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Witness:	Martin J. Lyons, Jr.
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

MARTIN J. LYONS, JR.

ON

BEHALF OF

UNION ELECTRIC COMPANY d/b/a AmerenUE

St. Louis, Missouri
April, 2008

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DIRECT TESTIMONY

OF

MARTIN J. LYONS, JR.

CASE NO. ER-2008-____

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Martin J. Lyons, Jr. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri, 63103.

Q. By whom are you employed and in what position?

A. I am Senior Vice President and Chief Accounting Officer of Ameren Corporation ("Ameren"), Union Electric Company d/b/a AmerenUE ("AmerenUE" or the "Company") and other Ameren subsidiaries.

Q. Please describe your educational background.

A. In 1988, I received a Bachelor's of Science in Business Administration, with an Accountancy major, from Saint Louis University. In 1997, I received a Masters of Business Administration degree from Washington University.

Q. Do you have any professional designations?

A. Yes, I am a certified public accountant licensed to practice in Missouri. I am a member of the American Institute of Certified Public Accountants and the Missouri Society of Certified Public Accountants.

Q. Please describe your professional work experience.

A. In 1988, I joined Price Waterhouse (now PricewaterhouseCoopers LLP) as an auditor. I was admitted to the PricewaterhouseCoopers LLP partnership in 1999. I resigned from PricewaterhouseCoopers to accept the Controller position at Ameren in October 2001. During my years as a partner at PricewaterhouseCoopers, I devoted approximately seventy-five percent of my time to supervising audits of, and consulting on accounting issues for PricewaterhouseCoopers' utility clients.

Q. Please describe the duties and responsibilities of your current position.

A. As Senior Vice President and Chief Accounting Officer, I manage the accounting, financial reporting, tax, commodities risk management, commodities back-office, and investor relations functions for Ameren, AmerenUE, and all other Ameren subsidiaries. I am responsible for assuring that transactions are accounted for in accordance with generally accepted accounting principles and, when applicable, specific regulatory reporting requirements. Additionally, I am responsible for Securities and Exchange Commission, Federal Energy Regulatory Commission, Missouri Public Service Commission (the "Commission") and Illinois Commerce Commission regulatory reporting requirements.

Q. Do you perform service for any non-Ameren entities?

A. Yes. I am Vice-Chairman of the Accounting Executive Advisory Committee of Edison Electric Institute, and on the Executive Committee of the Board of Directors of the St. Louis Zoo Friends Association ("ZFA"). I am also currently serving as Treasurer of the ZFA Board of Directors, and on the Board of Trustees of the St. Louis Zoo.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to sponsor the Company's proposed fuel adjustment clause ("FAC") and explain why the Commission should approve AmerenUE's request for an FAC.

An Executive Summary of my testimony is attached to this testimony as Attachment A.

III. DESCRIPTION OF THE PROPOSED FAC

Q. Please describe the general design and intended operation of the proposed fuel adjustment clause.

A. AmerenUE's proposed FAC tariff is attached as Schedule MJL-E1. The Company proposes to recover its normalized test-year level of fuel and purchased power costs, including transportation, net of off-system sales revenues (i.e., its "net base fuel costs"), through its base rates. To that end, 0.837 cents per kWh in net fuel and purchased power costs at the generation level has been included in base rates, as discussed further below.[1] To the extent the Company's actual net fuel costs deviate from this base amount, 95% of the difference between actual net fuel costs and base net fuel costs will be reflected in subsequent FAC rate adjustments. The proposed FAC is applicable to all energy supplied to all Missouri retail customers served by the Company.

The 0.837 cents per kWh of net base fuel costs was calculated by AmerenUE witness Gary S. Weiss by taking the sum of: (a) the normalized fuel and purchased power costs determined from the production cost modeling performed by AmerenUE witness Timothy D. Finnell, as discussed in Mr. Finnell's direct testimony and (b) additional fuel and purchased power cost components (principally net Midwest Independent Transmission System Operator, Inc ("MISO) Day 2 charges), reduced by normalized off-system sales revenues calculated by Mr. Finnell's production cost modeling using inputs provided by AmerenUE witness Shawn E. Schukar. As discussed in Mr. Weiss' direct testimony, this

[1] Absent the off-system sales revenue offset, fuel and purchased power costs would be approximately 1.97 cents per kWh.

calculation results in the net base fuel costs of $344.3 million, which Mr. Weiss then divides by the normalized AmerenUE load of 41,151,238,000 kWhs to arrive at net base fuel costs on a per kWh basis of 0.837 cents. The components of net base fuel costs, including the large offset provided by off-system sales revenues, are depicted on Schedule MJL-E2, attached to this testimony.

Deviations in actual net fuel costs from this net base fuel cost amount will be accrued over three separate four-month Accumulation Periods — March through June, July through October, and November through February. Any FAC adjustment resulting from actual net fuel cost deviations incurred during an Accumulation Period will be flowed through, with interest, over the 12-month Recovery Period commencing four months after the close of the Accumulation Period. In other words, any adjustment resulting from cost deviations incurred during the March through June 2009 Accumulation Period (to be filed by September 1, 2009) would be recovered over the November 2009 through October 2010 Recovery Period. Similarly, cost deviations attributable to the July through October Accumulation Period (to be filed by January 1, 2010) would be recovered during the March 2010 through February 2011 Recovery Period, and so forth. Staggering the adjustments and recovery periods in this manner will minimize rate volatility and seasonal fluctuation for customers, since accumulated variations would be recovered over a full 12 month period. The operation of the Accumulation and Recovery Periods are illustrated in Schedule MJL-E3, attached to this testimony.

Q. What costs are included in the FAC?

A. As I described above, the FAC would include all fuel and purchased power costs incurred to support sales to retail customers and the portion of off-system sales allocated to Missouri retail ratepayers,[2] net of the Company's off-system sales revenues that are allocated to Missouri ratepayers. A more detailed description of the costs and revenues addressed by the FAC is included in the FAC formula set forth in Schedule MJL-E1 and in Items (F), (H), and (I) of Schedule MJL-E4. AmerenUE witness Paul W. Mertens addresses these items in detail in his direct testimony. These cost items are also discussed further in the direct testimonies of AmerenUE witnesses Robert K. Neff, Scott A. Glaeser and Randall J. Irwin.

Q. Does AmerenUE's proposed FAC tariff include off-system sales revenues?

A. Yes. As noted earlier, the proposed FAC includes both revenues from off-system sales achieved by AmerenUE and the fuel costs associated with these off-system sales. This process reduces native load fuel and purchased power costs by the profits achieved on off-system sales (i.e., the off-system sales margin), and results in a significantly lower normalized level of net fuel costs that must be recovered from native load customers as shown in Schedule MJL-E2 and discussed in the direct testimony of Mr. Finnell. Mr. Weiss' and Mr. Finnell's testimonies address the calculation and normalization of the Company's net base fuel costs using the Company's PROSYM production cost model.

Q. Does the proposed FAC include any rate volatility mitigation measures?

A. Yes. While AmerenUE hedges portions of its fuel cost as well as purchased power and off-system sales exposure where practical and cost-effective to do so, the remaining volatility of native load fuel costs and off-system sales margins is still very significant, as documented in the direct testimony of AmerenUE witness Ajay K. Arora. This volatility is mitigated by the design of the proposed FAC in terms of its rate impacts by:

[2] Fuel and purchased power costs incurred to support wholesale sales are not included in the FAC.

(1) adjusting the FAC rate three times per year for separate Accumulation Periods, which avoids larger rate impacts that could result from less frequent adjustments; and (2) spreading recovery of these Accumulation Period adjustment amounts over a 12-month Recovery Period, which avoids rate fluctuations attributable to seasonal variations and volatility in fuel costs.

Q. Does AmerenUE's proposed FAC include any explicit incentive features?

A. Yes. In addition to the inherent incentives AmerenUE has to control its fuel costs, the proposed FAC also contains the explicit incentive that the Commission recently approved for a FAC for Aquila, Inc. in Case No. ER-2007-0004. This mechanism permits Aquila to recover only 95% of its deviations from net base fuel costs. Consistent with the Commission's finding in its Report and Order in the Aquila case, the fact that the proposed FAC passes through to customers only 95% of deviations from net base fuel costs will provide an additional incentive for the Company to take all reasonable actions to keep its net fuel costs low.

Q. Does AmerenUE's proposed tariff apply different FAC adjustment factors to customers receiving service at different voltage levels?

A. Yes. In accordance with 4 CSR 240-20.090(9), the proposed tariff applies three separate voltage level adjustment factors to customer classes taking service at different voltage levels—primary service customers, secondary service customers and large transmission customers (currently consisting only of Noranda Aluminum, Inc.).

Q. How will the proposed FAC be trued-up to reflect over- or under-collections over time?

A. The FAC will be trued-up on an annual basis after the completion of each true-up year. True-up filings will continue until all recoverable deviations from net base fuel costs that have been accumulated and deferred have been recovered and trued-up. Any true-up adjustments will also include interest, as required by S.B. 179, the Commission's FAC rules and the FAC tariff. Please see Schedule MJL-E4, Item (F) and Mr. Mertens' direct testimony for additional discussion of the true-up.

Q. How does AmerenUE propose to account for the loss of the Taum Sauk Plant in the FAC to ensure that customers are in fact held harmless until the plant returns to service?

A. We propose that the full value of Taum Sauk's capacity and output be reflected in the revenue requirement, which means customers' base rates are as low as they would be if Taum Sauk was still in operation. As explained in more detail in Mr. Finnell's testimony, the energy value of the Taum Sauk Plant is determined through production cost simulations run both with and without the Taum Sauk Plant in service. To that a capacity value calculated by Mr. Schukar is added. The total value is currently determined to be $19.4 million for the normalized test year, but the calculation will be updated as the remainder of the revenue requirement is updated within this rate case. To ensure that this customer value is not inadvertently recovered through the FAC, AmerenUE recommends that one third of this $19.4 million value ($6.47 million) be credited in each of the three annual FPA filings through the "TS" factor as defined in Schedule MJL-E1 until the next rate case or, if sooner, until Taum Sauk is placed back in service. To avoid potentially contentious annual modeling of the Taum Sauk impact on a going forward basis, AmerenUE proposes that an annual Taum Sauk value be determined ($19.4 million as updated) in this rate case and approved by the Commission for use in each year during which the FAC is operational until Taum Sauk is placed back in service or a new value is determined in AmerenUE's next rate case.

Q. Is AmerenUE submitting the minimum filing requirements required by the Commission's FAC rules?

A. Yes. Schedule MJL-E4 satisfies the 19 minimum filing requirements provided for by the Commission's FAC rules. Where applicable, Schedule MJL-E4 contains cross references to the direct testimony of other AmerenUE witnesses who sponsor a particular minimum filing requirement.

Q. As required by the FAC rules, does AmerenUE give its permission to the Commission Staff to release the previous five (5) years of historical surveillance reports submitted to the Staff by AmerenUE to the other parties to this case.

A. Yes. On behalf of AmerenUE, I hereby provide Staff that authorization.

IV. <u>THE NEED FOR A FUEL ADJUSTMENT CLAUSE</u>

Q. Why does AmerenUE ask the Commission to approve an FAC at this time?

A. AmerenUE is asking the Commission to approve an FAC because the mechanism is needed to address substantial increases in the Company's fuel costs and the significant volatility and uncertainty of the un-hedged portion of the Company's net fuel costs. An FAC is also critical to giving the Company a sufficient opportunity to earn a fair return on equity, and is needed to help the Company maintain its overall financial health so that it can effectively compete for the very large amounts of capital it needs, particularly given that nearly all similarly situated utilities are already able to utilize FACs.

A. Fuel Costs and Expected Cost Increases are Very Large, and Without an FAC AmerenUE Does Not Have a Sufficient Opportunity to Earn a Fair Return on Equity

Q. You noted that the FAC is needed to manage rapidly increasing, volatile and uncertain fuel costs, and to ensure the Company has a sufficient opportunity to earn a fair return in order to generally preserve its financial health. How large are AmerenUE's fuel costs?

A. Based on the normalized test year values filed in this rate case, AmerenUE's total fuel and purchased power costs are $810.5 million per year. Off-system sales revenues are calculated to be $466.2 million. See Mr. Weiss' direct testimony.

Q. What is the magnitude of fuel cost increases and earnings impacts that AmerenUE is facing today?

A. Through 2012, as discussed by Mr. Neff in his direct testimony, the Company expects the delivered cost of coal to increase approximately **[redacted]** from approximately **[redacted]** million in the normalized test year to approximately **[redacted]** million in 2012. Even over only the next two years and taking into account AmerenUE's hedged position, these coal cost increases are expected to amount to almost **[redacted]** million or **[redacted]** (from **[redacted]** million in the test year to **[redacted]** million in 2010). The expected **[redacted]** million increase through 2010 would depress AmerenUE's earnings by more than **[redacted]** basis points and the expected **[redacted]** million increase through 2012 would depress AmerenUE earnings more than **[redacted]** basis points, unless offset or recovered in rates. As also discussed in Mr. Neff's direct testimony, a portion of these increases in delivered coal costs is already known because the Company has already locked

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in or hedged a significant portion of its delivered coal and transportation needs for 2009 and 2010, and has also hedged some of its coal needs in 2011 and 2012.

Similarly, the Company expects gas costs to increase approximately **[redacted]** through 2012 (from approximately **[redacted]** million to over **[redacted]** million). The annual cost of nuclear fuel also continues to increase, and by 2012 is expected to be increased by nearly **[redacted]** above 2007 levels (from approximately **[redacted]** million to over **[redacted]** million). To put this in context, as Mr. Irwin's direct testimony indicates, annual nuclear fuel costs for the test year were $47.3 million, the May 2007 refueling cost was $67.9 million, and we know with virtual certainty that the November 2008 refueling, which will be done before this case is complete, will cost **[redacted]** million. Based on these refueling costs, the annual nuclear fuel costs are expected to rise to **[redacted]** million in 2009 and **[redacted]** million in 2010.

Q. Why do you believe that in the absence of an FAC the Company would not have a sufficient opportunity to earn a fair rate of return?

A. The large increases in fuel costs alone prevent AmerenUE from having a sufficient opportunity to earn a fair return. As shown in Mr. Neff's direct testimony, compared to the normalized test year coal costs of **[redacted]** million, in 2009 delivered coal cost increases are expected to be **[redacted]** million, and in 2010 they are an additional **[redacted]** million. AmerenUE's earnings at an authorized return on equity of 10.9% (the 10.9% return on equity recommended by Dr. Morin) total $334 million annually (the $334 million is the Company's return on rate base less interest expense). Consequently, these delivered coal cost increases alone (which are largely already locked in) would reduce AmerenUE's earnings by approximately **[redacted]** in 2009 and by an additional and much

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larger approximately **[redacted]** in 2010, unless recovered in rates. Thus, AmerenUE will not have a sufficient opportunity to earn a fair return on equity, because these fuel cost increases effectively stack the deck against AmerenUE, absent an FAC.

Q. Couldn't these cost increases be recovered through a normal rate case?

A. No. Under traditional ratemaking using an historical test year, even if a rate case was timed perfectly, AmerenUE would have to absorb 17-18 months of the 2009 cost increases and 5-6 months of the 2010 cost increases before rates reflecting these costs could be put into effect. To time a rate case to include the 2010 coal cost increases, for example, would require the filing of a new rate case in July of 2009—essentially immediately after the conclusion of this rate case—and we would still under-recover our fuel costs by approximately **[redacted]** million in 2010 alone by the time new rates could take effect. This would result in a 2010 earnings deficiency of more than 130 basis points, or approximately **[redacted]** million, which is more than a **[redacted]** reduction in 2010 earnings caused by these fuel cost increases alone.

Q. Couldn't reductions in other costs offset these known fuel cost increases?

A. Not in my opinion. While it is theoretically possible that other costs could decrease, in the environment in which we are currently operating, it is very unlikely costs will go down and in fact it is almost a given that costs will increase, as discussed in the testimonies of AmerenUE witnesses Thomas R. Voss and Dr. Kenneth Gordon.

Q. Couldn't off-system sales revenues increase to offset the known fuel cost increases AmerenUE is facing?

A. Future off-system sales revenues could be higher or lower than the normalized amount that the Commission sets in this rate case and we would certainly hope that increases

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in off-system sales margins would at least partially offset fuel cost increases if the Commission does not approve our proposed FAC. But while one can hope for such a result, it cannot be expected to occur. Mr. Arora's testimony discusses this issue in more detail.

Q. What do these cost increases and the uncertainty surrounding off-system sales revenues mean for AmerenUE's opportunity to earn a fair return on equity?

A. It means that given these significant fuel cost increases AmerenUE is facing and other cost items that will very likely exacerbate these fuel cost increases, the Company will not have a sufficient opportunity to earn the fair rate of return that the Commission will authorize in this case without an FAC.

Q. Mr. Voss testifies that Missouri utilities face a more pronounced regulatory lag than utilities in many other states. Is there anything about the FAC rules in Missouri that also contributes to the more pronounced regulatory lag discussed by Mr. Voss?

A. Yes. The Missouri FAC rules also result in a more pronounced regulatory lag than the FAC rules in many other states. Under the Commission's FAC rules, utilities must: (1) make FAC adjustments using historic (as opposed to projected) fuel costs; and (2) can, at most, make quarterly FAC adjustments. Schedule MJL-E5 shows that of 85 utilities with FACs operating in other non-restructured states (excluding Missouri), only 33 utilities (39%) rely on historic costs to adjust FAC rates. Schedule MJL-E5 also shows that 21 of these 33 utilities that rely on historic fuel costs are allowed to adjust their rates on a monthly basis, which is considerably more frequent than what is allowed under Missouri rules. The remaining 52 utilities (61%) adjust FAC rates based on projected costs, which are then trued-up as part of the true-up or reconciliation process. As noted, the Commission's FAC rules would allow, at most, an adjustment just four times per year. These features in the Commission's FAC rules thus create greater regulatory lag and more fuel cost deferrals than is often seen in other states' FACs, which, when coupled with the other facets of Missouri regulation noted in Mr. Voss' testimony, make regulatory lag in Missouri more pronounced. But that lag is substantially greater without an FAC.

In short, an FAC is a mainstream cost recovery mechanism that is critically important for AmerenUE to have a sufficient opportunity to earn a fair rate of return, maintain its financial health, and compete for capital with other utilities in the region and nationally.

B. <u>AmerenUE's Net Fuel Costs are Volatile and Uncertain</u>

Q. You mentioned that in addition to the sharp rise in fuel costs, AmerenUE is also exposed to significant volatility and uncertainty with regard to these costs. Has AmerenUE analyzed the sources and magnitude of this volatility and uncertainty?

A. Yes, we have. The volatility or uncertainty in the Company's net fuel costs is addressed in the testimonies of a number of AmerenUE witnesses. Mr. Neff addresses trends and uncertainty in the Company's coal and coal transportation costs, Mr. Irwin addresses nuclear costs, and Mr. Glaeser's testimony covers the level and uncertainty in the Company's natural gas costs. Mr. Schukar also addresses in his testimony the level, trend and uncertainty in AmerenUE's off-system sales revenues. And finally, Mr. Arora's testimony covers: (1) native load uncertainty; (2) the correlations between these various sources of uncertainty; and (3) the combined overall level of uncertainty in the Company's net fuel costs.

Mr. Arora's analysis combines the expected fuel cost increases, considers the extent to which fuel costs are hedged, anticipated off-system sales revenues, and the expected uncertainty surrounding the Company's various fuel costs (coal, natural gas, nuclear fuel), and presents an analysis that illustrates the combined effect of these costs, revenues, uncertainties and volatilities on net fuel cost uncertainty and volatility (i.e., the combined uncertainty and volatility of fuel and purchased power costs less off-system sales revenues). Mr. Arora's analysis reflects that, despite AmerenUE's substantial efforts to hedge the underlying cost of fuel commodities and its off-system sales where practical and cost-effective to do so, the remaining un-hedged portion of these costs exposes the Company to large operating margin uncertainties.

For example, according to Mr. Arora's analysis, there is a 50% chance that the Company's net fuel costs will be less than **[redacted]** million or more than **[redacted]** million (a range of **[redacted]** million) in 2009. This **[redacted]** million uncertainty range represents a potential swing in AmerenUE's earnings of approximately **[redacted]** basis points. As Mr. Arora's analysis of test year risks shows, even at the beginning of a year when essentially all of AmerenUE's fuel costs and a portion of our off-system sales are hedged, significant uncertainty remains. There is: (1) a 50% chance that the uncertainty in annual net fuel costs (i.e., the range between the 25th percentile and the 75th percentile) will be more than **[redacted]** million that year, and (2) a 20% chance that the uncertainty in net fuel costs will exceed **[redacted]** million in that year (i.e., representing the difference between the 10th and 90th percentile of net fuel costs). Of course, looking forward from the time of the rate case, these uncertainties are larger than at the beginning of a particular year because we do not

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know at what cost we will be able to hedge fuel between now and the beginning of any particular future year.

AmerenUE's FAC would accurately reflect in rates AmerenUE's actual net fuel costs (wherever those net fuel costs may fall within this range of uncertain outcomes) by allowing the Company to recover 95% of net fuel cost changes above the expected level, or allowing customers to benefit from 95% of net fuel cost changes below the expected level.

Q. By how much could net fuel cost uncertainty adversely affect AmerenUE's earnings?

A. Mr. Arora's analysis suggests there was a material (25%) chance, even with the substantial hedges that were in place at the beginning of the test year, that net fuel costs could have been at least **[redacted]** million (and potentially much more) above the average anticipated net fuel costs for the test year, which would have created at least an approximately **[redacted]** basis point reduction in AmerenUE's return on equity. Looking forward to, for example, 2010, this adverse earnings impact could be significantly greater.

For example, the simulation relating to 2010 net fuel costs discussed in Mr. Arora's testimony indicates that there is a 25% chance that 2010 net fuel costs will be more than **[redacted]** million above the test year average. If this occurred, it would represent an approximate **[redacted]** basis point reduction in AmerenUE's return on equity. To put this into perspective, a **[redacted]** million net fuel cost increase would reduce AmerenUE's earnings by approximately **[redacted]** based upon the $334 million of earnings included in AmerenUE's revenue requirement in this case at Dr. Morin's recommended return on equity of 10.9%.

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Considering the fuel cost increases that are already substantially locked in, while net fuel costs could decrease relative to the average anticipated levels and thus raise AmerenUE's earnings, that upside potential is far smaller. This too is shown by Mr. Arora's testimony which indicates that there is just a 10% chance in 2010 that net fuel costs will be less than the average net fuel costs for the test year. Conversely, there is a 10% chance that net fuel costs in 2010 could exceed the average test year value by approximately **[redacted]** million, which would reduce AmerenUE's earnings by approximately **[redacted]** based upon the 10.9% return on equity recommended by Dr. Morin.

Of course, fuel cost increases are not the only cost increases being faced by AmerenUE. The combination of already known and projected fuel cost increases, other operating cost increases, and large capital investment requirements to finance necessary infrastructure, including higher depreciation and interest costs associated with those capital investments, substantially increases the financial pressure on AmerenUE.

Q. Considering that AmerenUE mostly relies on coal and nuclear generation and both its coal and nuclear costs are partially hedged in the next few years, why is the uncertainty of net fuel costs so high?

A. One reason why net fuel costs are so volatile despite significantly hedged coal and nuclear costs is the fact that off-system sales revenues reduce the Company's native load fuel costs by approximately 58 percent, as depicted on Schedule MJL-E2. While this means our customers realize substantial savings from such off-system sales (in the form of a lower revenue requirement and the resulting lower rates), it also means that AmerenUE's exposure to volatile power prices is comparable to that of a company that supplies its customers in large part through power purchases. Even though AmerenUE's rates are significantly lower

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because it is a net seller of power and the off-system sales revenues reduce native load costs (while similar amounts of purchased power would increase native load costs), the exposure to power market volatility exists in both cases.

Moreover, net fuel costs are a function of many variables, notably loads, fuel prices, power market prices, and generation availability. The vast majority of AmerenUE's off-system sales are made from its coal-fired units and, as explained by Mr. Arora, AmerenUE's coal costs are not sufficiently correlated with power prices to create a meaningful offset to fuel cost risks. Thus, even though the Company's delivered coal costs are increasing substantially, there may or may not be an offsetting increase in off-system sales revenues. In fact, off-system sales uncertainty and volatility is a significant determinant of net fuel cost uncertainty and volatility. The point is that none of us know with any level of certainty what these commodity prices will do in the future, which creates a great deal of uncertainty around net fuel costs.

C. <u>AmerenUE's Net Fuel Costs are Outside the Company's Control</u>

Q. Does AmerenUE have significant control over the increases, volatility and uncertainty in fuel costs it faces?

A. No. The fuel costs faced by AmerenUE are largely outside the Company's control. While the Company works very hard to purchase fuel at the lowest possible cost consistent with minimizing volatility, maximizing revenues from off-system sales, and partially hedging both fuel and purchased power to stabilize its costs to the extent feasible and cost effective, AmerenUE does not have any meaningful control over the fundamental market conditions affecting fuel cost increases and market volatility. Mr. Arora's analysis of the uncertainty that remained at the beginning of the test year, despite significant hedging of the Company's fuel costs, also demonstrates that there are substantial limits on the Company's ability to control and predict these costs.

The cost items that would be tracked in the proposed FAC are coal, coal transportation, natural gas, oil, nuclear fuel, and purchased power net of off-system sales. AmerenUE generates its electricity from coal, nuclear and natural gas-fired power plants, and is able to reduce costs through significant amounts of off-system sales into the regional power market. As the Commission has already recognized in its approval of Aquila's FAC, referred to earlier, the price of coal and railroad freight rates to transport that coal are established by national, and in some cases, international markets. As Mr. Neff points out, the commodity price for coal is set by market conditions and the cost of coal transportation, which represents approximately **[redacted]** of the delivered price of a ton of coal, is set by two railroads operating in a duopoly, which are able to exercise substantial market power in setting coal transportation prices. As Mr. Glaeser points out in his direct testimony, markets for natural gas for generation, which is becoming a more and more important and significant part of all utilities' generation portfolios, including AmerenUE, are now being set by a market driven by international demand for liquefied natural gas because of a dwindling domestic supply of gas. AmerenUE simply does not have control over any of these prices.

V. <u>THE PREVALENCE OF FACS IN OTHER STATES</u>

Q. In the order approving an FAC for Aquila, the Commission noted that other states' experiences with FACs can be instructive in making its decision whether to grant requests for a FAC. What are other states' experiences with FACs?

A. When it approved Aquila's FAC, the Commission noted that outside of Missouri, all but two of the 29 non-restructured states without retail competition allow their

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electric utilities to apply to recover fuel and purchased power costs through some type of FAC. One of these two states was Vermont, which now also allows FACs through alternative regulatory plans and has already implemented an FAC for one of its two utilities, so those statistics are now 28 out of 29. In addition to these 29 other non-restructured states, there are 5 states with vertically integrated utilities (Arizona, Montana, Nevada, Oregon, and Virginia) which have suspended or repealed retail access after initial restructuring efforts—all of which are also using FACs. (Those states are now, effectively, also "non-restructured" because of the suspension or repeal of their retail access efforts.) Of these 34 other non-restructured states, all but one utilize FACs.

Q. Given that AmerenUE's proposed FAC is needed in part to allow the Company to compete with other utilities in the region and country, how many utilities currently operate under an FAC in other non-restructured states?

A. As shown in Schedules MJL-E6 and MJL-E7, there are 98 major utilities operating in non-restructured states, including Missouri. (These 98 "utilities" include all jurisdictional service areas of investor-owned utilities with retail sales of more than 500,000 MWh in a given state, a threshold that excludes only the very smallest utility service areas.) Of these 98 jurisdictional utilities, 94 operate outside Missouri. Focusing on these 94 utilities in other non-restructured states, 85 (90%) are already operating with a fuel adjustment clause and 5 more have an FAC application currently pending before their state regulatory commission.

Q. Are fuel adjustment clauses also as prevalent in other Midwestern states, many of which are served by coal-intensive utilities similar to AmerenUE?

A. Yes. In fact, FACs are even more prevalent in the surrounding states. As also shown in Schedules MJL-E6 and MJL-E7, 36 of 37 utilities in surrounding non-restructured Midwestern states are already operating with the benefit of an FAC.

Q. Could it be that the prevalence of adjustment clauses is due to legislative mandates that leave commissions in other states no choice but to implement FACs?

A. No. While adjustment clauses are required in a number of states, FACs are also used almost universally in states where implementation of adjustment clauses is discretionary—like in Missouri. This means that most state commissions choose to approve FACs for their utilities, even if the commissions have the discretion not to approve an FAC. For example, there are at least eight neighboring and other non-restructured Midwestern states—Arkansas, Oklahoma, Kansas, Kentucky, Minnesota, North Dakota, South Dakota and Tennessee—where state regulatory commissions are not required to accept and approve an FAC if requested by a utility. Of the 23 utilities located in these states, every single one of them has an FAC, and 17 of these utilities are coal intensive like AmerenUE.

Q. Is AmerenUE suggesting that the Commission should allow the proposed FAC simply because other regulatory agencies have approved an FAC for utilities in their jurisdiction?

A. No. However, as the Commission itself has already recognized, FACs are used by the overwhelming majority of utilities in other non-restructured states and it is certainly instructive that state commissions in those states have approved FACs for their utilities—even for their coal intensive utilities. AmerenUE must compete for capital with those utilities. If those utilities have the advantage of more robust earnings, more certain cash flows, and greater financial strength, AmerenUE will be disadvantaged in its access to capital markets and the return that will be required by investors. This would translate to higher rates for AmerenUE customers in the long-term.

Q. Does this conclude 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-2008-____

AFFIDAVIT OF MARTIN J. LYONS, JR.

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

Martin J. Lyons, Jr., being first duly sworn on his oath, states:

1. My name is Martin J. Lyons, Jr. I work in the City of St. Louis, Missouri, and I am employed by Ameren Corporation, Union Electric Company d/b/a AmerenUE and other Ameren subsidiaries as Senior Vice President and Chief Accounting Officer.

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 21 pages, Attachment A and Schedules MJL-E1 through MJL-E7, 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.

Martin J. Lyons, Jr.

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

MARTIN J. LYONS, JR.

Senior Vice President and Chief Accounting Officer

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The purpose of my testimony is to sponsor the Company's proposed fuel adjustment clause ("FAC") and explain why the Commission should approve AmerenUE's request for an FAC. AmerenUE's proposed FAC is attached to my testimony as Schedule MJL-E1.

The proposed FAC applies to AmerenUE's total fuel, transportation, and purchased power costs, net of off-system sales revenues (i.e., the Company's "net fuel costs"). The proposed FAC captures 95% of the deviations between actual net fuel costs and net base fuel costs (i.e., net fuel costs included in base rates) through three annual FAC rate adjustments and provide for recovery over 12-month recovery periods. The net base fuel costs will be set in this rate case to reflect a normalized level of fuel, transportation and purchased power costs, net of off-system sales revenues. As set out in Schedule MJL-E4, AmerenUE has also complied with the Commission's minimum filing requirements for an FAC application, as provided for in 4 CSR 240-3.161(2).

The proposed FAC is needed to address the combination of significant increases in AmerenUE's fuel costs and substantial volatility and uncertainty of net fuel costs, which adversely affect the Company's financial strength and prevent the Company from having an ability to have a sufficient opportunity to earn a fair return. Moreover, an FAC is needed to maintain the Company's overall financial health and to allow it to effectively compete for the very large amounts of capital it needs, particularly given that nearly all similarly situated utilities are already able to utilize FACs.

AmerenUE's fuel costs are large, volatile, and almost entirely beyond the control of AmerenUE. Total AmerenUE fuel and purchased power costs for the test year exceed $810. Test year off-system sales revenues are approximately $466 million. Those off-system sales revenues are netted against fuel costs in the proposed FAC resulting in net base fuel costs of approximately $344 million. See Schedule MJL-E2.

Both fuel costs and off-system sales are subject to significant uncertainties that have a large impact on the Company's finances, including its ability to earn a fair return and to compete for capital. For example, the increases in coal costs over the next two years alone taking into account AmerenUE's substantially hedged position amount to almost **[redacted]** million (from **[redacted]** million in the test year to **[redacted]** million in 2010). An increase of that size would depress AmerenUE earnings by approximately **[redacted]** basis points, unless offset or recovered in rates. Natural gas and nuclear fuel costs are also increasing. These fuel cost increases are discussed in detail in the direct testimonies of AmerenUE witnesses Robert K. Neff (delivered coal costs), Scott A. Glaeser (gas costs) and Randall J. Irwin (nuclear fuel costs).

Traditional ratemaking will not permit AmerenUE to timely recover these fuel cost increases. Because the Commission relies on an historic test year, even if a rate case was timed perfectly the Company would have to absorb 17 – 18 months of the 2009 cost increases and 5 - 6 months of the 2010 cost increases before rates reflecting them could take effect. To time a rate case to include the 2010 coal cost increases, for example, would require the filing of a new rate case in July of 2009 – essentially immediately after the conclusion of this rate case – and the Company would still under-recover our fuel costs by approximately **[redacted]** million in 2010

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alone by the time new rates could take effect. This would result in a 2010 earnings deficiency of approximately **[redacted]** million (more than **[redacted]** basis points of return on equity), which is more than a 12% reduction in 2010 earnings caused by fuel cost increases alone.

Future off-system sales revenues could be higher or lower than the normalized amount that the Commission sets in this rate case and we would certainly hope that any increases in off-system sales margins would at least partially offset fuel cost increases if the Commission did not approve our FAC. However, while we can hope for such a result, it cannot be expected to occur. The significant fuel cost increases facing AmerenUE, and other cost items that will very likely exacerbate these fuel cost increases, mean the Company will not have a sufficient opportunity to earn the fair rate of return that the Commission will authorize in this case without an FAC.

There is also a substantial amount of volatility and uncertainty in the un-hedged portions of the Company's net fuel costs. As shown in the direct testimony of AmerenUE witness Ajay K. Arora, despite AmerenUE's substantial efforts to hedge the underlying cost of fuel commodities and its off-system sales where practical and cost-effective to do so, the remaining un-hedged portion of these costs exposes the Company to large operating margin uncertainties.

For example, according to Mr. Arora's analysis, there is a 50% chance that the Company's net fuel costs will be less than **[redacted]** million or more than **[redacted]** million (a **[redacted]** million swing) in 2009. A **[redacted]** million uncertainty range represents a potential swing in AmerenUE's earnings of approximately **[redacted]** basis points. Mr. Arora's test year analysis shows that even at the beginning of a year when essentially all of AmerenUE's fuel costs and a portion of its off-system sales are hedged, significant uncertainty remains. There is (1) a 50% chance that the uncertainty in annual net fuel costs (i.e. the range between the 25th and the 75th percentiles) will be more than **[redacted]** million in that year, and (2) a 20% chance that

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the uncertainty in net fuel costs will exceed **[redacted]** million in that year (i.e., representing the difference between the 10^{th} and 90^{th} percentiles). Of course, we do not know at what cost we will be able to hedge fuel between now and the beginning of any future year.

AmerenUE's FAC would accurately reflect in rates AmerenUE's actual net fuel costs (wherever those net fuel costs may fall within this range of uncertain outcomes) by allowing the Company to recover 95% of net fuel cost changes above the expected level, or allowing customers to benefit from 95% of net fuel cost changes below the expected level.

Fuel cost increases are not the only cost increases being faced by AmerenUE. The combination of already known and projected fuel cost increases, other operating cost increases, and large capital investment requirements to finance necessary infrastructure, including higher depreciation and interest costs associated with those capital investments, substantially increases the financial pressure on AmerenUE.

While AmerenUE is able to very substantially reduce net fuel costs for customers,[1] this large reduction carries with it the volatility and uncertainty inherent in the power markets, much like the volatility and uncertainty experienced by utilities with a heavy reliance on purchased power to meet their load obligations.

The vast majority of utilities with which AmerenUE has to compete in capital markets are able to operate with the benefit of an FAC. Of the 94 utilities in other non-restructured states[2], 85 (90%) already operate under an FAC, and 5 more utilities have an FAC application currently pending before their respective state regulatory commissions. This prevalence of FACs is even more pronounced on a regional basis. Indeed, 36 of the 37 (97%) utilities in the surrounding

[1] The reduction is approximately 58% based upon normalized test year fuel and purchased power costs and off-system sales revenues.

[2] My references to "non-restructured" states includes 29 states (other than Missouri) that have not restructured their utility industries, as well as an additional 5 states with vertically integrated utilities that have now suspended restructuring.

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non-restructured Midwestern states already operate under an FAC, including virtually all utilities with a heavy reliance on coal-fired generation. That FACs are equally prevalent for coal-intensive utilities such as AmerenUE is evidenced by the fact that of 27 coal-intensive utilities in the surrounding non-restructured Midwestern states, 26 (96%) have a FAC.

In short, the proposed FAC is necessary to enable AmerenUE to timely recover the substantial fuel cost increases the Company is facing in the next several years, compete for the capital needed for investments the Company must make on more favorable terms, and address and manage the volatility and uncertainty of net fuel costs and their effect on the Company's ability to have a sufficient opportunity to earn a fair return, particularly in the face of the rapidly increasing costs to which AmerenUE, along with the rest of the industry, is exposed today.

* RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 8(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Fuel Costs) and Net Base Fuel Costs (factor NBFC, as defined below), calculated and recovered as provided for herein.

For purposes of this FAC, the true-up year shall be from March 1 through the last day of February of the following year. The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Filing Date	Recovery Period (RP)
March through June	By September 1	November through October
July through October	By January 1	March through February
November through February	By May 1	July through June

Accumulation Period (AP) means the historical period during which fuel and purchased power costs, including transportation, net of OSSR for all kWh of energy supplied to Missouri retail customers are determined.

Recovery Period (RP) means the billing months as set forth in the above table during which the difference between the Actual Net Fuel Costs during an Accumulation Period and NBFC are applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.

The Company will make a Fuel and Purchased Power Adjustment (FPA) filing by each Filing Date. The new FPA rates for which the filing is made will be applicable starting with the Accumulation Period that begins following the Filing Date. All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format.

FPA DETERMINATION

Ninety-five percent of the difference between Actual Net Fuel Costs and NBFC for all kWh of energy supplied to Missouri retail customers during the respective Accumulation Periods shall be reflected as an FPA_C credit or debit, stated as a separate line item on the customer's bill and will be calculated according to the following formulas.

For the FPA filing made by each Filing Date, the FPA_C rate, applicable starting with the Accumulation Period following the applicable Filing Date, to recover fuel and purchased power costs, including transportation, net of OSSR, to the extent they vary from Net Base Fuel Costs (NBFC), as defined below, during the recently-completed Accumulation Period is calculated as:

* Indicates Addition.

* RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

$$FPA_{(RP)} = [[(CF+CPP-OSSR-TS) - (NBFC \times S_{AP})] \times .95 + I + R]/S_{RP}$$

The FPA rate, which will be multiplied by the voltage level adjustment factors set forth below, applicable during the following Accumulation Period is calculated as:

$$FPA_C = FPA_{(RP)} + FPA_{(RP-1)} + FPA_{(RP-2)}$$

where:

FPA_C = Fuel and Purchased Power Adjustment rate applicable during the Accumulation Period following the applicable Filing Date.

FPA_{RP} = FPA Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended prior to the applicable Filing Date.

$FPA_{(RP-1)}$ = FPA Recovery Period rate component from prior FPA_{RP} calculation, if any.

$FPA_{(RP-2)}$ = FPA Recovery Period rate component from FPA_{RP} calculation prior to $FPA_{(RP-1)}$, if any.

CF = Fuel costs incurred to support sales to all retail customers and Off-System Sales allocated to Missouri retail electric operations, including transportation, associated with the Company's generating plants. These costs consist of the following:

a) For fossil fuel or hydroelectric plants:

(i) the following costs reflected in Federal Energy Regulatory Commission (FERC) Account Number 501: coal commodity, applicable taxes, gas, alternative fuels, fuel additives other than those used to comply with environmental rules and regulations, Btu adjustments assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs (for purposes of factor CF, hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), hedging costs associated with SO2 and fuel oil

* Indicates Addition.

* RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(ii) the following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation charges, fuel losses, hedging costs, and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

b) Costs in FERC Account Number 518 (Nuclear Fuel Expense).

CPP = Costs of purchased power reflected in FERC Account Numbers 555, 565, and 575, excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one (1) year, incurred to support sales to all Missouri retail customers and Off-System Sales allocated to Missouri retail electric operations. Also included in factor "CPP" are insurance premiums in FERC Account Number 924 for replacement power insurance (other than relating to the Taum Sauk Plant) to the extent those premiums are not reflected in base rates. Costs of purchased power will be reduced by replacement power insurance recoveries, except recoveries relating to the Taum Sauk Plant.

OSSR = Revenues from Off-System Sales allocated to Missouri electric operations.

Off-System Sales shall include all sales transactions (including MISO revenues in FERC Account Number 447), excluding Missouri retail sales and long-term full and partial requirements sales, that are associated with (1) AmerenUE Missouri jurisdictional generating units, (2) power purchases made to serve Missouri retail load, and (3) any related transmission.

TS = The Accumulation Period value of Taum Sauk. This factor will be used to reduce actual fuel costs to reflect the value of Taum Sauk, and will be credited in FPA filings (of which there are three each year as shown in the table above), until the next rate case or, if sooner, until Taum Sauk is placed back in service. This value is $19.4 million for each true-up year as determined in the rate proceeding in which this

* Indicates Addition.

* RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

FAC was established, one third of which (i.e., $6.47 million) will be applied to each Accumulation Period.

I = Interest applicable to (i) the difference between Actual Net Fuel Costs (adjusted for Taum Sauk) and NBFC for all kWh of energy supplied to Missouri retail customers during an Accumulation Period until those costs have been recovered; (ii) refunds due to prudence reviews (a portion of factor R, below); and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the annual true-up filings provided for herein (a portion of factor R, below). Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

R = Under/over recovery (if any) from currently active and prior Recovery Periods as determined for the annual FAC true-up adjustments, and modifications due to adjustments ordered by the Commission (other than the adjustment for Taum Sauk as already reflected in the TS factor), as a result of required prudence reviews or other disallowances and reconciliations, with interest as defined in item I.

S_{AP} = Billed kWh during the Accumulation Period that ended prior to the applicable Filing Date, at the generation level.

S_{RP} = Applicable Recovery Period estimated kWh, at the generation level, subject to the FPA_{RP} to be billed.

NBFC = Net Base Fuel Costs are the net costs determined by the Commission's order as the normalized test year value (and reflecting an adjustment for Taum Sauk, consistent with the term TS) for the sum of allowable fuel costs (consistent with the term CF), plus cost of purchased power (consistent with the term CPP), less revenues from off-system sales (consistent with the term OSSR), expressed in cents per kWh, at the generation level, as included in the Company's retail rates, which sum is 0.837 cents per kWh.

Customer bills that are based on more than one FPA_C in effect during the billing period shall be pro rated between the first and second FPA_C in proportion to the number of days in the customer's billing period that each such FPA_C was in effect.

* Indicates Addition.

* RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

To determine the FPA rates applicable to the individual Service Classifications, the FPA_C rate determined in accordance with the foregoing will be multiplied by the following voltage level adjustment factors:

Secondary Voltage Service	1.0888
Primary Voltage Service	1.0492
Large Transmission Voltage Service	1.0147

The FPA rates applicable to the individual Service Classifications shall be rounded to the nearest 0.001 cents, to be charged on a cents/kWh basis for each applicable kWh billed.

TRUE-UP OF FAC

After the completion of each true-up year, the Company will make a true-up filing by May 1 of each year (starting by May 1, 2010) with the Commission. Such filings shall be made by May 1 of every subsequent year until all fuel and purchased power costs accumulated during the effective period of the FAC have been recovered and trued-up. Any true-up adjustments or refunds shall be reflected in item R above, and shall include interest calculated as provided for in item I above.

The true-up adjustment shall be the difference between the revenues billed and the revenues authorized for collection during the true-up year.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this Fuel and Purchased Power Adjustment Clause, in accordance with Section 386.266.4, RSMo.and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be established in such general rate case to be no later than four years after the effective date of a Missouri Public Service Commission order implementing or continuing this Fuel and Purchased Power Adjustment Clause. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this Fuel and Purchased Power Adjustment Clause, or any period for which charges hereunder must be fully refunded. In the event a court determines that this Fuel and Purchased Power Adjustment Clause is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this Fuel and Purchased Power Adjustment Clause to file such a rate case.

Prudence reviews of the costs subject to this Fuel and Purchased Power Adjustment Clause shall occur no less frequently than every eighteen months, and any such costs which are determined by the Missouri Public Service Commission to have been imprudently incurred shall be returned to customers with interest at the Company's short-term borrowing rate.

*Indicates Addition.

Components of AmerenUE Test Year Net Base Fuel Costs

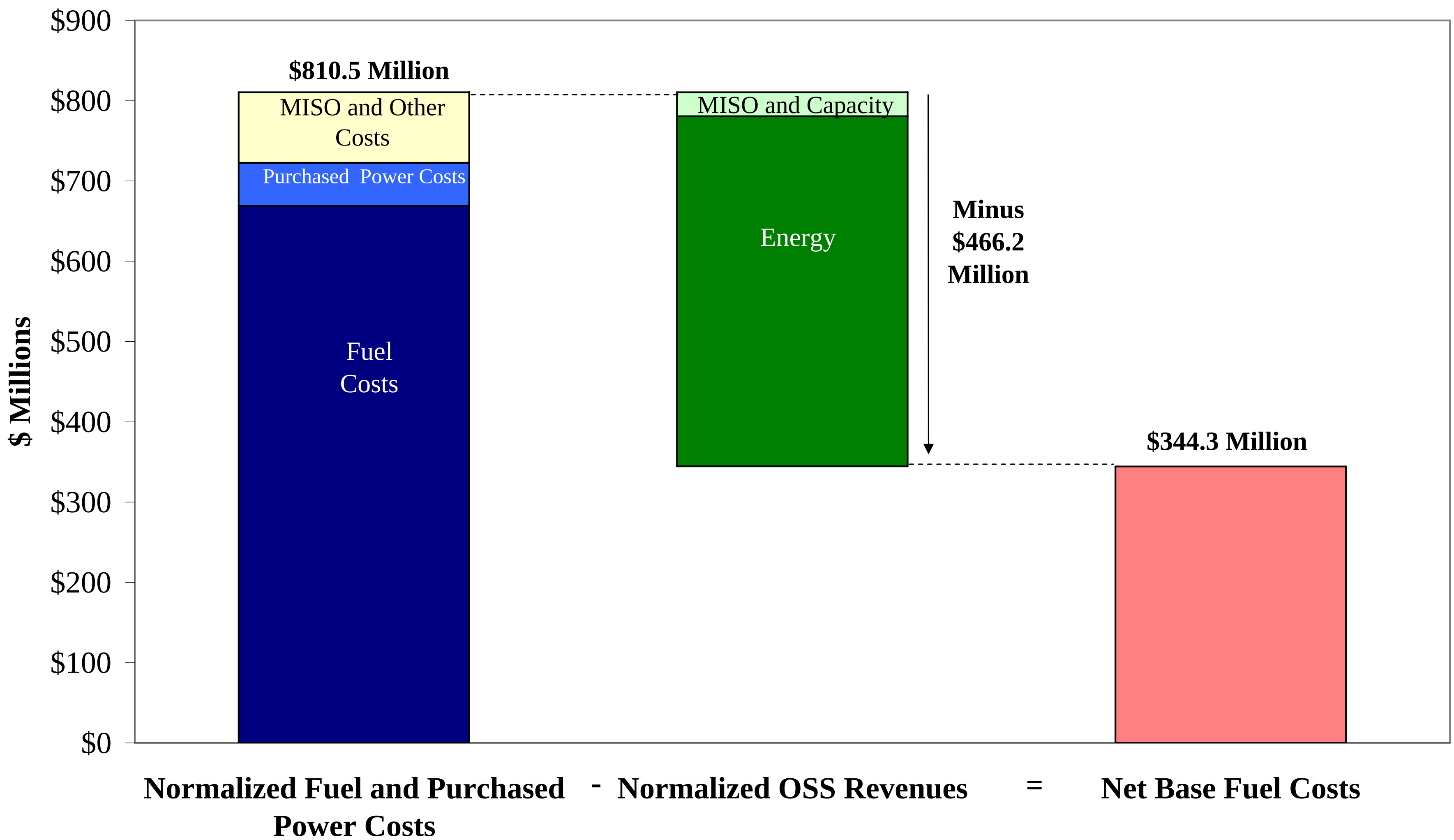
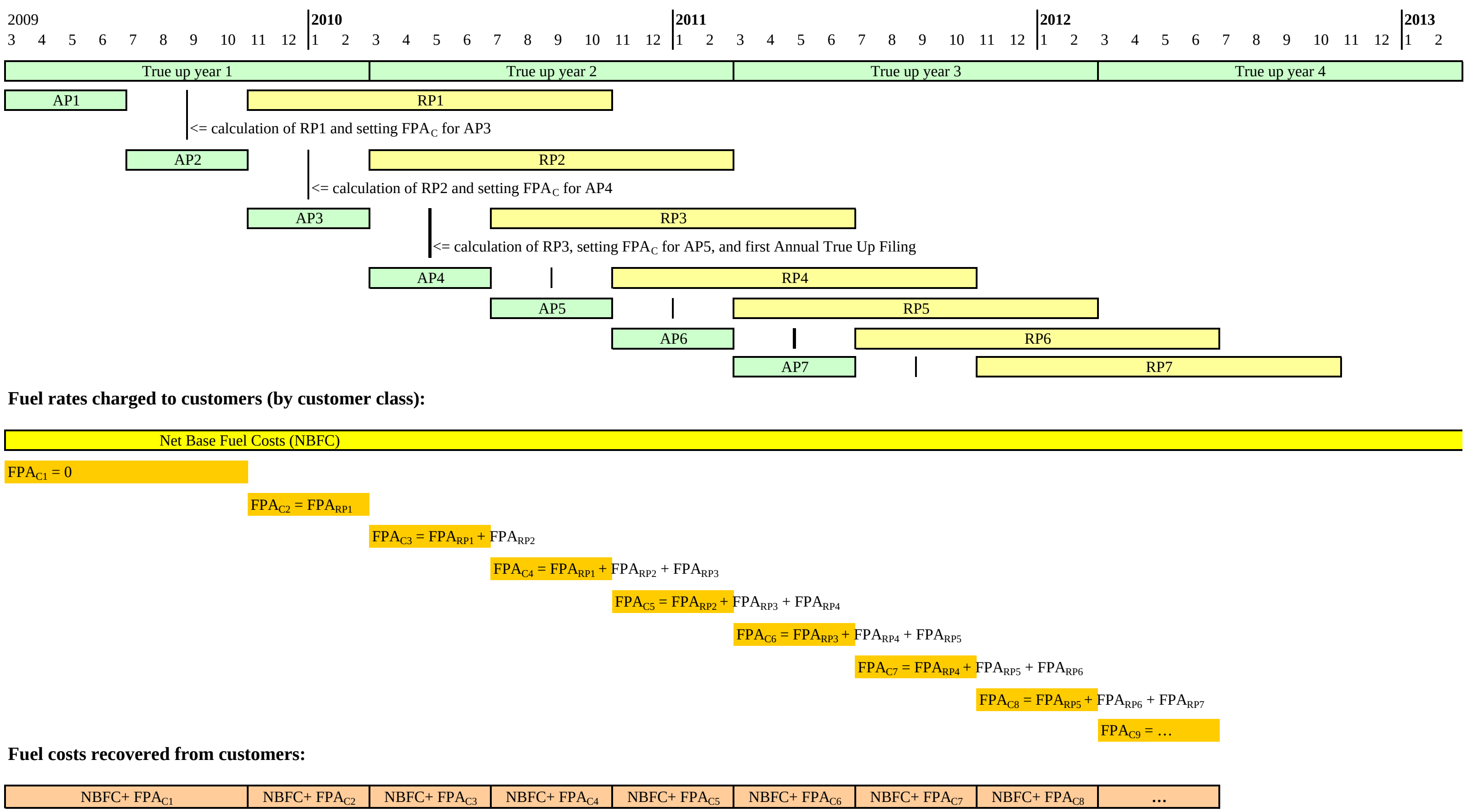


Illustration of Proposed FAC Operation



AP = Accumulation Period
RP = Recovery Period
FPA_C = Fuel and Purchased Power Adjustment Rate

Schedule MJL-E3

MINIMUM FILING REQUIREMENTS

(A) An example of the notice to be provided to customers as required by 4 CSR 240-20.090(2)(D);

NOTICE

AmerenUE has filed revised tariff sheets with the Missouri Public Service Commission (PSC) which would increase the company's electric service revenues by approximately $250.8 million. For the average residential customer the proposed increase would be approximately $8.66 per month. AmerenUE's rate filing includes a request to implement a fuel adjustment clause. A fuel adjustment clause, if approved by the Commission, would allow 95% of the net increases or decreases in fuel and purchased power costs less off-system sales revenues occurring after base electric rates are set by the pending rate case to be passed through to customers as a separate line on customer's bills. Ninety-five percent of the increases in net fuel and purchased power costs less off-system sales revenues above base electric rates would be applied to customer bills via a separate and additional charge and 95% of the net decreases would be applied to customer bills via a separate credit.

Public comment hearings have been set before the PSC as follows:

[To be determined by the Commission]

If you are unable to attend a live public hearing and wish to make written comments or secure additional information, you may contact the Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102, telephone (573) 751-4857, email opcservice@ded.mo.gov or the Missouri Public Service Commission, Post Office Box 360 Jefferson City, Missouri 65102, telephone 800-392-4211, email pscinfo@psc.mo.gov. The Commission will also conduct an evidentiary hearing at its offices in Jefferson City during the weeks of __________ through __________, beginning at _____ a.m. The hearings and local public hearings will be held in buildings that meet accessibility standards required by the Americans with Disabilities Act.

If a customer needs additional accommodations to participate in these hearings, please call the Public Service Commission's Hotline at 1-800-392-4211 (voice) or Relay Missouri at 711 prior to the hearing.

The above notice is very similar (except for the figures included therein, deletion of references to a natural gas case, and deletion of hearing dates and locations) to the notice approved by the Commission in the Company's last rate proceeding (Case No. ER-2007-0002). The Company requests the Commission to adopt the same.

(B) An example customer bill showing how the proposed RAM shall be separately identified on affected customers' bills in accordance with 4 CSR 240-20.090(8);

Attached hereto are two different examples of customer bills (one in the postcard format used by AmerenUE for residential customers and one in the billing format used by AmerenUE for non-residential customers), as required by 4 CSR 240-20.090(8).

See Attachments A and B hereto.

(C) Proposed RAM rate schedules;

Attached to the testimony to which this Schedule is attached as Schedule MJL-1 is Rider FAC - Fuel and Purchased Power Adjustment Clause, which is the proposed rate schedule for the fuel adjustment clause proposed by AmerenUE.

(D) A general description of the design and intended operation of the proposed RAM;

As discussed in the testimony to which this Schedule is attached, AmerenUE is proposing the implementation of a Fuel and Purchased Power Adjustment Clause falling within the definition of a fuel adjustment clause or “FAC” as defined in 4 CSR 240-20.090(1)(C). The FAC applies to all rate classes, and would reflect increases or decreases in fuel, transportation and purchased power costs, including transportation, net of off-system sales revenues, according to the formula expressed in the rate schedule referred to in item (C) above. Historic fuel, transportation and purchased power costs, including transportation, net of off-system sales revenues, would be accumulated during three different Accumulation Periods, as designated in the rate schedule, and then 95% of the change in fuel costs would be recovered (if an increase) or credited (if a decrease) using the calculated FPA_c (as defined in the rate schedule) over three different Recovery Periods (also designated in the rate schedule), each of which covers a period of 12 months. The FPA_c would be applied to customer bills on a per kilowatt-hour (kWh) basis, as adjusted for voltage level (to take into account varying line losses at different service voltage levels).

The FPA formula includes a factor to accommodate adjustments made as a result of the true-up process or any disallowances occurring as a result of prudence reviews. It also includes a factor to accommodate a reduction in fuel costs to account for the value of the Taum Sauk Plant.

(E) A complete explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity;

AmerenUE’s proposed FAC is reasonably designed to provide AmerenUE with a sufficient opportunity to earn a fair return on equity with respect to its fuel costs for several reasons. First, the proposed FAC provides for full and timely recovery of 95% of the changes in AmerenUE’s fuel, transportation, and purchased power costs, including transportation, net of off-system sales revenues, by reflecting increases and decreases in such costs in rates. The 5% of changes not passed through the FAC provides the Company with additional incentives to manage fuel and purchased power costs, but still provides recovery of 95% of those costs. Full and timely recovery of 95% of those costs is based upon the assumption that an appropriate level of costs for fuel and purchased power, including transportation, net of off-system sales, will be set in base rates based upon these costs in the test year, as updated and trued-up in the rate case, and it also assumes appropriate base rate recovery of other cost of service items. With the FAC, it is more likely that fuel and purchased power costs, which are often times much more significant, volatile, uncertain and much more difficult to control than other utility costs, will be timely and fairly reflected in the rates charged to customers. Examples of factors that can often make these very large but critical costs highly volatile, uncertain and beyond the utility's control include the fact that fuel and purchased power is purchased on national and international markets which are subject to increasing volatility due to global demand, increased trading activities, world events, weather (e.g. hurricanes), abnormally hot or cold weather, or other factors. Another example of a factor causing volatility is the potential for rail disruptions, as seen in the recent past. Second, an FAC assists in addressing the relentlessly increasing, volatile and uncertain fuel costs incurred by the Company in providing service for its customers. Third, an FAC will put AmerenUE on comparable footing with utilities operating in other states, the vast majority of which utilize rate adjustment mechanisms, including 85 of 94 utilities (90%) operating in other non-restructured states that have an FAC. Moreover, it will put AmerenUE on equal footing with nearly all – 26 of 27 -- coal-fired utilities in the Midwest that operate with an FAC, including 17 of 17 whose state utility commissions had the discretion to approve or not approve an FAC. Fourth, the proposed FAC is reasonably designed to provide AmerenUE with a sufficient opportunity to earn a fair return on equity because it mitigates the very significant regulatory lag which is prevalent when dealing with such large, uncertain and often volatile costs, by preventing deterioration in the utility's financial position (including relative credit standing, which is a key determinant of borrowing costs), particularly in the face of the known fuel cost increases facing the Company, and by ensuring recovery of actual net fuel and purchased power costs which may vary from expected levels substantially.

(F) A complete explanation of how the proposed FAC shall be trued-up to reflect over- or under-collections, or the refundable portion of the proposed IEC shall be trued-up, on at least an annual basis (This Item (F) is also addressed in the direct testimony of AmerenUE witness Paul W. Mertens);

The FAC will be trued-up on an annual basis after the completion of each true-up year, commencing after the end of the first true-up year. True-up filings will continue annually until all fuel costs accumulated and deferred have been recovered and trued-up. Any true-up adjustments will include interest, as provided for in the FAC tariff.

True-up amounts will reflect the difference between revenues billed for fuel costs authorized for recovery under the FAC for the true-up year and revenues authorized for collection. Actual collections can vary from those billed based upon actual fuel costs because of variations in the actual kilowatt-hour ("kWh") sales during a given recovery period versus the estimated kWh sales used to set the FAC rate in effect during a given recovery period.

(G) A complete description of how the proposed RAM is compatible with the requirement for prudence reviews (This Item (G) is also addressed in Mr. Mertens' testimony);

AmerenUE's proposed FAC is compatible with the requirement for prudence reviews for several reasons. AmerenUE's proposed FAC is based on actual, historical fuel and purchased power costs, including transportation, net of actual off-system sales revenues, which simplifies the prudence review. The fuel and purchased power costs included in the FAC are well defined in Rider FAC (the FAC tariff), including specific references to the FERC accounts in which the costs are recorded. Moreover, 4 CSR 240-3.161(5) requires the filing monthly of all the supporting data for the fuel and purchased power costs, revenues, plant generation and related information, all of which can be used as part of the prudence review process. This includes providing monthly Fuel Burned Reports and Generating Statistics for each of the generating plants. In addition, 4 CSR 240-3.190 requires monthly submission to the Commission Staff of information on system output, hourly generation, purchases and sales, planned outages, forced outages and capacity purchases. All contracts for fuel, transportation and purchased power will also be available for review in connection with the prudence review process.

(H) A complete explanation of all the costs that shall be considered for recovery under the proposed RAM and the specific account used for each cost item on the electric utility's books and records (This Item (G) is also addressed in Mr. Mertens' testimony).

These costs are generally described as follows:

Coal Commodity Costs. This will include costs associated with purchase of coal, as well as British thermal unit ("Btu") content adjustments associated with coal contracts. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the coal inventory account and allocation of dollars to each plant through the coal pooling mechanism will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Coal Transportation Costs. This will include costs associated with transportation of coal, as well as fuel adjustments (e.g., diesel surcharges) associated with transportation contracts and price hedging mechanisms. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as coal is used. A detailed accounting of all additions and adjustments to the coal inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period. Railcar costs are included in this account, and a separate accounting of all railcar costs flowing through inventory will be maintained as well as the allocation of costs to plant inventory accounts.

Fuel Oil Costs. This will include costs associated with fuel oil and any price hedging mechanisms. These costs are accumulated in an inventory account, and expensed on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the fuel oil inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Natural Gas Costs. This will include costs associated with the gas commodity, storage, reservation, transportation, hedging costs and oil costs associated with gas-fired plants. A detailed accounting of all additions and adjustments to inventory will be included in a reconciliation, including the calculation of fuel expenses recorded during the accounting period.

Water for Power. Details of water purchased for hydraulic power generation will be included in a reconciliation.

Nuclear Fuel Costs. This will include costs associated with nuclear fuel. These costs are accumulated in inventory accounts under FERC Account 120, and amortized on a weighted average cost basis as used. A detailed accounting of all additions and adjustments to the inventory account will be included in a reconciliation, as well as the calculation of the fuel expense recorded during the accounting period.

Cost of Purchased Power. This will include the cost at the point of receipt by the Company of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, this category will include costs incurred from regional transmission organizations (“RTOs”) for Revenue Sufficiency Guarantee, Losses, deviation charges, revenue neutrality and inadvertent charges, but shall exclude MISO administrative costs arising under MISO Schedules 10, 16, 17 and 24, and shall exclude capacity charges under contracts with a term in excess of one (1) year. [Also included are insurance premiums in FERC Account Number 924 for replacement power insurance (other than relating to the Taum Sauk Plant) to the extent those premiums are not reflected in base rates.]

The following table summarizes this information by account:

Type of Cost	Inventory Major	Expense Major	Description
Coal Commodity	151	501	Cost of coal delivered at the mine
Applicable Taxes	151	501/547/518	Applicable taxes on fuel and transportation costs
Btu adjustments	151	501	Added/subtracted amounts to coal contracts for Btu content of coal
Railroad, truck and barge transportation	151	501	Costs associated with delivering coal from mine to plant

Switching & Demurrage	151	501	Costs associated with switching and demurrage costs incurred in delivering coal from the mine to the plant
Railcar repair	151	501	All railcar costs will be aggregated in a separate minor account under major Account No. 151. As part of the monthly closing process, these costs will be allocated to transportation inventory at the plants based on tonnage delivered during the period.
Railcar depreciation	151	501	
Railcar leases	151	501	
Railcar inspection	151	501	
Heating Oil Hedge costs/ revenues	151	501	Costs/revenues associated with price hedges related to diesel fuel adjustments in coal transportation contracts
Hedge costs associated with coal	151	501	Costs/revenues associated with price swaps, options, or other derivatives to manage fuel costs
Commissions and fees	151	501	Broker costs and commissions associated with hedging activities of coal commodity and transportation
Oil	151	501/547	Costs associated with fuel oil used at plants for generation
Nuclear Fuel	120	518	Costs associated with nuclear fuel, including provisions for transportation, storage and disposal of nuclear fuel including spent fuel disposal fees, and handling costs for nuclear fuel assemblies.
Water for Power	Expensed	536	Costs associated with water used for hydraulic power generation
Fuel costs	151/direct expense	547	Delivered cost of gas, oil, propane, and other fuels used in other power generation
Ash Disposal Costs	Direct Expense	501	Cost to dispose of ash, net of ash revenues
Other Portfolio optimization activities	151	501/547	Revenues and expenses related to selling excess coal or natural gas and other portfolio optimization activities
Purchased Power Costs		555, 565, and 575	Cost of purchased power, but excluding MISO administrative costs under MISO Schedules 10, 16, 17 and 24, and excluding capacity charges under contracts with a term in excess of one (1) year. [Also included are insurance premiums in FERC Account Number 924 for replacement power insurance (other than relating to the Taum Sauk Plant) to the extent those premiums are not reflected in base rates.]

(I) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed RAM and the specific account where each such revenue item is recorded on the electric utility's books and records (This Item (G) is also addressed in Mr. Mertens' testimony);

Description	Major	Comments
Off-System Sales	447	All sales transactions (excluding retail sales or long-term full or partial requirements sales to non-jurisdictional customers) that are associated with (1) AmerenUE Missouri jurisdictional generating units and (2) power purchases made to serve Missouri retail including any associated transmission.
Coal Sales	151	Revenues from coal sales
Coal and Transportation Fuel Hedges	151	Revenues associated with price swaps and other hedges related to coal contracts and Fuel for Transportation adjustments
Railcar leases	151	Transportation costs reduced by revenue from lease of company owned/leased railcars to other companies
Gas Sales	151/547	Revenues and expenses associated with hedging activities and gas portfolio optimization
Ash Sales	501	Sales of fly ash and other types of ash produced at plants
Replacement Power Insurance Recoveries	555	Replacement power insurance recoveries, except recoveries relating to the Taum Sauk Plant.

(J) A complete explanation of any incentive features designed in the proposed RAM and the expected benefit and cost each feature is intended to produce for the electric utility's shareholders and customers;

AmerenUE's proposed FAC contains the same FAC-specific incentive feature the Commission included in the FAC approved for Aquila, Inc. in Case No. ER-2007-0004. The FAC incentive feature is symmetrical. That is, 95% of increases or decreases in net fuel costs are passed through the FAC. If net fuel costs increase (because of, for example, the increases the Company will experience in delivered coal costs) customers will benefit by not bearing 5% of those increases. If fuel costs were to decrease (because of, for example, higher off-system sales revenues), customers would receive 95% of the decrease. Customers benefit because of the incentive to mitigate fuel cost increases and optimize off-system sales revenues created by the fact that the Company will simply not recover 5% of the increase in net fuel costs.

(K) A complete explanation of any rate volatility mitigation features designed in the proposed RAM;

AmerenUE's proposed FAC spreads the recovery of the difference between the base fuel costs set in the rate proceeding and fuel costs during each Accumulation Period over a full 12-month period. This has a mitigating effect on rate increases or decreases that will occur as a result of the three periodic FAC adjustments each year. Moreover, as discussed in Item (L) below, AmerenUE utilizes a hedging strategy designed to mitigate fuel cost volatility.

(L) A complete explanation of any feature designed into the proposed RAM or any existing electric utility policy, procedure, or practice that can be relied upon to ensure that only prudent costs shall be eligible for recovery under the proposed RAM;

In addition to keeping books and records relating to fuel, transportation and purchased power in accordance with Generally Accepted Accounting Principles and the Uniform System of Accounts, AmerenUE employs a number of policies, procedures and practices, including the use of internal audits where appropriate, to ensure the prudency of such costs. Described below are relevant policies, procedures and practices.

Fuel Accounting

In order to ensure proper accounting for coal, gas, and nuclear fuel costs, the following procedures and practices are in place.

Coal. A trainbook is maintained by the coal supply and fuel accounting group. This database maintains information relating to all contracts, and deliveries scheduled and received against each contract. Fuel accounting enters invoice information into a database, and ensures that all coal paid for was contracted for, received by the plant, and that the invoice amount agrees with the contracted amount. This trainbook also calculates quality standards, and Btu and SO_2 adjustments (which are dealt with in the separate tracking mechanism implemented in the Company's last rate proceeding) are accrued for based on receipts and trued-up with actual invoices. This database is a critical tool in the month-end accrual process, to ensure that all coal commodity, transportation, and quality adjustment costs have been accrued in the proper period. All inventory, receivable, and payable accounts associated with coal are balanced on at least a quarterly basis.

Gas. Gas supply executives prepare a month-end estimated gas cost worksheet for AmerenUE's generating units. Current month estimates, plus a true-up of prior month actuals versus estimates, are recorded in the current month. All inventory, receivable, and payable accounts associated with gas are balanced on at least a quarterly basis.

Nuclear Fuel. Nuclear fuel expenses and month end balances are calculated in the nuclear fuel accounting system called Surf'n, which is maintained by the nuclear fuel procurement group. All accounts charged in the general ledger are balanced with the nuclear fuel system on at least a quarterly basis.

Fuel Procurement

Fossil (e.g., coal and natural gas): To ensure fuel purchases are prudent, the fuel acquisition for AmerenUE's generation is governed by the AmerenEnergy Fuels and Services Company (AFS) Risk Management Policy. The rules and guidelines within the Policy, which were approved by Ameren's Risk Management Steering Committee, identify the levels of coal and natural gas for generation that must be acquired and hedged for future periods, identifies the various types of allowable commodity transactions, and creates extensive management reporting to monitor all commodity transactions and price positions. The Policy provides that coal and natural gas be purchased using a risk management strategy that secures the required volume for future periods within maximum and minimum policy limits while reducing exposure to market volatility. The volumetric risk (securing the necessary quantities of fuel needed for electricity production) and price risk (entering into financial and physical transactions to hedge against price spikes and volatility in the market) for generation fuels are controlled through compliance with the Policy procurement limits. These limits create maximum and minimum levels of volumetric and price hedging for up to six years into the future to ensure disciplined acquisition of fuel and to diversify price risk over time. Purchasing fuel under these procurement limits provides several benefits, including avoiding the need to purchase large quantities of fuel during periods of price spikes, and ensuring that sufficient quantities are purchased in advance of actual need to minimize any physical shortage that might occur in the fuel markets. These limits do not necessarily result in the lowest possible price for fuel, but strike a balance between price stability and security of supply. In addition to the Risk Management Policy, there are annual fuel supply planning processes which determine the actual acquisition of fuel for generation needs from various production basins and other parameters of fuel supply including transportation, inventory levels, management of inventory levels through purchases and sales, and logistics with power plants/power traders/generation dispatchers. These processes also encompass the development of competitive or alternative transportation methods between transportation providers to ensure competitive and reliable fuel supply. To ensure competitive fuel supply in the commodity markets, the fuel is procured and hedged through several diverse methods including periodic competitive bids, negotiated purchases, electronic trading, Over-the-Counter (OTC) transactions, futures market transactions, and spot market transactions. In addition to the Risk Management Policy and fuel planning processes, the Internal Audit Department conducts routine audits of fuel supply on a three year cycle for purposes of reporting to senior executives and the Board of Directors. Fuel for generation is purchased by AFS, which is staffed with full-time fuel professionals to manage all aspects of fuel supply and operations with a mission of delivering reliable and competitive fuel supply for all Ameren affiliated companies, including AmerenUE.

Nuclear: To ensure nuclear fuel purchases are prudent, AmerenUE follows a number of corporate procurement practices (as outlined below), including a specific Nuclear Fuel Risk Management Policy approved by the Ameren Risk Management Steering Committee, and a Nuclear Procedure for Nuclear Fuel Contracts. These practices and policies provide very similar controls to those described above relating to procurement of fossil fuels. The foregoing practices, policies and procedures are designed to: i) ensure a reliable supply of nuclear fuel to the Callaway Plant, ii) effectively manage nuclear fuel costs, iii) reduce AmerenUE's exposure to nuclear fuel price volatility, iv) mitigate risks related to nuclear fuel, and v) provide highly reliable nuclear fuel to the Callaway Plant. Nuclear fuel is procured using several processes. AmerenUE utilizes long-term contracts to ensure nuclear fuel is available for Callaway requirements. In addition, inventories of nuclear fuel are maintained to enhance security of supply. AmerenUE also continually monitors market assessments of nuclear fuel supply and demand, price forecasts, and projections of Callaway fuel requirements. This monitoring is an integral part in the continued review of procurement plans. Price and non-price elements, such as reliability of supply, supplier diversity, quality and quantity must also be balanced. In appropriate instances, nuclear fuel procurements are also made through competitive bidding, with all qualified suppliers solicited (however, depending upon the need, in some instances only 2-3 suppliers may be available). Moreover, while the nuclear fuel supply market is worldwide, other than the uranium supply component itself, there are limited suppliers for the other components of the nuclear fuel cycle. With the excellent operating performance of existing plants, and the announced plans for new units, supplies of nuclear fuel have also tightened.

Nuclear fuel procurement is also under the direction and control of a full-time professional in nuclear fuel procurement to manage all aspects of nuclear fuel supply and operations.

(M) A complete explanation of the specific customer class rate design used to design the proposed RAM base amount in permanent rates and any subsequent rate adjustments during the term of the proposed RAM;

The proposed FAC applies the FPA_c to all of AmerenUE's Missouri electric retail customers (*see* Schedule No. 5 - Schedule of Rates for Electric Service customers). To the extent fuel and purchased power costs are included in base rates, the class cost of service study results discussed in the direct testimony of AmerenUE witness William Warwick is applied and the rate design discussed in the direct testimony of AmerenUE witness Wilbon C. Cooper is also applied. With regard to the proposed RAM amount in base rates, a level of 0.837 cents per kilowatt-hour at the generation level is included in Rider FAC as filed. Adjustments to the rates for each class will be performed in accordance with the formula reflected in Rider FAC and will be reflective of changes in the factors included in the formula versus the values used to determine the RAM amount in base rates. The adjustments reflect a calculation of the FPA_c based on test year costs and sales consistent with the factors included in the FPA_c formula in Rider FAC. Actual customer FPA_c adjustments will be applied to all retail billings for electric service on a per kilowatt-hour basis, as adjusted for losses based on the customers' service voltage (secondary, primary, large transmission service).

(N) A complete explanation of any change in business risk to the electric utility resulting from implementation of the proposed RAM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility (This Item (N) is also addressed in the direct testimony of AmerenUE witness Professor Roger Morin);

The implementation of a fuel adjustment mechanism (the proposed RAM) would allow AmerenUE to pass through to its customers increases and decreases in net fuel costs without the need for a costly and time-consuming rate proceeding necessitated by changes in fuel costs and off-system sales revenues. In recent years, the lack of a fuel adjustment mechanism in Missouri has been a major concern to the financial community because fuel costs have been highly volatile. Because fuel adjustment clauses predominantly are part of the regulation of other U.S. utilities, implementing a fuel adjustment mechanism will make the business risk of AmerenUE significantly more comparable to the risks of other utilities. Without a fuel adjustment mechanism, the business risk of AmerenUE would be higher than that of other utilities, all else being equal. However, since most of the electric utilities used in the sample groups of comparable companies in AmerenUE's cost of equity studies are able to recover their fuel costs through fuel adjustment clauses, the reduced risk of implementing the proposed RAM in Missouri is already reflected in AmerenUE's base cost of equity recommendation (10.9%) in this case. As Professor Morin indicates, however, if AmerenUE is not authorized to utilize Rider FAC, AmerenUE's business risk and resulting cost of capital is greater, resulting in a cost of equity of 11.15%.

(O) The supply side and demand side resources that the electric utility expects to use to meet its loads in the next four (4) true-up years, the expected dispatch of those resources, the reasons why these resources are appropriate for dispatch and the heat rates and fuel types for each supply-side resource; in submitting this information, it is recognized that supply and demand-side resources and dispatch may change during the next four (4) true-up years based upon changing circumstances and parties will have the opportunity to comment on this information after it is filed by the electric utility (This Item (O) is also addressed in the direct testimony of AmerenUE witness Timothy D. Finnell);

Attachment C to this Schedule lists the supply side resources expected to meet the AmerenUE load requirements for the periods March 1, 2009 to February 29, 2010, March 1, 2010 to February 28, 2011, March 1, 2011 to February 29, 2012, and March 1, 2012 to February 28, 2013. The data in 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 they were developed from a detailed production cost model run for the true up periods. 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, transportation and purchased power costs and off-system sales. 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.

(P) A proposed schedule and testing plan with written procedures for heat rate tests and/or efficiency tests for all of the electric utility's nuclear and non-nuclear generators, steam, gas, and oil turbines and heat recovery steam generators ("HRSG") to determine the base level of efficiency for each of the units (This Item (O) is also addressed in AmerenUE witness Mark C. Birk's direct testimony);

With very limited exceptions for older combustion turbine units ("CTGs") that are run very infrequently each year, AmerenUE uses real-time performance monitoring systems on its generating units. The performance monitoring systems allow AmerenUE to continuously track and record generator output, heat rates, and controllable parameters. Plant operators use this real time performance information to continuously optimize the heat rates of the AmerenUE fossil units by making the necessary operational adjustments. This information also allows AmerenUE to use data from a much longer and more representative time period to establish a baseline heat rate for each unit, which in turn allows the Company to track the efficiency of the units

Sample performance monitoring reports for the Callaway nuclear plant, one of the Company's coal-fired base load units, and one of the Company's gas-fired CTG units are attached to Mr. Birk's direct testimony as Schedule MCB-E1. The data obtained from the performance monitoring system as shown in the sample monitoring reports in Schedule MCB-E1 has been converted into a heat rate curve and an input/output curve for those same units attached to Mr. Birk's testimony as Schedule MCB-E2.

Mr. Birk's Schedule MCB-E3 (also attached here as Attachment D) lists the AmerenUE units and the type of performance monitoring system currently in use for each unit. As noted in Attachment D, there are a few units for which performance monitoring systems are not in place, all of which are older CTGs that are run very, very infrequently each year. The combined generation for these units was just 0.01% of the total nuclear, coal, natural gas, and oil generation for 2007. Because these units are such a small portion of AmerenUE's generation, the cost of performance monitoring systems for these units is not justified by the benefit of monitoring these systems more closely. For these units, AmerenUE uses accounting records to determine the heat rates. Procedures for each type of plant (nuclear, coal-fired, CTG) are attached to Mr. Birk's testimony as Schedule MCB-E4.

As shown in the last column of Attachment D, testing will be done annually. In general, the baseline heat rate test data will done in December for the nuclear and coal-fired units, and in August for the CTGs. If the unit is out of service or there was not enough run time in those months, data from an earlier month may be substituted. However, this period will not be used for the CTGs because of the limited amount of generation during December. Since CTG generation typically occurs during the summer time period, the summer month of August was selected as the appropriate baseline period for CTGs. It should be noted that real time heat rates typically vary throughout the year based upon ambient conditions, thus a comparison in heat rate between cooler and warmer months would not be valid.

(Q) Information that shows that the electric utility has in place a long-term resource planning process, important objectives of which are to minimize overall delivered energy costs and provide reliable service;

On February 5, 2008, AmerenUE made its most recently required Integrated Resource Plan (IRP) filing, reflecting that an important objective of AmerenUE's IRP process is to minimize overall delivered energy costs (i.e. least cost planning) and provide reliable service. This filing covers AmerenUE's long-term resource planning process and consisted of multiple volumes. AmerenUE's IRP filing reflected least cost analyses for a number of resource options and portfolios, and also examined the Company's capacity position and needs in detail. This information included AmerenUE's load forecasts as well as its analysis of available supply-side and demand-side resources. The end result is a twenty year resource plan, called the Integrated Resource Plan. AmerenUE's filing was made in compliance with 4 CSR 240-22.010, et. seq. This very comprehensive Commission rule is designed to insure utilities provide energy services which "…are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest." 4 CSR 240-22.010(2).

(R) If emissions allowance costs or sales margins are included in the RAM request and not in the electric utility's environmental cost recovery surcharge, a complete explanation of forecasted environmental investments and allowances purchases and sales;

Emissions allowance costs or sales margins are not included in the proposed FAC.

(S) Authorization for the commission staff to release the previous five (5) years of historical surveillance reports submitted to the commission staff by the electric utility to all parties to the case.

Mr. Lyons's testimony to which this schedule is attached includes authorization for the Commission Staff to release the previous five (5) years of historical surveillance reports submitted to the Commission Staff to all parties in the case.

ATTACHMENT A

68341	67852	489	ACTUAL	1M	34.73
RIDER FAC ADJUSTMENT					0.49

FIRST CLASS MAIL
U.S. POSTAGE
PAID 1 OUNCE
ST. LOUIS, MO
PERMIT NO. 2859

Service at:	XXX MAIN ST		
Service from	01/15 to 02/14/08		Days 30
Last Payment		01/28/08	$38.53
Acct. No	12345-67890	Bill Date	02/19/08

AMOUNT DUE ON 02/29 35.22

JOHN XXXXXX
XXX MAIN ST
SAINT LOUIS, MO 63101

Acct. No. **12345-67890**

AMT DUE	$35.22
Due By	02/29
Delinquent By	03/11

AmerenUE **CUSTOMER SERVICE BULLETIN** AmerenUE

You're in control with Budget Billing. Your energy payments are predictable. Avoid surprises, and gain peace of mind. Mark an "X" in the box to enroll in Budget Billing.

DOLLAR MORE is a year-round program that helps needy families survive. To give just a dollar more a month with your payment, please mark an "X" in the box.

AMOUNT DUE	**$35.22**
DUE BY	**02/29**

JOHN XXXXXX

XXX MAIN ST

Acct. No **12345-67890**

Amount Enclosed $ ____________

0010000 0012345678900 00000000 00000000 00035220

Schedule MJL-E4
Attachment A-2

Please Return This Portion With Your Payment

AmerenUE

AMOUNT DUE	DUE DATE
$3,387.42	March 19, 2008
AMOUNT PAYABLE AFTER DUE DATE	ACCOUNT NUMBER
$3,438.23	12345-67890

Amount Enclosed $ ________________

XXXXXX CORPORATION
XXX MAIN ST
ST LOUIS, MO 63110

AmerenUE
P. O. Box 66301
St. Louis, MO 63166-6301

80600000 001234567890O 000003387420 000003387420

Keep This Portion For Your Records

ACCOUNT NUMBER	12345-67890	BILL DATE	March 8, 2008
NAME	XXXXXX CORPORATION		
SERVICE AT	XXX MAIN ST ST LOUIS, MO 63110		

TOTAL AMOUNT DUE BY	March 19, 2008	$3,387.42
AMOUNT PAYABLE AFTER DUE DATE		$3,438.23

TYPE OF READING	METER NUMBER	SERVICE FROM TO	NO. DAYS	METER READING PREVIOUS	METER READING PRESENT	READING DIFFERENCE	METER MULTIPLIER	THERM FACTOR	USAGE	R D
Total KWH	01234567	02/05-03/05	29	60677.0000	61292.0000	615.0000	120.0000		73800.0000	A
Peak KW	01234567	02/05-03/05	29	0.0000	1.1440	1.1440	120.0000		137.2800	A

SUMMARY

	Service To			Service To	
Total KWH	03/05/2008	73800.0000	Peak KW	03/05/2008	137.3000
Total Billing Demand	03/05/2008	137.3000	October Winter Base kW	03/05/2008	122.3000
Base KWH Ratio	03/05/2008	0.8907	Winter Base Demand	03/05/2008	122.3000
Seasonal KWH (HUD)	03/05/2008	8066.0000	Base KWH (HUD)	03/05/2008	65734.0000

METERED ELECTRIC SERVICE BILLING

Rate 3M LGS - General Service **Service From 02/05/2008 To 03/05/2008**

Seasonal Energy Charge	8,066.00	KWH	@	$0.02760000	$222.62	
Demand Charge	137.30	KW	@	$1.30000000	$178.49	
Base Energy Charge/ Hours Used	18,345.00	KWH	@	$0.04730000	$867.72	
Base Energy Charge/ Hours Used	24,460.00	KWH	@	$0.03510000	$858.55	
Base Energy Charge/ Hours Used	22,929.00	KWH	@	$0.02760000	$632.84	
Rider FAC Adjustment	73,800.00	KWH	@	$0.00100000	$73.80	
Customer Charge					$67.11	
Total Service Amount						$2,901.13
Missouri State Sales Tax					$89.49	
Missouri Local Sales Tax					$74.46	
St. Louis City Municipal Charge					$322.34	
Total Tax Related Charges						$486.29

Current Amount Due	$3,387.42
Prior Amount Due	$0.00
Total Amount Due	$3,387.42

A late payment charge of 1.5% will be added for any unpaid balance on all accounts after the due date.

AmerenUE
P. O. Box 66301
St. Louis, MO 63166-6301
1-877-4AMEREN
www.ameren.com

Unit Name	Ownership	Primary Fuel Type	Heat Rate 12 m Avg Rating Btu/Kwh	12 Month Generation Data x 1,000 MWH 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 MJL-E4
Attachment C

Performance Monitoring Systems

Unit Name	12 Month Avg Net	Primary Fuel Type	Performance Monitoring Systems[1]	Data Archive System[1]	2007 Net Generation	% of 2007 Annual Generation	Baseline Heat Rate Testing Date	Heat Rate Testing Interval
Callaway	1,220	Nuclear	eDNA	eDNA	9,371,955	18.6%	Dec-08	12 months
Labadie 1	607	PRB Coal	EtaPRO/OPM	PI	4,604,520	9.2%	Dec-08	12 months
Labadie 2	596	PRB Coal	EtaPRO/OPM	PI	4,757,616	9.5%	Dec-08	12 months
Labadie 3	611	PRB Coal	EtaPRO/OPM	PI	4,680,336	9.3%	Dec-08	12 months
Labadie 4	611	PRB Coal	EtaPRO/OPM	PI	4,875,570	9.7%	Dec-08	12 months
Rush 1	600	PRB Coal	EtaPRO/OPM	PI	2,780,515	5.5%	Dec-08	12 months
Rush 2	592	PRB Coal	EtaPRO/OPM	PI	4,236,129	8.4%	Dec-08	12 months
Sioux 1	499	PRB /ILL Coal	EtaPRO/OPM	PI	3,284,409	6.5%	Dec-08	12 months
Sioux 2	503	PRB /ILL Coal	EtaPRO/OPM	PI	3,358,939	6.7%	Dec-08	12 months
Meramec 1	124	PRB Coal	EtaPRO/OPM	PI	910,461	1.8%	Dec-08	12 months
Meramec 2	125	PRB Coal	EtaPRO/OPM	PI	873,483	1.7%	Dec-08	12 months
Meramec 3	264	PRB Coal	EtaPRO	PI	1,810,654	3.6%	Dec-08	12 months
Meramec 4	355	PRB Coal	EtaPRO/OPM	PI	2,289,658	4.6%	Dec-08	12 months
Audrain CT 1	78	Gas	PI	PI	5,669	0.0%	Aug-08	12 months
Audrain CT 2	78	Gas	PI	PI	11,739	0.0%	Aug-08	12 months
Audrain CT 3	78	Gas	PI	PI	10,986	0.0%	Aug-08	12 months
Audrain CT 4	78	Gas	PI	PI	10,600	0.0%	Aug-08	12 months
Audrain CT 5	78	Gas	PI	PI	7,715	0.0%	Aug-08	12 months
Audrain CT 6	78	Gas	PI	PI	7,356	0.0%	Aug-08	12 months
Audrain CT 7	78	Gas	PI	PI	5,536	0.0%	Aug-08	12 months
Audrain CT 8	78	Gas	PI	PI	5,152	0.0%	Aug-08	12 months
Fairgrounds CT	58	Oil	----	----	471	0.0%	Aug-08	12 months
Goose Creek CT 1	76	Gas	PI	PI	21,701	0.0%	Aug-08	12 months
Goose Creek CT 2	76	Gas	PI	PI	20,563	0.0%	Aug-08	12 months
Goose Creek CT 3	76	Gas	PI	PI	21,405	0.0%	Aug-08	12 months
Goose Creek CT 4	76	Gas	PI	PI	18,663	0.0%	Aug-08	12 months
Goose Creek CT 5	76	Gas	PI	PI	19,081	0.0%	Aug-08	12 months
Goose Creek CT 6	76	Gas	PI	PI	18,467	0.0%	Aug-08	12 months
Howard Bend CT	45	Oil	----	----	22	0.0%	Aug-08	12 months
Kinmundy CT 1	110	Gas	PI	PI	8,485	0.0%	Aug-08	12 months
Kinmundy CT 2	110	Gas	PI	PI	9,218	0.0%	Aug-08	12 months
Kirksville CT	13	Gas	----	----	10	0.0%	Aug-08	12 months
Meramec CT 1	59	Oil	----	----	255	0.0%	Aug-08	12 months
Meramec CT 2	58	Gas	----	----	4,584	0.0%	Aug-08	12 months
Mexico CT	58	Oil	----	----	667	0.0%	Aug-08	12 months
Moberly CT	58	Oil	----	----	-132	0.0%	Aug-08	12 months
Moreau CT	58	Oil	----	----	-297	0.0%	Aug-08	12 months
Peno Creek CT 1	47	Gas	PI	PI	44,850	0.1%	Aug-08	12 months
Peno Creek CT 2	47	Gas	PI	PI	42,382	0.1%	Aug-08	12 months
Peno Creek CT 3	47	Gas	PI	PI	43,010	0.1%	Aug-08	12 months
Peno Creek CT 4	47	Gas	PI	PI	39,002	0.1%	Aug-08	12 months
Pinkneyville CT 1	40	Gas	PI	PI	36,147	0.1%	Aug-08	12 months
Pinkneyville CT 2	40	Gas	PI	PI	40,454	0.1%	Aug-08	12 months
Pinkneyville CT 3	40	Gas	PI	PI	40,020	0.1%	Aug-08	12 months
Pinkneyville CT 4	40	Gas	PI	PI	39,156	0.1%	Aug-08	12 months
Pinkneyville CT 5	37	Gas	PI	PI	2,733	0.0%	Aug-08	12 months
Pinkneyville CT 6	37	Gas	PI	PI	3,204	0.0%	Aug-08	12 months
Pinkneyville CT 7	37	Gas	PI	PI	2,741	0.0%	Aug-08	12 months
Pinkneyville CT 8	37	Gas	PI	PI	2,728	0.0%	Aug-08	12 months
Raccoon Creek CT 1	78	Gas	PI	PI	15,170	0.0%	Aug-08	12 months
Raccoon Creek CT 2	78	Gas	PI	PI	13,631	0.0%	Aug-08	12 months
Raccoon Creek CT 3	78	Gas	PI	PI	10,073	0.0%	Aug-08	12 months
Raccoon Creek CT 4	78	Gas	PI	PI	10,326	0.0%	Aug-08	12 months
Venice CT 1	27	Oil	----	----	0	0.0%	Aug-08	12 months
Venice CT 2	50	Gas	PI	PI	39,095	0.1%	Aug-08	12 months
Venice CT 3	173	Gas	PI	PI	111,798	0.2%	Aug-08	12 months
Venice CT 4	173	Gas	PI	PI	126,410	0.3%	Aug-08	12 months
Venice CT 5	110	Gas	PI	PI	20,778	0.0%	Aug-08	12 months
Viaduct CTG	27	Gas	---	---	0	0.0%	Aug-08	12 months
Osage	234				652,891	1.3%		
Keokuk	130				942,357	1.9%		
Taum Sauk	440				0	0.0%		
Totals	**10,586**				**50,321,117**			

Nuclear and Fossil Steam, CTG Generation without Performance Monitors	% of Total Generation
5,580	**0.01%**

Note: 1 eDNA is a product of InStep Software, LLC
EtaPRO is a product of the General Physics Corporation
OPM is a product of Black & Veatch
PI is a product of OSIsoft, Inc.

Summary of Cost Recovery Lag in Fuel Adjustment Clauses for Utilities in Other Non-Restructured States

Utility	State	FAC Rate Based on Historic or Projected Costs	Frequency of Rate Adjustment
Alabama Power Co	AL	Projected	Quarterly
Entergy Arkansas Inc	AR	Projected	Annually
Oklahoma Gas & Electric Co	AR	Projected	Annually
Southwestern Electric Power Co (AEP)	AR	Projected	Annually
Arizona Public Service Co	AZ	Projected	Annually
UNS Electric Inc	AZ	Projected	n/a
Aquila Inc	CO	Historic	Twice per year
Public Service Co of Colorado	CO	Projected	Quarterly
Florida Power & Light Co	FL	Projected	Annually
Florida Public Utilities Co	FL	Projected	Annually
Gulf Power Co	FL	Projected	Annually
Progress Energy Florida	FL	Projected	Annually
Tampa Electric Co	FL	Projected	Annually
Georgia Power Co	GA	Projected	Annually
Savannah Electric & Power Co	GA	Projected	Annually
Hawaiian Electric Co Inc	HI	Projected	Monthly
Maui Electric Co Ltd	HI	Projected	Monthly
Interstate Power & Light Co	IA	Projected	Monthly
Avista Corp	ID	Historic	Annually
Idaho Power Co	ID	Projected	Annually
Duke Energy Indiana	IN	Projected	Quarterly
Indiana Michigan Power Co (AEP)	IN	Projected	Quarterly
Indianapolis Power & Light	IN	Projected	Quarterly
Northern Indiana Public Service Co	IN	Projected	Quarterly
Southern Indiana Gas & Electric Co	IN	Projected	Quarterly
Kansas City Power & Light Co	KS	Projected	Annually, with quarterly updates and rate adjustments
Kansas Gas & Electric Co	KS	Projected	Monthly
Westar Energy Inc	KS	Projected	Monthly
Duke Energy Kentucky	KY	Historic	Monthly
Kentucky Power Co (AEP)	KY	Historic	Monthly
Kentucky Utilities Co	KY	Historic	Monthly
Louisville Gas & Electric Co	KY	Historic	Monthly

Summary of Cost Recovery Lag in Fuel Adjustment Clauses for Utilities in Other Non-Restructured States

Utility	State	FAC Rate Based on Historic or Projected Costs	Frequency of Rate Adjustment
CLECO Power LLC	LA	Historic	Monthly
Entergy Gulf States Inc	LA	Historic	Monthly
Entergy Louisiana Inc	LA	Historic	Monthly
Entergy New Orleans Inc	LA	Historic	Monthly
Southwestern Electric Power Co (AEP)	LA	Historic	Monthly
Allete Inc	MN	Historic	Monthly
Interstate Power & Light Co	MN	Historic	Monthly
Northern States Power Co (Minnesota)	MN	Projected	Monthly
Otter Tail Power Co	MN	Historic	Monthly
Entergy Mississippi Inc	MS	Projected	Quarterly
Mississippi Power Co	MS	Projected	Annually
NorthWestern Corp	MT	Projected	12 month projection, updated each month
Duke Energy Carolinas	NC	Projected	Annually
Progress Energy Carolinas	NC	Projected	Annually
Virginia Electric & Power CO	NC	Projected	Annually
MDU Resources Group Inc	ND	Historic	Monthly
Northern States Power Co (Minnesota)	ND	Historic	Monthly
Otter Tail Power Co	ND	Historic	Monthly
El Paso Electric Co	NM	Historic	Monthly
Southwestern Public Service Co	NM	Historic	Monthly
Nevada Power Co	NV	Historic	Quarterly
Sierra Pacific Power Co	NV	Historic	Quarterly
Oklahoma Gas & Electric Co	OK	Historic	No more than quarterly
Public Service Co of Oklahoma (AEP)	OK	Historic	Varies
PacifiCorp [1]	OR	Projected	Annually
Portland General Electric Co	OR	Projected	Annually
Duke Energy Carolinas	SC	Projected	Annually
Progress Energy Carolinas	SC	Projected	Annually
South Carolina Electric & Gas Co	SC	Projected	Annually
Black Hills Power Inc	SD	Historic	Annually
Northern States Power Co (Minnesota)	SD	Historic	Monthly
NorthWestern Corp	SD	Historic	Quarterly

Summary of Cost Recovery Lag in Fuel Adjustment Clauses for Utilities in Other Non-Restructured States

Utility	State	FAC Rate Based on Historic or Projected Costs	Frequency of Rate Adjustment
Kingsport Power Co (AEP)	TN	Historic	Monthly
Appalachian Power Co (AEP)	VA	Projected	Annually
Kentucky Utilities Co	VA	Projected	Annually
Potomac Edison Co (The)	VA	Projected	Annually
Virginia Electric & Power Co	VA	Projected	Annually
Green Mountain Power Corp	VT	Historic	Quarterly
Avista Corp	WA	Historic	Annual
Puget Sound Energy Inc	WA	Projected	Annual
Consolidated Water Power Co	WI	Historic	Monthly
Madison Gas & Electric Co	WI	Projected	Varies
Northern States Power Co (Wisconsin)	WI	Projected	Varies
Superior Water Light & Power Co	WI	Historic	Monthly
Wisconsin Electric Power Co	WI	Projected	Varies
Wisconsin Power & Light Co	WI	Projected	Varies
Wisconsin Public Service Corp	WI	Projected	Varies
Appalachian Power Co (AEP)	WV	Projected	Annually
Monongahela Power Co	WV	Projected	Annually
Potomac Edison Co (The)	WV	Projected	Annually
Wheeling Power Co (AEP)	WV	Projected	Annually
Cheyenne Light Fuel & Power Co	WY	Historic	Annually
PacifiCorp	WY	Historic	Annually

Number of Investor-Owned Utilities w/ FACs in Other Non-Restructured States:	**85**
Number of Utilities w/ FAC Rate Based on Projected Costs:	**52**
Number of Utilities w/ FAC Rate Based on Historic Costs:	**33**
Number of Utilities w/ FAC Rate Based on Historic Costs and Adjusted Monthly:	**21**

Sources and Notes:
Other non-restructured states include restructured states with limited or repealed retail access outside of MO.
Sample includes investor-owned utilities for which EIA/DOE Form 861 rate data were available in 2006 and total retail sales were greater than 500,000 MWh.
[1]: Refers to Pacificorp's Transition Adjustment Mechanism.

Fuel Adjustment Clauses Used by Utilities in Other Non-Restructured[1] States

	Number of Utilities by Jurisdiction	*Number with a FAC*	*Number with FAC Pending*	*Number of Remaining Utilities*	*Percentage with a FAC*	*Percentage with FAC Pending*	*Percentage for Remaining Utilities*
Other Non-Restructured[1] States (Excluding Missouri)	**94**	**85**	**5**	**4**	**90%**	**5%**	**4%**
Neighboring and Other Non-Restructured[1] Midwestern[2] States	**37**	**36**	**0**	**1**	**97%**	**0%**	**3%**
Utilities with More Than 50% Coal Capacity in Neighboring and Other Non-Restructured[1] Midwestern[2] States	**27**	**26**	**0**	**1**	**96%**	**0%**	**4%**
Neighboring and Other Non-Restructured[1] Midwestern[2] States where FAC Approval by Commission is Not Mandatory[3]	**23**	**23**	**0**	**0**	**100%**	**0%**	**0%**
Utilities with More Than 50% Coal Capacity in Neighboring and Other Non-Restructured[1] Midwestern[2] States where FAC Approval by Commission is Not Mandatory[3]	**17**	**17**	**0**	**0**	**100%**	**0%**	**0%**

Sources and Notes:
See Schedule MJL-E6-2 - MJL-E6-4.
[1]: Non-restructured states include restructured states with limited or repealed retail access.
[2]: Midwestern states based on DOE's definition of East North Central and West North Central: includes IA, IL, IN, KS, MI, MN, MO, ND, NE, OH, SD, and WI.

Fuel Adjustment Clauses Used by Utilities in Non-Restructured* States

	Utility	Operating State	Ownership Type	Midwest	Overall Utility % of Nameplate Generation Capacity				Fuel Adjustment Clause?	Mandatory vs. Non-Mandatory FAC Policy in State, Based on Updated 2006 Survey
					Nuclear	Coal	Natural Gas	Other		(Mandatory for Utility, Commission, Both, or Neither)
				[1]	[2]				[3]	[4]
	Alabama Power Co	AL	IOU	0	14%	56%	18%	13%	Yes	Neither
	Entergy Arkansas Inc	AR	IOU	0	38%	25%	35%	1%	Yes	Neither
	Oklahoma Gas & Electric Co	AR	IOU	0	0%	42%	57%	2%	Yes	Neither
	Southwestern Electric Power Co (AEP)	AR	IOU	0	0%	57%	43%	0%	Yes	Neither
	Arizona Public Service Co	AZ	IOU	0	17%	28%	54%	1%	Yes	Neither
[5]	Tucson Electric Power Co	AZ	IOU	0	0%	68%	32%	0%	No	Neither
	UNS Electric Inc	AZ	IOU	0	0%	0%	100%	0%	Yes	Neither
	Aquila Inc	CO	IOU	0	0%	48%	48%	4%	Yes	Neither
	Public Service Co of Colorado	CO	IOU	0	0%	67%	24%	9%	Yes	Neither
	Florida Power & Light Co	FL	IOU	0	13%	4%	51%	32%	Yes	Neither
	Florida Public Utilities Co	FL	IOU	0	No Reported Capacity				Yes	Neither
	Gulf Power Co	FL	IOU	0	0%	77%	21%	2%	Yes	Neither
	Progress Energy Florida	FL	IOU	0	8%	23%	43%	27%	Yes	Neither
	Tampa Electric Co	FL	IOU	0	0%	42%	54%	4%	Yes	Neither
	Georgia Power Co	GA	IOU	0	11%	61%	14%	13%	Yes	Both
	Savannah Electric & Power Co	GA	IOU	0	Acquired by Georgia Power				Yes	Both
	Hawaiian Electric Co Inc	HI	IOU	0	0%	0%	0%	100%	Yes	Neither
	Maui Electric Co Ltd	HI	IOU	0	0%	0%	0%	100%	Yes	Neither
	Interstate Power & Light Co	IA	IOU	1	0%	60%	25%	14%	Yes	Commission
	MidAmerican Energy Co	IA	Private	1	7%	57%	24%	12%	No	Commission
	Avista Corp	ID	IOU	0	0%	13%	31%	55%	Yes	Neither
	Idaho Power Co	ID	IOU	0	0%	36%	9%	56%	Yes	Neither
	PacifiCorp	ID	IOU	0	0%	66%	20%	14%	No	Neither
	Duke Energy Indiana	IN	IOU	1	0%	73%	23%	4%	Yes	Commission
	Indiana Michigan Power Co (AEP)	IN	IOU	1	32%	67%	0%	1%	Yes	Commission
	Indianapolis Power & Light	IN	IOU	1	0%	81%	12%	7%	Yes	Commission
	Northern Indiana Public Service Co	IN	IOU	1	0%	90%	9%	1%	Yes	Commission
	Southern Indiana Gas & Electric Co	IN	IOU	1	0%	76%	24%	0%	Yes	Commission
	Kansas City Power & Light Co	KS	IOU	1	13%	54%	20%	13%	Yes	Neither
	Kansas Gas & Electric Co	KS	IOU	1	21%	44%	22%	13%	Yes	Neither
	Westar Energy Inc	KS	IOU	1	0%	61%	32%	7%	Yes	Neither
	Duke Energy Kentucky	KY	IOU	0	0%	56%	44%	0%	Yes	Utility
	Kentucky Power Co (AEP)	KY	IOU	0	0%	100%	0%	0%	Yes	Utility
	Kentucky Utilities Co	KY	IOU	0	0%	64%	34%	2%	Yes	Utility
	Louisville Gas & Electric Co	KY	IOU	0	0%	75%	22%	2%	Yes	Utility
	CLECO Power LLC	LA	IOU	0	0%	37%	63%	0%	Yes	Both
	Entergy Gulf States Inc	LA	IOU	0	13%	9%	78%	0%	Yes	Both
	Entergy Louisiana Inc	LA	IOU	0	18%	0%	69%	13%	Yes	Both
	Entergy New Orleans Inc	LA	IOU	0	0%	0%	100%	0%	Yes	Both
	Southwestern Electric Power Co (AEP)	LA	IOU	0	0%	57%	43%	0%	Yes	Both
	Allete Inc	MN	IOU	1	0%	83%	0%	17%	Yes	Neither
	Interstate Power & Light Co	MN	IOU	1	0%	60%	25%	14%	Yes	Neither
	Northern States Power Co (Minnesota)	MN	IOU	1	26%	52%	17%	6%	Yes	Neither
	Otter Tail Power Co	MN	IOU	1	0%	74%	7%	18%	Yes	Neither
	AmerenUE	MO	IOU	1	12%	52%	29%	7%	No	Neither

Fuel Adjustment Clauses Used by Utilities in Non-Restructured* States

	Utility	Operating State	Ownership Type	Midwest	Overall Utility % of Nameplate Generation Capacity				Fuel Adjustment Clause?	Mandatory vs. Non-Mandatory FAC Policy in State, Based on Updated 2006 Survey
					Nuclear	Coal	Natural Gas	Other		(Mandatory for Utility, Commission, Both, or Neither)
				[1]		[2]			[3]	[4]
[7]	Aquila Inc	MO	IOU	1	0%	48%	48%	4%	Yes	Neither
[5] [8]	Empire District Electric Co (The)	MO	IOU	1	0%	28%	71%	1%	No	Neither
	Kansas City Power & Light Co	MO	IOU	1	13%	54%	20%	13%	No	Neither
	Entergy Mississippi Inc	MS	IOU	0	0%	12%	61%	28%	Yes	Neither
	Mississippi Power Co	MS	IOU	0	0%	47%	53%	0%	Yes	Neither
[5]	MDU Resources Group Inc	MT	IOU	0	0%	76%	23%	0%	No	Neither
	NorthWestern Corp	MT	IOU	0	0%	78%	12%	10%	Yes	Neither
	Duke Energy Carolinas	NC	IOU	0	27%	38%	19%	15%	Yes	Both
	Progress Energy Carolinas	NC	IOU	0	24%	40%	26%	10%	Yes	Both
	Virginia Electric & Power CO	NC	IOU	0	20%	21%	26%	33%	Yes	Both
	MDU Resources Group Inc	ND	IOU	1	0%	76%	23%	0%	Yes	Neither
	Northern States Power Co (Minnesota)	ND	IOU	1	26%	52%	17%	6%	Yes	Neither
	Otter Tail Power Co	ND	IOU	1	0%	74%	7%	18%	Yes	Neither
	El Paso Electric Co	NM	IOU	0	38%	7%	55%	0%	Yes	Neither
[5]	Public Service Co of New Mexico	NM	IOU	0	18%	48%	33%	1%	No	Neither
	Southwestern Public Service Co	NM	IOU	0	0%	49%	49%	1%	Yes	Neither
	Nevada Power Co	NV	IOU	0	0%	24%	76%	0%	Yes	Utility
	Sierra Pacific Power Co	NV	IOU	0	0%	22%	71%	7%	Yes	Utility
	Oklahoma Gas & Electric Co	OK	IOU	0	0%	42%	57%	2%	Yes	Utility
	Public Service Co of Oklahoma (AEP)	OK	IOU	0	0%	24%	75%	1%	Yes	Utility
[5]	Idaho Power Co	OR	IOU	0	0%	36%	9%	56%	No	Neither
	PacifiCorp	OR	IOU	0	0%	66%	20%	14%	Yes	Neither
	Portland General Electric Co	OR	IOU	0	0%	27%	49%	25%	Yes	Neither
	Duke Energy Carolinas	SC	IOU	0	27%	38%	19%	15%	Yes	Both
	Progress Energy Carolinas	SC	IOU	0	24%	40%	26%	10%	Yes	Both
	South Carolina Electric & Gas Co	SC	IOU	0	12%	26%	33%	29%	Yes	Both
	Black Hills Power Inc	SD	IOU	1	0%	63%	35%	2%	Yes	Neither
	Northern States Power Co (Minnesota)	SD	IOU	1	26%	52%	17%	6%	Yes	Neither
	NorthWestern Corp	SD	IOU	1	0%	78%	12%	10%	Yes	Neither
	Kingsport Power Co (AEP)	TN	IOU	0		No Reported Capacity			Yes	Neither
	PacifiCorp	UT	IOU	0	0%	66%	20%	14%	No	n/a
	Appalachian Power Co (AEP)	VA	IOU	0	0%	80%	8%	12%	Yes	Utility
	Kentucky Utilities Co	VA	IOU	0	0%	64%	34%	2%	Yes	Utility
[6]	Potomac Edison Co (The)	VA	IOU	0	0%	0%	0%	100%	Yes	Utility
	Virginia Electric & Power Co	VA	IOU	0	20%	21%	26%	33%	Yes	Utility
[5]	Central Vermont Public Service Corp	VT	IOU	0	19%	0%	0%	81%	No	Neither
	Green Mountain Power Corp	VT	IOU	0	0%	0%	0%	100%	Yes	Neither
	Avista Corp	WA	IOU	0	0%	13%	31%	55%	Yes	Neither
	PacifiCorp	WA	IOU	0	0%	66%	20%	14%	No	Neither
	Puget Sound Energy Inc	WA	IOU	0	0%	27%	49%	24%	Yes	Neither
	Consolidated Water Power Co	WI	IOU	1	0%	0%	0%	100%	Yes	Both
	Madison Gas & Electric Co	WI	IOU	1	0%	49%	42%	9%	Yes	Both
	Northern States Power Co (Wisconsin)	WI	IOU	1	0%	8%	41%	50%	Yes	Both
	Superior Water Light & Power Co	WI	IOU	1		No Reported Capacity			Yes	Both
	Wisconsin Electric Power Co	WI	IOU	1	0%	65%	28%	7%	Yes	Both

Fuel Adjustment Clauses Used by Utilities in Non-Restructured* States

	Utility	Operating State	Ownership Type	Midwest	Overall Utility % of Nameplate Generation Capacity				Fuel Adjustment Clause?	Mandatory vs. Non-Mandatory FAC Policy in State, Based on Updated 2006 Survey
					Nuclear	Coal	Natural Gas	Other		(Mandatory for Utility, Commission, Both, or Neither)
				[1]	[2]				[3]	[4]
	Wisconsin Power & Light Co	WI	IOU	1	0%	62%	36%	2%	Yes	Both
	Wisconsin Public Service Corp	WI	IOU	1	0%	70%	25%	4%	Yes	Both
	Appalachian Power Co (AEP)	WV	IOU	0	0%	80%	8%	12%	Yes	Neither
	Monongahela Power Co	WV	IOU	0	0%	100%	0%	0%	Yes	Neither
	Potomac Edison Co (The)	WV	IOU	0	0%	0%	0%	100%	Yes	Neither
	Wheeling Power Co (AEP)	WV	IOU	0	No Reported Capacity				Yes	Neither
	Cheyenne Light Fuel & Power Co	WY	IOU	0	No Reported Capacity				Yes	Neither
	PacifiCorp	WY	IOU	0	0%	66%	20%	14%	Yes	Neither
	Average, All Non-Restructured* States				6%	46%	31%	18%		
[1]	Average, Midwestern States				6%	57%	22%	12%		
	Average, Neighboring States				6%	51%	33%	5%		

Notes:

* Non-restructured states include restructured states with limited or repealed retail access.
Sample includes investor-owned utilities for which EIA/DOE Form 861 rate data were available in 2006 and total retail sales were greater than 500,000 MWh.

[1]: Midwestern states based on DOE's definition of East North Central and West North Central. Includes IA, IL, IN, KS, MI, MN, MO, ND, NE, OH, SD, and WI.

[2]: Capacity as a percentage of total owned nameplate capacity, as of March 2008.

[3]: Active fuel adjustment clause.

[4]: Mandatory indicates that either a utility must apply for a FAC ("Utility"), or the Commission must allow a FAC ("Commission").

[5]: Fuel adjustment clause pending for these utilities.

[6]: Only purchased power adjustment clause reinstated.

[7]: Aquila sold its electric retail business in Kansas on April 1, 2007, but previously had a fuel adjustment clause in that jurisdiction.

[8]: Empire District has fuel adjustment clauses in Arkansas, Kansas, and Oklahoma, but sales in these jurisdictions fall below the 500,000 MWh threshold.

State-specific notes:

MO: Legislation has been passed which allows the Missouri Public Service Commission to implement fuel, purchased power, and environmental cost riders.

NE: Nebraska does not have any investor-owned utilities, but Nebraska Public Power District has an inactive Production Cost Adjustment.

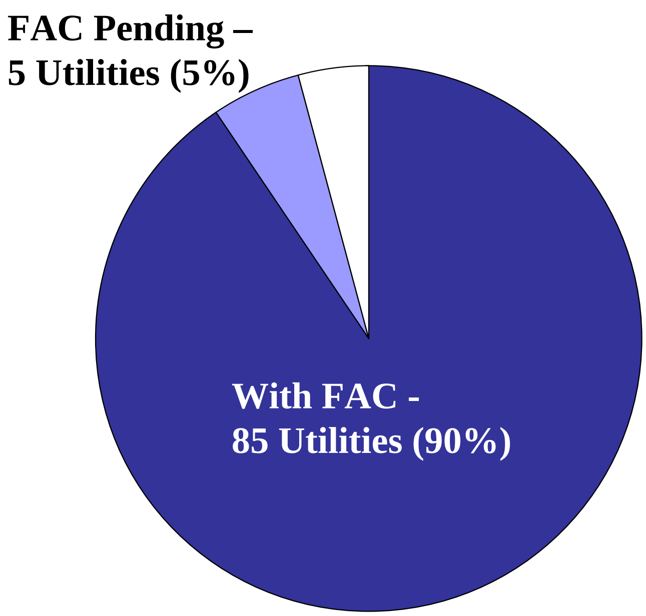
TN: Kingston Power, the only investor-owned utility in TN, has a Purchased Power Adjustment rider for energy and the capacity portions of purchased power.

UT: Utah has no FAC in place, but PacifiCorp has been allowed to recover replacement power costs through temporary rate increases.

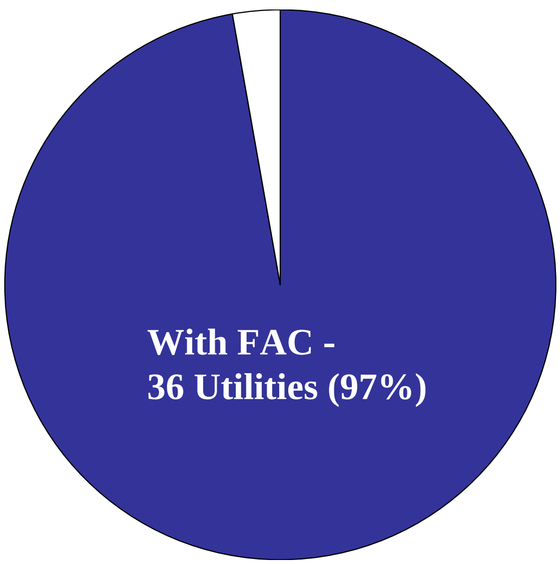
Sources:

Brattle Group analysis of EIA 861 data and Electric Generating Database (as compiled in Global Energy Decisions, Inc., The Velocity Suite), utility tariffs, state commission websites, FitchRatings: U.S. Electric Utilities-Credit Implications of Commodity Cost Recovery, 2/13/2006, Regulatory Research Associates: Fuel and Wholesale Power Cost Recovery, October 3, 2005, The Brattle Group Interviews with State Commission Staff, Regulatory Research Associates, NARUC, and EIA and State Commission websites.

Fuel Adjustment Clauses Used by Utilities in Other Non-Restructured States



Other Non-Restructured States (94 Utilities)



Neighboring and Other Non-Restructured Midwestern States (37 Utilities)

Sources and Notes:
See Schedule MJL-E6.
Other non-restructured states include restructured states with limited or repealed retail access outside of MO.
Midwestern states based on DOE's definition of East North Central and West North Central: includes IA, IL, IN, KS, MI, MN, MO, ND, NE, OH, SD, and WI.