Exhibit No.:	
Issue(s):	Production Cost Model
Witness:	Mark J. Peters
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Direct Testimony
Case No.:	ER-2012-0166
Date Testimony Prepared:	February 3, 2012

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2012-0166

DIRECT TESTIMONY

OF

MARK J. PETERS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
February, 2012

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DIRECT TESTIMONY

OF

MARK J. PETERS

CASE NO. ER-2012-0166

I. INTRODUCTION

Q. Please state your name and business address.

A. Mark J. Peters, Ameren Services Company ("Ameren Services"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Services?

A. I am a Managing Supervisor in the Corporate Planning department of Ameren Services. Ameren Services provides corporate, administrative and technical support for Ameren Corporation and its affiliates.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Arts degree in Liberal Arts & Sciences (Concentration in Economics) in August of 1985 from the University of Illinois (Urbana-Champaign). My current duties include supervision and guidance of the group responsible for developing fuel budgets, reviewing and updating economic dispatch parameters for the generating units owned by Ameren Corporation subsidiaries, including Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), providing power plant project justification studies, and performing other special studies.

I began employment with Illinois Power Company in August of 1985, holding a variety of roles prior to its acquisition by Ameren Corporation. These roles included assistant customer service supervisor, various functions within finance – (including responsibility for daily cash management activities for which I hold a permanent certification as a Certified Cash Manager), budget reporting and support for the Vice President – Supply Services, real time energy trading, short term (next day through 1 month) energy trading and scheduling, competitive retail contract pricing and structure development and management of the company's purchased power agreements and natural gas acquisition and scheduling functions. Following Illinois Power's acquisition by Ameren Corporation, I was a member of the Strategic Initiatives group of Ameren Services Company, concentrating on the Ameren Illinois Utilities' post-2006 energy supply acquisition process. In December of 2007, I accepted the position of Managing Supervisor – Asset & Trade Optimization in the Commercial Transactions section of Corporate Planning. In that role, I am responsible for the guidance and supervision of a group which provides analytical support to the Ameren Missouri trading group, which is managed by Ameren Missouri witness Jaime Haro, including transmission congestion analysis, regulatory support, and ad hoc reporting and analysis. I added the duties noted in the beginning of this section which were previously performed by the former Managing Supervisor – Operations Analysis (Timothy Finnell) upon his retirement at the end of December 2012.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. The purpose of my testimony is to sponsor the determination of a normalized level of net fuel costs, which was used by Company witness Gary S. Weiss in determining Ameren Missouri's revenue requirement for this case. Net fuel costs consist of nuclear fuel, coal, oil, and natural gas costs associated with producing electricity from the Ameren Missouri generation fleet, plus the variable component of purchased power, less the energy revenues from off-system sales.[1]

Q. Please summarize your testimony and conclusions.

A. Ameren Missouri's normalized net fuel costs were calculated using the PROSYM production cost model. The major inputs for the production cost model include: hourly load data, generating unit operational data, generating unit availability data, fuel costs, off-system market data, and system requirements. The normalized annual net fuel costs are $555 million, which consists of fuel costs of $866 million and variable purchase power costs of $30 million, offset by off-system energy sales revenues of $341 million.

III. PRODUCTION COST MODELING

Q. What is a production cost model?

A. A production cost model is a computer application used to simulate an electric utility's generation system and load obligations. One of the primary uses of a production cost model is to develop production cost estimates used for planning and decision making, including the development of a normalized level of net fuel costs upon which a utility's revenue requirement can be based.

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[1] "Net fuel costs" as used in this testimony is slightly different than "net base fuel costs" ("NBFC") discussed in the direct testimony of Mr. Weiss and which is contained in the Company's fuel adjustment clause tariff. This is because NBFC also include items that are not the product of the PROSYM modeling but which are a part of total fuel and purchased power expense included in Mr. Weiss' revenue requirement. These items include the following: fixed gas supply costs, credits against the cost of nuclear fuel from Westinghouse arising from a prior settlement of a nuclear fuel contract dispute, Day 2 energy market expenses and Day 3 ancillary service market expenses and revenues from the Midwest Independent Transmission System Operator, Inc. ("MISO"), excluding administrative fees, MISO Day 2 congestion charges, MISO Day 2 revenues, and capacity sales revenues.

Q. How long has PROSYM been used to model Ameren Missouri's system?

A. It is my understanding that PROSYM has been used to model Ameren Missouri's system since 1995.

Q. How is PROSYM used by Ameren Services?

A. PROSYM is operated and maintained by the Operations Analysis Group. Some of the most common uses of PROSYM are: preparation of the monthly and annual fuel burn projections; support for emissions planning; evaluation of major unit overhaul schedules; evaluation of power plant projects; and support for regulatory requirements, such as Federal Energy Regulatory Commission Public Utility Regulatory Policy Act ("PURPA") filings; and rate cases, such as this one.

Q. What are the major inputs to the PROSYM model run used for calculating a normalized level of net fuel costs?

A. The major inputs include: normalized hourly loads, unit operating characteristics, unit availabilities, fuel prices, and hourly energy prices.

IV. PRODUCTION COST MODEL INPUTS

Q. What type of load data is required by PROSYM?

A. PROSYM utilized normalized hourly loads developed from the actual loads for the test year period, October 1, 2010 through September 30, 2011. The normalized hourly loads reflect kilowatt-hour ("kWh") sales and distribution line losses. Ameren Missouri's normalized sales plus distribution line loss values were provided to me by Ameren Missouri witness Steven M. Wills.

Q. What operational data is used by PROSYM?

A. Operational data reflects the characteristics of the generating units used to supply the energy for native load customers and to make off-system energy sales. The major operational data includes: the unit input/output curve, which calculates the fuel input required for a given level of generator output; the unit minimum load, which is the lowest load level at which a unit normally operates; the unit maximum load, which is the highest level at which the unit normally operates; and fuel blending. Schedule MJP-E1 lists the operational data used for this case.

Q. Have there been any significant changes to the operational data since the last rate case?

A. Yes, the following are significant changes since the last rate case: 1) inclusion of the Maryland Heights Renewable Energy Center landfill gas fueled generators, which are expected to be placed into service no later than July 2012; 2) an efficiency gain and increase in unit capability at Labadie Unit 2 as a result of a turbine upgrade to be completed in the spring of 2012, and (3) an increase in the capability of Keokuk Units 2 & 4 as a result of runner upgrades.

Due to the limited amount of information relating to these changes at the time of this testimony, I recommend that these assumptions be updated as part of a later modeling run to be performed as part of the true-up contemplated in this case (i.e, to reflect actual data as of the anticipated July 31, 2012 true-up date).

Q. What unit availability data are used by PROSYM?

A. The unit availability data are categorized as planned outages, unplanned outages and deratings. Planned outages are major unit outages that occur at scheduled intervals. The length of the scheduled outage depends on the type of work being performed. Planned outage intervals vary due to factors such as: type of unit, unplanned outage rates during the maintenance interval, and plant modifications. A normalized planned outage length was used for this case, as reflected in Schedule MJP-E2. The length of the planned outages is based on a 6-year average of actual planned outages that occurred between October 1, 2005 and September 30, 2011, with one exception. The exception is for the Callaway nuclear plant, which was based on a historical average using Refuel 15 through Refuel 18.

In addition to the length of the planned outage, the time period when the planned outage occurs is also important. Planned outages are typically scheduled during the spring and fall months when system loads are low. Another important factor considered in scheduling planned outages is off-system power prices. The planned outage schedule used in modeling Ameren Missouri's generation with the PROSYM model is shown in Schedule MJP-E3.

Unplanned outages are short outages when a unit is completely off-line. These outages typically last from one to seven days and occur between the planned outages. The unplanned outages occur due to operational problems that must be corrected for the unit to operate properly. Several examples of causes of unplanned outages are tube leaks, boiler and economizer cleanings, and turbine/generator repairs. The unplanned outage rate for this case is based on a 6-year average of unplanned outages that occurred between October 1, 2005 and September 30, 2011, and is reflected in Schedule MJP-E4.

Derating occurs when a generating unit cannot reach its maximum output due to operational problems. The magnitude of the derating varies based on the operating issues involved and can result in output reductions ranging from 3% to 25% of the maximum unit rating. Several examples of causes of derating include: coal mill outages, boiler feed pump outages, and exceeding opacity limits due to precipitator performance problems. The derating rate used in this case is based on a 6-year average of deratings that occurred between October 1, 2005 and September 30, 2011, and is reflected in Schedule MJP-E5.

Q. What fuel cost data was used to determine Ameren Missouri's revenue requirement?

A. Ameren Missouri units burn four types of fuel: nuclear fuel, coal, natural gas, and oil. The fuel costs are based on costs as of the end of the anticipated true-up period, July 31, 2012. The coal costs reflect coal and transportation costs based upon coal and transportation prices that become effective as of January 1, 2012. The natural gas and oil prices are based on the average daily spot market prices for the 36 month period ending July 31, 2012, using 27 months of historical data and 9 months of forward prices for natural gas, and 26 months of historical data and 10 months of forward prices for oil. The nuclear fuel costs are based on the average nuclear fuel cost associated with Callaway Refuel 18, which was completed in the fall of 2011.

Q. What off-system energy purchase and sales data was used in PROSYM?

A. Off-system energy purchases are power purchases from energy sellers used to meet native load requirements. The purchases can be from long-term purchase contracts or short-term economic purchases. The only long-term power purchase contract included as an off-system energy purchase in PROSYM in this case is the purchase of

102 megawatts ("MW") from Horizon Wind Energy LLC, Pioneer Prairie Wind Farm under a purchase power contract which began September 1, 2009. This same long-term power purchase contract was also included in purchase power costs in the Company's last rate case. Short-term economic purchases are used to supply native load when the power prices are lower than Ameren Missouri's cost of generation and the generating unit operating parameters are not violated. (A violation of the generating unit operating parameters would occur when all units are operating at their minimum load and cannot reduce their output any further. In that case, short-term economic purchases are not made even when they are at lower costs than the cost of operating the Ameren Missouri generating units.) The price of short-term economic purchases is based on hourly market prices. The hourly market prices are based on the average market prices for the period August 1, 2009 through July 31, 2012. An explanation of the use of power prices from this time period is provided in Mr. Haro's direct testimony. Mr. Haro utilized 27 months of actual price data and 9 months of forward price data, subject to true-up later in this case. The ability to make short-term economic purchases was not limited beyond that noted above as Ameren Missouri is a participant in the Day 2 Energy Markets sponsored by the MISO.

With the exception of certain wholesale transactions with municipalities, the PROSYM modeling contains only spot sales. Spot sales are short-term economic off-system energy sales that occur when the cost of excess generation is below the market price of power. Excess generation is the generation that is not used to supply the native load customers. The market price used for short-term economic sales is the same price as for short-term economic purchases, which were previously described. No limits have been placed on the volume of short-term economic sales, again since Ameren Missouri participates in the MISO's Day 2 Energy Markets.

Q. Are there other net fuel costs that cannot be determined by the PROSYM production cost model?

A. Yes. There are other costs and revenues that should be considered, such as capacity purchase costs, capacity sales revenues, ancillary services costs and revenues, and the costs/revenues associated with load forecasting deviations and generation forecasting deviations. Mr. Haro has addressed all of these adjustments, with the exception of the costs associated with load and generation forecasting deviations, which I address below.

Q. Please list the items that are modeled in PROSYM that should be trued-up using data as of the end of the anticipated true-up date in this case, proposed to be July 31, 2012.

A. The following PROSYM inputs should be updated as of the true-up date: the three new plant operating characteristics mentioned above (the Maryland Heights Renewable Energy Center, Labadie Unit 2 turbine upgrade and Keokuk Units 2 & 4 runner upgrades); Ameren Missouri's retail kWh sales and distribution line losses; coal, nuclear, gas, and oil costs; power prices; and load forecasting and generation forecasting deviation costs/revenues (net).

V. LOAD AND GENERATION FORECAST DEVIATIONS

Q. You mentioned earlier a cost associated with load and generation forecasting deviations. Please describe what you mean by load forecasting deviations and generation forecasting deviations.

A. This component captures the additional costs and revenues associated with actual market settlements as compared to what such settlements would have been had Ameren Missouri's day-ahead awards perfectly matched their actual real time load and generation levels. Ameren Missouri's load is bid into the market on a day-ahead basis using a load forecast representing its best estimate of what its load obligation will be in each hour of the next market day. It also seeks to have its generating assets clear on a day-ahead basis. At the end of each day, the MISO issues day-ahead awards for each generating asset as well as the load. Deviations from these day-ahead awards result in additional costs or revenues, as compared to what the Company would have received if its day-ahead awards perfectly matched its actual load and generation levels in real time. These additional costs/revenues can be measured by multiplying the deviation from the day-ahead award by the difference in price between the real-time MISO market locational marginal price ("LMP") and the day-ahead LMP. This calculation is done for each hour, for the load and each generation asset with the exception of the Company's combustion turbine generating units ("CTGs"). The CTGs are excluded due to the high number of reliability starts required by the MISO which occur separately from the economic dispatch process and the associated Revenue Sufficiency Guarantee make-whole payments.

For generating assets, additional benefits are achieved when (1) the real time LMP is higher than the day-ahead LMP and the real time output level is higher than the day-ahead award or (2) when the real time LMP is lower than the day-ahead LMP and the real time output level is lower than the day-ahead award. Additional costs are incurred however if the change in LMP is in the opposite direction of the change in the real time output level. For the load, it is the opposite. Additional benefits are achieved when (1) the real time LMP is higher than the day-ahead LMP and the real time metered load is lower than the day-ahead award or (2) when the real time LMP is lower than the day-ahead LMP and the real time metered load is higher than the day-ahead award. Additional costs are incurred when the deviation in LMP is in the same direction as the deviation in load.

Q. What is the total impact of the load forecasting deviations and the generation forecasting deviations that have been calculated?

A. Using an annualized average for the two year period of October, 2009 – September, 2011, the calculated impact of load forecasting deviations is an additional cost of $4.8 million and the calculated impact of generation forecast deviations is additional revenues of $3.9 million, resulting in a net impact of $0.9 million of additional costs. This $0.9 million is accounted for in the modeling as an increase to purchased power expense. This is the same methodology used in the last two cases to capture the impact of load and generation forecasting deviations.

Q. Does this complete your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	Case No. ER-2012-0166

AFFIDAVIT OF MARK J. PETERS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Mark J. Peters, being first duly sworn on his oath, states:

1. My name is Mark J. Peters. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Managing Supervisor in the Corporate Planning department

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Ameren Missouri consisting of 11 pages, and Schedules MJP-E 1 through MJP-E 5, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Mark J. Peters

Subscribed and sworn to before me this 2nd day of February, 2012.

Mary Hoyt
Notary Public

My commission expires: 4-11-2014

Mary Hoyt - Notary Public
Notary Seal, State of
Missouri - Jefferson County
Commission #10397820
My Commission Expires 4/11/2014

Input / Output Curve #1

Unit Name	Minimum - Net	12 Month Avg Net	Primary Fuel Type	A	B	C	EDF
Callaway	800	1,224	Nuclear	-	9.942	-	1.000
Labadie 1	300	612	PRB Coal	-	9.282	415.1	0.999
Labadie 2	300	612	PRB Coal	0.00004	9.321	585.6	0.958
Labadie 3	300	610	PRB Coal	0.00122	8.177	596.5	0.999
Labadie 4	300	612	PRB Coal	0.00100	8.460	552.0	0.999
Rush 1	275	613	PRB Coal	-	9.452	331.9	0.986
Rush 2	275	613	PRB Coal	0.00123	7.756	698.1	0.986
Sioux 1	300	489	PRB/ILLINOIS Coal	-	8.429	514.8	1.037
Sioux 2	300	489	PRB/ILLINOIS Coal	-	8.505	533.7	1.037
Meramec 1	55	123	PRB Coal	0.01139	8.376	216.4	1.000
Meramec 2	55	125	PRB Coal	0.00963	8.420	214.3	1.000
Meramec 3	165	264	PRB Coal	0.00194	9.433	442.8	1.000
Meramec 4	185	346	PRB Coal	0.00266	8.310	398.8	1.000
Audrain CT 1	62	82	Natural Gas	0.00001	9.875	172.0	1.000
Audrain CT 2	62	82	Natural Gas	0.00001	9.875	172.0	1.000
Audrain CT 3	62	82	Natural Gas	0.00001	9.875	172.0	1.000
Audrain CT 4	62	82	Natural Gas	0.00001	9.875	172.0	1.000
Audrain CT 5	62	82	Natural Gas	0.00001	9.875	172.0	1.000
Audrain CT 6	62	82	Natural Gas	0.00001	9.875	172.0	1.000
Audrain CT 7	62	82	Natural Gas	0.00001	9.875	172.0	1.000
Audrain CT 8	62	82	Natural Gas	0.00001	9.875	172.0	1.000
Fairgrounds CT	60	60	Oil	0.00143	7.798	177.3	0.980
Goose Creek CT 1	50	81	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 2	50	81	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 3	50	81	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 4	50	81	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 5	50	81	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 6	45	81	Natural Gas	0.00001	8.866	224.9	1.000
Howard Bend CT	43	43	Oil	0.00261	9.654	118.6	0.950
Kinmundy CT 1	77	113	Natural Gas	0.00010	9.219	217.9	1.013
Kinmundy CT 2	77	113	Natural Gas	0.00010	9.219	217.9	1.013
Kirksville CT	14	14	Natural Gas	0.00261	9.654	118.6	1.200
Meramec CT 1	61	61	Oil	0.00143	7.798	177.3	0.960
Meramec CT 2	26	53	Natural Gas	0.00261	9.654	118.6	1.140
Mexico CT	60	60	Oil	0.00143	7.798	177.3	0.970
Moberly CT	60	60	Oil	0.00143	7.798	177.3	1.000
Moreau CT	60	60	Oil	0.00143	7.798	177.3	0.980
Peno Creek CT 1	51	51	Natural Gas	0.00001	9.046	61.7	1.000
Peno Creek CT 2	51	51	Natural Gas	0.00001	9.046	61.7	1.000
Peno Creek CT 3	51	51	Natural Gas	0.00001	9.046	61.7	1.000
Peno Creek CT 4	51	51	Natural Gas	0.00001	9.046	61.7	1.000
Pinkneyville CT 1	44	44	Natural Gas	0.00001	8.742	38.6	1.000
Pinkneyville CT 2	44	44	Natural Gas	0.00001	8.742	38.6	1.000
Pinkneyville CT 3	44	44	Natural Gas	0.00001	8.742	38.6	1.000
Pinkneyville CT 4	44	44	Natural Gas	0.00001	8.742	38.6	1.000
Pinkneyville CT 5	39	39	Natural Gas	0.00001	0.982	70.9	1.000
Pinkneyville CT 6	39	39	Natural Gas	0.00001	0.982	70.9	1.000
Pinkneyville CT 7	39	39	Natural Gas	0.00001	0.982	70.9	1.000
Pinkneyville CT 8	39	39	Natural Gas	0.00001	0.982	70.9	1.000
Raccoon Creek CT 1	42	83	Natural Gas	0.00001	8.462	255.1	1.000
Raccoon Creek CT 2	42	83	Natural Gas	0.00001	8.462	255.1	1.000
Raccoon Creek CT 3	42	83	Natural Gas	0.00001	8.462	255.1	1.000
Raccoon Creek CT 4	42	83	Natural Gas	0.00001	8.462	255.1	1.000
Venice CT 2	52	52	Natural Gas	0.00010	8.845	82.2	1.000
Venice CT 3	130	178	Natural Gas	0.00010	9.510	187.4	1.000
Venice CT 4	130	178	Natural Gas	0.00010	9.510	187.4	1.000
Venice CT 5	77	113	Natural Gas	0.00010	9.367	205.5	1.000
Viaduct CTG	29	29	Natural Gas	0.00457	9.738	132.1	1.200
Osage		233	Pond Hydro				
Keokuk		140	Run of River Hydro				
Taum Sauk 1		200	Pumped Storage				
Taum Sauk 2		200	Pumped Storage				

Note: # 1 Input Output equation: mmbtu = (Pnet^2 x A + Pnet x B + C) x EDF, where Pnet = Net power level

PLANNED OUTAGES

Actual	2005 (1) (hrs)	2006 (hrs)	2007 (hrs)	2008 (hrs)	2009 (hrs)	2010 (hrs)	2011 (2) (hrs)	Total (hrs)	Day / Year (days)	Total Days for Similar Units (days)
Labadie 1	0	0	0	2,095	0	0	0	2,095	**15**	
Labadie 2	0	0	0	0	169	340	0	509	**4**	
Labadie 3	0	0	0	0	676	0	0	676	**5**	
Labadie 4	0	0	0	0	682	237	0	919	**6**	
Labadie 1-4										**29**
Meramec 1	0	0	0	0	0	0	801	801	**6**	
Meramec 2	0	0	0	0	0	0	0	0	**0**	
Meramec 1-2										**6**
Meramec 3	369	1,548	0	0	0	0	0	1,917	**13**	
Meramec 4	0	0	0	0	0	0	0	0	**0**	
Rush Island 1	0	0	2,381	0	0	0	1,442	3,823	**27**	
Rush Island 2	0	0	0	0	360	2,342	0	2,702	**19**	
Rush 1-2										**45**
Sioux 1	0	0	0	1,794	0	577	1,799	4,170	**29**	
Sioux 2	0	1,383	0	0	0	1,347	0	2,730	**19**	
Sioux 1-2										**48**

Callaway

Refuel #	#15	#16	#17	#18	Avg Days / Refuel Outage	Annual Refuel Outage Length *
Start	04/01/07	10/10/08	04/16/10	10/15/11		
End	05/10/07	11/07/08	05/24/10	11/26/11		
Length	39	28	38	42	**40**	**27**

*** Annual Refuel Outage Length = Avg Days / Refuel Outage x 2/3**

(1) 2005 data is for October 1-December 31, 2005.
(2) 2011 data is for January 1- September 30, 2011.

2 0 1 0 **UE OA OUTAGE PLANNING SCHEDULE** **2 0 1 1** **2 0 1 1**

OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
3 10 17 24	31 7 14 21 28	5 12 19 26	2 9 16 23	30 6 13 20	27 6 13 20 27	3 10 17 24	1 8 15 22 29	5 12 19 26	3 10 17 24	31 7 14 21 28	4 11 18 25 2

Mws		Outage	Dates
1220	CAL 1	Callawy #1	(10/9 - 11/5)
607	RUSH 1	Rush #1	(3/5 - 4/19)
603	RUSH 2		
613	LAB 1	Labadie #1	(11/6 - 12/5)
595	LAB 2		
612	LAB 3		
613	LAB 4		
499	SX 1	Sioux #1	(3/19 - 5/6)
498	SX 2		
123	MER 1		
125	MER 2	M1	(9/17 - 9/23)
264	MER 3	Mer 3	(9/3 - 9/16)
350	MER 4		

OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
3 10 17 24	31 7 14 21 28	5 12 19 26	2 9 16 23	30 6 13 20	27 6 13 20 27	3 10 17 24	1 8 15 22 29	5 12 19 26	3 10 17 24	31 7 14 21 28	4 11 18 25 2

Unplanned Outage Rates - Full Outages

	2005 (1)	2006	2007	2008	2009	2010	2011	Average
Callaway 1	0.0%	5.0%	1.3%	3.4%	4.0%	5.3%	0.0%	**3.2%**
Labadie 1	2.7%	4.9%	5.0%	5.1%	3.3%	3.9%	2.2%	**4.1%**
Labadie 2	5.4%	5.1%	2.9%	6.8%	8.8%	7.1%	6.0%	**6.1%**
Labadie 3	6.0%	12.2%	7.0%	3.4%	6.6%	5.7%	6.1%	**6.8%**
Labadie 4	0.0%	4.1%	3.1%	5.2%	4.7%	2.0%	4.0%	**3.7%**
Meramec 1	4.0%	3.5%	5.1%	4.2%	7.1%	2.9%	2.9%	**4.3%**
Meramec 2	2.7%	5.5%	7.8%	4.2%	9.2%	10.4%	1.4%	**6.5%**
Meramec 3	0.0%	4.9%	10.0%	14.0%	21.1%	13.3%	12.6%	**12.4%**
Meramec 4	11.6%	15.7%	10.8%	15.0%	17.0%	19.4%	9.9%	**14.7%**
Rush Island 1	10.7%	7.2%	15.7%	2.1%	1.4%	3.3%	4.9%	**5.6%**
Rush Island 2	3.0%	7.2%	4.5%	5.7%	5.9%	6.9%	1.7%	**5.3%**
Sioux 1	4.0%	5.6%	5.5%	5.8%	6.5%	2.3%	4.9%	**5.1%**
Sioux 2	0.8%	6.2%	4.6%	6.7%	10.4%	5.1%	8.2%	**6.6%**

(1) 2005 data is for October 1-December 31, 2005.
(2) 2011 data is for January 1- September 30, 2011.

Derating

	2005 (1)	2006	2007	2008	2009	2010	2011	Average
Callaway 1	0.1%	0.4%	0.1%	0.9%	0.6%	0.0%	0.9%	**0.4%**
Labadie 1	0.7%	0.6%	1.3%	4.8%	5.7%	1.2%	1.1%	**2.3%**
Labadie 2	1.5%	1.3%	1.0%	2.7%	3.7%	2.1%	1.8%	**2.1%**
Labadie 3	1.6%	1.9%	0.5%	2.5%	1.6%	1.6%	2.6%	**1.8%**
Labadie 4	1.7%	2.3%	0.8%	2.5%	2.8%	2.9%	1.4%	**2.1%**
Meramec 1	0.1%	0.6%	0.8%	1.1%	2.1%	2.7%	0.9%	**1.4%**
Meramec 2	0.0%	0.3%	1.6%	2.3%	5.0%	0.4%	4.3%	**2.1%**
Meramec 3	0.8%	4.1%	4.8%	2.3%	0.8%	0.5%	1.4%	**2.2%**
Meramec 4	5.6%	1.5%	5.3%	5.1%	2.6%	7.5%	0.9%	**4.0%**
Rush Island 1	0.2%	2.0%	1.6%	1.0%	3.9%	6.8%	4.6%	**3.2%**
Rush Island 2	0.1%	1.2%	2.2%	2.2%	1.4%	0.3%	0.9%	**1.4%**
Sioux 1	0.3%	1.3%	0.5%	0.8%	0.3%	1.4%	0.6%	**0.8%**
Sioux 2	1.0%	1.4%	0.4%	0.3%	1.6%	3.1%	2.4%	**1.4%**

(1) 2005 data is for October 1-December 31, 2005.
(2) 2011 data is for January 1- September 30, 2011.