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Witness: Timothy D. Finnell
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2011-0028

DIRECT TESTIMONY

OF

TIMOTHY D. FINNELL

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
September, 2010

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DIRECT TESTIMONY

OF

TIMOTHY D. FINNELL

CASE NO. ER-2011-0028

I. INTRODUCTION

Q. Please state your name and business address.

A. Timothy D. Finnell, 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, Operations Analysis in the Corporate Planning Function 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 my Bachelor of Science Degree in Industrial Engineering from the University of Missouri-Columbia in May 1973. I received my Master of Science Degree in Engineering Management from the University of Missouri-Rolla in May 1978. My duties include 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 AmerenUE ("AmerenUE" or "Company"), providing power plant project justification studies, and performing other special studies.

I joined the Operations Analysis group in 1978 as an engineer. In that capacity, I was responsible for updating the computer code of the System Simulation Program, which was the production costing model used by Union Electric Company ("UE") at that time. I also prepared the UE fuel budget, performed economic studies for power plant projects, and prepared production cost modeling studies for UE rate cases since 1978. I was promoted to Supervising Engineer of the Operations Analysis work group in 1985. I became an Ameren Services employee in 1998, when UE and Central Illinois Public Service Company merged. My title was changed to Managing Supervisor in February 2008.

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 AmerenUE'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 AmerenUE 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. AmerenUE'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

[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.

dàta, fuel costs, off-system market data, and system requirements. The normalized annual net fuel costs are $465 million, which consists of fuel costs of $808 million and variable purchase power costs of $31 million, offset by off-system energy sales revenues of $374 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.

Q. Is the PROSYM model used by Ameren Services a commonly used production cost model?

A. Yes. PROSYM is a product of Ventyx. The PROSYM production cost model is widely used either directly or indirectly by utilities around the world. By indirectly I mean that the PROSYM logic is used to run numerous other products that Ventyx offers.

Q. How long has Ameren Services been using PROSYM to model AmerenUE's system?

A. Ameren Services has been using PROSYM to model AmerenUE'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.

Q. Do different production cost models produce similar results?

A. Most models should have similar logic for optimizing generation costs and should produce similar results, all else being equal. However, some models have a higher level of accuracy because, for example, they are able to perform a more detailed optimization for systems like AmerenUE's system with a run of river plant, a stored hydroelectric plant, and a pumped storage plant. The dispatch of hydroelectric and pumped storage plants is an important part of AmerenUE's generation cost optimization and requires a model that is able to optimize those types of plants. PROSYM is such a model. Our experience with PROSYM indicates that it does a superior job of simulating complex generating systems such as AmerenUE's system.

Q. Are there other key issues relating to production cost modeling?

A. Yes. Another very important issue is how well the model is calibrated to actual results. Model calibration is done by using model inputs that reflect actual (i.e. not normalized) data for a specific time period and comparing the simulated results produced by the model to the actual generation performance for that time period. Production cost model outputs that should be compared to actual data to properly calibrate the model include: unit generation totals for the period being evaluated; hourly unit loadings; unit heat rates; number of hot and cold starts; and off-system sales volumes.

Q. How well is the PROSYM model calibrated?

A. The PROSYM model is very well calibrated, as demonstrated by the results of a calibration conducted under my supervision which compared actual 2009 generation to model results. For example, the calibrated model calculated the generating output from AmerenUE to be 48,986,100 megawatt-hours ("MWh"). Actual generation was 48,762,916 MWhs, thus the model result was within 1/2% of the actual generation. Another example of how well the model is calibrated is reflected in the predicted off-system energy sales produced by the model versus the actual off-system energy sales for the study period. The result (12,284,900 MWh from the model versus 12,447,217 MWh actual) was within 1.3% of the actual results. Based upon my experience, these results demonstrate the high level of accuracy of the model. Detailed results of the calibration are shown in Schedule TDF-E1.

Q. What must one do to achieve a high level of calibration in modeling a utility's generation?

A. One must look carefully at the model inputs that could affect the results. For example, if the model's result for generation output is too low compared to actual values there are several items that would need to be reviewed. These items include the analysis of whether: (1) the dispatch price is too high; (2) the unit availability factor is too low; (3) the minimum load is too low; (4) the unit start-up costs are incorrect; (5) the minimum up and down times are incorrect; and (6) the off-system energy sales market is incorrectly modeled.

Q. What are the implications of using a less well calibrated model to determine revenue requirement in a rate case?

A. A poorly calibrated model will inevitably lead to an inaccurate determination of a normalized level of net fuel costs.

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, April 1, 2009 through March 31, 2010. The normalized hourly loads reflect kilowatt-hour ("kWh") sales and distribution line losses. AmerenUE's normalized sales plus line loss values were provided to me by AmerenUE 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 TDF-E2 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, there were three significant changes to the operational data since the last rate case. The first change is the result of the installation of wet flue gas desulfurization units (scrubbers) on the Sioux generating units. The addition of the scrubbers has resulted in a 12 megawatt (MW) reduction in the net capability of each unit and an increase in the unit's net heat rate due to the extra station service used by the scrubbers. The second change is a modification of the energy associated with the rebuilt Taum Sauk upper reservoir. The energy from the upper reservoir was increased to 2,450 MWh per day. The third change is a 24 MW increase in the Rush Island unit 2 capability and a reduction in the unit heat rate due to better efficiencies resulting from a major unit overhaul that was completed in April 2010.

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 February 28, 2011 true-up cutoff 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 TDF-E3. The length of the planned outages is based on a 6-year average of actual planned outages that occurred between April 1, 2004 and March 31, 2010, with one exception. The exception is for the Callaway nuclear plant, which was based on a historical average using Refuel 8 through Refuel 16 but excluding the two longest refuels (Refuels 13 and 14) and excluding the two shortest refuels (Refuels 8 and 9). This methodology was proposed by Missouri Industrial Energy Consumers witness James Dauphinais in his Surrebuttal Testimony in the last AmerenUE Rate Case (Case No. ER-2010-0036) and was used by the Company and the Missouri Public Service Commission Staff in their true-up modeling runs that produced the net fuel costs used to set the revenue requirement in the last case.

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 AmerenUE's generation with the PROSYM model is shown in Schedule TDF-E4.

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 April 1, 2004 and March 31, 2010, and is reflected in Schedule TDF-E5.

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 reduced outputs ranging from 2% to 50% 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 April 1, 2004 and March 31, 2010, and is reflected in Schedule TDF-E6.

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

A. AmerenUE 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, February 28, 2011. The coal costs reflect coal and transportation costs based upon coal and transportation prices that become effective as of January 1, 2011. The natural gas and oil prices are based on the average daily spot market prices for the 36 month period ending February 28, 2011 using 28 months of historical data (from March 1, 2008 to June 30, 2010) and 8 months of forward gas prices (from July 1, 2010 to February 28, 2011). The nuclear fuel costs are based on the average nuclear fuel cost associated with Callaway Refuel 17, which was completed in May 2010.

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 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 AmerenUE'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 AmerenUE 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 March 1, 2008 through February 28, 2011. An explanation of the use of power prices from this time period is provided in Company witness Jaime Haro's direct testimony. Mr. Haro utilized 28 months of actual price data and 8 months of forward price data, subject to true-up later in this case. The volume of short-term economic purchases was assumed to be unlimited since AmerenUE is a participant in the Day 2 Energy Markets sponsored by the MISO.

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 for short-term economic sales is the same price as for short-term economic purchases, which were previously described. The volume of short-term economic sales was assumed to be unlimited, again since AmerenUE 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 cutoff date in this case, February 28, 2011.

A. The following PROSYM inputs should be updated as of the true-up cutoff date: the three new plant operating characteristics mentioned above (Sioux scrubbers impact, Taum Sauk operating characteristics, and additional output resulting from the Rush Island construction projects which included a turbine retrofit); AmerenUE's kWh sales and line losses; coal, nuclear, gas, and oil costs; power prices; and load forecasting and generation forecasting deviation costs/revenues (net).

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. Load forecasting deviations and generation forecasting deviations are related to the operation of the MISO day-ahead and real time markets. The day-ahead market is based on market participants' estimates of loads and generation levels for the following day and the real time ("RT") market is based on market participants' actual loads and generation levels. When there is a deviation between the day-ahead values and real time values there is extra revenue or expense which is calculated by multiplying the MWh deviation times the difference between the DA-LMP and the real time locational marginal price ("RT-LMP"). For example, on March 21, 2010, for the hour ending 11 a.m., the day ahead forecast was 4,084.6 MW and the real time load was 4,469.1 MW. Thus, the load was under-forecasted by 384.5 MW. Also the DA-LMP was $25.94/MWh and the RT-LMP was $38.43/MWh, resulting in an additional cost of $12.49/MWh for meeting the extra (under-forecasted) load. The cost impact of this load forecast deviation in that hour is $4,802 (384.5 MW per hour x $12.49/MWh = $4,802). To determine the load forecasting deviations, this calculation is done for every hour and then the cost impacts for all the hours are summed for the period being analyzed.

For the generation forecasting deviations, this calculation is done for every hour and for every generating unit except for the combustion turbine generators ("CTGs") and then cost impacts for all the hours are summed for the period being analyzed. The CTGs have been excluded from the analysis because of the way the MISO dispatches the CTGs and because of the MISO's Revenue Sufficiency Guarantee make whole payments associated with the MISO's dispatch of the CTGs.

Q. What is the total impact of the load forecasting deviations and the generation forecasting deviations?

A. The impact of load forecasting deviations is an additional cost of $8.1 million and the impact of generation forecast deviations is additional revenues of $1.3 million, resulting in a net impact of $6.8 million of additional costs. This $6.8 million is accounted for as an increase to purchased power expense.

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 AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area.	))))	**Case No. ER-2011-0028**

AFFIDAVIT OF TIMOTHY D. FINNEL

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

I, Timothy D. Finnell, being first duly sworn on his oath, states:

1. My name is Timothy D. Finnell. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as a Managing Supervisor, Operations Analysis in the Corporate Planning Function of Ameren Services.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 13 pages and Schedules TDF-E1 through TDF-E6, 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.

Timothy D Finnell
Timothy D. Finnell

Subscribed and sworn to before me this 3 day of September, 2010.

Amanda Tesdall
Notary Public

My commission expires:

Amanda Tesdall - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07158967
My Commission Expires 7/29/2011

PROSYM CALIBRATION - Net MWH
2009 ACTUAL vs PROSYM 2009

		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Difference
Callaway	Actual	928,441	535,798	826,689	796,254	909,950	836,422	898,752	899,588	878,322	918,753	891,471	926,676	10,247,116	
	Calib DA	928,500	537,000	829,100	796,200	907,200	860,400	892,600	896,900	877,100	918,800	889,900	927,000	10,260,700	
	Actual - DA	-59	-1,202	-2,411	54	2,750	-23,978	6,152	2,688	1,222	-47	1,571	-324	-13,584	-0.1%
Rush	Actual	835,596	673,628	709,270	517,483	610,329	693,066	667,548	718,634	575,123	701,512	627,639	687,360	8,017,188	
	Calib DA	810,000	672,500	709,000	505,000	638,700	708,200	681,100	718,000	587,200	714,700	651,500	744,400	8,140,300	
	Actual - DA	25,596	1,128	270	12,483	-28,371	-15,134	-13,552	634	-12,077	-13,188	-23,861	-57,040	-123,112	-1.5%
Labadie	Actual	1,556,114	1,329,232	1,476,669	1,247,746	1,031,185	1,416,851	1,584,042	1,539,861	1,397,061	1,535,770	1,554,353	1,568,684	17,237,568	
	Calib DA	1,595,100	1,385,600	1,526,100	1,272,900	1,020,300	1,425,200	1,580,000	1,559,300	1,392,200	1,531,200	1,557,300	1,564,500	17,409,700	
	Actual - DA	-38,986	-56,368	-49,431	-25,154	10,885	-8,349	4,042	-19,439	4,861	4,570	-2,947	4,184	-172,132	-1.0%
Sioux	Actual	599,864	535,985	481,676	466,559	414,645	509,429	399,499	521,073	473,220	454,147	325,868	578,542	5,760,507	
	Calib DA	603,000	538,200	470,800	471,800	437,400	540,500	422,600	526,900	492,000	453,700	346,200	584,800	5,887,900	
	Actual - DA	-3,136	-2,215	10,876	-5,241	-22,755	-31,071	-23,101	-5,827	-18,780	447	-20,332	-6,258	-127,393	-2.2%
Meramec	Actual	496,313	510,079	459,013	497,469	521,632	439,334	462,901	441,442	445,492	399,009	252,980	436,846	5,362,510	
	Calib DA	462,600	493,300	443,600	483,800	515,100	441,400	464,600	438,300	448,800	401,000	262,900	428,200	5,283,600	
	Actual - DA	33,713	16,779	15,413	13,669	6,532	-2,066	-1,699	3,142	-3,308	-1,991	-9,920	8,646	78,910	1.5%
Osage	Actual	46,546	37,981	49,431	124,547	157,978	148,238	46,880	14,181	27,925	129,370	134,730	39,532	957,339	
	Calib DA	47,800	36,400	54,700	121,200	156,400	145,400	50,400	13,500	36,500	122,000	129,400	43,600	957,300	
	Actual - DA	-1,254	1,581	-5,269	3,347	1,578	2,838	-3,520	681	-8,575	7,370	5,330	-4,068	39	0.0%
Keokuk	Actual	72,840	70,047	69,675	72,492	70,469	76,332	94,140	90,132	70,719	87,062	88,243	87,749	949,900	
	Calib DA	73,900	68,200	71,000	72,300	70,100	76,600	94,300	89,400	71,900	86,500	87,600	88,000	949,800	
	Actual - DA	-1,060	1,847	-1,325	192	369	-268	-160	732	-1,181	562	643	-251	100	0.0%
UE CTG	Actual	8,552	11,275	10,525	4,540	14,624	72,379	13,086	48,955	8,943	18,785	8,012	11,112	230,788	
	Calib DA	65,300	6,500	400	400	0	17,600	0	6,600	0	0	0	0	96,800	
	Actual - DA	-56,748	4,775	10,125	4,140	14,624	54,779	13,086	42,355	8,943	18,785	8,012	11,112	133,988	58.1%
Purchases	Actual	156,719	114,530	109,737	150,204	296,833	132,070	199,731	175,205	123,718	135,698	102,416	171,105	1,867,966	
	Calib DA	150,600	128,900	148,000	165,400	147,300	185,200	99,600	128,900	52,100	47,100	48,500	91,800	1,393,400	
	Actual - DA	6,119	-14,370	-38,263	-15,196	149,533	-53,130	100,131	46,305	71,618	88,598	53,916	79,305	474,566	25.4%
Sales	Actual	963,294	992,950	1,293,995	1,162,522	1,119,903	768,563	885,619	833,907	998,048	1,547,846	1,123,233	757,337	12,447,217	
	Calib DA	995,700	1,016,500	1,405,400	1,196,000	1,006,100	823,800	808,600	783,900	968,100	1,419,900	1,130,200	730,700	12,284,900	
	Actual - DA	-32,406	-23,550	-111,405	-33,478	113,803	-55,237	77,019	50,007	29,948	127,946	-6,967	26,637	162,317	1.3%
Net Output	Actual	3,737,691	2,825,605	2,898,690	2,714,772	2,907,742	3,555,558	3,480,960	3,615,164	3,002,475	2,832,260	2,862,479	3,750,269	38,183,665	
	Calib DA	3,741,100	2,850,100	2,847,300	2,693,000	2,886,400	3,576,700	3,476,600	3,593,900	2,989,700	2,855,100	2,843,100	3,741,600	38,094,600	
	Actual - DA	-3,409	-24,495	51,390	21,772	21,342	-21,142	4,360	21,264	12,775	-22,840	19,379	8,669	89,065	0.2%
UE Coal	Actual	3,487,887	3,048,924	3,126,628	2,729,257	2,577,791	3,058,680	3,113,990	3,221,010	2,890,896	3,090,438	2,760,840	3,271,432	36,377,773	
	Calib DA	3,470,700	3,089,600	3,149,500	2,733,500	2,611,500	3,115,300	3,148,300	3,242,500	2,920,200	3,100,600	2,817,900	3,321,900	36,721,500	
	Actual - DA	17,187	-40,676	-22,872	-4,243	-33,709	-56,620	-34,310	-21,490	-29,304	-10,162	-57,060	-50,468	-343,727	-0.9%
UE Hydro	Actual	3,487,887	108,028	119,106	197,039	228,447	224,570	141,020	104,313	98,644	216,432	222,973	127,281	1,907,239	
	Calib DA	121,700	104,600	125,700	193,500	226,500	222,000	144,700	102,900	108,400	208,500	217,000	131,600	1,907,100	
	Actual - DA	3,366,187	3,428	-6,594	3,539	1,947	2,570	-3,680	1,413	-9,756	7,932	5,973	-4,319	139	0.0%
UE	Actual	7,912,767	3,704,025	4,082,948	3,727,090	3,730,812	4,192,051	4,166,848	4,273,866	3,876,805	4,244,408	3,883,296	4,336,501	48,762,916	
	Calib DA	4,586,200	3,737,700	4,104,700	3,723,600	3,745,200	4,215,300	4,185,600	4,248,900	3,905,700	4,227,900	3,924,800	4,380,500	48,986,100	
	Actual - DA	3,326,567	-33,675	-21,752	3,490	-14,388	-23,249	-18,752	24,966	-28,895	16,508	-41,504	-43,999	-223,184	-0.5%

Schedule TDF-E1

Input / Output Curve #1

Unit Name	Minimum - Net	12 Month Avg Net	Primary Fuel Type	A	B	C	EDF
Callaway	800	1,220	Nuclear	-	9.934	-	1.000
Labadie 1	280	613	PRB Coal	0.00110	8.265	565.8	1.007
Labadie 2	280	595	PRB Coal	0.00167	7.844	794.5	1.007
Labadie 3	280	612	PRB Coal	0.00110	8.265	565.8	1.007
Labadie 4	28	613	PRB Coal	0.00110	8.265	565.8	1.007
Rush 1	275	607	PRB Coal	0.00140	7.934	631.5	1.011
Rush 2	275	615	PRB Coal	0.00137	7.934	631.5	1.011
Sioux 1	307	499	PRB/ILLINOIS Coal	0.00001	8.641	359.6	1.038
Sioux 2	307	498	PRB/ILLINOIS Coal	0.00058	8.314	597.7	1.038
Meramec 1	48	123	PRB Coal	0.01407	8.209	216.1	0.968
Meramec 2	48	125	PRB Coal	0.01123	9.314	106.9	0.968
Meramec 3	180	264	PRB Coal	0.00624	8.384	475.5	0.968
Meramec 4	185	350	PRB Coal	0.00770	5.168	804.7	0.968
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	61	61	Oil	0.00143	7.798	177.3	0.980
Goose Creek CT 1	50	80	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 2	50	80	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 3	50	80	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 4	50	80	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 5	50	80	Natural Gas	0.00001	8.866	224.9	1.000
Goose Creek CT 6	45	80	Natural Gas	0.00001	8.866	224.9	1.000
Howard Bend CT	46	46	Oil	0.00261	9.654	118.6	0.950
Kinmundy CT 1	77	112	Natural Gas	0.00010	9.219	217.9	1.013
Kinmundy CT 2	77	112	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	62	62	Oil	0.00143	7.798	177.3	0.960
Meramec CT 2	26	56	Natural Gas	0.00261	9.654	118.6	1.140
Mexico CT	61	61	Oil	0.00143	7.798	177.3	0.970
Moberly CT	61	61	Oil	0.00143	7.798	177.3	1.000
Moreau CT	61	61	Oil	0.00143	7.798	177.3	0.980
Peno Creek CT 1	50	50	Natural Gas	0.00001	9.046	61.7	1.000
Peno Creek CT 2	50	50	Natural Gas	0.00001	9.046	61.7	1.000
Peno Creek CT 3	50	50	Natural Gas	0.00001	9.046	61.7	1.000
Peno Creek CT 4	50	50	Natural Gas	0.00001	9.046	61.7	1.000
Pinkneyville CT 1	43	43	Natural Gas	0.00001	8.742	38.6	1.000
Pinkneyville CT 2	43	43	Natural Gas	0.00001	8.742	38.6	1.000
Pinkneyville CT 3	43	43	Natural Gas	0.00001	8.742	38.6	1.000
Pinkneyville CT 4	43	43	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	81	Natural Gas	0.00001	8.462	255.1	1.000
Raccoon Creek CT 2	42	81	Natural Gas	0.00001	8.462	255.1	1.000
Raccoon Creek CT 3	42	81	Natural Gas	0.00001	8.462	255.1	1.000
Raccoon Creek CT 4	42	81	Natural Gas	0.00001	8.462	255.1	1.000
Venice CT 1	10	27	Oil	0.00457	9.738	132.1	0.950
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	112	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		133	Run of River Hydro				
Taum Sauk 1		220	Pumped Storage				
Taum Sauk 2		220	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	2004 (1) (hrs)	2005 (hrs)	2006 (hrs)	2007 (hrs)	2008 (hrs)	2009 (hrs)	2010 (2) (hrs)	Total (hrs)	Day / Year (days)	*Total Days for* Similar Units (days)
Labadie 1	0	0	0	0	2,095	0	0	2,095	**15**	
Labadie 2	1,263	0	0	0	0	0	169	1,432	**10**	
Labadie 3	0	0	0	0	0	676	0	676	**5**	
Labadie 4	0	0	0	0	0	682	0	682	**5**	
Labadie 1-4										**34**
Meramec 1	191	0	0	0	0	0	0	191	**1**	
Meramec 2	404	0	0	0	0	0	0	404	**3**	
Meramec 1-2										**4**
Meramec 3	135	369	1,548	0		0	0	2,051	**14**	
Meramec 4	0	1,685	0	0	0	0	0	1,685	**12**	
Rush Island 1	0	0	0	2,381	0	0	0	2,381	**17**	
Rush Island 2	0	0	0	0	0	360	2,138	2,498	**17**	
Rush 1-2										**34**
Sioux 1	0	1,570	0	0	1,794	0	0	3,364	**23**	
Sioux 2	1,367	0	1,383	0	0	0	0	2,750	**19**	
Sioux 1-2										**42**

Callaway

Refuel #	#8	#9	#10	#11	#12	#13	#14	#15	#16	Avg Days / Refuel Outage	*Annual Refuel* Outage Length *
Start	10/12/96	04/03/1998	10/02/99	04/07/01	10/23/02	04/10/04	09/17/05	04/01/07	10/10/08		
End	11/11/96	05/04/1998	11/05/99	05/21/01	11/26/02	06/13/04	11/19/05	05/10/07	11/07/08		
Length	30	31	34	44	34	64	63	39	28	**36**	**24**
	Short	Short				Long	Long				
	Eliminate	Eliminate				Eliminate	Eliminate				

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

(1) 2004 data is for April 1-December 31, 2004.
(2) 2010 data is for January 1- March 31, 2010.

2 0 0 9 UE OA OUTAGE PLANNING SCHEDULE 2 0 0 9 2 0 1 0

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

Mws	Unit	Outage	Dates
1220	CAL 1	Callawy #1	(10/3-10/27)
607	RUSH 1	Rush 1	(10/31-12/4)
603	RUSH 2		
613	LAB 1	Labadie #1	(4/25-5/29)
595	LAB 2		
612	LAB 3		
613	LAB 4		
499	SX 1	Sioux #1	(4/4-5/16)
498	SX 2		
123	MER 1	M1	(5/23-5/27)
125	MER 2		
264	MER 3	Mer 3	(10/31-11/14)
350	MER 4	Mer 4	(11/14-11/26)

Unplanned Outage Rates - Full Outages

	2004 (1)	2005	2006	2007	2008	2009	2010 (2)	Average
Callaway 1	0.0%	3.7%	5.0%	1.3%	3.4%	4.0%	0.0%	**3.0%**
Labadie 1	6.8%	3.3%	4.9%	5.0%	5.1%	3.3%	4.2%	**4.6%**
Labadie 2	7.1%	6.0%	5.1%	2.9%	6.8%	8.8%	9.0%	**6.2%**
Labadie 3	3.8%	3.1%	12.2%	7.0%	3.4%	6.6%	0.1%	**5.9%**
Labadie 4	6.3%	3.3%	4.1%	3.1%	5.2%	4.7%	0.0%	**4.2%**
Meramec 1	4.1%	1.3%	3.5%	5.1%	4.2%	7.1%	5.5%	**4.3%**
Meramec 2	1.4%	1.6%	5.5%	7.8%	4.2%	9.2%	31.5%	**6.2%**
Meramec 3	10.4%	6.7%	4.9%	10.0%	14.0%	21.1%	10.2%	**11.4%**
Meramec 4	3.0%	7.2%	15.7%	10.8%	15.0%	17.0%	14.1%	**12.1%**
Rush Island 1	26.2%	13.3%	7.2%	15.7%	2.1%	1.4%	3.4%	**9.8%**
Rush Island 2	4.2%	2.2%	7.2%	4.5%	5.7%	5.9%	0.0%	**5.0%**
Sioux 1	5.8%	2.9%	5.6%	5.5%	5.8%	6.5%	4.9%	**5.4%**
Sioux 2	4.7%	2.7%	6.2%	4.6%	6.7%	10.4%	5.6%	**5.9%**

(1) 2004 data is for April 1-December 31, 2004.
(2) 2010 data is for January 1- March 31, 2010.

Derating

	2004 (1)	2005	2006	2007	2008	2009	2010 (2)	Average
Callaway 1	0.1%	0.7%	0.4%	0.1%	0.9%	0.6%	0.0%	**0.5%**
Labadie 1	0.5%	0.7%	0.6%	1.3%	4.8%	5.7%	1.4%	**2.2%**
Labadie 2	0.5%	1.6%	1.3%	1.0%	2.7%	3.7%	3.7%	**2.0%**
Labadie 3	0.5%	1.5%	1.9%	0.5%	2.5%	1.6%	1.9%	**1.5%**
Labadie 4	0.6%	2.2%	2.3%	0.8%	2.5%	2.8%	3.8%	**2.0%**
Meramec 1	0.7%	0.1%	0.6%	0.8%	1.1%	2.1%	2.0%	**1.0%**
Meramec 2	0.6%	0.4%	0.3%	1.6%	2.3%	5.0%	0.5%	**1.7%**
Meramec 3	2.3%	0.6%	4.1%	4.8%	2.3%	0.8%	0.3%	**2.4%**
Meramec 4	7.6%	2.9%	1.5%	5.3%	5.1%	2.6%	8.8%	**4.3%**
Rush Island 1	0.4%	0.7%	2.0%	1.6%	1.0%	3.9%	7.2%	**1.9%**
Rush Island 2	3.9%	1.6%	1.2%	2.2%	2.2%	1.4%	0.0%	**2.0%**
Sioux 1	0.2%	0.2%	1.3%	0.5%	0.8%	0.3%	0.1%	**0.6%**
Sioux 2	0.0%	0.3%	1.4%	0.4%	0.3%	1.6%	0.4%	**0.7%**

(1) 2004 data is for April 1-December 31, 2004.
(2) 2010 data is for January 1- March 31, 2010.

Schedule TDF-E6