Exhibit No.:	
Issues:	Production Cost Model
Witness:	Timothy D. Finnell
Sponsoring Party:	Union Electric Co.
Type of Exhibit:	Direct Testimony
Case No.:	ER-2010-_____
Date Testimony Prepared:	July 24, 2009

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2010-_____

DIRECT TESTIMONY

OF

TIMOTHY D. FINNELL

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
July, 2009

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DIRECT TESTIMONY
OF
TIMOTHY D. FINNELL
CASE NO. ER-2010-_____

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.

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 AmerenUE 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 purchase 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 data, fuel costs, off-system market data, and system requirements. The normalized

[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, principally as follows: 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 Operator, Inc. ("MISO"), excluding administrative fees, MISO Day 2 congestion charges, MISO Day 2 revenues, and capacity sales revenues.

annual net fuel costs are $515 million, which consists of fuel costs of $764 million and variable purchase power costs of $51 million, offset by off-system sales revenues of $299.6 million.[2]

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.

[2] Please note that the off-system sales revenues figures used in my testimony are on a "total company" (retail and wholesale) basis for AmerenUE. The Missouri retail share of these figures is lower by approximately 5%, and is accounted for by Mr. Weiss when he applies the Missouri jurisdictional allocation factor in computing the revenue requirement and NBFC.

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 availabilities, fuel prices, unit operating characteristics, hourly energy prices, and system requirements.

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, a pumped storage plant, and reserve requirements. 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 2008 generation to model results. For example, the calibrated model results calculated the generating output from AmerenUE to be 49,515,400 megawatt-hours ("MWh"). Actual generation was 49,336,396 MWhs, thus the model result was within less than 1/2% of the actual generation. Another example of how well the model is calibrated is reflected in the predicted off-system sales produced by the model versus the actual off-system sales for the study period. Those results (10,708,800 MWh from the model versus 10,456,820 MWh actual) was within 2.4% 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 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 utilizes monthly energy with a historic hourly load pattern. The monthly energy reflects AmerenUE kilowatt-hour ("kWh") sales and 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 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 generator minimum load, which is the lowest load level at which a unit normally operates; the 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. What availability data is used by PROSYM?

A. The 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, 2003 and March 31, 2009 with one exception. The one exception was to remove the 2005 Callaway Nuclear Plant refueling outage from the 6-year average because the 2005 Callaway refueling outage included non-recurring outage work relating to the complete replacement of the steam generators at Callaway.

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 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, 2003 and March 31, 2009, 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, 2003 and March 31, 2009, and is reflected in Schedule TDF-E6.

Q. How was the Taum Sauk Plant's availability modeled in PROSYM?

A. In order to insulate ratepayers from the financial impact of the unavailability of the Taum Sauk Plant, AmerenUE's system was modeled assuming that Taum Sauk was in service. This lowers the normalized net fuel costs used in this case by capturing the economic benefit of the Taum Sauk Plant to AmerenUE's system. For the test year period, the annual operations of the Taum Sauk Plant resulted in a net fuel cost benefit of $28.2 million, $24.8 million of which was determined by the PROSYM model and $3.4 million of which reflect capacity sales from the Taum Sauk Plant as addressed in the direct testimony of AmerenUE witness Jamie Haro.

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, 2010. The nuclear fuel costs are based on the average nuclear fuel cost associated with Callaway Refueling Number 17 which will have fuel on site as of December 2009. The coal costs reflect coal and transportation costs based upon coal and transportation prices that become effective as of January 1, 2010. The natural gas and oil prices are based on the average monthly prices for the period March, 2007 to February 28, 2010.[3]

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

A. Off-system 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 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 begins September 1, 2009. The Arkansas Power & Light ("APL") purchase power contract of 160 megawatts ("MW), which was in place during the test year ending March 31, 2009 was not modeled because the contract ends in August 2009. 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

[3] Actual price data was used for the period March 1, 2007 through April 30, 2009, while forward gas prices were used for the remaining 10 months through February 28, 2010. Actual price data for those 10 months will be utilized as part of the true-up in this case.

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, 2007 through February 2010. An explanation of the use of power prices from this time period is provided in Mr. Haro's 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 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 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. While no off-system contract sales were included in my PROSYM run, because no off-system contract sales existed at the time of the run, any off-system contract sales that exist through the true-up cutoff date will be included in the true-up.

Q. What system requirements are used in PROSYM?

A. The modeling of system requirements for regulation, spinning reserves and supplemental reserves has been eliminated due to the MISO ancillary services market ("ASM"), which began in January 2009. Eliminating the modeling of system requirements results in AmerenUE purchasing all of the ancillary services needed to serve its load from the MISO ASM and allows the generating units to operate (in the modeling) at full output. Allowing the generating units to operate at full output rather than holding some of their capacity back for regulation or spinning reserves results in a $4.6 million reduction to net fuel costs. (Net fuel costs equal generation costs plus purchase power costs less off-system sales revenues).

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, revenue sufficiency guarantee make whole payments, ancillary services costs and revenues, and the costs/revenues associated with load forecasting deviations and generation forecasting deviations. Mr. Haro has addressed all of the adjustments except for the load forecasting deviations, generation forecasting deviations and ancillary services costs (which are accounted for by Mr. Weiss in his Cost of Service Study).

Q. 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 MISO day ahead and real time markets. The day ahead ("DA") market is based on the market participants' estimates of loads and generation levels for the following day and the real time ("RT") market is based on the 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 day ahead locational marginal price ("DA-LMP") and the real time locational marginal price ("RT-LMP"). For example, on January 2, 2008, for the hour ending 1 a.m., the day ahead forecast was 5,183 MW and the modeled real time load was 5,431 MW. Thus, the load was under-forecasted by 248 MW. Also the DA-LMP was $26.63/MWh and the RT-LMP was $30.64/MWh, resulting in an additional cost of $4.01/MWh for meeting the extra load. The cost impact of this load forecast deviation in that hour is $994 (248 MW per hour x $4.01/MWh = $994). 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 revenue sufficiency guarantee make whole payments addressed in Mr. Haro's direct testimony.

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 $10.7 million and the impact of generation forecast deviations is additional revenues of $0.1

million, resulting in a net impact of $10.6 million of additional costs. This $10.6 million increases net fuel costs.

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-2010-

AFFIDAVIT OF TIMOTHY D. FINNELL

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

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 Managing Supervisor, Operations Analysis.

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, 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 24th day of July, 2009.

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
2008 ACTUAL vs PROSYM 2008

		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Difference
Callaway	Actual	919,838	861,555	897,258	880,210	904,505	861,545	878,976	889,454	869,370	281,840	579,384	554,694	9,378,629	
	Calib DA	915,900	854,700	912,100	880,600	895,800	860,400	879,400	883,100	864,700	290,300	553,200	554,600	9,344,800	
	Actual - DA	3,938	6,855	-14,842	-390	8,705	1,145	-424	6,354	4,670	-8,460	26,184	94	33,829	0.4%
Rush	Actual	767,113	754,909	797,173	648,955	667,418	731,433	769,220	718,417	638,028	774,990	708,330	782,446	8,758,432	
	Calib DA	802,200	764,200	818,700	704,200	713,800	754,500	768,300	730,900	646,300	794,900	700,900	813,000	9,011,900	
	Actual - DA	-35,087	-9,291	-21,527	-55,245	-46,382	-23,067	920	-12,483	-8,272	-19,910	7,430	-30,554	-253,468	-2.9%
Labadie	Actual	1,505,744	1,575,092	1,225,266	1,160,137	1,125,908	1,491,759	1,522,959	1,652,273	1,483,221	1,454,326	1,642,242	1,568,926	17,407,853	
	Calib DA	1,517,900	1,572,200	1,222,800	1,184,600	1,124,400	1,540,700	1,517,600	1,627,200	1,526,500	1,474,400	1,646,800	1,604,300	17,559,400	
	Actual - DA	-12,156	2,892	2,466	-24,463	1,508	-48,941	5,359	25,073	-43,279	-20,074	-4,558	-35,374	-151,547	-0.9%
Sioux	Actual	506,977	576,059	560,484	537,719	560,495	533,679	521,385	591,070	341,840	239,541	326,853	552,514	5,848,616	
	Calib DA	494,900	568,800	563,900	521,400	548,500	516,600	508,500	568,300	329,600	222,600	285,200	503,900	5,632,200	
	Actual - DA	12,077	7,259	-3,416	16,319	11,995	17,079	12,885	22,770	12,240	16,941	41,653	48,614	216,416	3.7%
Meramec	Actual	483,100	508,872	458,620	513,101	470,812	500,584	564,096	540,721	379,743	546,014	341,864	505,642	5,813,169	
	Calib DA	480,000	504,500	480,400	505,700	455,700	505,300	556,800	537,000	379,900	563,300	345,900	500,700	5,815,200	
	Actual - DA	3,100	4,372	-21,780	7,401	15,112	-4,716	7,296	3,721	-157	-17,286	-4,036	4,942	-2,031	0.0%
Osage	Actual	32,053	61,710	113,679	114,901	149,053	111,362	150,100	29,613	92,702	51,012	31,663	10,807	948,655	
	Calib DA	35,700	60,600	111,300	114,800	149,100	111,400	149,900	29,800	91,000	50,500	29,700	10,800	944,600	
	Actual - DA	-3,647	1,110	2,379	101	-47	-38	200	-187	1,702	512	1,963	7	4,055	0.4%
Keokuk	Actual	81,079	81,023	67,998	52,311	46,661	25,160	76,429	80,964	73,611	74,003	77,167	66,508	802,914	
	Calib DA	81,400	82,100	66,700	52,900	45,200	19,400	76,000	81,000	74,200	74,800	75,800	66,500	796,000	
	Actual - DA	-321	-1,077	1,298	-589	1,461	5,760	429	-36	-589	-797	1,367	8	6,914	0.9%
UE CTG	Actual	35,948	16,687	5,598	23,558	11,418	45,097	119,556	46,817	38,051	24,079	5,394	9,209	381,412	
	Calib DA	43,600	3,100	1,800	2,400	0	93,800	123,900	35,300	49,300	4,000	6,100	48,000	411,300	
	Actual - DA	-7,652	13,587	3,798	21,158	11,418	-48,703	-4,344	11,517	-11,249	20,079	-706	-38,791	-29,888	-7.8%
Purchases	Actual	229,887	114,443	134,307	127,062	116,489	127,237	113,026	157,353	146,847	141,320	124,181	225,056	1,757,208	
	Calib DA	233,400	130,200	152,200	130,300	131,700	103,500	117,300	109,800	96,100	172,800	140,600	312,500	1,830,400	
	Actual - DA	-3,513	-15,757	-17,893	-3,238	-15,211	23,737	-4,274	47,553	50,747	-31,480	-16,419	-87,444	-73,192	-4.2%
Sales	Actual	838,992	1,055,255	1,030,332	1,159,837	1,137,060	819,732	738,503	875,547	875,869	628,192	752,101	545,399	10,456,820	
	Calib DA	883,000	1,048,500	1,097,800	1,206,900	1,139,600	894,600	724,500	776,100	877,900	685,500	694,500	679,900	10,708,800	
	Actual - DA	-44,008	6,755	-67,468	-47,063	-2,540	-74,868	14,003	99,447	-2,031	-57,308	57,601	-134,501	-251,980	-2.4%
Net Output	Actual	3,722,396	3,494,748	3,229,778	2,897,915	2,915,534	3,607,928	3,977,036	3,830,912	3,187,301	2,958,688	3,084,625	3,729,924	40,636,784	
	Calib DA	3,722,000	3,491,900	3,232,100	2,890,000	2,924,600	3,611,000	3,973,200	3,826,300	3,179,700	2,962,100	3,089,700	3,734,400	40,637,000	
	Actual - DA	396	2,848	-2,322	7,915	-9,066	-3,072	3,836	4,612	7,601	-3,412	-5,075	-4,476	-216	0.0%
UE Coal	Actual	3,262,934	3,414,932	3,041,543	2,859,912	2,824,633	3,257,455	3,377,660	3,502,481	2,842,832	3,014,871	3,019,289	3,409,528	37,828,070	
	Calib DA	3,295,000	3,409,700	3,085,800	2,915,900	2,842,400	3,317,100	3,351,200	3,463,400	2,882,300	3,055,200	2,978,800	3,421,900	38,018,700	
	Actual - DA	-32,066	5,232	-44,257	-55,988	-17,767	-59,645	26,460	39,081	-39,468	-40,329	40,489	-12,372	-190,630	-0.5%
UE Hydro	Actual	113,132	142,733	181,677	167,212	195,714	136,522	226,529	110,577	166,313	125,015	108,830	77,315	1,751,569	
	Calib DA	117,100	142,700	178,000	167,700	194,300	130,800	225,900	110,800	165,200	125,300	105,500	77,300	1,740,600	
	Actual - DA	-3,968	33	3,677	-488	1,414	5,722	629	-223	1,113	-285	3,330	15	10,969	0.6%
UE	Actual	4,331,501	4,435,560	4,125,803	3,930,690	3,936,105	4,300,423	4,602,513	4,549,106	3,916,323	3,445,560	3,712,545	4,050,267	49,336,396	
	Calib DA	4,371,600	4,410,200	4,177,700	3,966,600	3,932,500	4,402,100	4,580,400	4,492,600	3,961,500	3,474,800	3,643,600	4,101,800	49,515,400	
	Actual - DA	-40,099	25,360	-51,897	-35,910	3,605	-101,677	22,113	56,506	-45,177	-29,240	68,945	-51,533	-179,004	-0.4%

Input / Output Curve #1

Unit Name	Minimum - Net	12 Month Avg Net	Primary Fuel Type	A	B	C	EDF
Callaway	800	1,220	Nuclear	-	9.941	-	1.000
Labadie 1	300	614	PRB Coal	-	9.005	304.8	1.013
Labadie 2	300	595	PRB Coal	0.00167	7.844	794.5	1.013
Labadie 3	300	611	PRB Coal	0.00106	8.265	565.8	1.013
Labadie 4	300	611	PRB Coal	0.00126	8.261	638.2	1.013
Rush 1	275	608	PRB Coal	0.00129	7.859	724.4	0.986
Rush 2	275	591	PRB Coal	0.00137	8.757	679.6	0.986
Sioux 1	307	500	PRB/ILLINOIS Coal	0.00001	8.641	359.6	1.001
Sioux 2	307	503	PRB/ILLINOIS Coal	0.00058	8.314	597.7	1.001
Meramec 1	48	124	PRB Coal	0.01407	8.209	216.1	0.975
Meramec 2	48	125	PRB Coal	0.01123	9.314	106.9	0.975
Meramec 3	160	264	PRB Coal	0.00624	8.384	475.5	0.975
Meramec 4	185	352	PRB Coal	0.00770	5.168	804.7	0.975
Audrain CT 1	62	82	Natural Gas	0.00010	10.618	160.4	0.927
Audrain CT 2	62	82	Natural Gas	0.00010	10.618	160.4	0.927
Audrain CT 3	62	82	Natural Gas	0.00010	10.618	160.4	0.927
Audrain CT 4	62	82	Natural Gas	0.00010	10.618	160.4	0.927
Audrain CT 5	62	82	Natural Gas	0.00010	10.618	160.4	0.927
Audrain CT 6	62	82	Natural Gas	0.00010	10.618	160.4	0.927
Audrain CT 7	62	82	Natural Gas	0.00010	10.618	160.4	0.927
Audrain CT 8	62	82	Natural Gas	0.00010	10.618	160.4	0.927
Fairgrounds CT	61	61	Oil	0.00143	7.798	177.3	0.980
Goose Creek CT 1	50	80	Natural Gas	0.00010	8.808	237.8	0.986
Goose Creek CT 2	50	80	Natural Gas	0.00010	8.808	237.8	0.986
Goose Creek CT 3	50	80	Natural Gas	0.00010	8.808	237.8	0.986
Goose Creek CT 4	50	80	Natural Gas	0.00010	8.808	237.8	0.986
Goose Creek CT 5	50	80	Natural Gas	0.00010	8.808	237.8	0.986
Goose Creek CT 6	45	80	Natural Gas	0.00010	8.808	237.8	0.986
Howard Bend CT	46	46	Oil	0.00261	9.654	118.6	0.950
Kinmundy CT 1	77	118	Natural Gas	0.00010	9.219	217.9	1.013
Kinmundy CT 2	77	118	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	0.00010	9.191	52.1	1.000
Peno Creek CT 2	50	50	Natural Gas	0.00010	9.191	52.1	1.000
Peno Creek CT 3	50	50	Natural Gas	0.00010	9.191	52.1	1.000
Peno Creek CT 4	50	50	Natural Gas	0.00010	9.191	52.1	1.000
Pinkneyville CT 1	43	43	Natural Gas	0.00010	7.796	84.7	1.000
Pinkneyville CT 2	43	43	Natural Gas	0.00010	7.796	84.7	1.000
Pinkneyville CT 3	43	43	Natural Gas	0.00010	7.796	84.7	1.000
Pinkneyville CT 4	43	43	Natural Gas	0.00010	7.796	84.7	1.000
Pinkneyville CT 5	39	39	Natural Gas	0.00100	8.603	134.9	1.050
Pinkneyville CT 6	39	39	Natural Gas	0.00100	8.603	134.9	1.050
Pinkneyville CT 7	39	39	Natural Gas	0.00100	8.603	134.9	1.050
Pinkneyville CT 8	39	39	Natural Gas	0.00100	8.603	134.9	1.050
Raccoon Creek CT 1	42	81	Natural Gas	0.00010	8.553	269.0	0.979
Raccoon Creek CT 2	42	81	Natural Gas	0.00010	8.553	269.0	0.979
Raccoon Creek CT 3	42	81	Natural Gas	0.00010	8.553	269.0	0.979
Raccoon Creek CT 4	42	81	Natural Gas	0.00010	8.553	269.0	0.979
Venice CT 1	10	27	Oil	0.00457	9.738	132.1	0.950
Venice CT 2	52	52	Natural Gas	0.00010	9.932	29.4	1.011
Venice CT 3	130	178	Natural Gas	0.00010	9.479	190.2	1.011
Venice CT 4	130	178	Natural Gas	0.00010	9.479	190.2	1.011
Venice CT 5	77	118	Natural Gas	0.00010	9.367	205.5	1.011
Viaduct CTG	29	29	Natural Gas	0.00457	9.738	132.1	1.200
Osage		233	Pond Hydro				
Keokuk		132	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	2003 (1) (hrs)	2004 (hrs)	2005 (hrs)	2006 (hrs)	2007 (hrs)	2008 (hrs)	2009 (2) (hrs)	Total (hrs)	Day / Year (days)	Total Days for Similar Units (days)
Labadie 1	178	0	0	0	0	2,095	0	2,273	16	
Labadie 2	0	1,263	0	0	0	0	0	1,263	9	
Labadie 3	1,473	0	0	0	0	0	0	1,473	10	
Labadie 4	1,118	0	0	0	0	0	0	1,118	8	
Labadie 1-4										43
Meramec 1	0	2,019	0	0	0	0	0	2,019	14	
Meramec 2	0	2,058	0	0	0	0	0	2,058	14	
Meramec 1-2										28
Meramec 3	0	135	369	1,548	0		0	2,051	14	
Meramec 4	0	0	1,685	0	0	0	0	1,685	12	
Rush Island 1	0	0	0	0	2,381	0	0	2,381	17	
Rush Island 2	1,152	661	0	0	0	0	0	1,813	13	
Rush 1-2										29
Sioux 1	1,102	0	1,570	0	0	1,794	0	4,466	31	
Sioux 2	157	2,041	0	1,383	0	0	0	3,581	25	
Sioux 1-2										56

Actual

Callaway 1	2003 (1)	2004	2005	2006	2007	2008	2009 (2)	Total	Day / Year		
Hours per year	0	1,542	1,526	0	919	672	0	4,659	32		
									# of Refuel Outages	**Avg Days / Refuel Outage**	**Annual Refuel Outage Length** *
Days / Refuel		64	64		38	28	0	166	4	42	28
**** Adjusted - Removed 2005 Refuel Outage**											
Days / Refuel		64	**		38	28	0	131	3	44	29

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

(1) 2003 data is for April 1-December 31, 2003.
(2) 2009 data is for January 1- March 31, 2009.

Schedule TDF-E3

2 0 0 9 UE-OA OUTAGE PLANNING SCHEDULE **2 0 0 9**

Mws		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	DMQ 2009
		28 4 11 18 25	1 8 15 22	1 8 15 22	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	
1220	CAL 1										CALLAWAY #1	(10/3) 29		CAL 1
608	RUSH 1											RUSH #1	(10/31) 29	RUSH 1
591	RUSH 2													RUSH 2
614	LAB 1				LABADIE #1	(3/28) 43								LAB 1
595	LAB 2													LAB 2
611	LAB 3													LAB 3
611	LAB 4													LAB 4
500	SX 1			SIOUX #1		(2/28) 56								SX 1
500	SX 2													SX 2
124	MER 1			MERAMEC #1	(2/28) 28									MER 1
125	MER 2													MER 2
264	MER 3											M #3 (10/31) 14		MER 3
352	MER 4											M #4	(11/14) 12	MER 4
														Joppa
0.0%	EA Impact	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
		28 4 11 18 25	1 8 15 22	1 8 15 22	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	2009

Schedule TDF-E4

Unplanned Outage Rates - Full Outages

	2003 (1)	2004	2005	2006	2007	2008	2009 (2)	Average
Callaway 1	1.9%	5.3%	3.6%	4.9%	1.3%	3.4%	13.5%	3.9%
Labadie 1	5.0%	5.6%	3.2%	4.9%	4.9%	4.8%	10.2%	5.0%
Labadie 2	5.6%	8.4%	5.9%	5.0%	2.8%	6.6%	6.6%	5.7%
Labadie 3	10.4%	4.1%	3.1%	12.0%	7.0%	3.3%	8.6%	6.5%
Labadie 4	2.7%	5.6%	3.3%	4.0%	3.1%	5.1%	4.8%	4.1%
Meramec 1	4.8%	3.9%	1.3%	3.4%	5.1%	4.1%	8.9%	4.0%
Meramec 2	7.0%	1.9%	1.6%	5.5%	7.6%	4.1%	1.8%	4.5%
Meramec 3	9.6%	7.8%	6.7%	4.7%	9.6%	13.7%	17.1%	9.1%
Meramec 4	10.3%	3.8%	7.0%	15.5%	10.3%	14.3%	9.4%	10.3%
Rush Island 1	6.5%	23.2%	13.2%	7.0%	15.5%	2.1%	0.0%	10.7%
Rush Island 2	6.8%	12.5%	2.2%	7.1%	4.4%	5.6%	3.6%	6.2%
Sioux 1	8.3%	8.0%	2.9%	5.5%	5.4%	5.7%	0.0%	5.7%
Sioux 2	4.2%	3.7%	2.7%	6.1%	4.6%	6.7%	7.8%	4.8%

(1) 2003 data is for April 1-December 31, 2003.
(2) 2009 data is for January 1- March 31, 2009.

Derating

	2003 (1)	2004	2005	2006	2007	2008	2009 (2)	Average
Callaway 1	0.4%	0.3%	0.7%	0.4%	0.1%	0.9%	0.6%	0.5%
Labadie 1	0.4%	1.2%	0.7%	0.6%	1.3%	4.6%	3.2%	1.5%
Labadie 2	2.2%	2.1%	1.5%	1.2%	1.0%	2.6%	3.7%	1.8%
Labadie 3	4.0%	0.7%	1.5%	1.9%	0.5%	2.5%	1.9%	1.7%
Labadie 4	1.2%	0.7%	2.1%	2.2%	0.8%	2.4%	1.2%	1.6%
Meramec 1	7.1%	0.7%	0.1%	0.6%	0.8%	1.1%	5.6%	1.7%
Meramec 2	0.1%	0.6%	0.4%	0.3%	1.6%	2.2%	9.6%	1.3%
Meramec 3	2.7%	2.6%	0.6%	3.9%	4.5%	2.3%	0.5%	2.7%
Meramec 4	2.9%	6.2%	2.9%	1.5%	5.0%	4.9%	3.6%	4.0%
Rush Island 1	2.4%	0.3%	0.7%	2.0%	1.6%	1.0%	3.1%	1.4%
Rush Island 2	2.7%	3.2%	1.5%	1.2%	2.2%	2.2%	2.9%	2.2%
Sioux 1	2.2%	0.2%	0.2%	1.3%	0.5%	0.8%	0.6%	0.8%
Sioux 2	0.3%	0.0%	0.3%	1.4%	0.4%	0.3%	0.0%	0.4%

(1) 2003 data is for April 1-December 31, 2003.
(2) 2009 data is for January 1- March 31, 2009.