Exhibit No.:	
Issues:	Production Cost Model; Normalized Net Fuel Costs; FAC Minimum Filing Requirement – Supply/Demand Side Resources
Witness:	Timothy D. Finnell
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Direct Testimony
Case No.:	ER-2008-____
Date Testimony Prepared:	April 4, 2008

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2008-____

DIRECT TESTIMONY

OF

TIMOTHY D. FINNELL

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
April, 2008

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DIRECT TESTIMONY

OF

TIMOTHY D. FINNELL

CASE NO. ER-2008-____

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 work experience, and the duties of your position.

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"), 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 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] I also address a minimum filing requirement associated with AmerenUE's request for a fuel adjustment clause ("FAC"), specifically, the requirement found at 4 CSR 240-3.161(2)(O).

An executive summary of my testimony is attached hereto as Attachment A.

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[1] "Net fuel costs" as used in my testimony are slightly different than the "net base fuel costs" ("NBFC") discussed in the direct testimony of AmerenUE witness Martin J. Lyons, Jr., and as defined in the Company's proposed FAC tariff. This is because NBFC also includes costs that are not the product of my production cost modeling but which are 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 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. Please summarize your testimony and conclusions.

A. The 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 $290 million, which consists of fuel costs of $678 million and variable purchase power costs of $55 million, offset by off-system sales revenues of $443 million.

III. PRODUCTION COST MODELING - GENERALLY

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 Global Energy Decisions ("GED"). 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 GED 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 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 2007 generation to model results. For example, the calibrated model results calculated the generating output from AmerenUE to be 50,459,800 megawatt-hours ("MWh"). Actual generation was 50,319,199 MWhs, thus the model result was within 1% 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 (10,962,200 MWh from the model versus 10,984,356 MWh actual) were also within 1% 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. There appears to be a larger difference between the calibrated model combustion turbine generator ("CTG") generation and the actual CTG generation. Why is that?

A. The calibrated model's annual CTG generation was 714,200 MWh and the actual CTG generation for 2007 was 889,692 MWh, which results in a 25% difference between model generation and actual generation. The CTG generation is influenced by many factors, such as: loads, availability of other units, cost of CTG generation, energy market prices, AmerenUE system requirements, transmission considerations, and MISO operations. Since the calibrated model used actual loads, actual unit availabilities, actual operating costs, actual energy market prices, and actual AmerenUE system requirements, I have concluded that transmission considerations and, notably, MISO operations were responsible for the inaccuracy of the model's CTG generation. This conclusion is supported by a review of the monthly variations between modeled and actual CTG generation. For example, in October, a month when little CTG generation is expected, the model calculated 30,900 MWh of CTG generation, yet there was 118,467 MWh of actual CTG generation. In that same month AmerenUE received $3.3 million of MISO make-whole payments for generation that did not receive adequate revenues (because it was dispatched uneconomically by the MISO). In general, the CTG modeling is not only difficult because of transmission considerations and MISO operations, but it is also very dependent on loads, availability of other units, and market prices.

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 Mr. Weiss. For this case, the actual 2007 hourly load pattern is applied to normalized monthly energy and generates a normalized hourly load pattern.

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 2002 and 2007, 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 2002 and 2007, 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 2002 and 2007, 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 $19.4 million, $17 million of which was determined by the PROSYM model and $2.4 million of which are capacity sales from the Taum Sauk Plant as addressed in the direct testimony of AmerenUE witness Shawn E. Schukar.

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

A. The AmerenUE units burn four types of fuel: nuclear fuel, coal, natural gas, and oil. The nuclear fuel costs are based on the average nuclear fuel cost associated with

Callaway Refueling Number 15 which began May 2007 and ends in October 2008. These costs are discussed in detail in the direct testimony of AmerenUE witness Randall J. Irwin.

The coal costs reflect coal and transportation costs based upon coal and transportation prices that became effective as of January 1, 2008, which are discussed in detail in the direct testimony of AmerenUE witness Robert K. Neff.

The natural gas and oil prices are based on the average monthly prices for the period January 1, 2006 to December 31, 2007.

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 160 megawatts ("MW") from Arkansas Power & Light Company ("APL") under a purchase power contract entered into with APL in 1991. The price of the APL contract is based on the average contract price for the period January 1, 2007 through December 31, 2007. Short-term economic purchases are used to supply native load when the prices are lower than the 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 this 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 January 1, 2006 through December 31, 2007. 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 also included contract sales as well as spot sales. The contract sales are based on actual contracts that were made for calendar year 2008. The sales volumes, time periods, and prices are listed in Schedule TDF-E7. Short-term economic off-system sales 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. What system requirements are used in PROSYM?

A. The system requirements are the non-plant specific inputs that impact the dispatch of the generating units. The system requirements include three types of reserves: regulation, spinning, and supplemental. The regulation requirement is sometimes also called the "load following" requirement because it is used to match the generation output at a given time to the load at that time. AmerenUE's regulation reserve requirement is 25 MW. The 25 MW of regulation reserve is actually a band of + 25 MW to – 25 MW, thus it can be thought of as an average of 25 MW of stranded capacity that cannot be used to supply native load or for making off-system sales.

AmerenUE's spinning reserve requirement is comprised of the AmerenUE generating units that are on-line and not fully loaded. Thus, spinning reserves may also be thought of as stranded MWs that are not used for supplying native load or for making off-system sales. One of the main purposes for spinning reserves is to provide quick response to a system disturbance, such as a generating unit being forced off line. UE's current spinning reserve requirement is 43 MW.

Supplemental reserves can be either spinning or quick start generation that can be made available within 15 minutes after a disturbance. The supplemental reserves are not considered stranded MW since they include units that are on line and not fully loaded due to economics as well as units that are off line. UE's current supplemental reserve requirement is 63 MW. AmerenUE's quick start units include: Taum Sauk, Osage, Fairground CTG, Mexico CTG, Moberly CTG, Moreau CTG, Meramec CTG #2, Venice CTG #2, Howard Bend and the Peno Creek CTGs #1- #4.

Q. How does the MISO's ancillary service market impact the regulation reserves, spinning reserves, and supplemental reserves levels used in the PROSYM modeling addressed in this direct testimony?

A. The MISO ancillary services market is projected to begin operation September 9, 2008. Thus it was not modeled at this time.

Q. Is AmerenUE selling ancillary services to the utility operating subsidiaries owned by Ameren Corporation in Illinois?

A. Yes, for 2008, AmerenUE is selling 39 MW of spinning reserves and 68 MW of supplemental reserves to Illinois affiliates.

Q. Does the PROSYM model include the sales of ancillary services to these Illinois utilities?

A. No. The sales of these ancillary services were not included because they are based on a short-term contract that will end when the MISO ancillary service market begins.

Q. Does eliminating the sales of ancillary services to these Illinois utilities distort the net fuel and purchase power calculation?

A. No. The fact that the sale of ancillary services to the Ameren-owned operating utilities in Illinois was eliminated does not distort the net fuel and purchase power costs. The capacity that was held back to provide the spinning reserves was used in the capacity sales calculation discussed by Mr. Schukar in his direct testimony. The lost opportunity costs associated with holding back generation for the Illinois utilities' spinning reserves was replaced by additional off-system sales in the PROSYM model run used to develop the net fuel costs. For example, the PROSYM model has an extra 39 MW of capacity that is made available for off-system sales. The extra sales will be made by the PROSYM model when the cost of the generation is less than the price received from off-system sales.

V. FAC MINIMUM FILING REQUIREMENT

Q. What is Requirement (O) of 4 CSR 240-3.161(2)?

A. Requirement (O) is a list of supply side and demand side resources that the electric utility expects to use to meet its load for the next four true-up years, the expected dispatch of those resources, the reasons why the resources are appropriate for dispatch and the heat rates and fuel types for each supply side resources. Schedule TDF-E8 lists the supply side resources AmerenUE expects to use to meet its load requirements for the periods March 1, 2009 to February 28, 2010; March 1, 2010 to February 29, 2011; March 1, 2011 to February 29, 2012; and March 1, 2012 to February 28, 2013. The table lists the resource name, ownership, primary fuel type, heat rate at full load, and projected generation for the four true-up years. The projected generation for the four true-up years is appropriate because it was developed from a detailed production cost model run for the true-up years. The production cost model used by AmerenUE is the PROSYM production cost model. This is the same model that is used by AmerenUE in this case to calculate fuel, purchased power costs and off-system sales revenues. The major inputs to the PROSYM production cost model include: normalized hourly loads, unit availabilities, fuel prices, unit operating characteristics, hourly energy market prices, and system requirements.

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) Case No. ER-2008-____
Service Provided to Customers in the)
Company's Missouri Service Area.)

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 a Managing Supervisor.

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 14 pages, Attachment A and Schedules TDF-E1 through TDF-E8, 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 4th day of April, 2008.

Danielle R. Moskop

Notary Public

My commission expires:

Danielle R. Moskop
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: July 21, 2009
Commission # 05745027

EXECUTIVE SUMMARY

Timothy D. Finnell

Managing Supervisor, Operations Analysis in the Corporate Planning Function of Ameren Services Company

* * * * * * * * * *

The purpose of my testimony is to explain the production cost model used to determine the normalized net fuel costs which consists of fuel costs, the variable component of purchased power costs and off-system sales revenues for this case. I also supply the supply and demand side resources that are expected to serve AmerenUE's load during the four true-up years when the Company's requested fuel adjustment clause would be in effect.

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. The program I used for my analysis is PROSYM. AmerenUE's experience with this program indicates that it does a superior job of simulating complex generating systems such as AmerenUE's system.

PROSYM utilizes monthly energy with a historic hourly load pattern. The monthly energy reflects AmerenUE kilowatt-hour ("kWh") sales and line losses. The fuel expenses used include the nuclear, coal, oil, and natural gas costs associated with producing electricity from the AmerenUE generation fleet. For purposes of this model, it was presumed that AmerenUE's Taum Sauk plant was available as a generation resource for the entire year. The model also considers normalized hourly loads, unit availabilities, fuel prices, unit operating characteristics, hourly energy market prices, and system requirements.

The normalized net fuel costs for this case are $290 million, which consists of fuel costs of $678 million, variable purchase power costs of $55 million, offset by off-system sales revenues of $443 million. These results are utilized by AmerenUE witness Gary S. Weiss in developing the revenue requirement for AmerenUE.

2007 ACTUAL vs PROSYM 2007

		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Difference
Callaway	Actual	921,372	832,148	773,355	17,380	592,863	866,741	894,646	888,978	869,464	906,068	888,687	920,253	9,371,955	
	Calib 07	921,100	831,900	782,800	28,600	579,200	866,900	894,300	889,100	869,800	906,200	888,500	920,300	9,378,700	
	Actual - Calib 07	-272	-248	9,445	11,220	-13,663	159	-346	122	336	132	-187	47	6,745	-0.1%
Rush	Actual	773,733	553,787	377,283	327,285	301,602	692,832	743,074	809,680	700,380	521,228	426,841	788,919	7,016,644	
	Calib 07	765,100	555,800	380,400	323,400	320,700	733,800	764,400	808,900	731,300	533,300	420,900	804,400	7,142,400	
	Actual - Calib 07	-8,633	2,013	3,117	-3,885	19,098	40,968	21,326	-780	30,920	12,072	-5,941	15,481	125,756	-1.8%
Labadie	Actual	1,655,941	1,562,972	1,471,137	1,676,491	1,539,354	1,579,045	1,554,994	1,643,164	1,406,145	1,664,666	1,648,148	1,515,985	18,918,042	
	Calib 07	1,674,900	1,557,800	1,515,900	1,681,300	1,564,100	1,603,400	1,541,600	1,667,900	1,410,500	1,668,600	1,622,000	1,550,100	19,058,100	
	Actual - Calib 07	18,959	-5,172	44,763	4,809	24,746	24,355	-13,394	24,736	4,355	3,934	-26,148	34,115	140,058	-0.7%
Sioux	Actual	630,757	542,157	613,982	486,392	526,524	539,465	574,369	576,108	502,188	596,949	501,609	552,848	6,643,348	
	Calib 07	607,200	576,900	623,600	496,300	530,000	547,700	573,200	586,200	521,400	589,500	493,000	554,100	6,699,100	
	Actual - Calib 07	-23,557	34,743	9,618	9,908	3,476	8,235	-1,169	10,092	19,212	-7,449	-8,609	1,252	55,752	-0.8%
Meramec	Actual	455,702	385,184	440,657	525,111	520,445	515,229	546,480	567,976	410,945	476,607	500,829	539,106	5,884,271	
	Calib 07	479,500	400,700	450,800	536,000	552,100	510,800	537,500	565,700	396,400	457,200	481,500	518,000	5,886,200	
	Actual - Calib 07	23,798	15,516	10,143	10,890	31,655	-4,429	-8,980	-2,276	-14,545	-19,407	-19,329	-21,106	1,930	0.0%
Osage	Actual	16,056	32,109	23,200	74,757	115,915	124,638	157,801	74,102	12,856	10,179	3,574	7,704	652,891	
	Calib 07	18,900	28,900	26,000	69,800	111,300	119,800	151,500	78,600	12,600	9,800	4,500	7,200	638,900	
	Actual - Calib 07	2,844	-3,209	2,800	-4,957	-4,615	-4,838	-6,301	4,498	-256	-379	926	-504	-13,991	2.2%
Keokuk	Actual	78,979	53,725	78,439	63,812	87,855	91,484	76,494	72,518	84,878	89,848	87,152	77,173	942,357	
	Calib 07	78,100	55,600	77,600	64,100	87,200	91,600	76,200	74,400	83,300	89,600	87,700	76,800	942,200	
	Actual - Calib 07	-879	1,875	-839	288	-655	116	-294	1,882	-1,578	-248	548	-373	-157	0.0%
UE CTG	Actual	17,101	14,379	13,393	43,147	58,020	79,109	98,861	258,853	93,194	118,467	49,473	45,695	889,692	
	Calib 07	10,500	36,000	41,800	33,800	89,800	53,300	57,800	219,400	70,300	30,900	7,100	63,500	714,200	
	Actual - Calib 07	-6,601	21,621	28,407	-9,347	31,780	-25,809	-41,061	-39,453	-22,894	-87,567	-42,373	17,805	-175,492	24.6%
Purchases	Actual	134,943	107,537	145,931	199,625	190,996	150,376	148,991	109,731	143,080	160,950	173,873	250,529	1,916,562	
	Calib 07	136,900	126,400	134,700	166,100	209,000	119,800	130,600	172,400	140,900	137,800	132,100	142,900	1,749,600	
	Actual - Calib 07	1,957	18,863	-11,231	-33,525	18,004	-30,576	-18,391	62,669	-2,180	-23,150	-41,773	-107,629	-166,962	9.5%
Sales	Actual	1,107,455	728,236	912,815	520,615	698,920	999,108	860,228	530,539	827,787	1,453,532	1,179,237	1,165,885	10,984,356	
	Calib 07	1,120,200	799,600	969,500	479,100	808,300	1,042,700	794,700	573,900	833,500	1,318,900	1,128,100	1,093,700	10,962,200	
	Actual - Calib 07	12,745	71,364	56,685	-41,515	109,380	43,592	-65,528	43,361	5,713	-134,632	-51,137	-72,185	-22,156	0.2%
Net Output	Actual	3,577,129	3,355,762	3,024,562	2,893,384	3,234,654	3,639,812	3,935,482	4,470,570	3,395,343	3,091,430	3,100,949	3,532,327	41,251,404	
	Calib 07	3,572,000	3,370,400	3,064,100	2,920,300	3,235,100	3,604,400	3,932,400	4,488,700	3,403,000	3,104,000	3,009,200	3,543,600	41,247,200	
	Actual - Calib 07	-5,129	14,638	39,538	26,916	446	-35,412	-3,082	18,130	7,657	12,570	-91,749	11,273	-4,204	0.0%
UE Coal	Actual	3,516,133	3,044,100	2,903,059	3,015,279	2,887,925	3,326,571	3,418,917	3,596,928	3,019,658	3,259,450	3,077,427	3,396,858	38,462,305	
	Calib 07	3,526,700	3,091,200	2,970,700	3,037,000	2,966,900	3,395,700	3,416,700	3,628,700	3,059,600	3,248,600	3,017,400	3,426,600	38,785,800	
	Actual - Calib 07	10,567	47,100	67,641	21,722	78,975	69,129	-2,217	31,772	39,942	-10,850	-60,027	29,742	323,496	-0.8%
UE Hydro	Actual	95,035	85,834	101,639	138,569	203,770	216,122	234,295	146,620	97,734	100,027	90,726	84,877	1,595,248	
	Calib 07	97,000	84,500	103,600	133,900	198,500	211,400	227,700	153,000	95,900	99,400	92,200	84,000	1,581,100	
	Actual - Calib 07	1,965	-1,334	1,961	-4,669	-5,270	-4,722	-6,595	6,380	-1,834	-627	1,474	-877	-14,148	0.9%
UE-Total Gen	Actual	4,549,641	3,976,461	3,791,446	3,214,374	3,742,578	4,488,543	4,646,719	4,891,379	4,080,050	4,384,012	4,106,313	4,447,683	50,319,199	
	Calib 07	4,555,300	4,043,600	3,898,900	3,233,300	3,834,400	4,527,300	4,596,500	4,890,200	4,095,600	4,285,100	4,005,200	4,494,400	50,459,800	
	Actual - Calib 07	5,659	67,139	107,454	18,926	91,822	38,757	-50,219	-1,179	15,550	-98,912	-101,113	46,717	140,601	-0.3%

				Input / Output Curve #1			
Unit Name	**Minimum - Net**	**12 Month Avg Net**	**Primary Fuel Type**	**A**	**B**	**C**	**EDF**
Callaway	800	1,220	Nuclear	-	9.944	-	1.00
Labadie 1	300	607	PRB Coal	0.00338	6.867	684.6	1.01
Labadie 2	300	596	PRB Coal	0.00338	6.867	684.6	1.01
Labadie 3	300	611	PRB Coal	0.00374	6.158	878.7	1.01
Labadie 4	300	611	PRB Coal	0.00374	6.158	878.7	1.01
Rush 1	275	600	PRB Coal	0.00161	7.875	814.4	0.99
Rush 2	275	592	PRB Coal	0.00161	7.875	814.4	0.99
Sioux 1	307	499	PRB/ILLINOIS Coal	0.00010	9.009	398.3	1.00
Sioux 2	307	503	PRB/ILLINOIS Coal	0.00010	9.009	398.3	1.00
Meramec 1	48	124	PRB Coal	0.01378	7.310	194.9	1.04
Meramec 2	48	125	PRB Coal	0.01378	7.310	194.9	1.04
Meramec 3	160	264	PRB Coal	0.00471	7.174	249.3	1.19
Meramec 4	185	355	PRB Coal	0.00164	9.458	173.4	0.98
Audrain CT 1	62	78	Natural Gas	0.00010	8.590	245.9	1.00
Audrain CT 2	62	78	Natural Gas	0.00010	8.590	245.9	1.00
Audrain CT 3	62	78	Natural Gas	0.00010	8.590	245.9	1.00
Audrain CT 4	62	78	Natural Gas	0.00010	8.590	245.9	1.00
Audrain CT 5	62	78	Natural Gas	0.00010	8.590	245.9	1.00
Audrain CT 6	62	78	Natural Gas	0.00010	8.590	245.9	1.00
Audrain CT 7	62	78	Natural Gas	0.00010	8.590	245.9	1.00
Audrain CT 8	62	78	Natural Gas	0.00010	8.590	245.9	1.00
Fairgrounds CT	58	58	Oil	0.00143	7.798	177.3	0.98
Goose Creek CT 1	50	76	Natural Gas	0.00010	8.590	245.9	1.00
Goose Creek CT 2	45	76	Natural Gas	0.00010	8.590	245.9	1.00
Goose Creek CT 3	45	76	Natural Gas	0.00010	8.590	245.9	1.00
Goose Creek CT 4	45	76	Natural Gas	0.00010	8.590	245.9	1.00
Goose Creek CT 5	45	76	Natural Gas	0.00010	8.590	245.9	1.00
Goose Creek CT 6	45	76	Natural Gas	0.00010	8.590	245.9	1.00
Howard Bend CT	45	45	Oil	0.00261	9.654	118.6	0.95
Kinmundy CT 1	77	110	Natural Gas	0.00923	6.381	423.2	1.07
Kinmundy CT 2	77	110	Natural Gas	0.00923	6.381	423.2	1.07
Kirksville CT	13	13	Natural Gas	0.00261	9.654	118.6	1.20
Meramec CT 1	59	59	Oil	0.00143	7.798	177.3	0.96
Meramec CT 2	26	58	Natural Gas	0.00261	9.654	118.6	1.00
Mexico CT	58	58	Oil	0.00143	7.798	177.3	0.97
Moberly CT	58	58	Oil	0.00143	7.798	177.3	1.00
Moreau CT	58	58	Oil	0.00143	7.798	177.3	0.98
Peno Creek CT 1	47	47	Natural Gas	0.00010	8.467	94.1	1.02
Peno Creek CT 2	47	47	Natural Gas	0.00010	8.467	94.1	1.02
Peno Creek CT 3	47	47	Natural Gas	0.00010	8.467	94.1	1.02
Peno Creek CT 4	47	47	Natural Gas	0.00010	8.467	94.1	1.02
Pinkneyville CT 1	40	40	Natural Gas	0.01190	6.662	111.0	1.04
Pinkneyville CT 2	40	40	Natural Gas	0.01190	6.662	111.0	1.04
Pinkneyville CT 3	40	40	Natural Gas	0.01190	6.662	111.0	1.04
Pinkneyville CT 4	40	40	Natural Gas	0.01190	6.662	111.0	1.04
Pinkneyville CT 5	37	37	Natural Gas	0.00100	8.603	134.9	1.05
Pinkneyville CT 6	37	37	Natural Gas	0.00100	8.603	134.9	1.05
Pinkneyville CT 7	37	37	Natural Gas	0.00100	8.603	134.9	1.05
Pinkneyville CT 8	37	37	Natural Gas	0.00100	8.603	134.9	1.05
Raccoon Creek CT 1	42	78	Natural Gas	0.00010	8.882	225.7	1.00
Raccoon Creek CT 2	42	78	Natural Gas	0.00010	8.882	225.7	1.00
Raccoon Creek CT 3	42	78	Natural Gas	0.00010	8.882	225.7	1.00
Raccoon Creek CT 4	42	78	Natural Gas	0.00010	8.882	225.7	1.00
Venice CT 1	25	27	Oil	0.00457	9.738	132.1	0.95
Venice CT 2	50	50	Natural Gas	0.00010	8.467	94.1	1.02
Venice CT 3	130	173	Natural Gas	0.00603	6.616	473.0	1.00
Venice CT 4	130	173	Natural Gas	0.00603	6.616	473.0	1.00
Venice CT 5	77	110	Natural Gas	0.00923	6.381	432.3	1.07
Viaduct CTG	27	27	Natural Gas	0.00457	9.738	132.1	1.20
Osage		234	Pond Hydro				
Keokuk		130	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

Schedule TDF-E2

PLANNED OUTAGES

Actual	**2002** **(hrs)**	**2003** **(hrs)**	**2004** **(hrs)**	**2005** **(hrs)**	**2006** **(hrs)**	**2007** **(hrs)**	**Total** **(hrs)**	**Day / Year** **(days)**	**Total Days for Similar Units** **(days)**
Labadie 1	1,808	178	0	0	0	0	1,987	14	
Labadie 2	0	0	1,263	0	0	0	1,263	9	
Labadie 3	0	1,473	0	0	0	0	1,473	10	
Labadie 4	1,564	1,118	0	0	0	0	2,682	19	
Labadie 1-4									51
Meramec 1	0	0	2,019	0	0	0	2,019	14	
Meramec 2	0	0	2,058	0	0	0	2,058	14	
Meramec 1-2									28
Meramec 3	457	1,600	135	369	1,548	0	4,108	29	
Meramec 4	561	0	0	1,685	0	0	2,246	16	
Rush Island 1	0	0	0	0	0	2,381	2,381	17	
Rush Island 2	1,502	1,152	661	0	0	0	3,314	23	
Rush 1-2									40
Sioux 1	0	1,558	0	1,570	0	0	3,128	22	
Sioux 2	1,380	157	2,041	0	1,383	0	4,961	34	
Sioux 1-2									56

Actual

Callaway 1	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**Total**	**Day / Year**		
Hours per year	796	0	1,542	1,526	0	919	4,783	33		
								# of Refuel Outages	**Avg Days / Refuel Outage**	**Annual Refuel Outage Length** *
Days / Refuel	33		64	64		38	199	4	50	33
Adjusted - Removed 2005 Refuel Outage										
Days / Refuel	33		64	**		38	136	3	45	30

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

**** Removed 2005 Refuel Outage**

Feb 20 Run

2008 UE PLANNED OUTAGE SCHEDULE 2008

	DMQ	JAN				FEB				MAR					APR				MAY				JUN					JUL				AUG					SEP				OCT				NOV					DEC				DMQ
Mws	mpsc08	30	6	13	20	27	3	10	17	24	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	5	12	19	26	2	9	16	23	30	7	14	21	2008
1220	CAL 1															**CALLAWAY #1**				(4/5 - 5/5) 30 Days																																				CAL 1
600	RUSH 1									**RUSH ISLAND #1**						(2/16 - 4/3) 40 Days																																						RUSH 1
592	RUSH 2																																																					RUSH 2
603	LAB 1																																								**LABADIE #1**							(9/27 - 11/17) 51 Days						LAB 1
596	LAB 2																																																					LAB 2
611	LAB 3																																																					LAB 3
611	LAB 4																																																					LAB 4
499	SX 1																																									**SIOUX #1 56 Days**								(10/4 - 11/29)				SX 1
503	SX 2																																																					SX 2
124	MER 1										**MERAMEC #1**				(3/1 - 3/29) 28 Days																																							MER 1
125	MER 2																																																					MER 2
264	MER 3																																								**MERAMEC #3**				(9/27 - 10/25) 28 Days									MER 3
355	MER 4																																												**MER #4**		(10/25 - 11/10) 16 Days							MER 4

Schedule TDF-E4

Unplanned Outage Rates - Full Outages

	2002	2003	2004	2005	2006	2007	Average
Callaway 1	6.0%	4.1%	5.3%	3.6%	4.9%	1.3%	4.2%
Labadie 1	8.0%	4.8%	5.6%	3.2%	4.9%	4.9%	5.1%
Labadie 2	3.8%	5.6%	8.4%	5.9%	5.0%	2.8%	5.2%
Labadie 3	6.8%	10.0%	4.1%	3.1%	12.0%	7.0%	7.1%
Labadie 4	38.0%	4.2%	5.6%	3.3%	4.0%	3.1%	8.9%
Meramec 1	5.0%	3.6%	3.9%	1.3%	3.4%	5.1%	3.7%
Meramec 2	3.0%	6.1%	1.9%	1.6%	5.5%	7.6%	4.4%
Meramec 3	12.1%	9.8%	7.8%	6.7%	4.7%	9.6%	8.5%
Meramec 4	10.3%	12.3%	3.8%	7.0%	15.5%	10.3%	9.9%
Rush Island 1	12.4%	7.1%	23.2%	13.2%	7.0%	15.5%	12.9%
Rush Island 2	11.4%	6.1%	12.5%	2.2%	7.1%	4.4%	7.1%
Sioux 1	8.6%	8.9%	8.0%	2.9%	5.5%	5.4%	6.6%
Sioux 2	2.9%	3.2%	3.7%	2.7%	6.1%	4.6%	3.8%

Derating

	2002	2003	2004	2005	2006	2007	Average
Callaway 1	0.6%	0.4%	0.3%	0.7%	0.4%	0.1%	0.4%
Labadie 1	3.1%	0.4%	1.2%	0.7%	0.6%	1.3%	1.2%
Labadie 2	2.1%	1.8%	2.1%	1.5%	1.2%	1.0%	1.6%
Labadie 3	1.5%	3.3%	0.7%	1.5%	1.9%	0.5%	1.5%
Labadie 4	1.3%	1.4%	0.7%	2.1%	2.2%	0.8%	1.4%
Meramec 1	2.8%	6.7%	0.7%	0.1%	0.6%	0.8%	2.0%
Meramec 2	2.9%	0.1%	0.6%	0.4%	0.3%	1.6%	1.0%
Meramec 3	1.6%	2.6%	2.6%	0.6%	3.9%	4.5%	2.6%
Meramec 4	4.2%	2.6%	6.2%	2.9%	1.5%	5.0%	3.8%
Rush Island 1	0.8%	2.3%	0.3%	0.7%	2.0%	1.6%	1.3%
Rush Island 2	1.0%	2.6%	3.2%	1.5%	1.2%	2.2%	2.0%
Sioux 1	1.4%	1.8%	0.2%	0.2%	1.3%	0.5%	0.9%
Sioux 2	0.9%	0.3%	0.0%	0.3%	1.4%	0.4%	0.5%

Off-System Sales Contracts

On-Peak- 5x16		
2008	Mws	$/Mwh
Jan	502	$59.00
Feb	500	$55.46
Mar	700	$62.60
Apr	750	$60.83
May	650	$64.33
Jun	350	$69.96
Jul	0	$70.54
Aug	0	$69.03
Sep	150	$57.53
Oct	500	$53.04
Nov	500	$57.75
Dec	500	$58.32

Off-Peak - wrap		
2008	**Mws**	**$/Mwh**
Jan	400	$29.54
Feb	400	$35.83
Mar	400	$33.38
Apr	400	$32.32
May	400	$33.37
Jun	400	$34.13
Jul	400	$34.56
Aug	400	$31.25
Sep	400	$28.32
Oct	400	$27.83
Nov	400	$29.84
Dec	400	$35.45

			Heat Rate 12 m Avg Rating	12 Month Generation Data x 1,000 MWH				
Unit Name	**Ownership**	**Primary Fuel Type**	**Btu/Kwh**	**3/08-2/09**	**3/09-2/10**	**3/10-2/11**	**3/11-2/12**	**3/12-3/13**
Callaway	AmerenUE	Nuclear	9,944	9,915,900	10,617,800	9,742,200	9,772,100	10,637,100
Labadie 1	AmerenUE	PRB Coal	10,099	3,583,700	4,793,300	4,744,400	4,800,700	4,539,500
Labadie 2	AmerenUE	PRB Coal	10,082	4,674,200	4,646,200	4,649,000	4,182,900	4,556,600
Labadie 3	AmerenUE	PRB Coal	9,931	4,811,800	4,787,900	3,933,600	4,803,900	4,575,200
Labadie 4	AmerenUE	PRB Coal	9,931	4,765,000	3,999,800	4,760,200	4,779,100	4,562,900
Rush 1	AmerenUE	PRB Coal	10,058	4,415,800	4,396,000	4,208,000	4,234,100	3,579,400
Rush 2	AmerenUE	PRB Coal	10,063	4,167,300	3,388,300	4,454,200	4,488,000	4,398,100
Sioux 1	AmerenUE	PRB /ILL Coal	9,887	2,779,500	3,137,900	3,533,100	2,676,100	3,660,600
Sioux 2	AmerenUE	PRB /ILL Coal	9,881	3,356,000	2,900,800	3,677,500	3,395,000	2,541,800
Meramec 1	AmerenUE	PRB Coal	11,046	876,900	893,800	681,600	885,100	867,100
Meramec 2	AmerenUE	PRB Coal	11,047	902,600	881,100	683,000	879,300	865,500
Meramec 3	AmerenUE	PRB Coal	11,150	1,930,100	1,812,900	1,808,700	1,536,700	1,895,400
Meramec 4	AmerenUE	PRB Coal	10,319	2,327,400	2,054,200	2,478,500	2,498,500	2,454,100
Audrain CT 1	AmerenUE	Gas	11,750	13,900	15,400	15,300	16,900	33,100
Audrain CT 2	AmerenUE	Gas	11,750	13,800	12,700	14,700	17,700	31,600
Audrain CT 3	AmerenUE	Gas	11,750	11,900	14,000	13,600	14,600	32,900
Audrain CT 4	AmerenUE	Gas	11,750	11,800	12,500	13,100	16,100	33,200
Audrain CT 5	AmerenUE	Gas	11,750	11,200	13,200	14,500	16,300	31,600
Audrain CT 6	AmerenUE	Gas	11,750	10,700	12,400	13,100	17,100	31,300
Audrain CT 7	AmerenUE	Gas	11,750	11,300	12,100	11,600	14,600	30,400
Audrain CT 8	AmerenUE	Gas	11,750	10,900	12,400	14,300	15,500	31,100
Fairgrounds CT	AmerenUE	Oil	10,719	300	700	600	400	2,300
Goose Creek CT 1	AmerenUE	Gas	11,833	14,100	11,700	13,200	12,800	28,000
Goose Creek CT 2	AmerenUE	Gas	11,833	13,900	12,000	12,900	12,100	27,300
Goose Creek CT 3	AmerenUE	Gas	11,833	12,500	11,000	12,800	12,100	26,100
Goose Creek CT 4	AmerenUE	Gas	11,833	13,300	11,800	12,800	13,300	27,500
Goose Creek CT 5	AmerenUE	Gas	11,833	11,400	10,400	10,800	12,700	26,200
Goose Creek CT 6	AmerenUE	Gas	11,833	11,900	11,700	11,500	12,900	26,300
Howard Bend CT	AmerenUE	Oil	11,788	300	300	400	300	1,400
Kinmundy CT 1	AmerenUE	Gas	12,031	13,800	14,300	12,400	12,000	29,700
Kinmundy CT 2	AmerenUE	Gas	12,031	13,600	12,300	11,700	11,100	30,200
Kirksville CT	AmerenUE	Gas	22,576	100	-	100	100	600
Meramec CT 1	AmerenUE	Oil	10,452	-	1,000	700	500	2,300
Meramec CT 2	AmerenUE	Gas	11,851	4,300	4,400	4,400	5,600	9,500
Mexico CT	AmerenUE	Oil	10,609	300	300	600	400	2,300
Moberly CT	AmerenUE	Oil	10,937	100	500	500	300	1,800
Moreau CT	AmerenUE	Oil	10,719	300	600	600	400	1,700
Peno Creek CT 1	AmerenUE	Gas	10,683	31,600	28,200	27,300	31,300	32,300
Peno Creek CT 2	AmerenUE	Gas	10,683	28,500	27,300	25,900	29,500	31,700
Peno Creek CT 3	AmerenUE	Gas	10,683	28,900	26,000	27,500	30,000	30,600
Peno Creek CT 4	AmerenUE	Gas	10,683	29,100	26,000	26,100	29,100	30,100
Pinkneyville CT 1	AmerenUE	Gas	10,310	22,900	22,600	25,100	25,300	32,800
Pinkneyville CT 2	AmerenUE	Gas	10,310	21,900	21,500	25,100	26,000	32,100
Pinkneyville CT 3	AmerenUE	Gas	10,310	22,400	22,200	23,200	26,100	30,500
Pinkneyville CT 4	AmerenUE	Gas	10,310	20,800	20,500	22,300	23,900	29,600
Pinkneyville CT 5	AmerenUE	Gas	12,900	3,300	3,300	3,000	3,400	7,900
Pinkneyville CT 6	AmerenUE	Gas	12,900	2,400	3,400	3,000	3,400	7,700
Pinkneyville CT 7	AmerenUE	Gas	12,900	2,400	3,400	2,200	3,200	7,700
Pinkneyville CT 8	AmerenUE	Gas	12,900	3,200	3,100	2,600	3,200	7,500
Raccoon Creek CT 1	AmerenUE	Gas	11,783	7,100	7,300	9,900	12,000	25,000
Raccoon Creek CT 2	AmerenUE	Gas	11,783	7,000	8,300	9,800	11,000	24,000
Raccoon Creek CT 3	AmerenUE	Gas	11,783	7,700	8,000	10,300	12,000	22,000
Raccoon Creek CT 4	AmerenUE	Gas	11,783	7,200	6,900	7,900	9,200	20,500
Venice CT 1	AmerenUE	Oil	14,017	-	-	-	-	-
Venice CT 2	AmerenUE	Gas	10,561	11,800	13,200	15,200	15,800	23,600
Venice CT 3	AmerenUE	Gas	10,393	49,200	45,400	53,800	54,700	87,600
Venice CT 4	AmerenUE	Gas	10,393	47,200	47,700	51,800	55,800	83,700
Venice CT 5	AmerenUE	Gas	12,119	11,200	11,200	11,200	13,400	28,300
Viaduct CTG	AmerenUE	Gas	17,705	400	600	700	700	2,100
Osage	AmerenUE	Pond Hydro		439,700	440,900	443,000	439,900	441,100
Keokuk	AmerenUE	Run of River Hydro		895,900	916,500	946,000	972,900	996,300
Taum Sauk 1	AmerenUE	Pumped Storage		-	152,300	392,350	404,800	408,200
Taum Sauk 2	AmerenUE	Pumped Storage			152,300	392,350	404,800	408,200
Wind	Purchase Power Begins in 2010				58,100	287,200	288,200	288,200

Schedule TDF-E8