan as it was the action of Michigan which  
7 required these costs to be incurred, inputting these costs in  
8 the calculation of Wisconsin Electric's average system-wide  
9 cost is consistent with the methodology historically used in  
10 calculating PSCR costs.

11 Q. Were the costs of the wind and hydro project removed from base  
12 rates in Case No.U-15981 reasonably and prudently incurred?

13 A. Yes. For example, all of Wisconsin Electric's hydro systems  
14 were originally constructed more than 50 years old, pre-date  
15 any renewable energy requirement, and the costs thereof have  
16 always been included in base rates and PSCR factors. None were  
17 constructed for the purpose of complying with Wisconsin's RPS.  
18 For the generation from these plants to be included in the PSCR  
19 calculation, the investment and costs removed from rate base in  
20 Case No. U-15981 would have to be added to the Michigan PSCR  
21 costs, so that these costs could be recovered through the PSCR  
22 factor until the next general rate case.

23 **LOAD MANAGEMENT PROGRAMS**

24 Q. Does the Company have interruptible service rates on its  
25 system?

26 A. Yes.

1 Q. Please describe such service and its use in system operation.

2 A. In the Wisconsin retail area, the Company offers two general  
3 primary service rates for 15-minute integrated demands of 1,000  
4 kilowatts interruptible or greater, Cp2M and CPFN.

5 Cp2M provides the Company with the ability to interrupt such  
6 service during periods of operating capacity or reserve  
7 deficiency and for system energy economy constraints. The rate  
8 provides for no more than 300 hours of interruption per year.

9 An interruption is credited as the actual time of interruption  
10 or six hours, whichever is greater. Cp2M requires customers to  
11 be 100 percent interruptible.

12 CPFN is similar to Cp2M with the exception that it allows  
13 customers to select a level of firm load as long as they have  
14 at least 1,000 kW of interruptible load.

15 Q. How many customers are served on each interruptible rate?

16 A. As of September 2010, 10 customers are served on rate Cp2M and  
17 11 customers are served on rate CPFN. (There are no customers  
18 in Michigan on an interruptible rate.)

19 Q. How often are the interruptible customers typically  
20 interrupted?

21 A. Interruptions averaged 0.0 capacity related and 0.2 economy  
22 related interruptions per year for the six years ending in  
23 2009. In 2002 - 2004, and 2006 - 2009, and to date in 2010  
24 there were zero hours of capacity and zero hours of economic  
25 interruptions. In 2005, there were six hours of economic  
26 interruptions and zero hours of capacity interruptions

1 Q. Does the Company also offer curtailable service rates?

2 A. Yes.

3 Q. Please describe the various curtailable service rate options  
4 and their use in system operation.

5 A. The Company offers a general primary curtailable service rate  
6 for customers with a minimum of 500 kW of curtailable load and  
7 a secondary curtailable rate for customers with a minimum of  
8 100 kW of curtailable load. The rates provide for a maximum  
9 individual curtailment period of eight hours and no more than  
10 300 hours of curtailment per year. A curtailment is credited  
11 at the actual time of curtailment or four hours, whichever is  
12 greater. We also offer both general primary and general  
13 secondary Energy Co-operative Curtailable rate options  
14 available to customers with a minimum of 100 kW of curtailable  
15 load for general secondary customers and 300 kW for general  
16 primary customers. These services are utilized during periods  
17 of operating capacity or reserve deficiency and for daily  
18 operating economy. We also offer both general primary and  
19 general secondary Seasonal Curtailable rate options available  
20 to customers with a minimum of 100 kW of curtailable load for  
21 general secondary customers and 300 kW for general primary  
22 customers. These services are utilized during periods of  
23 operating capacity or reserve deficiency and for daily  
24 operating economy. This rate is effective April 1 - Sept 30  
25 annually.

1 Q. How many customers are served on curtailable rates and how  
2 often have they been curtailed?

3 A. Through September 2010, there were 76 customers, on the  
4 general primary and general secondary curtailable rates and 20  
5 customers on the general primary and general secondary Energy  
6 Co-operative Curtailable rate of which 4 customers in Michigan  
7 were served on curtailable rates. Two other Michigan  
8 customers have contracts with a curtailable option. There are  
9 6 customers on the new Seasonal Curtailable rate Cp3S  
10 (described above.) During 2002, 2004, 2007 through September  
11 2010 there were no curtailments. In 2003, there were two  
12 capacity related curtailments for a total of 16 hours. In  
13 2005, there was one economic curtailment for six hours. In  
14 2006, there was one capacity related curtailment for 5.25  
15 hours.

16 **BULK POWER OPERATIONS**

17 Q. Please describe the responsibility of the Company's Power  
18 Traders in WEAFF.

19 A. The Power Traders forecast system loads, evaluate generation  
20 availability and market opportunities, and develop generation  
21 resource offers and demand bids to reliably meet, at minimal  
22 system costs, the real time electric load requirements of the  
23 Company.

24 Q. How do the Power Traders project what load conditions will  
25 occur over the next 24-hour period?

1 A. The Power Traders use a variety of load-forecasting programs  
2 that integrate forecasted weather, calendar and historic data  
3 and simulate and calculate the various factors and conditions  
4 which affect load levels. The programs produce hour-by-hour  
5 projections of system load levels for the next seven days. The  
6 Power Traders develop load forecasts using the output of these  
7 programs along with adjustments based on current conditions,  
8 weather expectations and experience.

9 Q. How do the Power Traders minimize the cost of meeting electric  
10 load requirements?

11 A. This is done by effectively and continuously assessing and  
12 utilizing available resources, including company-owned or  
13 contracted generating assets, load assets, MISO and PJM energy  
14 market transactions, virtual bids and offers, transmission  
15 resources, and load management programs. The Power Traders are  
16 supported by sophisticated computer hardware and software  
17 programs that produce updated generator offer price matrices  
18 using up to the minute fuel cost data and perform analysis on  
19 large amounts of market operations data. These programs  
20 consider such factors as unit heat rates, unit fuel costs, ramp  
21 rates, maximum and minimum operating levels, and historic  
22 market operations data.

23 Power traders use these programs and tools to create  
24 demand bids in each of the two Wisconsin Electric load zones  
25 (WEC North and WEC South) and develop and adjust generation  
26 resource offers for each generator owned or under contract to

1 Wisconsin Electric. This information is submitted to the MISO  
2 Market, a bid/offer based energy market using security-  
3 constrained economic dispatch to produce locational marginal  
4 prices for the MISO market footprint. Resources located in the  
5 PJM market footprint are offered into the PJM market, with the  
6 energy and capacity represented by Dispatchable Tags in the  
7 MISO market.

8 Q. You have described how the Power Traders plan for the Day-Ahead  
9 operation. How does he/she operate in the Real-Time?

10 A. The Power Traders monitor current and projected generation  
11 status, load and market conditions, along with the operating  
12 plan represented by the Day-Ahead schedule and modify resource  
13 offers or, in some cases, utilize load management programs, as  
14 necessary to minimize the overall cost to serve load. Aided by  
15 the computerized, automatic generation control system, the  
16 Power Traders work with Electric System Operations personnel to  
17 schedule the generating units on- and off-line and load the  
18 units according to actual and anticipated MISO energy market  
19 results. In response to increases and decreases in load, and  
20 changes in the MISO generator setpoint instructions, the  
21 automatic generation control system adjusts loading on  
22 generating units consistent with the MISO energy market and  
23 reliability standards in order to achieve minimum system  
24 production costs.

25 Q. How do the Power Traders utilize load management programs for  
26 daily operating economy?

1 A. Included in the resources available to the Power Traders for  
2 minimizing overall system costs are numerous load management  
3 programs. While some programs are limited to capacity  
4 constraint situations and can only be utilized to avoid  
5 capacity shortfalls, others are designed to provide economic  
6 signals to customers to remove load from the system. These  
7 "economic" load management programs include a variety of  
8 programs offered to varying customer classes with both fixed  
9 and varying cost or incentive structures. The Power Traders  
10 are able to utilize these programs when it is economical to do  
11 so rather than to purchase more expensive energy.

12 Q. Is it your evaluation that the Company's decisions to provide  
13 power supply in the manner described in your testimony are  
14 reasonable and prudent?

15 A. Yes, in my opinion such decisions are reasonable and prudent.

16 **NATURAL GAS AND OIL PROCUREMENT**

17 Q. How does the Company procure natural gas and oil for  
18 generation?

19 A. Since a portion of the Company's gas fired generation is  
20 peaking capacity, called upon to run only after lower cost  
21 resources are already utilized, there can be significant  
22 uncertainty regarding the timing and quantity of natural gas  
23 consumption for electric generation. Because of this  
24 uncertainty, much of the Company's gas procurement must be in  
25 the daily and intra-day cash market. It would be highly  
26 speculative to make large quantities of natural gas purchases

1 far in advance of an uncertain need. Based upon the plan  
2 developed by the Power Trader, the Gas Resources group  
3 acquires natural gas through the combination of spot purchases  
4 and monthly term/baseload purchases. The Company solicits  
5 pricing proposals from multiple suppliers when seeking  
6 additional gas purchases and selects the lowest cost option,  
7 taking into consideration counter party credit issues and  
8 reliability concerns. This results in the most economical  
9 purchase plan for natural gas because of the variable and  
10 unpredictable amount of incremental load for which natural gas  
11 is utilized.

12 Oil is acquired through the use of spot purchases and bulk  
13 purchases stored in local terminals.

14 Q. What share of generation is met using natural gas and oil?

15 A. Including igniter usage at coal plants and the addition of the  
16 Port Washington combined cycle unit, natural gas and oil will  
17 account for approximately 16 percent of the energy generated  
18 (in MWh) by the Company, and approximately 26 percent of the  
19 Company's owned and leased generating capacity (in MW) in  
20 2011. In addition, the gas purchased for the Calpine Zion  
21 plant will provide 48,160 MWhs of energy in 2011.

22 Q. Does the Company purchase natural gas for any of its purchase  
23 power agreements ("PPAs")?

24 A. Yes. The Company's PPAs for the Calpine Zion plant has a  
25 tolling arrangement which allows the Company to purchase and  
26 deliver the natural gas to this plant as part of its natural

1 gas portfolio. As a benefit, the Company is able to achieve  
2 greater flexibility in natural gas scheduling, resulting in  
3 lowering natural gas costs.

4 Q. Does the Company supply natural gas to the LSP-Whitewater  
5 plant?

6 A. No.

7 Q. What is the impact of natural gas and oil costs in 2011?

8 A. The Company forecasts the use of 28 million MMBTU of natural  
9 gas in 2011 at \$5.45/MMBTU, for a total estimated cost of  
10 approximately \$152.4 million. The Company forecasts the use  
11 of 328,443 gallons of fuel oil in 2011 at \$2.73 per gallon,  
12 for a total estimated cost of approximately \$0.9 million.  
13 Forecasted gas usage at the Calpine Zion plant for 2011 is  
14 594,047 MMBTU at \$5.28/MMBTU, for a total projected cost of  
15 approximately \$3.1 million.

16 Q. In its 2011 PSCR plan, the Company has included risk  
17 management hedging costs for (1) natural gas for gas-fired  
18 generation, (2) oil for coal transportation and generation and  
19 (3) electric energy market. What is the basis for this hedging  
20 program, its intent and how does it benefit utility customers.

21 A. As a result of revisions to the Wisconsin Administrative  
22 Code (ch. PSC 116, Electric fuel rules), utilities in  
23 Wisconsin, may include the costs and benefits of fuel price  
24 risk management hedging tools in their fuel costs, provided  
25 the Public Service Commission of Wisconsin ("PSCW") has  
26 approved a risk management plan. The Company's most recent

1 integrated risk management plan was approved in December, 2008  
2 in Docket No.6630-GF-130.

3 The purpose of the program is to mitigate and protect against  
4 price spikes. The cost of the risk management hedging program  
5 is equivalent to an insurance premium against higher price  
6 spikes. Given the recent gas and oil prices, high volatility  
7 and concerns about storage and supply/demand imbalances, the  
8 Company believes it is important to protect customers from  
9 future price swings. While managing price risk does not  
10 equate to guaranteed savings, financially settled hedging can  
11 act like insurance and be a proper and prudent action when a  
12 negative event such as a price spike occurs.

13 Q. What is the amount for risk management plan that the Company  
14 is requesting to be included in its 2011 PSCR plan?

15 A. The Company has projected a cost of \$3,047,113 for the 2011  
16 PSCR plan.

17  
18 **TRANSMISSION COSTS**

19 Q. Will the Company's participation in American Transmission  
20 Company, LLC ("ATC") improve transmission access and  
21 reliability?

22 A. Yes. The transfer of the Company's transmission facilities to  
23 ATC, together with ATC's participation in the MISO, will  
24 benefit customers by improving reliability through the  
25 institution of a comprehensive, long-term planning process for

1 making needed transmission enhancements and upgrades on a  
2 regional basis.

3 Q. Is the Company active in reviewing transmission service rate  
4 proceedings by ATC and MISO?

5 A. Yes. The Company is active in reviewing transmission rate  
6 proceedings and where/when appropriate files intervention at  
7 FERC.

8 Q. What is the amount of transmission costs the Company is  
9 proposing to include in its 2011 PSCR plan costs?

10 A. The 2011 PSCR plan includes the 2011 network transmission costs  
11 for ATC, MISO and PJM of \$259,202,122. Exhibit A-6 (TPL-6)  
12 contains the forecasted ATC, MISO and PJM transmission costs  
13 including any administrative costs for the period 2011 through  
14 2015.

15 **2010 PSCR Estimated True-up**

16 Q. Have you included an estimate of the 2010 PSCR reconciliation  
17 and 2009 PSCR reconciliation true-up amount and factor?

18 A. Yes. The estimated 2010 PSCR reconciliation amounts to an under  
19 recovery of \$5,334,773 and the estimated 2009 PSCR  
20 Reconciliation true-up amounts to an under recovery of  
21 \$496,010. The projected total under recovery for 2010 and 2009  
22 true-up is \$5,830,783 and based on projected 2011 sales subject  
23 to PSCR, the estimated 2010 true-up factor equals \$0.00233 per  
24 kWh. See Exhibit A-9 (TPL-9), page 1.

25 **PSCR FACTORS**

1 Q. Have you compared the change in power supply costs from the  
2 2010 PSCR plan?

3 A. Yes. Exhibit A-7 (TPL-7) shows the power supply plan costs for  
4 both 2010 and 2011 and the difference in cost and MWh. For  
5 comparison purposes, the following 2010 plan costs were  
6 disaggregated: MISO Energy Market, Capacity Sales, Oppty. Sales  
7 - PJM and Oppty. Sales - MISO. For generation, the increased  
8 cost per MWh for 'Fuel' is due in part to the increase in coal  
9 price and a change in production mix due to the addition of the  
10 second unit of ERGS. For purchased power, the decrease in  
11 contribution to power supply cost is due to additional  
12 purchases from FPL (Point Beach) at a lower cost per MWh. The  
13 replacement power cost of hydro and wind generation contributed  
14 to an increase in the power supply costs. The lower projected  
15 price of opportunity sales, which includes capacity, also  
16 contributed to an increase in power supply costs.  
17 Transmission-related costs increased power supply costs. The  
18 following table shows the contribution by source of power  
19 supply costs:

20	<u>Description</u>	<u>PSCR Cost</u>
21	2010 PSCR Factor	(\$.00024)
22	Fuel	\$.00290
23	Purchased Power	(\$.00138)
24	Repl. Power - Hydro & Wind	\$.00096
25	Opportunity Sales	\$.00107
26	Network Transmission	<u>\$.00020</u>

1	Total Change	\$ .00351
2	Less: Change in PSCR Base	<u>(\$ .00046)</u>
3	2011 PSCR Plan Year Factor	\$ .00305

4 Q. Please describe Exhibit A-10 (TPL-10).

5 A. Page 1 of Exhibit A-10 (TPL-10) shows the Company's annual  
6 power supply cost recovery factor of 3.05 mills per kWh for  
7 January through December, 2011. The calculations in the top  
8 section of page 1 of Exhibit A-10 (TPL-10) derive monthly and  
9 an annual power supply cost recovery factors for 2011 using a  
10 base cost of power supply of \$40.54 per MWh at transmission  
11 level for costs. The base cost represents the power supply  
12 cost that was authorized by the Commission in Case No.U-15981,  
13 adjusted for distribution losses.

14 Page 2 of Exhibit A-10 (TPL-10) details the anticipated power  
15 supply costs and the net system requirement for the various  
16 energy sources for each month from January through December,  
17 2011. The net system requirements section of the page shows  
18 the anticipated generation mix which will be utilized in  
19 meeting the system requirements, includes coal and gas. The  
20 net system requirement also includes purchased power and  
21 external sales.

22 Q. What are the total system power supply costs for 2011?

23 A. The total system power supply costs for 2011 are  
24 \$1,316,273,335.

25 Q. Would you please describe the sources of the amounts provided  
26 on Page 2 of Exhibit A-10 (TPL-10)?

1 A. The costs and megawatt-hours for fossil, combustion turbine,  
2 hydraulic generation, purchased power, and external sales are  
3 summarized from Exhibit A-3 (TPL-3).

4 Q. Are there any anticipated adjustments to the costs?

5 A. No.

6 Q. How does the Company propose to apply the proposed power supply  
7 cost recovery factors?

8 A. The Company proposes to apply a uniform 2011 PSCR Plan Year  
9 Factor of \$0.00305 per kWh and a Prior Year's Factor of  
10 \$0.00233 per kWh. The proposed factors by month are shown on  
11 Exhibit A-11 (TPL-11).

12 Q. Does this conclude your testimony?

13 A. Yes, it does.

S T A T E   O F   M I C H I G A N  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of )  
**WISCONSIN ELECTRIC POWER COMPANY** )  
d/b/a We Energies for approval of a power )  
supply cost recovery plan and authorization ) Case No. U-16424  
of monthly power supply cost recovery factors )  
for the calendar year 2011 )

**EXHIBITS OF THOMAS P. LORDEN**  
  
**ON BEHALF OF**  
  
**WISCONSIN ELECTRIC POWER COMPANY**

SEPTEMBER, 2010

WISCONSIN ELECTRIC POWER COMPANY  
 Annual System Energy Obligation  
 2011-2015 (Megawatthours)

Line No.	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
Booked Sales					
1. Residential	8,278,235	8,172,377	8,174,333	8,265,527	8,363,258
2. General Secondary	8,611,116	8,757,827	8,925,510	9,052,752	9,131,053
3. General Primary	9,514,376	9,577,415	9,774,574	9,912,648	9,102,849
4. Public Authority	156,577	156,577	156,577	156,577	156,577
5. Ultimate Retail Sales	26,560,304	26,664,196	27,030,994	27,387,504	26,753,737
6. Municipal Sales	16,989	3,409	3,409	3,409	3,409
7. Company Use	65,254	65,254	65,254	65,254	65,254
8. Calendar - Customer Level	26,642,547	26,732,859	27,099,657	27,456,167	26,822,400
9. Losses: Distribution	1,118,183	1,121,795	1,132,866	1,146,845	1,158,184
10. Losses: Transmission	510,797	512,526	519,478	526,295	514,843
11. Total Native System Energy	28,271,527	28,367,180	28,752,001	29,129,307	28,495,427
12. Firm Wholesale Sales	2,644,125	2,805,066	2,593,457	2,431,766	2,439,574
13. Total Energy Obligation	30,915,652	31,172,246	31,345,458	31,561,073	30,935,001

WISCONSIN ELECTRIC POWER COMPANY  
 Monthly System Native Energy and Peak  
 2011-2015

**System Native Energy (Megawatthours)**

<u>Year</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>	<u>Total</u>
2011	2,442,334	2,205,648	2,323,355	2,138,895	2,184,694	2,499,419	2,685,378	2,690,291	2,320,199	2,257,038	2,131,588	2,392,689	28,271,528
2012	2,450,290	2,212,651	2,330,604	2,147,350	2,184,730	2,517,455	2,697,246	2,702,941	2,332,882	2,263,243	2,126,613	2,401,173	28,367,178
2013	2,485,373	2,243,398	2,364,403	2,179,957	2,207,697	2,560,727	2,735,762	2,742,676	2,368,231	2,292,256	2,145,169	2,426,352	28,752,001
2014	2,520,163	2,273,972	2,397,909	2,210,759	2,228,526	2,603,851	2,775,225	2,782,773	2,402,346	2,318,303	2,162,322	2,453,159	29,129,308
2015	2,469,410	2,227,156	2,345,067	2,158,100	2,163,316	2,567,024	2,735,618	2,738,893	2,357,528	2,250,341	2,096,775	2,386,197	28,495,425

**System Native Peak - Net (Megawatts)**

<u>Year</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>
2011	3,678	3,642	3,511	3,235	3,489	4,774	5,307	5,200	4,251	3,516	3,466	3,778
2012	3,693	3,533	3,524	3,249	3,477	4,798	5,322	5,215	4,264	3,526	3,459	3,781
2013	3,739	3,700	3,568	3,292	3,507	4,871	5,387	5,282	4,321	3,560	3,479	3,813
2014	3,787	3,747	3,614	3,335	3,538	4,948	5,459	5,355	4,380	3,595	3,501	3,851
2015	3,826	3,784	3,650	3,371	3,560	5,016	5,521	5,417	4,429	3,618	3,514	3,879

WISCONSIN ELECTRIC POWER COMPANY  
 Monthly Michigan Energy Obligation  
 2011 (Megawatthours)

Line No.	January	February	March	April	May	June	July	August	September	October	November	December	Total
<b>Booked Sales</b>													
1. Residential	17,911	14,344	14,852	12,461	11,742	12,044	13,262	13,216	12,047	13,063	14,325	17,951	167,218
2. General Secondary	12,631	11,312	12,677	11,252	11,586	12,525	13,403	13,129	12,277	11,949	10,825	12,630	146,196
3. General Primary	191,193	173,145	189,861	186,575	191,371	180,828	180,527	189,712	162,430	191,194	167,653	186,266	2,190,755
4. Public Authority	210	202	206	212	200	215	204	203	203	205	203	207	2,470
5. Ultimate Retail Sales (1)	221,945	199,003	217,596	210,500	214,899	205,612	207,396	216,260	186,957	216,411	193,006	217,054	2,506,639
6. Municipal Sales	3,953	3,567	3,345	2,748	1,417	231	258	266	255	284	319	344	16,987
7. Company Use	162	133	137	115	94	89	86	87	87	88	100	129	1,307
8. Calendar - Customer Level	226,060	202,703	221,078	213,363	216,410	205,932	207,740	216,613	187,299	216,783	193,425	217,527	2,524,933
9. Losses: Distribution	2,115	1,801	1,878	1,645	1,569	1,607	1,751	1,722	1,621	1,672	1,656	1,942	20,979
10. Losses: Transmission	4,198	3,763	4,102	3,956	4,011	3,819	3,855	4,017	3,476	4,020	3,589	4,038	46,844
11. Total Native System Energy	232,373	208,267	227,058	218,964	221,990	211,358	213,346	222,352	192,396	222,475	198,670	223,507	2,592,756
12. Firm Wholesale Sales	58,429	54,179	51,839	45,600	42,646	40,666	43,032	43,187	41,146	45,060	48,227	54,964	568,975
13. Total Energy Obligation	290,802	262,446	278,897	264,564	264,636	252,024	256,378	265,539	233,542	267,535	246,897	278,471	3,161,731

(1) Equals Michigan Sales Subject to PSCR.

WISCONSIN ELECTRIC POWER COMPANY  
 Annual Michigan Energy Obligation  
 2011-2015 (Megawatthours)

Line No.	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
Booked Sales					
1. Residential	167,218	165,023	166,138	170,168	173,503
2. General Secondary	146,196	148,366	151,114	153,236	154,568
3. General Primary	2,190,755	2,069,083	2,141,799	2,187,005	1,309,757
4. Public Authority	2,470	2,470	2,470	2,470	2,470
5. <b>Ultimate Retail Sales (1)</b>	<b>2,506,639</b>	<b>2,384,942</b>	<b>2,461,521</b>	<b>2,512,879</b>	<b>1,640,298</b>
6. Municipal Sales	16,987	3,409	3,409	3,409	3,409
7. Company Use	1,307	1,307	1,307	1,307	1,307
8. Calendar - Customer Level	2,524,933	2,389,658	2,466,237	2,517,595	1,645,014
9. Losses: Distribution	20,979	20,698	20,966	21,370	21,677
10. Losses: Transmission	46,844	44,351	45,765	46,717	30,667
11. Total Native System Energy	2,592,756	2,454,707	2,532,968	2,585,682	1,697,358
12. Firm Wholesale Sales	568,975	637,194	705,125	712,874	720,682
13. Total Energy Obligation	3,161,731	3,091,901	3,238,093	3,298,556	2,418,040

(1) Equals Michigan Sales Subject to PSCR.

Wisconsin Electric Power Company  
 2011 FUEL RUN

	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUN</u>	<u>JUL</u>	<u>AUG</u>	<u>SEP</u>	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>TOTAL</u>
<b><u>FOSSIL STEAM (ELECTRIC ONLY)</u></b>													
OAK CREEK													
ENERGY (MWH)	463,025	407,622	456,956	399,980	397,038	528,547	584,936	616,068	524,594	589,927	398,459	381,534	5,748,686
\$ - TOTAL	11,707,041	10,277,511	11,603,462	10,154,418	10,081,838	13,367,755	14,814,136	15,601,181	13,257,954	14,936,985	10,093,385	9,732,393	145,628,058
\$/MWh	25.28	25.21	25.39	25.39	25.39	25.29	25.33	25.32	25.27	25.32	25.33	25.51	25.33
PLEASANT PRAIRIE													
ENERGY (MWH)	723,829	357,805	378,561	425,715	366,703	573,846	674,387	640,641	690,753	666,582	665,981	721,620	6,886,424
\$ - TOTAL	15,242,194	8,002,923	8,592,805	9,889,174	8,477,060	13,216,446	15,574,942	14,850,279	15,972,853	15,470,766	15,428,615	16,842,653	157,560,710
\$/MWh	21.06	22.37	22.70	23.23	23.12	23.03	23.09	23.18	23.12	23.21	23.17	23.34	22.88
ELMROAD													
ENERGY (MWH)	293,348	416,637	512,247	412,300	520,267	468,269	489,214	497,678	408,280	213,751	375,145	293,248	4,900,383
\$ - TOTAL	7,808,251	11,317,717	14,098,497	11,541,043	14,632,827	13,236,690	13,911,450	14,180,427	11,700,139	6,238,402	10,798,445	8,519,406	137,983,294
\$/MWh	26.62	27.16	27.52	27.99	28.13	28.27	28.44	28.49	28.66	29.19	28.78	29.05	28.16
PRESQUE ISLE													
ENERGY (MWH)	237,814	186,367	175,667	198,231	203,111	179,016	180,415	186,278	197,275	201,198	213,500	232,326	2,391,198
\$ - TOTAL	6,805,458	5,287,198	5,161,450	6,159,412	6,416,782	5,423,443	5,860,434	5,985,428	6,354,681	6,421,115	7,089,423	8,012,229	74,977,054
\$/MWh	28.62	28.37	29.38	31.07	31.59	30.30	32.48	32.13	32.21	31.91	33.21	34.49	31.36
VALLEY													
ENERGY (MWH)	60,548	49,963	59,160	28,730	29,868	29,449	39,862	30,765	29,900	30,720	58,456	61,605	509,026
\$ - TOTAL	3,777,617	3,127,352	3,706,376	1,803,493	1,864,522	1,822,359	2,457,736	1,892,513	1,827,658	1,878,910	3,537,811	3,741,737	31,438,084
\$/MWh	62.39	62.59	62.65	62.77	62.43	61.88	61.66	61.52	61.13	61.16	60.52	60.74	61.76
MILW COUNTY PP													
ENERGY (MWH)	3,274	2,957	3,274	1,056	2,429	3,168	3,285	3,307	3,185	3,274	3,168	3,274	35,649
\$ - TOTAL	178,916	159,895	174,559	59,507	129,398	166,640	172,344	173,345	167,062	171,599	166,478	172,287	1,892,030
\$/MWh	54.65	54.08	53.32	56.35	53.28	52.60	52.47	52.41	52.46	52.42	52.55	52.63	53.07
So2 Allowances (ACCT. 509)	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FOSSIL STEAM(Electric Only)													
ENERGY (MWH)	1,781,837	1,421,350	1,585,865	1,466,011	1,519,416	1,782,296	1,972,100	1,974,737	1,853,986	1,705,452	1,714,709	1,693,608	20,471,367
\$ - TOTAL	45,519,476	38,172,596	43,337,149	39,607,047	41,602,428	47,233,332	52,791,041	52,683,174	49,280,347	45,117,777	47,114,156	47,020,705	549,479,229
\$/MWh	25.55	26.86	27.33	27.02	27.38	26.50	26.77	26.68	26.58	26.46	27.48	27.76	26.84
Other Power Generation Fuel Expense													
PORT WASHINGTON GENERATING STATION													
ENERGY (MWH)	260,291	367,615	374,305	262,448	205,416	388,899	279,124	473,232	201,949	297,979	354,582	362,877	3,828,716
\$ - TOTAL	10,578,790	14,255,510	14,310,772	10,187,970	8,317,641	14,652,251	11,097,540	18,014,611	8,445,852	11,996,669	14,724,177	15,803,278	152,385,061
\$/MWh	40.64	38.78	38.23	38.82	40.49	37.68	39.76	38.07	41.82	40.26	41.53	43.55	39.80
CONCORD													
ENERGY (MWH)	0	0	0	0	0	0	0	1,139	0	0	0	0	1,139
\$ - TOTAL	51,364	51,364	51,364	51,364	51,364	51,363	51,363	135,150	51,363	51,363	51,364	51,364	700,151
\$/MWh	0.00	1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00	11.00	614.80
GERMANTOWN													
ENERGY (MWH)	0	0	0	0	0	0	2,348	1,054	0	0	0	0	3,403
\$ - TOTAL	1,800	1,800	1,800	1,800	1,800	1,800	158,611	72,734	1,800	1,799	1,800	1,800	249,344
\$/MWh	0.00	1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00	11.00	73.28

Wisconsin Electric Power Company  
 2011 FUEL RUN

	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUN</u>	<u>JUL</u>	<u>AUG</u>	<u>SEP</u>	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>TOTAL</u>
PARIS													
ENERGY (MWH)	0	0	0	0	0	0	2,765	1,840	0	0	0	0	4,604
\$ - TOTAL	25,200	25,200	25,200	25,200	25,200	25,199	231,023	163,550	25,199	25,199	25,200	25,200	646,571
\$/MWh	0.00	1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00	11.00	140.42
TOTAL CTs													
ENERGY (MWH)	0	0	0	0	0	0	5,113	4,033	0	0	0	0	9,146
\$ - TOTAL	78,364	78,364	78,364	78,364	78,364	78,363	440,997	371,434	78,363	78,362	78,364	78,364	1,596,067
\$/MWh	0.00	0.00	0.00	0.00	0.00	0.00	86.25	92.10	0.00	0.00	0.00	0.00	174.51
REAL TIME GURARANTEE MAKE WHOLE - \$	-194,757	-491,037	-652,499	-246,634	-335,882	-813,703	-429,606	-715,317	-292,201	-648,733	-768,429	-13,461	-5,602,258
TOTAL OTHER PRODUCTION													
ENERGY (MWH)	260,291	367,615	374,305	262,448	205,416	388,899	284,237	477,265	201,949	297,979	354,582	362,877	3,837,862
\$ - TOTAL	10,462,397	13,842,837	13,736,637	10,019,701	8,060,122	13,916,910	11,108,932	17,670,728	8,232,014	11,426,298	14,034,112	15,868,181	148,378,870
\$/MWh	40.20	37.66	36.70	38.18	39.24	35.79	39.08	37.02	40.76	38.35	39.58	43.73	38.66
HYDRO													
HYDRO GENERATION (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
WIND													
WIND GENERATION (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL GENERATION FOSSIL,WIND & HYDRO													
ENERGY (MWH)	2,042,128	1,788,965	1,960,170	1,728,459	1,724,831	2,171,195	2,256,337	2,452,002	2,055,934	2,003,431	2,069,291	2,056,485	24,309,229
\$ - TOTAL	55,981,873	52,015,433	57,073,786	49,626,747	49,662,551	61,150,243	63,899,973	70,353,902	57,512,361	56,544,075	61,148,268	62,888,886	697,858,099
\$/MWh	27.41	29.08	29.12	28.71	28.79	28.16	28.32	28.69	27.97	28.22	29.55	30.58	28.71

Wisconsin Electric Power Company  
 2011 FUEL RUN

	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUN</u>	<u>JUL</u>	<u>AUG</u>	<u>SEP</u>	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>TOTAL</u>
PURCHASES													
LS POWER													
ENERGY (MWH)	76,647	99,661	117,843	58,274	77,953	75,978	135,463	135,125	103,137	104,662	99,908	66,953	1,151,604
\$ - TOTAL	7,237,439	8,139,139	8,778,519	6,410,742	7,185,472	7,135,847	9,557,353	9,591,594	8,311,008	8,438,116	8,447,226	7,209,045	96,441,501
REAL TIME GURARANTEE MAKE WHOLE - \$	-43,502	-105,555	-124,093	-56,097	-85,008	-98,665	-138,593	-167,100	-212,120	-185,900	-207,400	-4,532	-1,428,565
Total \$ Less Make Whole Revenue	7,193,938	8,033,585	8,654,426	6,354,644	7,100,463	7,037,182	9,418,761	9,424,494	8,098,888	8,252,216	8,239,826	7,204,513	95,012,936
\$/MWh	93.86	80.61	73.44	109.05	91.09	92.62	69.53	69.75	78.53	78.85	82.47	107.61	83.75
TOTAL NET GENERATION													
ENERGY (MWH)	2,118,775	1,888,626	2,078,013	1,786,733	1,802,784	2,247,173	2,391,799	2,587,127	2,159,071	2,108,093	2,169,200	2,123,438	25,460,832
\$ - TOTAL	63,175,811	60,049,018	65,728,212	55,981,392	56,763,014	68,187,424	73,318,734	79,778,396	65,611,250	64,796,291	69,388,095	70,093,399	792,871,035
\$/MWh	29.82	31.80	31.63	31.33	31.49	30.34	30.65	30.84	30.39	30.74	31.99	33.01	31.14
PURCHASES													
NET PURCHASES FROM MISO MARKET													
ENERGY (MWH)	18,106	12,496	101,525	127,177	115,329	12,149	28,081	1,195	7,506	38,853	18,775	51,937	533,130
\$ - TOTAL	557,373	344,336	2,752,255	3,750,350	3,607,135	388,835	2,391,595	394,299	286,559	1,116,129	641,202	1,595,508	17,825,575
\$/MWh	30.78	27.56	27.11	29.49	31.28	32.01	85.17	329.87	38.18	28.73	34.15	30.72	33.44
WIND & HYDRO REPL.. POWER													
ENERGY (MWH)	74,479	73,340	74,507	73,947	74,501	73,604	73,808	73,439	74,179	74,488	74,159	74,501	888,952
\$ - TOTAL	2,296,572	2,328,441	2,217,410	2,370,006	2,111,978	2,212,094	2,497,447	2,479,278	2,259,757	2,203,846	2,378,514	2,502,724	27,858,068
\$/MWh	30.84	31.75	29.76	32.05	28.35	30.05	33.84	33.76	30.46	29.59	32.07	33.59	31.34
TOTAL NET PURCHASES FROM MISO MARKET													
ENERGY (MWH)	92,585	85,836	176,032	201,123	189,830	85,753	101,889	74,635	81,685	113,341	92,934	126,438	1,422,082
\$ - TOTAL	2,853,945	2,672,778	4,969,665	6,120,356	5,719,113	2,600,929	4,889,042	2,873,577	2,546,315	3,319,975	3,019,716	4,098,232	45,683,643
\$/MWh	30.82	31.14	28.23	30.43	30.13	30.33	47.98	38.50	31.17	29.29	32.49	32.41	32.12
RENEWABLE ENERGY - OTHER													
ENERGY (MWH)	57,895	26,678	44,354	51,234	48,816	32,632	-2,312	5,831	17,208	17,770	24,248	23,284	347,638
\$ - TOTAL	2,935,912	1,359,978	2,255,495	2,604,051	2,481,561	1,661,658	-108,676	303,846	880,230	908,721	1,236,874	1,188,090	17,707,740
\$/MWh	50.71	50.98	50.85	50.83	50.83	50.92	47.00	52.11	51.15	51.14	51.01	51.03	50.94
ACT 295 - RENEWABLE ENERGY PLAN													
ENERGY (MWH)	4,726	13,826	13,826	13,824	13,826	13,826	13,826	13,826	13,826	13,826	13,826	13,826	156,809
\$ - TOTAL	236,516	691,989	691,989	691,900	691,989	691,989	691,989	691,989	691,989	691,989	691,989	691,970	7,848,290
\$/MWh	50.05	50.05	50.05	50.05	50.05	50.05	50.05	50.05	50.05	50.05	50.05	50.05	50.05
PJM Market - Zion													
ENERGY (MWH)	0	0	0	0	0	10,378	16,844	19,022	1,915	0	0	0	48,160
\$ - TOTAL	1,020,669	1,020,669	1,020,669	1,020,669	1,020,669	3,592,427	4,019,873	4,146,196	1,158,889	1,029,919	1,029,919	1,029,919	21,110,485
\$/MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	217.96	0.00	0.00	0.00	0.00	438.34
NEXTERA (PBNP_PPA)													
ENERGY (MWH)	761,748	685,171	724,182	631,368	702,961	754,221	816,912	809,981	760,281	810,624	687,938	575,143	8,720,531
\$ - TOTAL	30,017,832	27,382,340	24,450,255	21,172,856	29,335,373	38,850,175	49,407,307	51,072,719	39,289,647	26,917,334	22,943,952	22,948,657	383,788,446
\$/MWh	39.41	39.96	33.76	33.53	41.73	51.51	60.48	63.05	51.68	33.21	33.35	39.90	44.01
Other Purchases - Fixed Payments - \$													
Point-to-Point Transmission - \$	0	0	0	19,200	38,640	38,640	57,840	57,840	38,640	19,200	0	0	270,000
	16,054	16,054	16,054	16,054	16,054	16,054	16,054	16,054	16,054	16,054	16,054	16,054	192,643
TOTAL PURCHASES													
ENERGY (MWH)	993,601	911,172	1,076,237	955,824	1,033,386	972,789	1,082,622	1,058,419	978,051	1,060,223	918,855	805,644	11,846,822
\$ - TOTAL	44,274,866	41,177,392	42,058,552	37,999,730	46,403,861	54,489,053	68,392,190	68,586,715	52,720,652	41,155,408	37,178,329	37,177,434	571,614,183
\$/MWh	44.56	45.19	39.08	39.76	44.90	56.01	63.17	64.80	53.90	38.82	40.46	46.15	48.25

Wisconsin Electric Power Company  
 2011 FUEL RUN

	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUN</u>	<u>JUL</u>	<u>AUG</u>	<u>SEP</u>	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>TOTAL</u>
<b>SALES</b>													
<b>NET SALES INTO MISO MARKET</b>													
ENERGY (MWH)	404,563	321,556	529,963	368,737	379,609	485,502	487,727	649,881	561,033	644,250	695,309	303,934	5,832,064
\$ - TOTAL	11,204,093	9,380,485	14,950,587	11,153,049	10,769,801	11,601,250	12,849,810	17,306,663	15,164,086	18,379,895	21,552,069	8,962,059	163,273,847
\$/MWh	27.69	29.17	28.21	30.25	28.37	23.90	26.35	26.63	27.03	28.53	31.00	29.49	28.00
<b>Non-Firm Sales to PJM Market</b>													
ENERGY (MWH)	0	0	0	0	0	10,378	16,844	19,022	1,915	0	0	0	48,160
\$ - TOTAL	0	0	0	0	0	562,584	912,545	1,142,854	108,348	0	0	0	2,726,332
\$/MWh	0.00	0.00	0.00	0.00	0.00	54.21	54.18	60.08	56.58	0.00	0.00	0.00	56.61
Other Sales - Fixed Capacity Payments - \$	675,385	675,385	675,385	675,385	667,885	1,496,919	1,496,918	1,496,919	1,496,919	1,496,919	1,499,919	1,499,918	13,853,856
<b>TOTAL SALES</b>													
ENERGY (MWH)	404,563	321,556	529,963	368,737	379,609	495,880	504,571	668,903	562,948	644,250	695,309	303,934	5,880,223
\$ - TOTAL	11,879,478	10,055,870	15,625,972	11,828,434	11,437,686	13,660,753	15,259,273	19,946,436	16,769,352	19,876,814	23,051,988	10,461,977	179,854,035
\$/MWh	29.36	31.27	29.48	32.08	30.13	27.55	30.24	29.82	29.79	30.85	33.15	34.42	30.59
<b>NET OUTPUT = TOTAL GEN PLUS PURCHASES LESS SALES</b>													
ENERGY (MWH)	2,631,166	2,378,580	2,506,443	2,315,546	2,378,608	2,648,104	2,834,388	2,841,518	2,471,038	2,419,404	2,292,837	2,558,196	30,275,828
\$ - TOTAL	88,377,261	83,136,956	83,506,366	75,798,044	84,628,726	101,978,543	117,032,890	118,994,180	93,463,661	77,822,668	75,274,609	89,604,343	1,089,618,247
\$/MWh	33.59	34.95	33.32	32.73	35.58	38.51	41.29	41.88	37.82	32.17	32.83	35.03	35.99
MISO Energy Market Costs/Revenues	-2,805,975	-2,613,586	-2,177,317	-1,434,309	-1,442,280	-3,581,621	-2,819,284	-2,702,374	-2,068,045	-2,302,258	-2,053,822	-2,288,903	-28,289,774
<b>TOTAL NET OUTPUT AND MISO COSTS</b>													
ENERGY (MWH)	2,631,166	2,378,580	2,506,443	2,315,546	2,378,608	2,648,104	2,834,388	2,841,518	2,471,038	2,419,404	2,292,837	2,558,196	30,275,828
\$ - TOTAL	85,571,286	80,523,370	81,329,048	74,363,735	83,186,446	98,396,922	114,213,606	116,291,806	91,395,617	75,520,410	73,220,787	87,315,440	1,061,328,474
\$/MWh	32.52	33.85	32.45	32.11	34.97	37.16	40.30	40.93	36.99	31.21	31.93	34.13	35.06
NETWORK TRANSMISSION SERVICES	21,600,177	21,600,177	21,600,177	21,600,177	21,600,177	21,600,177	21,600,177	21,600,177	21,600,177	21,600,177	21,600,177	21,600,177	259,202,122
<b>ANCILLIARY SERVICES and PJM FTR MARKET REVENUE</b>													
MISO - ASM \$ - TOTAL	-737,993	-1,149,529	-355,691	-50,137	104,207	-35,759	-4,738	-20,280	18,918	-152,293	-287,654	-357,010	-3,027,958
PJM - FTR\$ - TOTAL	-150,000	-150,000	-150,000	-150,000	-150,000	0	0	0	0	0	0	0	-750,000
PJM - ASM \$ - TOTAL	0	0	0	0	0	-146,419	-188,447	-118,564	-25,872	0	0	0	-479,302
Total ASM Revenue	-887,993	-1,299,529	-505,691	-200,137	-45,793	-182,178	-193,185	-138,844	-6,954	-152,293	-287,654	-357,010	-4,257,260
<b>TOTAL POWER SUPPLY COSTS</b>													
ENERGY (MWH)	2,631,166	2,378,580	2,506,443	2,315,546	2,378,608	2,648,104	2,834,388	2,841,518	2,471,038	2,419,404	2,292,837	2,558,196	30,275,828
\$ - TOTAL	106,283,470	100,824,017	102,423,535	95,763,775	104,740,830	119,814,920	135,620,598	137,753,139	112,988,840	96,968,294	94,533,310	108,558,607	1,316,273,335
\$/MWh	40.39	42.39	40.86	41.36	44.03	45.25	47.85	48.48	45.73	40.08	41.23	42.44	43.48

**2011  
 GENERATION BY FUEL TYPE**

	<u>Fuel Type</u>	<u>MWh</u>	<u>Quantity(1)</u>	<u>\$/Mbtu</u>	<u>\$000</u>
<b>January</b>	Coal	1,778,787	1,017	2.39	45,159
	Gas/Prop.	263,027	1,890	5.69	10,760
	Oil	313	1	0.00	63
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	2,042,128		0.00	55,982
	<b>February</b>	Coal	1,419,442	753	2.58
Gas/Prop.		368,926	2,642	5.32	14,052
Oil		597	51	16.82	119
Hydro		0		0.00	0
Wind		0		0.00	0
SYSTEM		1,788,965		0.00	52,015
<b>March</b>		Coal	1,584,368	830	2.65
	Gas/Prop.	375,478	2,689	5.18	13,936
	Oil	324	27	16.87	64
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	1,960,170		0.00	57,074
	<b>April</b>	Coal	1,459,106	783	2.58
Gas/Prop.		268,831	1,945	5.40	10,506
Oil		523	45	16.87	105
Hydro		0		0.00	0
Wind		0		0.00	0
SYSTEM		1,728,459		0.00	49,627
<b>May</b>		Coal	1,516,100	784	2.66
	Gas/Prop.	208,599	1,500	5.57	8,363
	Oil	132	11	16.89	26
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	1,724,831		0.00	49,663
	<b>June</b>	Coal	1,778,057	966	2.55
Gas/Prop.		392,723	2,821	5.06	14,264
Oil		415	36	16.92	84
Hydro		0		0.00	0
Wind		0		0.00	0
SYSTEM		2,171,195		0.00	61,150
<b>July</b>		Coal	1,967,151	1,077	2.57
	Gas/Prop.	288,497	2,110	5.44	11,482
	Oil	689	59	17.04	140
	Hydro	0		15.92	0
	Wind	0		0.00	0
	SYSTEM	2,256,337		0.00	63,900

(1) Fuel Units: Coal-1,000Tons; Gas-1,000,000cf; Oil-1,000Gal.

**2011  
 GENERATION BY FUEL TYPE**

	<u>Fuel Type</u>	<u>MWh</u>	<u>Quantity(1)</u>	<u>\$/Mbtu</u>	<u>\$000</u>
<b>August</b>	Coal	1,969,190	1,071	2.57	52,145
	Gas/Prop.	482,230	3,490	5.18	18,091
	Oil	582	50	17.16	118
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	2,452,002		0.00	70,354
<b>September</b>	Coal	1,850,095	1,031	2.54	48,895
	Gas/Prop.	205,607	1,482	5.78	8,569
	Oil	232	20	17.32	48
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	2,055,934		0.00	57,512
<b>October</b>	Coal	1,701,515	990	2.48	44,724
	Gas/Prop.	301,726	2,169	5.43	11,781
	Oil	189	16	0.00	39
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	2,003,431		0.00	56,544
<b>November</b>	Coal	1,712,258	956	2.60	46,812
	Gas/Prop.	356,896	2,560	5.59	14,308
	Oil	137	12	17.60	29
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	2,069,291		0.00	61,148
<b>December</b>	Coal	1,688,171	966	2.59	46,501
	Gas/Prop.	368,009	2,648	6.17	16,324
	Oil	305	0	0.00	63
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	2,056,485		0.00	62,889
<b>Total</b>	Coal	20,424,241	11,225	2.56	544,525
	Gas/Prop.	3,880,549	27,945	5.45	152,435
	Oil	4,439	328	17.05	898
	Hydro	0		0.00	0
	Wind	0		0.00	0
	SYSTEM	24,309,229		0.00	697,858

(1) Fuel Units: Coal-1,000Tons; Gas-1,000,000cf; Oil-1,000Gal.

**ANNUAL INTERCHANGE PURCHASES FOR 2011-2015**  
 Dollars in (000)

<u>DESCRIPTION</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
<b>Firm Purchases - Specific</b>					
LSP Whitewater LP					
GWh	1,152	427	380	401	398
Total Cost	\$ 95,013	\$ 73,304	73,240	76,738	\$ 79,406
Zion Energy LLC (a)					
GWh	48	18	-	-	-
Total Cost	\$ 21,303	\$ 13,148	\$ 2,610	\$ -	\$ -
LSP Whitewater Excess					
GWh				-	-
Total Cost	\$ 270	\$ -	\$ -	\$ -	\$ -
<b>RENEWABLE ENERGY - OTHER</b>					
GWh	348	173	174	174	331
Total Cost	\$ 17,708	\$ 15,917	\$ 15,974	\$ 16,033	\$ 16,093
<b>Act 295 - Renewable Energy Plan</b>					
GWh	157	157	157	157	-
Total Cost	\$ 7,848	\$ 7,848	\$ 7,848	\$ 7,848	\$ -
<b>Net MISO Purchase Transactions</b>					
GWh	1,422	717	1,133	1,068	504
Total Cost	\$ 45,684	\$ 27,577	\$ 41,560	\$ 40,447	\$ 20,522
<b>NextEra Energy Point Beach, LLC</b>					
GWh	8,720	10,293	10,236	9,726	9,725
Total Cost	\$ 383,788	\$ 462,123	\$ 463,720	\$ 449,332	\$ 457,581
<b>Total Purchases</b>					
GWh	11,847	11,785	12,080	11,526	10,957
Total Cost	\$ 571,614	\$ 599,917	\$ 604,951	\$ 590,398	\$ 573,602

(a) Costs include a portion of the transmission costs. See Exhibit A-14 (JEK-2) for 2011.

**ANNUAL INTERCHANGE SALES FOR 2011-2015**  
 Dollars in (000)

<u>DESCRIPTION</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
<b>Non-firm Sales</b>					
<b>Net MISO Sales Transactions</b>					
GWh	5,832	4,924	4,493	4,244	4,432
Total Cost	\$ 163,274	\$ 158,940	\$ 139,547	\$ 138,375	\$ 154,274
Sales to PJM Market					
GWh	48	19	-	-	-
Total Sales	\$ 2,726	\$ 1,468	-	-	-
<b>Capacity Sales</b>					
Contracted - \$	13,854	10,752	4,668	4,103	1,740
Undesignated - \$	-	-	-	-	-
Total Capacity Sales	\$ 13,854	\$ 10,752	\$ 4,668	\$ 4,103	\$ 1,740
<b>Total Sales</b>					
GWh	5,880	4,943	4,493	4,244	4,432
Total Sales	\$ 179,854	\$ 171,160	\$ 144,215	\$ 142,478	\$ 156,014

**WISCONSIN ELECTRIC POWER COMPANY**  
**Projected MWh, Fuel, and Purchase Energy Expense**

For Year 2011

<u>PLANT</u>	<u>FUEL</u>	<u>GWH</u>	<u>GBTU</u>	<u>Cost</u> (\$000)	<u>\$/MWh</u>	<u>\$/MMBTU</u>
Oak Creek 5-8	Coal	5,738	58,016	144,916	25.26	2.50
Elm Road Generating Station	Coal	4,893	43,295	136,234	27.84	3.15
Port Washington 1-2	Gas	3,829	27,375	147,064	38.41	5.37
Valley 1-2	Coal	508	7,067	31,384	61.73	4.44
Pleasant Prairie 1-2	Coal	6,863	75,484	156,085	22.74	2.07
Presque Isle 5-9	Coal	2,387	28,506	74,079	31.04	2.60
Milwaukee County	Coal	36	385	1,827	51.27	4.75
Auxiliary Fuel	Oil	4	53	898	202.35	17.05
Auxiliary Fuel	Gas	43	445	4,056	95.02	9.11
Combustion Turbine	Gas	9	124	1,315	143.76	10.58
Hydro		-				
Wind		-				
<b>TOTAL GENERATION</b>		<b>24,309</b>	<b>240,750</b>	<b>697,858</b>	<b>28.71</b>	<b>2.90</b>
Purchase Energy		11,342		477,487	42.10	
Renewable Energy - Other		348		17,708	50.89	
Act 295 - Renewable Energy Plan		157		7,848	50.05	
Purchase Capacity				68,378		
Transmission Services				193		
Sales Energy		5,880		166,000	28.23	
Sales Capacity				13,854		
<b>NET OUTPUT</b>		<b>30,276</b>		<b>1,089,618</b>	<b>35.99</b>	
Open Market (MISO costs)				(28,290)		
Network Transmission Service				259,202		
Ancillary Services Market				(4,257)		
<b>TOTAL POWER SUPPLY COSTS</b>		<b>30,276</b>		<b>1,316,273</b>	<b>43.48</b>	

**WISCONSIN ELECTRIC POWER COMPANY**  
**Projected MWH, Fuel, and Purchase Energy Expense**

For Year 2012

<u>PLANT</u>	<u>FUEL</u>	<u>GWH</u>	<u>GBTU</u>	<u>Cost</u> (\$000)	<u>\$/MWh</u>	<u>\$/MMBTU</u>
Oak Creek 5-8	Coal	5,365	54,268	140,344	26.16	2.59
Elm Road Generating Station	Coal	5,253	46,494	157,138	29.91	3.38
Port Washington 1-2	Gas	1,550	11,082	81,565	52.63	7.36
Valley 1-2	Coal	509	7,079	31,036	60.94	4.38
Pleasant Prairie 1-2	Coal	7,226	79,485	171,686	23.76	2.16
Presque Isle 5-9	Coal	2,412	28,752	73,418	30.44	2.55
Milwaukee County	Coal	39	419	2,039	52.52	4.86
Auxiliary Fuel	Oil	1	10	181	217.95	18.34
Auxiliary Fuel	Gas	14	148	2,788	197.41	18.79
Combustion Turbine	Gas	16	219	1,948	121.85	8.89
Hydro		407				
Wind		325				
Act 295 - Renewable Energy Plan		395		31,877	80.41	
<b>TOTAL GENERATION</b>		<b>23,512</b>	<b>227,955</b>	<b>694,019</b>	<b>27.97</b>	<b>2.90</b>
Purchase Energy		11,455		512,627	44.75	
Renewable Energy - Other		330		15,917	48.23	
Act 295 - Renewable Energy Plan		157		7,848	50.05	
Purchase Capacity				63,502		
Transmission Services				24		
Sales Energy		4,943		160,408	32.45	
Sales Capacity				10,752		
<b>NET OUTPUT</b>		<b>30,512</b>		<b>1,122,778</b>	<b>36.80</b>	
Open Market (MISO costs)				(28,290)		
Network Transmission Service				266,727		
Ancilliary Services Market				(3,507)		
<b>TOTAL POWER SUPPLY COSTS</b>		<b>30,512</b>		<b>1,357,707</b>	<b>44.50</b>	

**WISCONSIN ELECTRIC POWER COMPANY**  
**Projected MWH, Fuel, and Purchase Energy Expense**

For Year 2013

<u>PLANT</u>	<u>FUEL</u>	<u>GWH</u>	<u>GBTU</u>	<u>Cost</u> (\$000)	<u>\$/MWh</u>	<u>\$/MMBTU</u>
Oak Creek 5-8	Coal	5,864	59,329	147,780	25.20	2.49
Elm Road Generating Station	Coal	4,930	43,611	156,783	31.80	3.60
Port Washington 1-2	Gas	1,297	9,274	72,970	56.26	7.87
Valley 1-2	Coal	498	6,923	31,057	62.35	4.49
Pleasant Prairie 1-2	Coal	6,802	74,806	167,429	24.61	2.24
Presque Isle 5-9	Coal	2,358	28,122	75,890	32.19	2.70
Milwaukee County	Coal	39	417	2,099	54.38	5.04
Auxiliary Fuel	Oil	1	11	200	221.79	18.63
Auxiliary Fuel	Gas	14	152	2,848	198.51	18.75
Combustion Turbine	Gas	1	11	50	56.93	4.43
Hydro		407				
Solar		7				
Wind Existing		324				
Act 295 - Renewable Energy Plan		396		31,825	80.41	
<b>TOTAL GENERATION</b>		<b>22,938</b>	<b>222,655</b>	<b>688,930</b>	<b>30.03</b>	<b>3.09</b>
Purchase Energy		11,748		524,851	44.67	
Renewable Energy - Other		332		15,974	48.11	
Act 295 - Renewable Energy Plan		157		7,848	50.05	
Purchase Capacity				56,256		
Transmission Services				24		
Sales Energy		4,493		139,547	31.06	
Sales Capacity				4,668		
<b>NET OUTPUT</b>		<b>30,682</b>		<b>1,149,667</b>	<b>37.47</b>	
Open Market (MISO costs)				(28,290)		
Network Transmission Service				278,271		
Ancillary Services Market				(3,507)		
<b>TOTAL POWER SUPPLY COSTS</b>		<b>30,682</b>		<b>1,396,141</b>	<b>45.50</b>	

**WISCONSIN ELECTRIC POWER COMPANY**  
**Projected MWH, Fuel, and Purchase Energy Expense**

For Year 2014

<u>PLANT</u>	<u>FUEL</u>	<u>GWH</u>	<u>GBTU</u>	<u>Cost</u> (\$000)	<u>\$/MWh</u>	<u>\$/MMBTU</u>
Oak Creek 5-8	Coal	5,807	58,785	148,877	25.64	2.53
Elm Road Generating Station	Coal	4,926	43,594	162,573	33.00	3.73
Port Washington 1-2	Gas	1,401	10,019	79,477	56.72	7.93
Valley 1-2	Coal	527	7,330	33,757	64.00	4.61
Pleasant Prairie 1-2	Coal	6,907	75,964	175,355	25.39	2.31
Presque Isle 5-9	Coal	2,408	28,702	77,014	31.99	2.68
Milwaukee County	Coal	39	418	2,147	55.49	5.14
Rothschild	Wood	137	2,078	6,487	47.18	3.12
Auxiliary Fuel	Oil	1	10	189	224.81	18.90
Auxiliary Fuel	Gas	14	150	2,927	207.25	19.57
Combustion Turbine	Gas	11	149	1,430	130.76	9.62
Hydro		407				
Solar		7				
Wind Existing		324				
Act 295 - Renewable energy Plan		396		31,825	80.41	
<b>TOTAL GENERATION</b>		<b>23,312</b>	<b>227,198</b>	<b>722,057</b>	<b>30.97</b>	<b>3.18</b>
Purchase Energy		11,195		510,984	45.65	
Renewable Energy - Other		332		16,033	48.29	
Act 295 - Renewable Energy Plan		157		7,848	50.05	
Purchase Capacity				55,510		
Transmission Services				23		
Sales Energy		4,244		138,375	32.60	
Sales Capacity				4,103		
<b>NET OUTPUT</b>		<b>30,752</b>		<b>1,169,976</b>	<b>38.05</b>	
Open Market (MISO costs)				(28,290)		
Network Transmission Service				286,984		
Ancillary Services Market				(3,028)		
<b>TOTAL POWER SUPPLY COSTS</b>		<b>30,752</b>		<b>1,425,643</b>	<b>46.36</b>	

**WISCONSIN ELECTRIC POWER COMPANY**  
**Projected MWh, Fuel, and Purchase Energy Expense**

For Year 2015

<u>PLANT</u>	<u>FUEL</u>	<u>GWH</u>	<u>GBTU</u>	<u>Cost</u> (\$000)	<u>\$/MWh</u>	<u>\$/MMBTU</u>
Oak Creek 5-8	Coal	5,408	54,704	141,627	26.19	2.59
Elm Road Generating Station	Coal	5,092	45,057	171,946	33.77	3.82
Port Washington 1-2	Gas	1,448	10,357	83,238	57.47	8.04
Valley 1-2	Coal	628	8,732	40,869	65.05	4.68
Pleasant Prairie 1-2	Coal	7,113	78,227	184,675	25.96	2.36
Presque Isle 5-9	Coal	2,410	28,728	78,231	32.46	2.72
Milwaukee County	Coal	39	420	2,178	56.03	5.19
Rothschild	Wood	137	2,078	6,487	47.35	3.12
Auxiliary Fuel	Oil	1	11	206	158.21	19.20
Auxiliary Fuel	Gas	14	151	2,990	208.38	19.74
Combustion Turbine	Gas	19	261	2,558	138.06	9.78
Hydro		407				
Solar		17				
Wind Existing		325				
Act 295 - Renewable Energy Plan		398		31,974	80.41	
<b>TOTAL GENERATION</b>		<b>23,456</b>	<b>228,728</b>	<b>746,978</b>	<b>31.85</b>	<b>3.27</b>
Purchase Energy		10,783		507,426	47.06	
Renewable Energy - Other		331		16,093	48.57	
Act 295 - Renewable Energy Plan		0		0	0.00	
Purchase Capacity				57,440		
Transmission Services				23		
Sales Energy		4,432		154,274	34.81	
Sales Capacity				1,740		
<b>NET OUTPUT</b>		<b>30,138</b>		<b>1,171,945</b>	<b>38.89</b>	
Open Market (MISO costs)				(28,290)		
Network Transmission Service				295,550		
Ancillary Services Market				(3,028)		
<b>TOTAL POWER SUPPLY COSTS</b>		<b>30,138</b>		<b>1,436,177</b>	<b>47.65</b>	

WISCONSIN ELECTRIC POWER COMPANY  
 PSCR PLAN COST COMPARISON

	PSCR Plan 2010 - Approved			PSCR Plan 2011			Change from prior plan		
	Cost (\$)	Generation MWH	Cost \$/MWH	Cost (\$)	Generation MWH	Cost \$/MWH	Cost (\$)	Generation MWH	Cost \$/MWH
<b>Electric Utility:</b>									
Valley	43,460,601	793,273	54.79	31,438,084	509,026	61.76	(12,022,517)	(284,247)	6.97
Oak Creek	127,801,010	5,274,649	24.23	145,628,058	5,748,686	25.33	17,827,048	474,037	1.10
Elm Road	91,724,116	3,777,159	24.28	137,983,294	4,900,383	28.16	46,259,178	1,123,224	3.88
Pleasant Prairie	140,435,911	7,613,894	18.44	157,560,710	6,886,424	22.88	17,124,799	(727,470)	4.44
Edgewater 5	13,520,520	526,296	25.69	-	-	-	(13,520,520)	(526,296)	(25.69)
Milw. County	1,922,130	35,702	53.84	1,892,030	35,649	53.07	(30,100)	(53)	(0.77)
Presque Isle	74,797,434	2,522,285	29.65	74,977,054	2,391,198	31.36	179,620	(131,087)	1.71
Total Steam	493,661,722	20,543,258	24.03	549,479,230	20,471,366	26.84	55,817,508	(71,892)	2.81
Port Washington	150,187,032	3,194,599	47.01	152,385,061	3,828,716	39.80	2,198,029	634,117	(7.21)
Germantown	549,397	6,972	78.80	249,344	3,403	73.27	(300,053)	(3,569)	(5.53)
Concord	778,227	2,141	363.49	700,151	1,139	614.71	(78,076)	(1,002)	251.22
Paris	334,798	462	724.67	646,571	4,604	140.44	311,773	4,142	(584.23)
Other CT	-	-	-	-	-	-	-	-	-
Total Turbine	151,849,454	3,204,174	47.39	153,981,127	3,837,862	40.12	2,131,673	633,688	(7.27)
Hydro	-	260,429	-	-	-	-	-	(260,429)	-
Wind	-	482,066	-	-	-	-	-	(482,066)	-
MISO Credits	(10,888,708)	-	-	(5,602,258)	-	-	5,286,450	-	-
<b>Total Fuel</b>	634,622,468	24,489,927	25.91	697,858,099	24,309,228	28.71	63,235,631	(180,699)	2.80
LS Power	86,899,843	927,394	93.70	95,012,936	1,151,604	82.50	8,113,093	224,210	(11.20)
Zion	18,030,822	7,836	2,301.02	21,110,485	48,160	438.34	3,079,663	40,324	(1,862.68)
FPL (Point Beach)	356,411,219	8,232,192	43.29	383,788,446	8,720,531	44.01	27,377,227	488,339	0.72
Renewable Energy - Other	20,309,754	201,835	100.63	17,707,740	347,638	50.94	(2,602,014)	145,803	(49.69)
Act 295 - Renewable Energy Plan	7,848,290	156,809	50.05	7,848,290	156,809	50.05	-	-	-
Wind & Hydro Repl. Power	-	-	-	27,858,068	888,952	31.34	27,858,068	888,952	31.34
Other - Fixed Payments	270,000	-	-	270,000	-	-	-	-	-
Subtotal Purchases	489,769,928	9,526,066	51.41	553,595,965	11,313,694	48.93	63,826,037	1,787,628	(2.48)
MISO Energy Market	10,572,024	362,738	29.15	17,825,575	533,130	33.44	7,253,551	170,392	4.29
Point-to-Point Transm.	780,643	-	-	192,643	-	-	(588,000)	-	-
<b>Total Purchases</b>	501,122,595	9,888,804	50.68	571,614,183	11,846,824	48.25	70,491,588	1,958,020	(2.43)
WUMS Socialized Cost	1,200,000	-	-	-	-	-	(1,200,000)	-	-
MISO Uplift & Admin.	(31,351,920)	-	-	(28,289,774)	-	-	3,062,146	-	-
Ancillary Revenue	(6,533,912)	-	-	(4,257,260)	-	-	2,276,652	-	-
<b>Fuel &amp; Purchases</b>	1,099,059,231	34,378,731	31.97	1,236,925,248	36,156,052	34.21	137,866,017	1,777,321	2.24
Less: Capacity Sales	6,226,150	-	-	13,853,856	-	-	7,627,706	-	-
Less: Oppty. Sales - PJM	573,505	7,836	73.19	2,726,332	48,160	56.61	2,152,827	40,324	(16.58)
Less: Oppty. Sales - MISO	157,127,579	4,677,229	33.59	163,273,847	5,832,064	28.00	6,146,268	1,154,835	(5.59)
Net Output	935,131,997	29,693,666	31.49	1,057,071,213	30,275,828	34.91	121,939,216	582,162	3.42
Network Transmission	248,678,952	29,693,666	8.37	259,202,122	30,275,828	8.56	10,523,170	-	0.19
<b>TOTAL System Costs</b>	1,183,810,949	29,693,666	39.87	1,316,273,335	30,275,828	43.48	132,462,386	582,162	3.61
Loss Factor			1.04			1.04			1.04
Total PSCR Costs			41.46			45.21			3.75
Less: PSCR Base (Adjusted for losses)			41.71			42.16			
<b>PSCR Factor (adjusted for losses)</b>			(0.24)			3.05			

CAPACITY AND RESERVE REQUIREMENTS  
 FOR PEAK MONTH 2011 - 2015

<u>Line No.</u>	<u>Description</u>	<u>2011</u> (MW)	<u>2012</u> (MW)	<u>2013</u> (MW)	<u>2014</u> (MW)	<u>2015</u> (MW)
1.	Demand (a)	5,645	5,661	5,687	5,760	5,823
	Firm Sale	708	484	115	120	-
2.	Incremental Losses (b)	5	5	5	5	5
3.	Minimum Reserve Requirement ( c)	819	822	825	836	845
4.	Demand w/Reserves (line 1 + line 2 + line 3)	7,177	6,971	6,632	6,721	6,673
5.	Company Generation (d)	6,185	6,188	6,181	6,231	6,232
	<b>Committed Long-term Capacity Purchases:</b>					
	LSP-Whitewater	234	234	234	234	234
	Zion Energy LLC	334	168			
	LSP-Whitewater Excess	12				
	Renewable Energy Sources	5	5	5	5	5
	Florida Power and Light Co. (Point Beach PPA)	1,113	1,193	1,193	1,193	1,193
6.	Total Previously Committed Capacity Purchases	1,698	1,600	1,432	1,432	1,432
7.	Total Resources (line 5 + line 6)	7,883	7,788	7,613	7,663	7,664
8.	Total Committed Long-term Capacity above/(below) Minimum Reserve Requirement (line 7 - line 4)	706	817	981	942	992
	<b>Capacity Sale(s):</b>					
9.	Undesignated Capacity Sales	-				
10.	Total Capacity above/(below) Minimum Reserve Requirement (line 8-line 9)	706	817	981	942	992

Notes:

- (a) Based on 9/08/2010 System Demand Forecast
- (b) Incremental loss of 5 MW occurs due to the curtailment of the mines at the time of peak demand.
- (c) Minimum Planning reserves at 14.5%.
- (d ) Company owned/operated generating capacity and leased capacity

**WISCONSIN ELECTRIC POWER COMPANY**

**Total WE-Owned/Operated Capacity  
 FOR PEAK MONTH 2011 - 2015**

<b><u>PLANT</u></b>	<b><u>2011</u></b> (MW)	<b><u>2012</u></b> (MW)	<b><u>2013</u></b> (MW)	<b><u>2014</u></b> (MW)	<b><u>2015</u></b> (MW)
Oak Creek 5-8	1,094	1,094	1,084	1,076	1,076
Edgewater Unit 5	102				
Valley 1-2	267	267	267	267	267
Pleasant Prairie 1-2	1,200	1,200	1,200	1,200	1,200
Presque Isle 5-9	428	428	428	428	428
Milwaukee County	10	10	10	10	10
Germantown 1-5	345	296	296	296	296
Concord 1-4	400	352	352	352	352
Paris 1-4	400	352	352	352	352
Other Combustion Turbines	5	5	5	5	5
Solar				1	1
Biomass					50
Hydro	54	54	54	54	54
Wind	12	12	26	26	26
<b>TOTAL GENERATION</b>	<b>4,316</b>	<b>4,070</b>	<b>4,073</b>	<b>4,066</b>	<b>4,116</b>
<b>System Upgrades and Retirement:</b>					
Concord Unit 1-4 Retire Inlet Chillers	(48)				
Paris Unit 1-4 Retire Inlet Chillers	(48)				
Germantown Units 1-5 Retire Inlet Chillers	(49)				
Edgewater Unit 5 Sale Effective 12/31/2010	(102)				
Oak Creek 5-8		(10)	(8)		
Wind		13			
Solar			1		1
Biomass				50	
<b>Total WE-Owned Capacity</b>	<b>4,070</b>	<b>4,073</b>	<b>4,066</b>	<b>4,116</b>	<b>4,117</b>
<b>PTF Leased Units</b>					
Port Washington Generating Station 1-2	1,090	1,090	1,090	1,090	1,090
Elm Road Generating Station	1,025	1,025	1,025	1,025	1,025
<b>Total WE-Owned/Leased Operated Capacity</b>	<b>6,185</b>	<b>6,188</b>	<b>6,181</b>	<b>6,231</b>	<b>6,232</b>







**POWER SUPPLY COST RECOVERY**

**PSCR Factors:**

All rates for metered electric service shall include an amount up to the Power Supply Cost Recovery (PSCR) Factor for the specified billing period as set forth below. The PSCR Factor includes an increase or decrease of 0.0104 mills per kWh for each full 0.01 mill increase or decrease in the projected annual power supply costs above or below a cost base of 42.16 mills per kWh, rounded to the nearest one-hundredth of a mill per kWh. The projected power supply costs per kWh shall equal the total projected annual net power cost divided by the projected annual net system energy requirements. Net system energy requirements shall be the sum of net generation and net purchased and interchange power.

An amount not exceeding the PSCR Factor for each month shall be placed into effect in the first billing cycle of that month and shall continue in effect until the first billing cycle of a subsequent month for which a subsequent PSCR Factor becomes operative.

The PSCR Factor shall be applicable to all Power Supply charges for the following Rate Schedules:

<u>Class of Service</u>	<u>Rate Schedule No.</u>
Residential	Rg 1 and Rg 2
General Secondary	Cg 1, Cg 2, Cg 3, Cg3C and Cg 5
General Primary	Cp 1, Cp 2, Cp 3, Cp 4, Schedule A & Cp LC
Lighting	Ms2, Ms3, GL1, LED1
Other	Mg 1, DS 1
ERER 1, ERER 3	
100% Renewable power	No adjustment for PSCR
50% Renewable power	(1-.50) x PSCR factor applicable to rate schedule customer is served under. Customer pays 50% of PSCR factor.
25% Renewable power	(1-.25) x PSCR factor applicable to rate schedule customer is served under. Customer pays 75% of PSCR factor.
ERER 2	
Kilowatt-hour in excess of nominated block	PSCR factor applicable to rate schedule customer is served under.
Customer Generating System	CGS Category 1, CGS Category 2, CGS Biogas

<u>Month</u>	<u>2011 Plan Year PSCR Factor (\$ per kWh)</u>	<u>Prior Year's Factor (\$ per kWh)</u>	<u>Maximum Authorized 2011 PSCR Factor (\$ per kWh)</u>	<u>Actual Factor Billed (\$ per kWh)</u>
Jan 2011	0.00305	0.00233	0.00538	
Feb 2011	0.00305	0.00233	0.00538	
Mar 2011	0.00305	0.00233	0.00538	
Apr 2011	0.00305	0.00233	0.00538	
May 2011	0.00305	0.00233	0.00538	
Jun 2011	0.00305	0.00233	0.00538	
Jul 2011	0.00305	0.00233	0.00538	
Aug 2011	0.00305	0.00233	0.00538	
Sep 2011	0.00305	0.00233	0.00538	
Oct 2011	0.00305	0.00233	0.00538	
Nov 2011	0.00305	0.00233	0.00538	
Dec 2011	0.00305	0.00233	0.00538	

Parentheses indicate a credit factor. Should the Company apply lesser factors than those above or if the factors are later revised pursuant to commission orders or 1982 PA 304, the Company will notify the commission if necessary and file a revision of the above list.

(Continued on Sheet No. D-4.00)

Issued *December 15, 2010*  
 R.A. Draba  
 Vice-President,  
 Milwaukee, Wisconsin

Effective for bills rendered *for  
 the 2011 Plan year*

Issued under authority of  
*Section 6j(9) of 1982 PA304*  
*For implementing in*  
 Case No. *U-16424*

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **WISCONSIN** )  
**ELECTRIC POWER COMPANY** d/b/a We Energies for )  
approval of a power supply cost recovery plan )Case No. U-16424  
and authorization of monthly power supply cost )  
recovery factors for the calendar year 2011. )

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**DIRECT TESTIMONY OF JEFF KNITTER**  
**ON BEHALF OF**  
**WISCONSIN ELECTRIC POWER COMPANY**

SEPTEMBER, 2010

1 Q. Please state your name and business address.

2 A. My name is Jeff Knitter. I am the Manager - Special  
3 Projects in Wisconsin Electric Power Company's  
4 ("Wisconsin Electric" or "Company") Wholesale Energy and  
5 Fuels Department, and my business address is 333 West  
6 Everett Street, Milwaukee, Wisconsin 53201.

7 Q. Please describe your educational and business  
8 experience.

9 A. I graduated from the University of Wisconsin - Madison  
10 in 1982 with a degree in Mechanical Engineering. Since  
11 that time, I have been employed by Wisconsin Electric in  
12 various capacities. From 1995 to 2000, I was the Manager  
13 of Resource Planning in the Business Planning  
14 Department, where I was responsible for generation  
15 planning. From 2000 to 2004, I was Manager - Special  
16 Projects in the Legal Department and was active in the  
17 planning and development of the Power The Future project  
18 since its inception. Among my responsibilities were the  
19 development and evaluation of Wisconsin Electric's long  
20 range supply plans and their economic analysis for which  
21 I provided testimony in the Port Washington and Elm Road  
22 construction dockets before the Public Service  
23 Commission of Wisconsin ("PSCW"). Since 2004, I have  
24 worked in the Wholesale Energy and Fuels Department on

1 the MISO energy market, MISO ancillary services market,  
2 financial transmission rights and longer range planning.  
3 Since June 1, 2009, I have also managed the planning  
4 staff.

5 Q. Have you previously testified before this Commission?

6 A. No. However, I have testified before the PSCW in many  
7 construction dockets and the most recent fuel filing.

8 Q. Are you sponsoring any exhibits?

9 A. Yes, I am sponsoring the following exhibits:

- 10 • Exhibit A-12 (JEK-1) - Capacity and Reserve  
11 Requirements in July 2011.
- 12 • Exhibit A-13 (JEK-2) - Power Purchase and Sales  
13 Agreements in 2011. Exhibit A-13 (JEK-2) is provided  
14 in redacted form because it contains detailed  
15 confidential cost information with regard to purchase  
16 power contracts. In accordance with prior Protective  
17 Orders, an unredacted version will be made available  
18 to the Commission Staff subject to the appropriate  
19 confidential restrictions.
- 20 • Exhibit A-14 (JEK-3) - MISO Transactions in 2011.  
21 Exhibit A-14 (JEK-3) is provided in redacted form  
22 because it contains detailed confidential information  
23 with regard to MISO transactions.
- 24 • Exhibit A-15 (JEK-4) - Coal Contracts in 2011.

1 Q. Were these exhibits prepared by you or under your  
2 direction and supervision?

3 A. Yes.

4 Q. What is the purpose of your testimony in this  
5 proceeding?

6 A. The purpose of my testimony is to provide information  
7 and exhibits affecting 2011 power supply costs including  
8 the Company's power purchase and sales contracts, new  
9 generating facilities in 2011, and coal contracts.

10 Q. Turning first to the power purchase contracts, has the  
11 Company entered into any new power purchase contracts  
12 beyond the contracts included in the 2010 PSCR filing?

13 A. Yes, the Company expects to have two new power purchase  
14 contracts totaling 300,000 MWh/yr for five years  
15 beginning in 2011(150,000 MWh/yr for Renewable Energy  
16 Credits ("RECs")-only plus 150,000 MWh/yr for RECs and  
17 energy). The new and ongoing contracts and the costs  
18 associated with these purchases for 2011 are included in  
19 Exhibit A-13(JEK-2). The energy (MWh) and cost (\$) of  
20 these contracts are reflected in Mr. Lorden's exhibits  
21 for the 2011 forecast.

22 **Zion Energy Purchase Power Agreements:**

23 Q. Please explain the background regarding the purchases  
24 from the Zion units.

1 A. The long-term PPA with Zion Energy LLC was found to be  
2 reasonable and prudent and was approved by the MPSC in  
3 Case No. U-13266.

4 Q. Has the capacity and energy from the Zion Energy LLC PPA  
5 been included in the 5-year forecast filed as part of  
6 the Company's annual PSCR Plan cases?

7 A. Yes. The capacity and energy from the Zion Energy LLC  
8 been included in the PSCR plans and 5-year forecast  
9 filed as part of the Company's annual PSCR Plan cases  
10 every year, starting with the 2003 PSCR Plan case.

11 Q. Does the commencement of commercial operation of Elm  
12 Road Generating Station (ERGS) Unit 1 and the  
13 anticipated commencement of operations at ERGS Unit 2  
14 impact the reasonableness and prudence of the Company's  
15 previous decision to enter into the agreements with  
16 Zion.

17 A. No. These circumstances do not detract from the fact  
18 that, as the Commission previously found, the decision  
19 to enter into the PPA with Zion Energy LLC was  
20 reasonable and prudent. The fact that the ERGS Unit 1  
21 commenced, and ERGS Unit 2 is scheduled to commence,  
22 commercial operation does not change the reasonableness  
23 of the decisions to enter into the PPAs with Zion Energy  
24 LLC. In fact, the length of the initial term of the

1 PPAs with Zion coincided with the anticipated  
2 commencement of operations of ERGS. Thus, the PPA for  
3 Zion Unit 3 expired in 2008 and was not renewed. Under  
4 the PPAs, existing Zion capacity commitments will be  
5 further reduced by 2013. Furthermore, the current  
6 capacity situation is not due to any unreasonable  
7 planning with respect to Zion, but is more due to  
8 unanticipated intervening events such as the recent  
9 economic recession and the associated decrease in  
10 customer energy usage, reduction in required minimum  
11 reserve margins and requirements to secure additional  
12 renewable energy. The Company has reasonably and  
13 prudently sought to sell capacity from the Zion Energy  
14 LLC PPA since 2008. The efforts to sell such capacity  
15 do not detract from the reasonableness and prudence of  
16 the 2002 decisions to enter into the PPA with Zion  
17 Energy LLC. Also, customers benefit from such sales as  
18 the revenues are offset against PSCR costs.

19 Q. In your opinion, was Wisconsin Electric reasonable and  
20 prudent in entering into the long-term purchase power  
21 agreements included in Exhibit A-13 (JEK-2) to augment  
22 its own generation fleet?

23 A. Yes. Each was selected with the best information  
24 available and under the market conditions at the time.

1 Prices, terms, and conditions vary since these  
2 agreements were entered into at different times and in  
3 order to meet different requirements as part of a energy  
4 portfolio of low-cost supply options.

5 Q. Has the Company purchased firm transmission rights  
6 associated with its power supply portfolio?

7 A. Yes. The Company has access to 300 MW of point-to-point  
8 transmission service from PJM for the period January 1,  
9 2011 to May 15, 2011 as the result of Commonwealth  
10 Edison joining PJM. This transmission service  
11 facilitates access to the Zion facility as a capacity  
12 resource. The cost of the transmission service for 2011  
13 is projected based on various tariffs subject to Federal  
14 Energy Regulatory Commission ("FERC") approval, as shown  
15 on Exhibit A-13 (JEK-2).

16 Q. How will the power supply mix projected for 2011 affect  
17 PSCR costs?

18 A. The changes in the resource supply plan from 2010 to  
19 2011 are summarized below:

- 20 • Both Elm Road Generating Station units will be in  
21 commercial operation throughout 2011.
- 22 • The sale of the Company's share of Edgewater 5 is  
23 assumed to be approved by the MPSC and the PSCW and  
24 closed prior to 2011.

1       • The planned capacity upgrades for Point Beach Unit 1  
2       and 2 are currently scheduled for 2011. Unit 2 will  
3       have its upgraded capacity (80MW) available to deliver  
4       energy on or about June 1, 2011, and Unit 1 will have  
5       its upgraded capacity (80MW) available on or about  
6       December 15, 2011. While the Company has not yet made  
7       a final decision on whether it will take all or a  
8       portion of the upgraded capacity and associated  
9       energy, for the purpose of this filing, the Company  
10      has assumed that the Company will take all of the  
11      upgraded capacity.

12 Q. Why does the Company assume it will take all of the  
13      upgraded Point Beach capacity and associated energy?

14 A. While the Point Beach contract's energy price is  
15      forecasted to be above market in 2011, the Company  
16      believes that, in the long run, the net present value of  
17      the contract will reduce customer energy costs by adding  
18      energy with no CO2 emissions to its energy portfolio.

19 Q. Based on the above changes in resource supply plan, what  
20      is the amount of capacity above the Minimum Reserve  
21      Requirement in 2011?

22 A. Based on the projected peak demand for 2011 and the  
23      resource supply plan in place to meet that peak demand,

1 the Company expects to have 706 MW of capacity above the  
2 Minimum Reserve Requirement(Exhibit A-12 (JEK-1)).

3 Q. What are the Company's plans regarding capacity above  
4 the Minimum Reserve Requirement?

5 A. The Company is pursuing the sale of firm capacity to  
6 other MISO market participants, PJM market participants,  
7 and utilities outside of organized markets under both  
8 short and long-term contracts.

9 Q. What level of new capacity sales has the Company assumed  
10 for 2011?

11 A. Based on its knowledge of the capacity market, the  
12 Company projects some combination of new short-term  
13 sales and new bilateral transactions. However, due to  
14 very low capacity market prices, revenue from new  
15 capacity sales are expected to be less than \$20,000 and  
16 has been assumed to be zero for this filing.

17 Q. What has the Company assumed for revenue related to all  
18 2011 projected capacity sales?

19 A. The Company has assumed that the capacity sold under  
20 existing short-term contracts will yield about  
21 \$13,800,000 of revenues to offset 2011 power supply  
22 costs.

1 **Long-term Sales Contracts:**

2 Q. Does the Company have any combined capacity and energy  
3 sales contracts for 2011?

4 A. Yes. The Company currently has three FERC-approved  
5 tariff-based wholesale long-term sales agreements for  
6 2011 which total 347 MW of firm capacity.

7 **PJM Capacity Auction:**

8 Q. Did the Company participate in the PJM capacity auction  
9 held in May 2007 for planning year 2010/2011?

10 A. No. The Company did not participate in the PJM capacity  
11 auction held in May 2007 for planning year 2010/2011  
12 because, among other things, a PJM deliverability study  
13 was required for the Zion capacity to qualify as PJM  
14 capacity for auction purposes. This study was not  
15 completed until after May 2007.

16 Q. Did the Company participate in the PJM capacity auction  
17 held in May 2008 for planning year 2011/2012?

18 A. Yes. The Company participated in the PJM capacity  
19 auction held in May 2008 for planning year 2011/2012 by  
20 offering the capacity from units under contract at the  
21 Zion Energy Center into the auction. One hundred percent  
22 of the capacity under contract at Zion (319.5MW) cleared  
23 the May 2008 auction for planning year 2011/2012.

1 Q. When will these revenues be included in the PSCR?

2 A. These capacity-related revenues are included in the PSCR  
3 calculations for 2011 and 2012.

4 Q. Did the Company participate in the PJM capacity auction  
5 held in May 2009 for planning year 2012/2013?

6 A. Yes, the Company participated in the PJM capacity  
7 auction held in May 2009 for planning year 2012/2013.  
8 However, the Company's offer did not clear so no  
9 capacity was sold by the Company in this auction.

10 Q. Did the Company participate in the PJM First Energy  
11 capacity auction held in March 2010 for planning year  
12 2012/2013?

13 A. Yes, the Company participated in the PJM First Energy  
14 capacity auction held in March 2010 for planning year  
15 2012/2013 and the Company's offer was accepted.

16 Q. Did the Company participate in the PJM capacity auction  
17 held in May 2010 for planning year 2013/2014?

18 A. No, the Company did not participate in the PJM capacity  
19 auction held in May 2010 for planning year 2013/2014  
20 since it does not have available PJM capacity for that  
21 time period.

22 Q. Switching now from long-term purchases and sales to  
23 short-term energy purchases and sales, please describe  
24 how these energy transactions are conducted under the

1 MISO energy market, and the role these transactions play  
2 in Wisconsin Electric's overall cost of power supply.

3 A. Under the MISO Energy Market, the Company is required to  
4 offer all available generation into both Day-Ahead and  
5 Real-Time energy and operating reserve markets, and bid  
6 virtually all its load into the Day-Ahead market. MISO  
7 pays the Company for energy generated and operating  
8 reserves carried at the hourly Locational Marginal Price  
9 for each product; MISO charges the Company hourly for  
10 energy purchased at each load node. The MISO financial  
11 settlement for each operating day nets these payments  
12 and charges, along with other charges and credits. The  
13 net of hourly generation revenue and load cost  
14 represents short-term energy purchases or sales under  
15 the MISO energy market. The Company's projection for the  
16 net of MISO generation revenue and load cost for 2011 is  
17 a net revenue of \$117,600,000 (Net MISO Energy  
18 Transactions) and is provided on Exhibit A-14 (JEK-3).  
19 The item "Net Purchase to replace Hydro and Wind  
20 Generation" in Exhibit A-14 (JEK-3) is explained in Mr.  
21 Lorden's testimony.

22 Q. Please describe any other impacts on power supply costs  
23 related to the MISO energy market in the 2011 PSCR plan.

1 A. In addition to energy transactions (sales & purchases)  
2 with MISO, other MISO costs associated with operating in  
3 the energy and ancillary service markets are included in  
4 this 2011 PSCR filing (Exhibit A-14 (JEK-3)). A listing  
5 of these cost elements is provided below:

- 6 • Financial Transmission Rights (FTR) and Auction  
7 Revenue Rights (ARR) Revenues
- 8 • Real-Time Distribution of Loss
- 9 • Real Time Price volatility Make Whole Payment
- 10 • Real Time Net Inadvertent Distribution Amount
- 11 • Real Time Revenue Sufficiency Guarantee (RSG) First  
12 Pass Uplift
- 13 • Day Ahead RSG Distribution Amount
- 14 • Real Time Revenue Neutrality Uplift
- 15 • Day-Ahead RSG Make Whole Payments
- 16 • Real Time RSG Make Whole Payments

17 Q. How did the Company project these charges and credits  
18 for 2011?

19 A. The Company used 12 months of actual MISO charges and  
20 credit amounts for the period July 1, 2009 through June  
21 30, 2010 for the MISO charges and credits listed above  
22 to establish monthly and annual amounts for 2011.

1 Q. Please describe the method you used to project Ancillary  
2 Services Market (ASM) impacts on 2011 Power Supply  
3 Costs.

4 A. ASM market revenues and costs in 2011 are also based  
5 on actual MISO ASM charges and credit amounts for the  
6 period July 1, 2009 through June 30, 2010

7 **COAL PROCUREMENT**

8 Q. Have the Company's methods and procedures for coal  
9 procurement changed from those described in the 2010  
10 PSCR filing

11 A. No.

12 Q. What coal contracts will be in effect in 2011?

13 A. Exhibit A-15 (JEK-4) codes the identity of Wisconsin  
14 Electric's coal contract suppliers and lists the date of  
15 expiration and the 2011 delivered price. The Company  
16 has rail transportation agreements in place:

- 17 • through 2013 for coal deliveries to the Pleasant  
18 Prairie Power Plant ("P4");
- 19 • through 2015 for Elm Road Generating Station;
- 20 • through 2011 for Oak Creek Power Plant and Valley  
21 Power Plants; and
- 22 • through 2011 for Colorado coal and through 2010 for  
23 PRB coal for Presque Isle Power Plant ("PIPP").

1           There is a pending rail agreement on PRB coal through  
2           2013 to PIPP.

3 Q. Please describe the increase in coal costs in 2011  
4           compared to 2010.

5 A. FOB mine coal costs increased by \$10,000,000 from levels  
6           in 2010 primarily driven by increased coal contract  
7           costs for Valley and Presque Isle-East, and at Elm Road.  
8           The changes at Valley and Presque Isle-East reflect  
9           escalation in coal costs observed in 2009 and 2010, the  
10          effects of which were muted in those years due to  
11          carryover of lower priced coal from 2008 and 2009 into  
12          2010. The full impacts of the escalation across those  
13          years are now observed in coal costs projected for 2011.  
14          The FOB mine coal costs for Elm Road are projected to  
15          increase due to contract coal price increases.

16 Q. Now please describe the impacts of and drivers behind  
17          increased coal transportation costs.

18 A. Coal transportation costs increased from levels in 2010  
19          by \$33,000,000. The primary driver behind this increase  
20          is a change in carrier for coal delivered to P4 and  
21          PIPP-West. One of the coal transportation carriers for  
22          P4 and PIPP-West for 2009 and 2010 is DTE. This coal  
23          transportation contract expires in 2010, and through a  
24          process of competitive bidding, the Company selected the

1 Union Pacific (UP) and the Burlington Northern (BN)  
2 railroads for delivery to P4 and PIPP-West, respectively  
3 in 2011.

4 Q. Please describe the impacts of changes in coal inventory  
5 between 2010 and 2011 on projected 2011 fuel costs.

6 A. Changes in coal inventory are projected to increase 2011  
7 fuel costs by \$7,000,000. Changes in coal inventory  
8 costs for 2011 incorporate the difference in the coal  
9 costs in inventory at the start of 2010 and at the start  
10 of 2011, and reflect that higher cost coal was delivered  
11 during 2010 (inventory 2011) versus 2009 (inventory  
12 2010).

13 Q. Please describe the change in projected coal  
14 transportation surcharge levels for 2011.

15 A. Coal transportation surcharge levels increase 2011 fuel  
16 costs by \$8,000,000 due to new or increased oil  
17 surcharge costs.

18 Q. In general, how are coal tonnage requirements  
19 determined?

20 A. The Finance Department develops the forecast of system  
21 demand and energy requirements. The Planning Section  
22 then establishes likely unit operation, and  
23 corresponding coal burn through the use of PROMOD, a  
24 security constrained economic dispatch model which

1       simulates the MISO Energy Market. The fuel requirement  
2       projections are then forwarded to the Coal Resources  
3       Section for planning and acquisition.

4   Q.   Were these fuel consumption projections incorporated in  
5       Exhibit A-4 (TPL-4)?

6   A.   Yes. Exhibit A-4 (TPL-4) includes the consumed coal cost  
7       in dollars per million BTU ("\$/MMBTU") by year for a  
8       five-year period for each coal burning power plant.

9   Q.   Does the Company anticipate any coal delivery shortage  
10       during 2011?

11  A.   No.

12  Q.   Are the power supply costs addressed in your testimony  
13       incurred pursuant to reasonable and prudent management  
14       and actions?

15  A.   Yes.

16  Q.   Does this conclude your testimony?

17  A.   Yes, it does.

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **WISCONSIN** )  
**ELECTRIC POWER COMPANY** d/b/a We Energies for )  
approval of a power supply cost recovery plan )Case No. U-16424  
and authorization of monthly power supply cost )  
recovery factors for the calendar year 2011. )

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**EXHIBITS OF JEFF KNITTER**

**ON BEHALF OF**

**WISCONSIN ELECTRIC POWER COMPANY**

SEPTEMBER, 2010

CAPACITY AND RESERVE REQUIREMENTS  
 FOR PEAK MONTH JULY 2011

Description	2011 (MW)
1 Demand (a)	5,645
2 Sale of Capacity	708
3 Incremental Losses (b)	5
4 Minimum Reserve Requirement (c)	819
5 Demand w/Reserves & Incremental losses (1 + 2 + 3 + 4)	7,177
6 Company Generation	4,070
7 Company Leased Capacity (d)	2,115
Committed Long-term Capacity Purchases	
LSP-Whitewater	234
Zion Energy LLC	334
LSP-Whitewater - Excess Capacity	12
Renewable Energy Sources	5
NextEra Energy Point Beach, LLC (Point Beach PPA)	1,113
8 Total Committed Capacity Purchases	1,698
9 Total Resources (6 + 7+ 8)	7,883
10 Capacity above/(below) Minimum Reserve Requirement - Long-Term Capacity Purchases (9 - 5)	706
11 Undesignated Capacity Sale	0
12 Total Capacity above/(below) Minimum Reserve Requirement (10 - 11)	706

- (a) Based on 9/08/2010 System Demand Forecast
- (b) Incremental loss of 5 MW occurs due to the curtailment of the mines at the time of peak demand.
- (c) Minimum Planning reserves are based on 14.5%.
- (d) The Company leases the Port Washington Generating Station and Elm Road from WE Power.

WISCONSIN ELECTRIC POWER COMPANY

Power Purchase Agreements

Supplier	2011 During Year	MW	2011 CAPACITY		2011 ENERGY			Total Capacity and Energy \$
			\$	\$/kw -mo	MWh	\$	\$/MWh	
<u>Long-term Capacity &amp; Energy Agreements (1)</u>								
LS Power Whitewater LP	12 Months	234.0	50,131,851	\$17.85	1,151,604	44,881,085	\$38.97	95,012,936
Zion Energy, LLC Units 1 & 2 (2)	12 Months	334.0						21,110,485
LS Power Whitewater LP - Excess (3)	7 Months	12.0						270,000
Renewable Energy - Other	12 Months	5.0	0	\$0.00	347,638	17,707,740	\$50.94	17,707,740
Act 295 Renewable Energy Plan (4)	12 Months	0.0	0	\$0.00	156,809	7,848,290	\$50.05	7,848,290
Total Long-Term Capacity & Energy Agreements		585	68,378,380		1,704,210	73,571,070	\$43.17	141,949,451
NextEra Energy Point Beach, LLC					8,720,531	383,788,446	\$44.01	383,788,446
Net Energy Purchase from MISO Market (Net of energy sales)					1,422,082	45,683,643		45,683,643
Total Purchase Power Costs \$		585	68,378,380		11,846,823	503,043,159	\$42.46	571,421,539
Total Purchase Power Costs \$/MWh								\$48.23

(1) Agreements under contract or planned

(2) This is protected material pursuant to the January 17, 2003 Protective Order entered in Case No. U-13266.

(3) This is protected material pursuant to the April 20, 2004 Protective Order entered in Case Nos. U-13907.

(4) This wind PPA is valued at the transfer price established in Michigan Docket U-15812.

WISCONSIN ELECTRIC POWER COMPANY

Power Purchase Agreements

Supplier	Transmission Path	Total Capacity and Energy \$	2011 Transmission Cost	2011 Grand Total
<u>Long-term Capacity &amp; Energy Agreements (1)</u>				
LS Power Whitewater LP	(ATC) - MISO (Part of Network Service)	95,012,936	0	95,012,936
Zion Energy, LLC Units 1 & 2 (2)	PJM - (Point-to-Point)	21,110,485	192,643	21,303,128
LS Power Whitewater LP - Excess (3)	(ATC) - MISO (Part of Network Service)	270,000	0	270,000
Renewable Energy - Other	No Transmission Path Required	17,707,740	0	17,707,740
Act 295 Renewable Energy Plan (4)	No Transmission Path Required	7,848,290	0	7,848,290
Total Long-Term Capacity & Energy Agreements		141,949,451	192,643	142,142,094
NextEra Energy Point Beach, LLC		383,788,446		383,788,446
Net Energy Purchase from MISO Market (Net of energy sales)		45,683,643		45,683,643
Total Purchase Power Costs \$		571,421,539	192,643	571,614,183
Total Purchase Power Costs \$/MWh		\$48.23		\$48.25

(1) Agreements under contract or planned

(2) This is protected material pursuant to the January 17, 2003 Protective Order entered in Case No. U-13266.

(3) This is protected material pursuant to the April 20, 2004 Protective Order entered in Case Nos. U-13907.

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Summary of Open Market Transactions (MISO)

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total
<b>NET PURCHASES FROM MISO MARKET</b>													
ENERGY (MWH)	18,106	12,496	101,525	127,177	115,329	12,149	28,081	1,195	7,506	38,853	18,775	51,937	533,130
\$ - TOTAL	557,373	344,336	2,752,255	3,750,350	3,607,135	388,835	2,391,595	394,299	286,559	1,116,129	641,202	1,595,508	17,825,575
\$/MWh	30.78	27.56	27.11	29.49	31.28	32.01	85.17	329.87	38.18	28.73	34.15	30.72	33.44
Net Purchases to replace Hydro & Wind Generation													
ENERGY (MWH)	74,479	73,340	74,507	73,947	74,501	73,604	73,808	73,439	74,179	74,488	74,159	74,501	888,952
\$ - TOTAL	2,296,572	2,328,441	2,217,410	2,370,006	2,111,978	2,212,094	2,497,447	2,479,278	2,259,757	2,203,846	2,378,514	2,502,724	27,858,068
\$/MWh	30.84	31.75	29.76	32.05	28.35	30.05	33.84	33.76	30.46	29.59	32.07	33.59	31.34
<b>TOTAL NET PURCHASES FROM MISO MARKET</b>													
ENERGY (MWH)	92,585	85,836	176,032	201,123	189,830	85,753	101,889	74,635	81,685	113,341	92,934	126,438	1,422,082
\$ - TOTAL	2,853,945	2,672,778	4,969,665	6,120,356	5,719,113	2,600,929	4,889,042	2,873,577	2,546,315	3,319,975	3,019,716	4,098,232	45,683,643
\$/MWh	30.83	31.14	28.23	30.43	30.13	30.33	47.98	38.50	31.17	29.29	32.49	32.41	32.12
<b>NET SALES INTO MISO MARKET</b>													
ENERGY (MWH)	404,563	321,556	529,963	368,737	379,609	485,502	487,727	649,881	561,033	644,250	695,309	303,934	5,832,064
\$ - TOTAL	11,204,093	9,380,485	14,950,587	11,153,049	10,769,801	11,601,250	12,849,810	17,306,663	15,164,086	18,379,895	21,552,069	8,962,059	163,273,847
\$/MWh	27.69	29.17	28.21	30.25	28.37	23.90	26.35	26.63	27.03	28.53	31.00	29.49	28.00
<b>NET MISO ENERGY TRANSACTIONS</b>													
Market - MWh	(311,978)	(235,721)	(353,931)	(167,613)	(189,779)	(399,749)	(385,838)	(575,246)	(479,348)	(530,909)	(602,375)	(177,496)	-4,409,982
Market - Energy \$	(8,350,148)	(6,707,707)	(9,980,922)	(5,032,693)	(5,050,688)	(9,000,321)	(7,960,768)	(14,433,087)	(12,617,770)	(15,059,921)	(18,532,354)	(4,863,827)	-117,590,204
<b>FTR - Revenue</b>													
Estimated FTR/ARR Revenues													
<b>MISO - Losses</b>													
Real Time Distribution of Losses													
<b>Uplift Costs</b>													
Real Time Price Volatility Make Whole Payment													
Real Time Net Inadvertent Distribution Amount													
Real Time Revenue Sufficiency Guarantee First Pass Uplift													
Day Ahead Revenue Sufficiency Guarantee Distribution													
Real Time Revenue Neutrality Uplift													
Total Uplift Costs													
Day Ahead Revenue Sufficiency Guarantee Make Whole Payments													
Real Time Revenue Sufficiency Guarantee Make Whole Payments													
Total Guarantee Make Whole													
Total Other MISO Market Costs/Revenues													
Grand Total	(11,394,382)	(9,917,885)	(12,934,831)	(6,769,732)	(6,913,858)	(13,494,310)	(11,348,250)	(18,017,878)	(15,190,136)	(18,196,812)	(21,562,005)	(7,170,723)	(152,910,801)

**WISCONSIN ELECTRIC POWER COMPANY**

**COAL CONTRACT DATA**

2011

<b>Supplier Code</b>	<b>Contract Expiration Date</b>	<b>2011 Delivered Price \$/MMbtu (1)</b>		
A	December 31, 2011		\$2.082	
A	December 31, 2012		\$2.451	
A	December 31, 2012		\$2.745	
A	December 31, 2011	\$4.544	\$4.751	\$5.185
B	December 31, 2011		\$2.080	
B	December 31, 2013		\$1.982	
B	December 31, 2013		\$2.211	
C	December 31, 2011	\$3.875	\$4.068	\$4.473
D	December 31, 2012		\$3.263	
E	December 31, 2011		\$3.033	

(1) Note: The delivered price will vary depending on delivery location.