Exhibit No.: 126
Issues: Fuel Adjustment Clause - Off-System Sales
Witness: Jaime Haro
Sponsoring Party: Union Electric Co.
Type of Exhibit: FAC Rebuttal Testimony
Case No.: ER-2010-0036
Date Testimony Prepared: February 26, 2010

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2010-0036

FUEL ADJUSTMENT CLAUSE REBUTTAL TESTIMONY

OF

JAIME HARO

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
February, 2010

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FUEL ADJUSTMENT CLAUSE REBUTTAL TESTIMONY

OF

JAIME HARO

CASE NO. ER-2010-0036

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jaime Haro. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri.

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

A. I am Director, Asset Management and Trading for Union Electric Company d/b/a AmerenUE (AmerenUE or Company).

Q. **Are you the same Jaime Haro who filed direct testimony in this case?**

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony filed by Office of the Public Counsel (OPC) witness Ryan P. Kind on February 22, 2010, which was filed in response to the Commission's February 17, 2010 **Order Directing Parties To Submit Testimony Concerning the Appropriateness of AmerenUE's Current Fuel Adjustment Clause**. In particular, I will address the two "concerns" Mr. Kind expresses regarding the operation of AmerenUE's fuel adjustment clause (FAC). I will also address the 95%/5% sharing mechanism in the FAC as it relates to off-system sales.

II. MR. KIND'S "CONCERNS"

Q. What is Mr. Kind's first "concern?"

A. Mr. Kind states that "during the Technical Conference for this case in the week of January 11-15, OPC first learned that....UE apparently entered into some bilateral OSS contracts where it did not believe the OSS margins needed to be passed through the FAC."

Q. Did these contracts involve off-system sales margins?

A. No, these contracts are long-term full or partial requirements contracts which are specifically excluded from off-system sales under the terms of the Company's fuel adjustment clause. They were entered into by the Company after the January 2009 ice storm reduced Noranda's load by approximately two-thirds, which had the effect of exposing a materially higher percentage of the Company's generation to the volatility and risk associated with the wholesale power markets than has generally been the case at AmerenUE. Prior to the severe loss of load at Noranda, the balance between sales assigned directly to serve load (native load and long-term full/partial requirements sales) and off-system sales had been approximately 78%/22%. The severe loss of load at Noranda, the duration of which at the time was unknown, upset this balance (it became approximately 74%/26%). Noranda's load has recently started to approach its pre-ice storm levels, but Noranda is still not at full load.

Q. You indicated that AmerenUE has maintained a balance for years. How was this accomplished?

A. AmerenUE has utilized long-term full and partial requirements contracts for many years. As I noted, this fact is recognized by the fuel adjustment clause's exclusion of these contracts from off-system sales (see Factor OSSR in the fuel adjustment clause tariff).

Q. What does that mean for retail customers?

A. It means that a greater percentage of the Company's costs are allocated away from retail customers, which lowers the retail revenue requirement.

Q. Please explain.

A. When rates are set, the Company's total cost of service is first determined, and then it is allocated between the retail ratepayers (i.e., via the revenue requirement being set in this rate case) and these long-term full and partial requirements customers. In this case, and taking the two contracts to which Mr. Kind refers (and the Company's other requirements contracts) into account, approximately 3.4 percent of the $3.1 billion in total Company revenue requirement has been allocated away from the retail customers whose rates will be set in this case. That means that restoring the balance lost when Noranda's load fell after the ice storm results in a retail revenue requirement in this case that is approximately $88 million less than it would have been had that balance not been restored.[1]

Q. Do you have an opinion then regarding why Mr. Kind expresses "concern" about these contracts?

A. I can only conclude that Mr. Kind fails to recognize that Factor OSSR in the Company's fuel adjustment clause does not include revenues under these kinds of contracts, and for good reason. If the exclusion for these contracts from Factor OSSR did not exist, and the Company was unable to restore the balance between retail/requirements customers' revenues and off-system sales in the event of the kind of drastic loss of load experienced when the ice storm damaged Noranda's smelter, then AmerenUE would suffer a drastic loss of revenues, would still incur the same level of fixed expenses and the fuel expense associated with the megawatthours (MWhs) Noranda did not take, but would then pass all of the revenues Noranda's misfortune

[1] I would also note that the revenue requirement in this case has been calculated by both the Company and the Staff on the assumption that the Company's normalized loads include Noranda at full operation. Thus, the higher retail revenues from Noranda at full operation cover a greater share of the total retail revenue requirement (reducing the shares borne by other customer classes).

allowed to occur through the fuel adjustment clause as off-system sales revenues. Thus, Noranda would be losing money due to its lost production, AmerenUE would lose money because it couldn't restore the balance, and the other retail customers would receive a windfall.

Q. Why would the other retail customers receive a windfall?

A. Because they would actually be better off as a result of Noranda's loss of load than if Noranda had continued to operate at full load. This is illustrated in the February 11, 2010 rebuttal testimony of AmerenUE witness Wilbon C. Cooper. See pages 14 to 17 and Schedule WLC-ER11.

Q. Has the Company profited from these two contracts?

A. No. The Company has mitigated part of the loss of Noranda revenues, but the price it is receiving under these contracts is similar to the price (on a per MWh basis) it would have received from Noranda had the ice storm not damaged Noranda's facility.

Q. Have other customers been harmed?

A. No. The rates paid by other customers, both in base rates and through the fuel adjustment clause, were no higher than they would have been had the ice storm never occurred and had Noranda continued to operate normally, as had been assumed in setting the Company's rates in the last rate case.

Q. Aside from matching the cost allocations assumed when rates are set with the revenues received, are there other reasons to maintain a balance between retail loads/requirements customers and off-system sales?

A. Yes there are. These reasons include reducing exposure to potentially weak counterparties, and the risk that power prices could drop even further than they already have. With regard to the first reason, at the time of the loss of Noranda's load, the Company was concerned with increasing its exposure to commercial bank counterparties, who trade in the power markets, particularly given the financial condition of those banks in the wake of the financial crisis that began in late 2008. This in turn led the Company to have greater concerns about ensuring revenues for excess generation in a market that had become even more uncertain. The need to avoid more exposure to counterparties that might have financial problems is illustrated by the fact that late in 2008 and during the first half of 2009, there were several major players in the energy markets that were affected by the financial crisis, including Constellation Energy, which was close to bankruptcy, and Lehman Brothers which had filed for bankruptcy. Consequently, it was my opinion that it was prudent for the Company to transact with counterparties that had retail loads backing their ability to pay.

With regard to the second reason, market conditions were such that power prices could have dropped even further than they already had due to the financial crisis, and it was important to mitigate that risk.

Q. You earlier noted that the Company's revenue requirement has been calculated in this case assuming that this balance is restored, but also assuming that Noranda is at full load. How does Mr. Kind's concern relate to those two assumptions?

A. If, as perhaps Mr. Kind is suggesting, the FAC were to be changed so that the Company could not maintain this balance (i.e., could not enter into these kinds of full and partial requirements contracts), then it would be imperative that the revenue requirement used to establish the billing units used to set rates in this case be changed. That is, the allocation of the approximately $88 million of costs away from the retail customers I mentioned earlier would need to be allocated to the retail customers. Otherwise, the retail customers would have their revenue requirement reduced because normalized revenues in this case would assume revenues from Noranda at full load, but the retail customers will bear less than their full share of the costs incurred to serve them. In other words, the billing units when this case was filed assumed that approximately 3.4% of the Company's costs would be borne by these full and partial requirements customers. If these kinds of contracts are not allowed, then the appropriate percentage would be just approximately 1%.[2]

Q. How does this relate to the take or pay tariff revision for the LTS rate class or the "N" factor discussed in Mr. Cooper's direct and rebuttal testimonies?

A. Prospectively, adoption of the take or pay tariff revision or the N factor would address what appears to be Mr. Kind's concern if Noranda's load were to substantially drop again.

Q. Were you surprised that Mr. Kind "first learned" of these contracts in January of this year?

A. Yes, I was. These contracts, which were entered into in March and May of 2009, were expressly identified in the monthly FAC reports provided to all parties to the Company's last rate case, including OPC, starting June 1, 2009. The Staff and the Missouri Industrial Energy Consumers both sent data requests to the Company – including Data Requests MPSC-0184 and MIEC 8-19 through 8-22 – all of which dealt with these contracts and all of which were available to Mr. Kind via the Company's Caseworks Extranet site well in advance of the date when he states he first became aware of them. In particular, it should be noted that AmerenUE's reply to Data Request MPSC-0184, which identifies both of these contracts, is

[2] There are a few other requirements contracts (which comprise the remaining 1%) with which Mr. Kind apparently doesn't express a concern.

dated September 29, 2009. While I understand Mr. Kind's viewpoint to be that OPC has limited staff, the Company has been up-front about these contracts at every turn.

Q. Did AmerenUE "circumvent" the FAC, to use Mr. Kind's word, by entering into these contracts?

A. No. As I have already addressed, these contracts and the rate treatment they are being given in this case is expressly contemplated by the fuel adjustment clause and fair to all customers, as well as the Company.

Q. What is Mr. Kind's second "concern?"

A. Mr. Kind also expresses a concern that AmerenUE is "attempting to remove certain off-systems sales revenues from its revenue requirement by asserting that certain non-asset based trading operations were 'non-regulated.'" I am unaware of any assertion by AmerenUE that non-asset based trading is somehow "non-regulated," which is not a term that I would associate this activity.

That said, AmerenUE's treatment of non-asset based trading revenues and the associated cost in its revenue requirement is consistent with that approved by the Commission in each of the prior two rate cases, the Uniform System of Accounts (USOA), which under the Commission's rules the Company must follow, as well as pertinent Securities and Exchange Commission rules. Its treatment in regard to the determination of the FAC is consistent with that approved by the Commission when the FAC was established in Case No. ER-2008-0318.[3]

[3] In fairness, I would note that OPC raised these issues in that case, but settled a number of FAC-related issues and did not relinquish the right to raise those issues in a subsequent rate case. My only point is that no other party in the last rate case has raised these same concerns, and the Company has treated revenues and costs from its non-asset based trading activities in accordance with the approved FAC.

It is important to note here, that in his surrebuttal testimony in Case No. ER-2008-0318, AmerenUE witness Shawn E. Schukar, stated that "(h)owever, if the Commission were to determine that these costs and revenues should be included in the rates of the AmerenUE customers, AmerenUE would not object to the treatment, provided the Commission gave the Company the required accounting authority to depart from the USOA by recording these costs and revenues 'above-the-line.'" AmerenUE continues to hold that position today.

Q. Was that the extent of Mr. Schukar's testimony that may shed light on the issue in this proceeding?

A. No. I would also note that in that same section of his surrebuttal testimony, Mr. Schukar provided the rationale for excluding the non-asset based revenues and associated costs from the FAC when he stated that:

> AmerenUE's FAC does not include the costs and revenues associated with speculative trading conducted by AmerenUE's Asset Marketing and Trading ("AM&T") group because AmerenUE believes these costs and revenues are properly recorded "below the line," consistent with the requirements of the Uniform System of Accounts ("USOA"), which as I understood it have been adopted by the Commission. In addition, AmerenUE believes that ratepayers should not be exposed to the risks associated with speculative trading, even though ratepayers receive the benefits of the increased liquidity and market transparency that AmerenUE receives as a result of the speculative trading activity. Ratepayers receive those benefits because this increased liquidity and market transparency helps facilitate and promote asset based off-system sales, which do offset AmerenUE's production costs in the FAC.

These same factors and rationale are applicable today.

Q. Would customers indeed benefit from a change in the rate treatment for non-asset based trading margins and associated costs?

A. That is dependent on whether such trading activity yields a positive or negative margin in a given year, and if positive, if that amount is great enough to offset the costs (including associated labor costs) which would then be included in the revenue requirement, which under the current treatment are excluded. I do know that in 2008 and 2009, non-asset based trading experienced a negative margin before even considering the elimination of the cost allocation. Thus, if non-asset based trading were included in off-system sales in the FAC, customers would have paid more since the FAC has been in effect.

Q. Mr. Kind suggests that "of course, the mixture of regulated and "non-regulated" activities always raises concerns about affiliate transactions..." Do you agree?

A. No. I don't understand how activities within the same organization (AM&T, which is a division within AmerenUE and conducts no activities by or on behalf of any Ameren affiliate) can somehow raise affiliate issues.

Q. Mr. Kind expresses a concern that having UE's power trading shop (AM&T) involved in what he terms "non-regulated" work activity may be distracting AM&T from making its best efforts to achieve positive outcomes from the regulated off-system sales activities. Do you agree?

A. Absolutely not. First, I would again note his misuse of the term "non-regulated." One need only recognize that that the labor associated with this activity is only 1.5 full time equivalent's (FTE) out of an available staff of 31 FTE to understand that this is far from our primary focus. Furthermore, non-asset based trading not only does not distract AmerenUE, but provides better perspectives on the markets in which AmerenUE makes asset-based trades, which are included in off-system sales. Mr. Kind is well aware that the level of activity associated with non-asset based trading is rather small in relation to the asset-based trading conducted by AM&T given that he acknowledges having received and reviewed AmerenUE's response to DR OPC 2021, which details the net margin of this activity – an amount which is clearly immaterial when compared to the balance of our asset-based activity.

Q. You earlier indicated that the non-asset based trading has incurred losses, not profits, as Mr. Kind seems to suggest. Please explain.

A. Attached as Schedule JH-FR1 is the Company's response to OPC Data Request 2021, including the attachment "2021 – 2023 Summary.xls" "Net (Profit)/Loss from Speculative Trading." In examining this response, it must be understood that the numbers in parentheses reflect profits, while the other numbers reflect losses.[4] I can only assume that perhaps Mr. Kind got confused with the accounting conventions, but the last row on the spreadsheet entitled "Net (Profit)/Loss from Speculative Trading" clearly shows losses over one million dollars for 2008, and over $600,000 for the first eleven months of 2009. In short, Mr. Kind's suggestion that this data request response shows a "magnitude of profits" from this trading activity is mistaken; instead, over the past two years there are losses.

Q. Please comment on Mr. Kind's claim that "UE has not provided information that OPC has explicitly requested in OPC DR 2021 . . ."?

A. Again, Mr. Kind is mistaken. The attachment to AmerenUE's response to OPC Data Request 2021 (Schedule JH-FR1 hereto) broke out accounting entries booked to FERC Account 426. Account 426 is used to book costs other than energy purchases (which are reported net of energy sales in the other accounts listed in the attachment, and as was explained in the text of the data request response). OPC Data Request 2021 asked for "dollar amount of costs and revenues (by month if available) associated with non-asset based trading of wholesale capacity and energy products for UE during the test year ending 3/31/09." This is exactly what was provided by AmerenUE in its response. If Mr. Kind believed that we had not provided

[4] For example, in March 2009 the Company lost (taking into account trading expenses) $149,957.30; in April 2009, the Company made $188,822.78.

responsive data, I would have expected for OPC to have contacted the Company, via phone or e-mail, to inquire, but I am unaware of any such contact having been made. Nor am I aware of any subsequent data request by OPC seeking clarification or greater granularity in the response that we provided. Had Mr. Kind asked for clarification (which again, we had no idea he needed), we could have easily shown him that for the first 11 months of 2009, the costs related to the non-asset based trading were approximately $230,000 (for 2008, they were approximately $261,000). This information is contained in the data request response.

Q. Are these costs included in the Company's revenue requirement in this case?

A. No. These costs are all booked below-the-line, as are the losses the Company incurred on this trading activity. Thus, the 2009 losses were not passed on to customers through the fuel adjustment clause.

III. <u>95%/5% SHARING MECHANISM</u>

Q. Has OPC provided any facts in this case to support the contention that the existing 95%/5% sharing mechanism in the currently approved FAC does not provide the utility with a sufficient financial incentive to be prudent in its fuel and purchased power costs and optimize off-system sales margins for the benefit of ratepayers?

A. No. Mr. Kinds simply states his "belief" that it does not.

Q. Has AmerenUE provided testimony in this case to support the contention that the existing 95%/5% sharing mechanism in its currently approved FAC provides the utility with a sufficient financial incentive to be prudent in its fuel and purchased power costs and optimize off-system sales for the benefit of ratepayers?

A. Yes. In response to the Commission's order, AmerenUE witness Lynn M. Barnes provided such testimony. Furthermore, Mr. Schukar addressed this same issue in the last case, when he said:

> **Q. Are there any additional comments that you would make in reference to the financial margin goals?**
>
> A. Yes. The purpose of the financial margin goals and the gross margin goals is to ensure that the AM&T group has the appropriate incentives to maximize the amount of margin that can reliably be achieved from the AmerenUE assets – i.e., to maximize off-system sales. As noted above, these goals include the incentive to improve capacity and ancillary services sales, reduce costs from forecasting errors, and optimize generating fleet operations. These financial incentives are the bulk of the incentive compensation available to the dispatch, marketing and trading personnel working in the AM&T group, and, as AmerenUE witness Krista Bauer discusses in her rebuttal testimony, incentive compensation is an important component of these employees' pay. As Mr. Lyons notes in his rebuttal testimony, these financial incentives drive the employees most responsible for maximizing off-system sales revenues to do the best job they possibly can in doing so, with or without a fuel adjustment clause for AmerenUE.[5]

Mr. Schukar's points all still remain valid. My experience has been that AmerenUE employees are in fact highly motivated to maximize off-system sales revenues, and have continued to do so since the fuel adjustment clause was approved.

Q. Are off-system sales volatile, such that the changes in net fuel costs versus the base level can be very substantial, which in turn could expose AmerenUE to a significant under-recovery of prudently incurred net fuel costs due to the 5% sharing provision in the FAC?

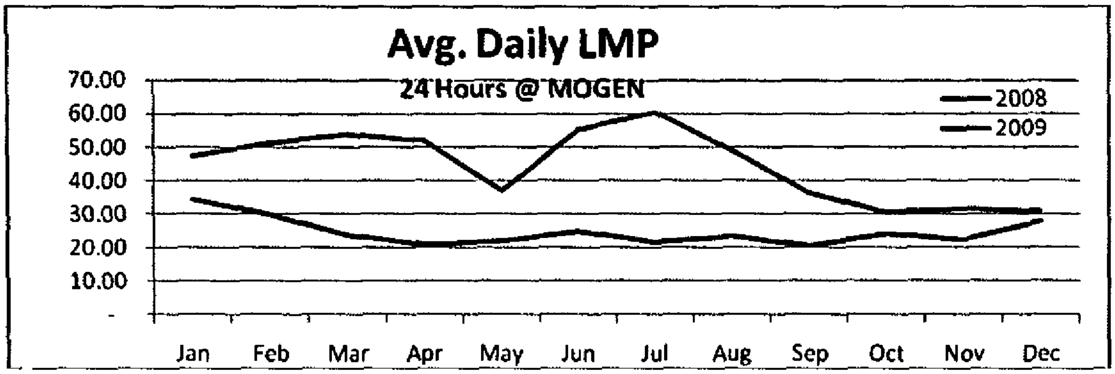
A. Yes. As Mr. Schukar pointed out, the level of AmerenUE's off-system sales is a function of the amount of available AmerenUE generation that is in excess of that required to serve the AmerenUE native load and requirements customers, and the market price of energy at

[5] Mr. Schuckar's Rebuttal Testimony, Case No. ER-2008-0318.

the time that the excess generation is available for sale. Accordingly, changes in load, generation availability and prices will all affect the quantity and financial benefit of off-system sales, particularly when compared to the modeled levels utilized in the ratemaking process. In other words, the base net fuel costs against which changes in the FAC are tracked can vary significantly from the actual net fuel costs incurred. Consider that there has been an approximately $200 million change from just the last case to this case in the normalized level of net fuel costs due in large part to reduced power prices.

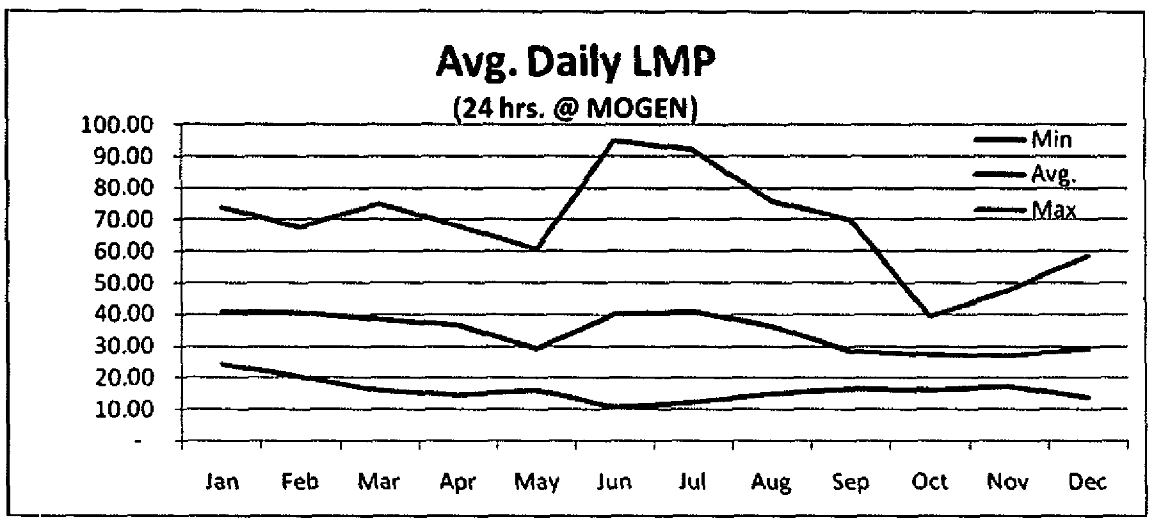
Mr. Schukar highlighted the impact of differences between actual and normalized loads, generator availability and prices in his prior testimony. His points remain valid, and consequently, I have attached Mr. Schukar's Direct Testimony to this testimony as Schedule JH-FR2. Please pay particular attention to Section V of that testimony, which addresses off-system sales volatility and uncertainty.

AmerenUE's actual experience during 2008 and 2009 reinforces the analysis Mr. Schukar presented previously. Specifically, AmerenUE had sales to retail customers and requirement sales combined of 38.6 million MWh in 2008 and only 36.6 million MWh in 2009. Similarly, in 2008 net generation was 49.3 million MWh, while in 2009 that number was 48.8 million MWh. Even more telling though, is the difference in average price available to AmerenUE's excess generation between the two years – $44.54 and $24.67, respectively, as shown by the graph, below. This price volatility is discussed in greater detail below.



Mr. Schukar's discussion of the impact of the timing of unit outages is as true now as it was then. While the level of market prices has indeed fallen, there is still a significant difference between the prices on the highest days and the lowest days within a month.

If we simply look at the average daily locational marginal price (LMP) (average LMP at MOGEN for a full 24 hours) for 2008 and 2009, we can see the wide range between the average daily price, and the highest and lowest average daily price (for a single day) in each month, as depicted in the graph below.[6]



[6] LMPs are the prices at AmerenUE's generation stations (MOGEN) in the Midwest Independent Transmission System Operator, Inc's "Day 2" wholesale power market.

When one considers that a 600 megawatt unit accounts for up to 14,400 MWh's of sales per day, a five-day outage during the highest priced period of a month vs. the lowest priced period of the month could result in the loss of off-system sales revenues of between $1.5 million and $5 million just from that unit in that month (depending on the month.) Looked at more broadly, considering that AmerenUE historically has around 11 million MWhs of off-system sales (14 million in 2009), it is readily evident that even a small change in the price per MWh can have a significant impact on off-system sales revenue, let alone experiencing a nearly $20/MWh hour difference in average price as we did between 2008 and 2009.

Q. **Does this conclude your rebuttal testimony?**

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company	)	
d/b/a AmerenUE for Authority to File	)	
Tariffs Increasing Rates for Electric	)	Case No. ER-2010-0036
Service Provided to Customers	)	
In the Company's Missouri Service Area.	)	

AFFIDAVIT OF JAIME HARO

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

Jaime Haro, being first duly sworn on his oath, states:

1. My name is Jaime Haro. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a AmerenUE as Director, Asset Management and Trading.

2. Attached hereto and made a part hereof for all purposes is my Fuel Adjustment Clause Rebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 15 pages, and Schedule JH-FR 1 through JH-FR 2, 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.

Jaime Haro

Subscribed and sworn to before me this 26th day of February, 2010.

Mary Hoyt
Notary Public

My commission expires: 4-1-2010

Mary Hoyt - Notary Public
Notary Seal, State of
Missouri - Jefferson County
Commission #06397820
My Commission Expires 4/1/2010

AmerenUE
Response to OPC Data Request
MPSC Case No. ER-2010-0036
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

Data Request No.: OPC 2021 – Ryan Kind

Please specify the dollar amount of costs and revenues (by month if available) associated with non-asset based trading of wholesale capacity and energy products for UE during the test year ending 3/31/09. UE sometimes refers to non-asset based trading of wholesale capacity and energy products as "speculative trading."

RESPONSE

Prepared By: Dominic Perniciaro
Title: Supervisor, Power Accounting
Date: 12/30/2009

See attached file: 2021-2023 Summary.xls.

The data included therein was derived using the Accounting General Ledger and includes current monthly charges and adjustments to prior period estimates.

We net speculative revenues and expenses in accordance with generally accepted accounting principles and The Securities and Exchange Commission's requirements. Therefore, a separate detail of revenue and expenses was not readily available.

Please specify the dollar amount of costs and revenues (by month if available) associated with non-asset based trading of wholesale capacity and energy products for UE during 2009 (OPC 2023), 2008 (OPC 2024), and test year ended 3/31/2009 (OPC 2025). UE sometimes refers to non-asset based trading of wholesale capacity and energy products as "speculative trading."

A. Speculative Trading

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
421	$ (128,474.22)	$ (284,819.57)	$ 524,023.19	$ (402,038.14)	$ 254,761.60	$ 724,776.94	$ (983,590.52)	$ (493,731.18)	$ 1,856,339.07	$ 333,022.48	$ (485,625.15)	$ 22,357.47
426	$ 23,529.49	$ 25,832.72	$ -	$ 11,519.15	$ (12,391.08)	$ 98,132.25	$ 15,530.65	$ 36,377.48	$ 9,453.64	$ 19,948.32	$ 18,823.45	$ 15,070.12
447	$ 12,238.70	$ (38,214.71)	$ (432,600.00)	$ (136,229.10)	$ -	$ -	$ -	$ -	$ -	$ 411,622.50	$ -	$ -
555	$ -	$ -	$ -	$ -	$ (2.45)	$ -	$ -	$ -	$ -	$ -	$ -	$ (382.90)
565	$ -	$ -	$ (15.69)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net (Profit)/Loss from Speculative Trading	$ (92,706.03)	$ (297,201.56)	$ 91,407.50	$ (526,748.09)	$ 242,368.07	$ 822,909.19	$ (968,059.87)	$ (457,353.70)	$ 1,865,792.71	$ 764,593.30	$ (466,801.70)	$ 37,044.69

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09
421	$ (193,807.99)	$ 13,538.43	$ 121,163.68	$ (199,299.49)	$ (15,894.11)	$ 254,401.50	$ (28,526.32)	$ (107,795.24)	$ 111,207.55	$ 437,153.91	$ 41,009.37
426	$ 20,371.77	$ 21,965.64	$ 28,793.62	$ 10,476.71	$ 13,180.72	$ 51,393.56	$ 18,934.03	$ 8,461.77	$ 15,702.65	$ 16,378.56	$ 23,961.28
447	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
555	$ 382.90	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
565	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net (Profit)/Loss from Speculative Trading	$ (173,053.32)	$ 35,504.07	$ 149,957.30	$ (188,822.78)	$ (2,713.39)	$ 305,795.06	$ (9,592.29)	$ (99,333.47)	$ 126,910.20	$ 453,532.47	$ 64,970.65

Per the SEC's netting requirement and in accordance with generally accepted accounting principles, both speculative purchases and sales are required to be booked to a revenue account. This is why the revenue accounts used for speculative trading activity can switch between a net debit or a net credit.

Exhibit No.:	
Issues:	Pricing for Off-System Sales; Off-System Sales Uncertainty/Volatility
Witness:	Shawn Schukar
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

SHAWN E. SCHUKAR

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

** <u>DENOTES HIGHLY CONFIDENTIAL INFORMATION</u> **

St. Louis, Missouri
April, 2008

Schedule JH-FR2

HC

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DIRECT TESTIMONY

OF

SHAWN E. SCHUKAR

CASE NO. ER-2008-_____

I. INTRODUCTION

Q. Please state your name and business address.

A. Shawn E. Schukar, One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your current position and what are your responsibilities relating to off-system sales for AmerenUE?

A. Effective January 1, 2008, I became Vice President, Strategic Initiatives, for Ameren Services Company ("Ameren Services"). In that capacity, I am responsible for the coordination of policy related activities associated with climate, Regional Transmission Organizations ("RTOs"), including the operation of RTO energy markets, and other strategic activities. Prior to becoming Vice President, Strategic Initiatives, I was the Vice President of Ameren Energy, Inc. In that role I was responsible for the unit dispatch, energy trading, and wholesale marketing associated with Union Electric Company d/b/a AmerenUE's ("AmerenUE" or "Company") generating units. As part of these responsibilities, I managed AmerenUE's off-system sales.

Q. What is Ameren Services?

A. Ameren Services provides various corporate, administrative and technical support services for Ameren Corporation ("Ameren") and its affiliates, including AmerenUE. Part of that work as it relates to my position is consulting for AmerenUE with respect to its off-system sales, which are largely made into the Day 2 Energy Markets operated by the Midwest Independent Transmission System Operator, Inc. ("MISO"), which is the RTO in which AmerenUE participates.

Q. Please describe your educational background and work experience.

A. I received a Bachelor's degree in Mechanical Engineering from the University of Illinois in 1984 and a Master's of Business degree from the University of Illinois in 2001. I joined Illinois Power Company ("Illinois Power") in 1984 as a power plant engineer. I subsequently held several power plant positions from 1986 through 1996, including positions in plant performance management, plant operations management, and plant engineering management. In 1996 I became responsible for the generation control function, which included the dispatch and short-term energy sales associated with the Illinois Power control area. I was responsible for generation control, energy trading and energy marketing from 1997 through 1999. I then managed the retail pricing and risk management portions of the business from 1999 through 2000, and transmission operations from 2000 through 2001. I was responsible for the transmission, generation dispatch and gas control functions at Illinois Power from 2001 through 2004. In 2004, I became responsible for the Illinois Power field operations and continued with that responsibility after Ameren's acquisition of Illinois Power until 2005. In 2005, I became responsible for the short-term management of the generation included in the now-terminated Joint Dispatch Agreement ("JDA"). In 2007, after the JDA was terminated, I became responsible for the dispatch, load management, energy trading, and wholesale energy marketing associated with AmerenUE's generating units. As noted above, in January 2008, I became the Vice President, Strategic Initiatives for Ameren Services.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I am providing testimony in support of the level of off-system sales in the cost of service utilized for the purpose of setting AmerenUE's rates. I also address the volatility of off-system sales due to uncertainty in energy prices, generation performance, and rate regulated load.

Q. Please summarize your testimony and conclusions.

A. My testimony addresses the following issues:

1. AmerenUE's opportunities to realize off-system sales are greatly dependent on and limited by its load serving obligations, the availability of its generation resources, and the cost of its generating resources relative to the market prices for energy. To the extent the test year is not representative of normal conditions or does not reflect known and measurable changes, adjustments must be made. In this particular case, such adjustments include, (i) weather normalization of load, (ii) normalization of generation outages, (iii) annualized increases in AmerenUE coal and coal transportation costs based on price changes occurring during the test year (specifically, effective January 1, 2008), (iv) normalized electricity prices, and (v) the impact associated with the unavailability of the Company's Taum Sauk facility.

2. AmerenUE incorporated all of these adjustments in its PROSYM production cost model (the operation of which is addressed in the direct testimony of AmerenUE witness Timothy D. Finnell) to determine the normalized level of off-system sales to include in the determination of the Company's revenue requirement. Using the results obtained from the operation of this model, I have determined that the appropriate level of normalized off-

system sales revenues to use in determining the revenue requirement is $454.3 million. (These off-system sales revenues cover fuel costs associated with off-system sales and, in addition, reduce the Company's revenue requirement by virtue of the profits or margins made on these sales.)

3. AmerenUE is exposed to significant uncertainty associated with the level of off-system sales revenues as a result of (i) native load variability, (ii) generation performance and unplanned outages, and (iii) market price volatility.

An executive summary of my testimony is contained in Attachment A.

III. TEST YEAR OFF-SYSTEM SALES

Q. What are off-system sales?

A. Off-system sales are sales of energy, capacity, and ancillary services to customers other than Missouri retail customers and certain Missouri wholesale customers.

Q. Have you determined the appropriate level of off-system sales to include in AmerenUE's revenue requirement?

A. Yes, I have.

Q. Please indicate the level of off-system sales revenues that you have determined is appropriate to include in AmerenUE's revenue requirement.

A. I have determined that the normalized level of AmerenUE off-system sales revenues for inclusion in AmerenUE's revenue requirement in this case is $454.3 million per year. This includes $443.2 million per year for energy sales, $7.6 million per year for capacity sales, and $3.5 million per year for ancillary services sales. This determination is based on normalization of test year data adjusted for known and measurable changes through June 2008.

Q. How did you determine the normalized off-system sales for the test year?

A. The normalized off-system sales of energy were determined by utilizing the Company's PROSYM production cost model (discussed in detail in the direct testimony of Mr. Finnell) with inputs including weather normalized loads, normalized generation outages, and normalized gas and electric prices. The fuel cost inputs to the model were also adjusted for known and measurable changes associated with fuel and transportation contracts and for the Company's previous commitment to hold ratepayers harmless of the unavailability of the Taum Sauk Plant. The off-system sales associated with capacity were based on test year capacity sales, adjusted for estimated lost capacity sales opportunities as a result of the unavailability of the Taum Sauk Plant. Finally, the off-system sales associated with ancillary services were determined based on the test year ancillary services transactions adjusted for known and measurable changes in ancillary services contracts.

Q. Why was the normalized level of off-system sales of energy determined by modeling rather than utilizing actual test year off-system sales?

A. The amount of off-system sales of energy is determined from the amount of generation that is available to produce energy and the portion of the generation that is utilized by the load. Because load is adjusted to reflect normal weather in determining the Company's revenue requirement and because the level of generation available for off-system sales must reflect that load and also be adjusted to account for the unavailability of the Taum Sauk Plant, it is necessary to model the overall system to identify the appropriate off-system sales to use in setting the Company's revenue requirement. In order to assure that off-system sales utilized to determine the cost of service are consistent with normalized conditions, it is necessary to determine the off-system sales based on production cost modeling using normalized loads and generation rather than relying on actual test year off-system sales data. If actual off-system sales data were utilized, the off-system sales would not be consistent with the load and generation that are utilized to determine the revenue requirement. For instance, if the weather conditions for a given test year were such that actual load was greater than the amount of weather normalized load utilized to determine the revenue requirement, the actual load would result in a reduction in the total volume of off-system sales and the amount of off-system sales revenues would be expected to be understated relative to the normalized load utilized to determine rates.

Additionally, in order to ensure ratepayers are not impacted by the failure of the Taum Sauk Plant, it is necessary to model the overall system including Taum Sauk generation that was unavailable during the test year. Inclusion of Taum Sauk generation with normalized generation outages, weather normalized loads, normalized fuel costs, and normalized market prices provides the appropriate level of off-system sales for the test year, recognizing the impact of the unavailability of the Taum Sauk Plant.

Q. What were the adjustments for known and measurable changes to the inputs to the PROSYM production cost modeling that you provided to Mr. Finnell in order to determine the appropriate level of off-system sales?

A. I provided Mr. Finnell with forward energy sales volumes that have already been made for 2008 to reduce the volatility in the price received for off-system sales for future periods. Forward energy sales are contracted for sales for delivery of energy at a specified time or period, in this case during 2008. I also provided Mr. Finnell the sale (contract) price for these sales, which was adjusted for the basis differential between the location of the sale and the location of the generating unit that was expected to supply the power for the sale. The inclusion of the forward sales results in some of the energy sales within the model being sold at the forward (contract) prices, adjusted for basis differentials, rather than at the market prices that were used for modeling spot (short-term) sales. The forward sales are made in an effort to mitigate the exposure of AmerenUE and its customers to energy price volatility.

Q. What are the levels of capacity and ancillary services sales that you determined was appropriate to include in total off-system sales?

A. The amount of capacity sales and ancillary services sales recognized in 2007 and adjusted for known and measurable changes through June 2008 was $7.6 million and $3.5 million, respectively.

Q. Can you explain the adjustments that were made to determine the appropriate amount of capacity and ancillary services sales?

A. Yes. In the first instance the outage of the Taum Sauk Plant during the test year period as a result of the facility failure resulted in a lost opportunity to sell capacity. I reflected this by adding $2.4 million to the capacity sales to recognize the lost opportunity. The addition of $2.4 million to the $5.2 million of recognized capacity sales adjusted for known sales through June 2008 results in total capacity sales of $7.6 million. This level of capacity sales was added to the modeled off-system energy sales revenues to recognize both actual test year capacity sales and the estimated additional capacity sales that could have been made if the Taum Sauk facility had been available.

Secondly, the amount of ancillary services sales that was recognized during the test year was based on a sale of ancillary services to the Illinois operating utilities owned by Ameren during the interim period prior to the start of the MISO ancillary services market.

The total revenues received from ancillary services sales, as adjusted for known sales through June 2008, was $13.8 million, which is comprised of $10.3 million of opportunity associated with energy sales and $3.5 million for the "reservation fee" associated with holding back the capacity for ancillary services. The production cost model that was utilized to determine the amount of off-system energy sales did not reserve or hold back any unit capability associated with the sale of ancillary services. Since the model did not hold back any unit capability for the sales of ancillary services, the portion of the ancillary services sales associated with energy sales opportunity is already recognized in the off-system energy sales determined in the PROSYM production cost model. Thus, the only portion of the ancillary services sales that was not recognized in the off-system energy sales was the $3.5 million "reservation fee" which has been added to the total off-system energy sales calculated by the PROSYM production cost model.

Q. How were the capacity sales opportunities associated with the unavailability of the Taum Sauk Plant determined?

A. If the Taum Sauk Plant had not failed, the capacity associated with the facility would have been available for sale during the whole test year period. However, there was also capacity available from other units during the test year. The only time when there would have been an opportunity for incremental capacity sales (assuming the Taum Sauk Plant was available) was during those periods when AmerenUE had sold all of the excess capacity from the other AmerenUE generating units. The only period of time that AmerenUE sold all of the available excess capacity was during the summer months of July and August. Based on the market price of capacity for that period of approximately $2.75 per kilowatt (kW)-month, the additional capacity revenue that AmerenUE could have achieved from sales of Taum

Sauk capacity was 440 megawatts ("MW") multiplied by the $2.75 per kW-month for the 2 month period. This results in $2.4 million which was added to the actual capacity sales.

IV. METHODOLOGY USED TO DETERMINE TEST YEAR OFF-SYSTEM SALES OF ENERGY

Q. What production cost model was used to calculate a normalized level of off-system sales of energy utilized to set AmerenUE's revenue requirement in this case?

A. The $443 million in annual off-system sales of energy was derived from the same PROSYM model run that was used to determine the normalized production costs utilized by AmerenUE witness Gary S. Weiss in calculating AmerenUE's revenue requirement. The PROSYM model incorporates load requirements, generation and generation availability, any existing wholesale sales, and hourly market prices. As discussed in detail in Mr. Finnell's direct testimony, PROSYM is a production cost model that simulates the dispatch of the AmerenUE generation fleet to supply existing commitments including native load and wholesale sales, while buying or selling energy economically. As Mr. Finnell explains, the model has been calibrated against historical information to ensure that the model accurately reflects the AmerenUE system and economic opportunities associated with the dispatch of the system. Mr. Finnell's direct testimony demonstrates a very accurate match between modeled results and actual results, validating the use of the model for determining normalized off-system sales.

Q. How are off-system sales of energy derived from the PROSYM output?

A. PROSYM simulates the dispatch of AmerenUE's system by utilizing the lowest cost resources to meet the hourly load and operating reserves requirements. As part of its hourly dispatch, the model identifies opportunities for off-system sales based on the generation that is not being utilized to serve native load that has dispatch costs below the hourly market price. The model also identifies opportunities to buy from the market to reduce the cost to serve native load and offset AmerenUE's generation costs. The simulated off-system sales are determined based on the hourly market price achieved for the megawatt-hours ("MWh") that are sold to the market.

Q. What are the major inputs and assumptions included in the PROSYM model run?

A. As discussed in more detail by Mr. Finnell, the major inputs include AmerenUE's hourly loads, unit operating characteristics, fuel and emission costs, variable operation and maintenance costs, and hourly market prices for purchases and sales.

Q. Do the inputs and assumptions reflect actual conditions for the test year?

A. The inputs are based on test year conditions with adjustments for known and measurable changes and normalization of loads, generation outages, and market prices, as necessary. The inputs also incorporate the Taum Sauk Plant as if it were available for the test year.

Q. Please describe these inputs and how you made adjustments to test year conditions.

A. I will first explain the market price of energy that I recommended be used to determine the off-system sales and economic purchases cost. I will also explain how fuel and emission costs that were used to dispatch the system were adjusted to be consistent with the market price of energy.

Q. What market prices for energy were utilized to determine the off-system sales and economic purchases?

A. Normalized market prices were determined based on a two-year average of prices for each month during the period from January 2006 through December 2007. The average market price for that period of time was $40.47 per MWh.

Q. Why did you normalize the actual test year market prices for the determination of off-system sales of energy?

A. Since the PROSYM model used weather normalized load and normalized unit performance, it is appropriate to determine test year market prices that are also normalized. If the prices are not normalized for weather and outages, there is a risk that the use of actual off-system sales of energy will not appropriately reflect a normal year.

Q. Please explain how you normalized the market price for the test year.

A. I used a two-year weighted average of the locational marginal prices ("LMPs") at the generator nodes that are associated with off-system sales. LMPs are the prices paid at specific locations within the MISO energy market. The weighted LMPs are determined by multiplying the LMP at each of the generating units by the following weights:

Labadie	28%
Sioux	17%
Meramec	19%
Rush Island	29%
CTGs	7%

This weighting was determined by identifying the AmerenUE generators whose cost was assigned to the actual off-system made during 2007. This weighting ensures that the prices utilized to determine the off-system sales of energy are consistent with the price that would be expected to be recognized when energy sales are made.

Q. Please explain why you chose to utilize a two-year average of the LMPs at the generator nodes referenced in the previous question.

A. As explained in my answer to the previous question, the utilization of the weighted average of the LMPs at the generation nodes addresses the need to recognize where off-system sales are expected to be made with normalized loads and generation performance. However, the weighted averages do not address the impact that generation outages and weather patterns would have on the LMPs for any specific year. By utilizing more than one year of LMPs, the impact of weather within the MISO footprint for each month of the year can be averaged to minimize the impacts of warmer than normal or cooler than normal conditions on energy prices within the MISO footprint. Schedule SES-E1 provides an example of how averaging two years of actual weather at the most significant load centers within the MISO's footprint achieves weather measures that are closer to normal than using just one year of actual weather.

It is also important that the averaging of the temperatures occur on a monthly basis because of the different effects that warmer (or cooler) weather can have on different periods of the year. For example, everything else held constant, LMPs would be expected to be lower if January temperatures are warmer than normal, but higher if August temperatures are warmer than normal. As a result of this impact, I asked Mr. Finnell to utilize the monthly average price distribution across the 2006 - 2007 period.

Finally, the use of more than one year provides an averaging effect associated with the impact of generation and transmission system outages. Transmission and generation outages can impact the congestion component of the LMPs at the AmerenUE generation nodes. By utilizing more than one year of price data, unusual effects of transmission and generation outages in any given year on the AmerenUE generator node LMPs (both positive and negative) can be limited.

Q. Why have you not used an average over more than two years?

A. I did not average more than 2006 and 2007 because market conditions prior to 2006 were highly unusual and in my opinion not representative of normalized market conditions. This was particularly true in 2005, when disruptions in coal transportation, the effects of Hurricanes Dennis and Katrina, and the start-up of the MISO's energy markets created highly unusual market conditions.

Q. How did you apply the two years of price data to your simulation of the normalized test year in PROSYM?

A. Prices for each month were set to the average of the two prices in the corresponding months during the period January 2006 through December 2007. For example, the October prices were set at the average of the October 2006 and October 2007 prices.

Q. What spot-market fuel and emission costs were utilized to determine the dispatch of AmerenUE's generating units in the PROSYM model?

A. The period used to determine the "dispatch costs" of each generating unit was consistent with the period used to determine the adjusted market prices for power. This consistency is necessary because the generating dispatch of AmerenUE and the other market participants depend on both market prices for power and the dispatch price (i.e., cost of incremental fuel usage and emissions allowances). For the purpose of modeling the dispatch of the AmerenUE system, the input market prices of coal, gas, emissions, and wholesale energy consequently need to be consistent.

Q. What AmerenUE fuel costs were used to calculate the costs of off-system sales?

A. AmerenUE's coal and nuclear costs were based on the known costs associated with already executed fuel contracts with prices that were effective January 2008. AmerenUE's fuel costs for natural gas are based on the actual prices paid for natural gas during the same period of time as the market prices to maintain the consistency noted previously.

V. <u>OFF-SYSTEM SALES VOLATILITY AND UNCERTAINTY</u>

Q. Are AmerenUE's off-system sales uncertain and volatile?

A. Yes.

Q. Please explain why AmerenUE's off-system sales are uncertain and volatile.

A. The level of AmerenUE's off-system sales is a function of the amount of available AmerenUE generation that is in excess of that required to serve the AmerenUE native load and the market price of energy at the time that the excess generation is available for sale. The variability inherent in generation availability, native load, and market prices can cause the amount and value of off-system sales to vary significantly from one period to another, both on a short-term and a long-term basis.

When off-system sales are determined by modeling, the calculated level of off-system sales is determined from inputs of generation availability or unplanned outage rates, native or retail load levels, and market prices, among other factors. As I will illustrate, differences between the actual level and the modeled level of each one of these variables can create a significant difference between the amount of off-system sales actually achieved and the modeled level of off-system sales.

The actual native loads for AmerenUE vary as a result of changes in weather and load growth. Schedule SES-E2 shows the actual AmerenUE native load versus the projected weather-normalized loads for the last 9 years. In this illustration, the range of variation between actual and projected weather normalized loads, which is primarily weather related, for the nine-year period was 4.1% (from -1.4% to +2.7%). Based on 41,080,000 MWh of retail load and an average normalized market price of $40.47, the impact of retail load uncertainty can affect the level of off-system sales by an estimated $68.2 million from year to year.

Unplanned generation outages can also cause significant additional uncertainty in off-system sales. The generation equivalent normalized unplanned outage rate utilized for modeling purposes is 8.1%, which is the average for the six-year period 2002 through 2007. During this period the generation equivalent unplanned outage rate ranged by 6%, from 5.6% to 11.6%. See Schedule SES-E2. Based on the generation output level of 49.8 million MWh, this 6% range in plant availability alone results in an off-system sales uncertainty of 2,988,000 MWh or $120.9 million a year.

In addition, the timing associated with unplanned generation outages can have a significant effect on off-system sales. A two-week unplanned outage of a 600 MW unit in February rather than March would reduce the off-system sales by over $1 million based on the prices utilized in the model. Thus, the timing of generation outages, if different than modeled, can also result in significant changes to the level of off-system sales.

Finally, market price uncertainty has a significant impact on off-system sales. The expected level of off-system sales is approximately 10.5 million MWh annually. Thus, each $1.00 change in market prices for energy causes off-system sales revenues to vary by approximately $10.5 million. Schedule SES-E3 shows the variability in the forward around-the-clock ("ATC") market price at the Cinergy hub for delivery in calendar year 2007, as quoted during 2006. As can be seen from the graph, the forward market price for 2007 ranged from a low of $39.21 per MWh to a high of $69.07 per MWh, for a total high-low range of $29.86 per MWh. Even if the price spike in January 2006 was ignored, there is still a $15.82 per MWh difference between the high and the low forward ATC prices for calendar year 2007. This illustrates that if AmerenUE were able to sell half of the generation available for off-system sales into the forward market, based on just these difference in the prices of forward sales and total off-system sales of approximately 10.5 million MWh, the off-system sales revenue uncertainty from such forward sales could vary from between $83 million (at the $15.82 per MWh forward price range) to $157 million (at the $29.86 per MWh forward price range).

Similar off-system sales revenue uncertainty results from uncertainty in spot market prices. Schedule SES-E4 shows the 12-month rolling average of the day-ahead LMPs at the AmerenUE coal fired generating plants. This represents the change in prices that AmerenUE would be exposed to if the plants were able to sell all of their MWhs at the day-ahead LMP. As can be seen, the 12-month rolling average LMP at the AmerenUE coal fired plants (as calculated beginning 12 months from the start of the MISO energy market), has varied $9.91 per MWh from a low of $38.27 per MWh to a high of $48.18 per MWh. Selling the approximately 10.5 million MWh of off-system sales into the day-ahead market, given this uncertainty in the 12-month average of the day ahead market prices, exposes AmerenUE to off-system sales revenue uncertainty of $104 million.

As can be seen from these illustrations, AmerenUE is exposed to a significant amount of uncertainty and volatility in the level of off-system sales as a result of price volatility, generation performance, and native load variability.

This significant uncertainty and volatility in off-system sales revenues is summarized in the following table.

Uncertainty Factor	Annual Uncertainty of Off-System Sales Revenues
(1) Retail load	$68 million
(2) Unplanned Generation outages	$120 million
(3a) Forward market prices	$83 - $157 million
(3b) Spot market prices	$104 million

Q. Please identify other areas that also affect the uncertainty and volatility of off-system sales.

A. One other area that can affect the level of off-system sales and costs experienced by AmerenUE are system operations. Generation and transmission outages within the MISO footprint can cause congestion on the system that either lowers or raises the LMPs at the AmerenUE generators and at the point of delivery for off-system sales. As was shown earlier, LMP or price differences can have a significant impact on AmerenUE's off-system sales. System operations may also dictate that AmerenUE units are brought on to meet the requirements of the MISO to manage congestion and ramping requirements. The operation of these units may be a result of the Reliability Assessment Commitment ("RAC") at the MISO. Quite often when a unit is "RAC'd on" (dispatched by the RAC for reliability, not economic, reasons) within MISO, the owner of the unit does not receive enough compensation through the LMP to cover the cost of the unit and MISO provides a payment to the unit's owner to cover the costs. These payments, which are uplifted to deviations in the MISO market and which may include both off-system sales and loads, will further increase the uncertainty in off-system sales revenues beyond the uncertainties I have already discussed above.

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 SHAWN E. SCHUKAR

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

Shawn E. Schukar, being first duly sworn on his oath, states:

1. My name is Shawn E. Schukar. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Vice President, Strategic Initiatives.

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 18 pages, Attachment A and Schedules SES-E1 through SES-E4, 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.

Shawn E. Schukar

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

Shawn E. Schukar

Vice President, Strategic Initiatives, Ameren Services Company

* * * * * * * * * *

The purpose of my testimony is to address four areas relating to off-system sales revenues: 1) a determination of the normalized level of off-system sales that is appropriate to utilize for the determination of the Company's revenue requirement; 2) an explanation of how the level of off-system sales is dependent on the Company's loads, generation availability, and market energy prices; 3) an explanation of why it is appropriate to determine off-system sales revenues through the use of the PROSYM production cost model, and 4) documenting the significant uncertainty in the level of off-system sales revenues.

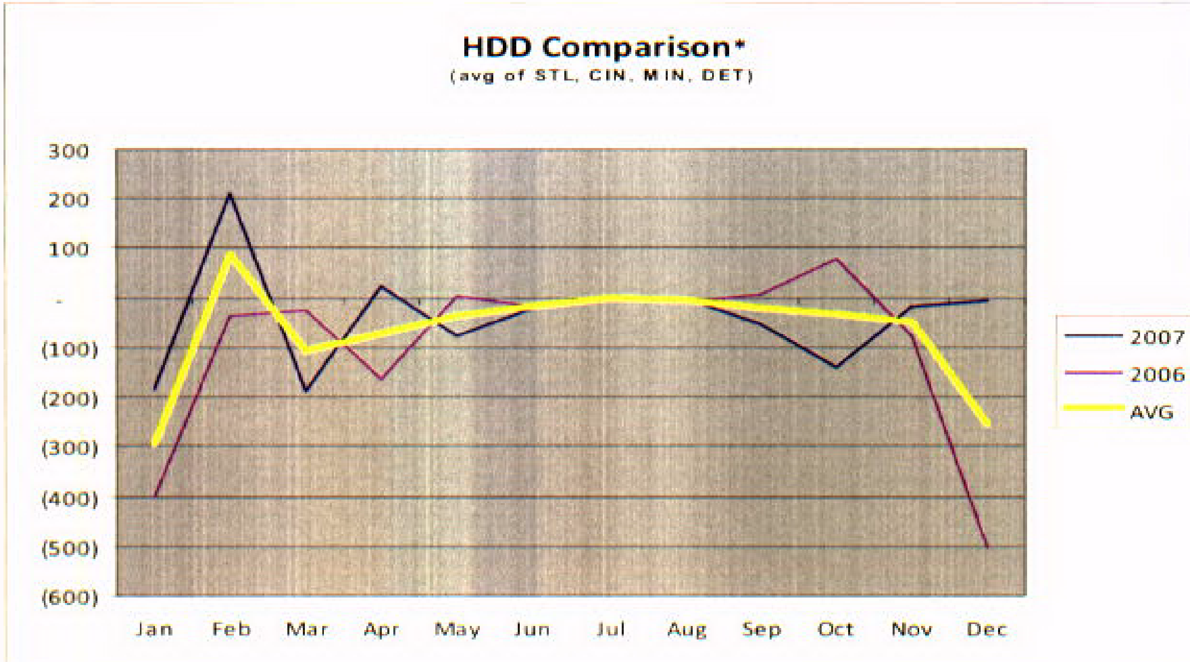
The appropriate level of off-system sales revenues to utilize in the determination of AmerenUE's revenue requirement is $454.3 million per year, which includes $443.2 million per year of off-system energy sales, $7.6 million per year of capacity sales, and $3.5 million per year of ancillary services sales. The energy sales values were determined based on modeling of AmerenUE's weather normalized load, normalized generation unplanned outages, normalized gas and electricity prices, and including the Taum Sauk generation facility as if it remained in service. This is appropriate because it is necessary to align the normalized generation unplanned outages and weather normalized loads that are utilized in determining rates with the level of off-system sales revenues that are used as an offset to the Company's revenue requirement for purposes of setting rates. In addition, to ensure that the customer is not affected by the unavailability of the Taum Sauk generation facility, AmerenUE's costs and revenues were modeled as if the Taum Sauk Plant was available.

This includes an adjustment for capacity sales that could have reasonably been expected to have been made had the Taum Sauk generation facility been available during the test year. In addition, an adjustment to energy sales values was made for forward sales of capacity, energy, and ancillary services that have been made for 2008.

The PROSYM production cost model was used for the determination of the off-system sales energy revenues. The key inputs used in the PROSYM model were normalized hourly loads, unit operating characteristics, fuel and emission costs, variable operation and maintenance costs and hourly market prices. For dispatch purposes, the market prices for normalized off-system sales, consistent with the fuel and emissions costs, are monthly energy prices for the period from January 2006 through December 2007, which results in a normalized average energy price of $40.47. The use of this two-year weighted average, which is based on the locational marginal prices at the generators that had actually made off-system sales during 2007, is appropriate to ensure consistency with normalized loads and unplanned outages.

The level of off-system sales has a significant amount of uncertainty associated with: (1) native load variability (which reduces the amount of generation that is available for sales); (2) generation unplanned outage rates; and (3) market prices for power. Based on historical information associated with native load variability, native load variability can cause approximately $68 million in uncertainty of off-system sales revenues. Unplanned forced outages for the AmerenUE generating plants historically varied by 6%, from 5.6% and 11.6%. This 6% variability in the unplanned outages at AmerenUE generating plants creates uncertainty in AmerenUE off-system sales revenues of approximately $121 million. Finally, the uncertainty in spot and forward market prices for energy creates uncertainty in off-system sale revenues of up to $157 million.

EXHIBIT SES-E1



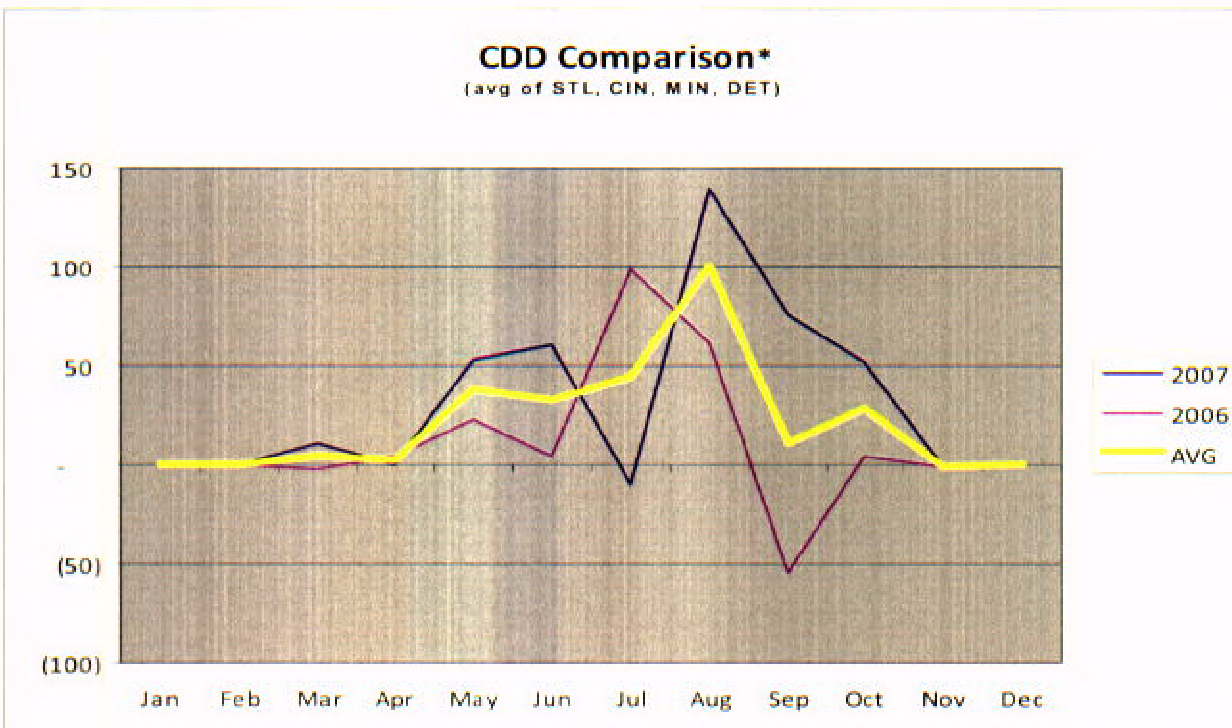


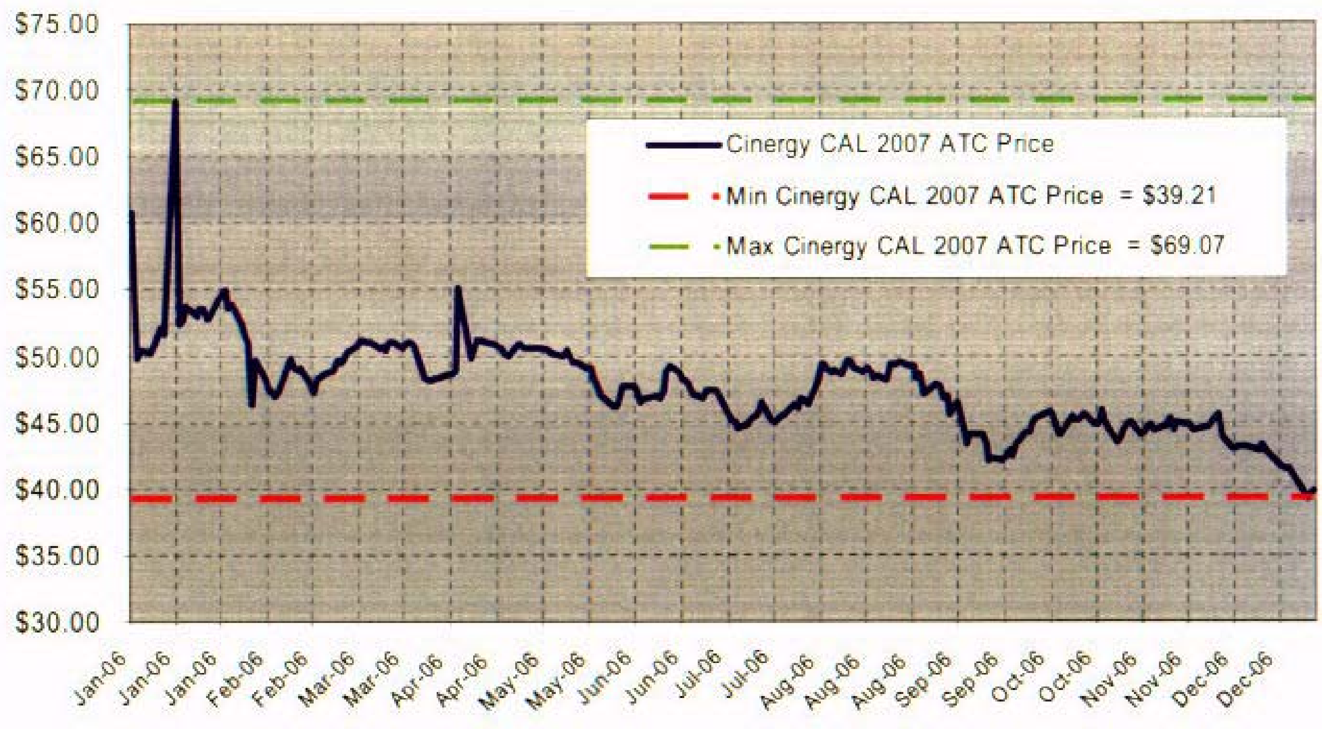
Exhibit SES-E2

Year	% Difference Between Actual Load and Weather Normalized Projected Load
1999	(1.4%)
2000	2.7%
2001	(0.9%)
2002	0.6%
2003	(0.5%)
2004	0.3%
2005	1.8%
2006	(0.4%)
2007	1.3%
Range	(1.4%) – 2.7%

Year	Generation Equivalent Unplanned Outage Rate
2002	11.6%
2003	7.8%
2004	9.2%
2005	5.6%
2006	7.9%
2007	6.7%
Range	5.6% - 11.6%

Exhibit SES-E3

Cinergy Hub CAL 2007 ATC*** Prices in 2006



- Confidential -

Source: ICAP

*** Values represent the hour weighted, daily observations in 2006 for the Calendar 2007 Around The Clock pricing

Schedule SES-E3
HIGHLY CONFIDENTIAL

Exhibit SES-E4