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Witness:	Kevin C. Higgins
Sponsoring Party:	The Commercial Group
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BEFORE
THE MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2007-0002

Direct Testimony of Kevin C. Higgins

on behalf of

The Commercial Group

December 15, 2006

Commercial Group Exhibit No. 850NP
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DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by The Commercial Group. The Commercial Group is comprised of the Missouri locations of Lowe's Home Centers, Inc.; Wal-Mart Stores East LP; and J.C. Penney Corporation; Inc. Collectively, the members of The Commercial Group purchase more than 236 million kWh annually from AmerenUE in Missouri, primarily on rate schedules LGS and SPS.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified previously before any state utility regulatory commissions?

A. Yes. I have testified in over sixty proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Nevada, New York, Ohio, Oregon, Pennsylvania, South Carolina, Utah, Virginia, Washington, West Virginia, and Wyoming.

A more detailed description of my qualifications is contained in Attachment A to this testimony.

Overview and Conclusions

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

A. My testimony addresses: (1) The appropriate ratemaking treatment for AmerenUE's ownership share of the EEInc. generation resource, and (2) AmerenUE's alternative proposal for sharing of off-system sales margins.

As part of my testimony, I offer recommendations to the Commission on these issues in support of a just and reasonable outcome.

Q. Are your recommendations relevant to the Fuel Adjustment Clause portion of this proceeding?

A. My recommendations are applicable whether or not a Fuel Adjustment Clause ("FAC") is approved by the Commission as part of this proceeding. However, the preferred means of implementing my recommendations pertaining to the EEInc. resource may vary depending on whether an FAC is adopted. Consequently, I will tailor my recommendations for both outcomes, i.e., whether an FAC is adopted or rejected at this time.

Q. What conclusions and recommendations do you offer based on your analysis?

A. I offer the following conclusions and recommendations:

(1) AmerenUE, acting in concert with its corporate affiliates, has chosen to forego the opportunity to purchase cost-based power from its share of the EEInc. Joppa generating plant. In my opinion, the incremental costs associated with this action are imprudent. Consequently, rates for retail customers should be established such that the incremental cost of serving Missouri retail load absent the EEInc. resource are absorbed by the Company, and not by customers. I estimate this amount to range from approximately $21.7 million to $62.6 million per year, depending on whether foregone off-system sales margins are included in the calculation. If an FAC is adopted, the necessary adjustment to rates can be

implemented as part of the FAC mechanism. If an FAC is not adopted, the adjustment should be incorporated into base rates.

(2) AmerenUE proposes a fixed credit to customers from off-system sales of $183 million. In addition, the Company proposes an alternative approach that incorporates a sharing of off-system sales margins between customers and the Company. I believe a properly structured sharing mechanism for off-system sales can have merit and is worthy of adoption. However, the specific sharing proposal put forward by the Company should <u>not</u> be adopted, as it does not strike the necessary balance between added risk and added potential reward for customers compared to the fixed-credit approach. I propose an alternative sharing approach based on a 50/50 sharing of *deviations* from the pro-forma level of $183 million in off-system sales margins.

<u>EEInc. Generation</u>

Q. Please describe the situation pertaining to EEInc. generation.

A. AmerenUE owns 40 percent of the stock of Electric Energy Inc. ("EEInc."), an affiliate company that owns and operates a coal-fired power plant located near Joppa, Illinois. The Joppa plant has a nameplate capacity of approximately 1,100 MW. An additional 40 percent of EEInc. is owned by Ameren Energy Marketing Company (another AmerenUE affiliate that is a wholly-owned subsidiary of Ameren Corporation) and the remaining 20 percent is owned by Kentucky Utilities Company. Consistent with its majority ownership of EEInc. through its affiliates, Ameren Corporation controls a majority of the seats on the EEInc. Board of Directors.

According to the Company's witnesses in this proceeding and other public documents, the Joppa facility came on line in 1954 and has been used primarily to deliver capacity and energy to a Federally-owned uranium enrichment facility located at Paducah, Kentucky, and secondarily to provide available capacity and energy to EEInc.'s owners or affiliates pursuant to cost-based power supply agreements ("PSAs".) The most recent PSA was entered into in 1987 and expired on December 31, 2005.

By 2003, the Federal purchase obligation from the Joppa facility had been reduced to 10 percent of the plant's output, and in 2004 and 2005 the Federal purchase obligation was reduced to zero.[1] Consequently, AmerenUE's 40 percent share of the plant, or approximately 440 MW, was available to serve AmerenUE retail customers at cost-based rates in 2004 and 2005. In 2005, AmerenUE purchased 4,974,178 MWHs of power from the Joppa plant at an average price of just under $17.40 per MWH.[2]

On September 15, 2005, EEInc. filed an application with the Federal Energy Regulatory Commission seeking market-based rate authority for the output of the Joppa facility, effective upon expiration of the PSA. This request was granted, and at the present time the full output of the plant is sold to Ameren Energy Marketing at market prices. As a result of this action, no portion of the

[1] EEInc. FERC Form 1, 2004, p. 123.2.
[2] EEInc. FERC Form 1, 2005, pp. 310-311.

Joppa plant's output is used any longer for serving AmerenUE customers at cost-based rates.

Q. What are the consequences for AmerenUE's retail customers stemming from the decision to discontinue the sale of power from the Joppa facility to AmerenUE at cost-based rates?

A. As the Joppa facility produces power at relatively low cost, the decision to discontinue the sale of power from the Joppa facility to AmerenUE at cost-based rates causes the utility's fuel expense to increase. The incremental cost associated with this increase in fuel expense is included in AmerenUE's overall rate increase request of $360.7 million. In addition, it is likely that the removal of the Joppa resource will cause a net reduction in AmerenUE's off-system sales margins, as less AmerenUE capacity will be available for such sales. As described below, I conservatively estimate that the increase in fuel cost due to AmerenUE's decision to forgo cost-based power from the Joppa facility is about $21.7 million per year. If the likely reduction in off-system sales margins is taken into consideration, the impact on retail customer rates may be as a high as $62.6 million.

Q. How does AmerenUE justify the decision to forego the opportunity to purchase power from the Joppa facility at cost-based rates?

A. The Company uses three witnesses to explain and justify its actions: Warner L Baxter, Michael L. Moehn, and Robert C. Downs. The gist of the Company's explanation boils down to the following:

- AmerenUE's ownership of EEInc. was purchased with shareholder funds and is a "below-the-line" investment. The plant was never included in rate base and the previous PSAs between EEInc. and AmerenUE were arm's length agreements. Given the expiration of the most recent PSA on December 31, 2005, there is no basis for conveying any future benefits to ratepayers from the Joppa facility.

- The Board of Directors of EEInc. has a fiduciary responsibility to its shareholders to maximize the value of their investment in the Joppa facility. With more attractive market-priced options available, it was not in shareholders' interest to renew the cost-based sales arrangement with AmerenUE.

Q. In your opinion, do AmerenUE's justifications for not renewing the PSA provide a reasonable basis for subjecting ratepayers to the higher incremental costs associated with foregoing the opportunity to purchase cost-based power from the Joppa facility?

A. No. As I will explain below, the Company's justifications are characterized by an undue emphasis on only one set of interests – that of shareholders. The Company ignores the important equities concerning ratepayer interests.

Q. In your opinion, should the Commission accept the ratemaking consequences for AmerenUE's customers that stem from the Company's decision to forego the opportunity to purchase power from the Joppa facility at cost-based rates?

A. No. AmerenUE is a regulated utility with an obligation to provide safe, reliable service at just and reasonable rates. To achieve rates that are just and reasonable, the interests of utility shareholders must be balanced with the interests of retail customers. In foregoing the opportunity to purchase cost-based power from the Joppa facility, AmerenUE has failed to adequately consider the interests of its retail customers. In my opinion, the incrementally-higher fuel and purchased power costs incurred as a result of this failure are imprudent. Consequently, rates for retail customers should be established such that the incremental costs of serving AmerenUE's retail load absent the output of the Joppa facility are absorbed by the Company, and not by its customers.

Q. You state that AmerenUE made a decision to forego the opportunity to purchase power from the Joppa facility at cost-based rates. Wasn't the decision to deny AmerenUE retail customers continued access to cost-based power from the Joppa facility really a decision of the EEInc. Board of Directors and not a decision of AmerenUE or Ameren Corporation?

A. AmerenUE describes this decision as being that of the EEInc. Board of Directors. According to the Company's filing, EEInc.'s Board consists of seven members, five of whom are employees of Ameren Corporation or its affiliates. (The other two Directors are employees of Kentucky Utilities or its affiliates.)[3] As Ameren Corporation and its affiliates control a majority of the EEInc. Board, the decision by that Board to deny AmerenUE retail customers continued access to cost-based power from the Joppa facility was, clearly, also a decision of Ameren Corporation. So although the formal decision not to renew the PSA may be depicted as an action of EEInc., that action could only have occurred with the full support of Ameren Corporation.

This obvious conclusion is reinforced [redacted]

[redacted][4]

The Sponsors are the companies that own EEInc: AmerenUE, Ameren Energy Marketing, and Kentucky Utilities. [redacted] Thus, one can only conclude that the Power Supply Agreement emerging from such a process is a product that reflects the corporate objectives of the individual Sponsor companies with a controlling interest in EEInc., namely AmerenUE and its affiliates.

Q. **But doesn't Ameren witness Robert C. Downs assert that it would have been improper and unlawful for the EEInc. Directors to agree to sell power to AmerenUE at cost-based rates in order to benefit Missouri retail customers at the expense of shareholders?**

A. Yes, but Professor Downs is careful to state that his conclusions are drawn using an important distinction based on his understanding of Mr. Moehn's testimony. The distinction is that the Joppa facility has not been included in rate

[3] Direct testimony of Robert C. Downs, p. 6, lines 7-9.

[4] [redacted].

base.[5] Based on that distinction and based on his understanding of Mr. Moehn's testimony, Professor Downs concludes that the only party to whom the Ameren corporate representatives on the EEInc. Board have any duty is that of shareholders. I am not attorney and will not attempt to draw conclusions of law, but I have twenty years of experience in utility regulation and policy. Based on my understanding of the facts concerning the Joppa plant, I conclude that the simple fact that the Joppa plant was not in rate base does not eliminate the need – from the standpoint of regulatory policy – to consider the interests of retail customers in this matter.

Q. Why should retail customer interests be considered in determining the appropriate disposition of power from the Joppa plant if the facility is not in rate base?

A. The fact that this fifty-year-old plant is not in rate base does make it an atypical case. However, it is clear from the history of the plant that Missouri retail customers have played an important role in assuring the financial viability of the facility. It is also clear that the business arrangements associated with the EEInc. venture have not been characterized by a single-dimensional "seller's" interest among the owners, as AmerenUE would have us believe, but has been accompanied by a reciprocal set of "customer" interests and obligations among the owners. These "customer" interests and obligations have generally corresponded to the proportion of ownership of each sponsor in EEInc. The dual "seller" and "customer" attributes of the EEInc. business arrangement, which

[5] Direct testimony of Robert C. Downs, p. 6, line 20 – p. 7, line 19.

distinguish it from a more conventional enterprise, should be taken into consideration by the Commission in this proceeding to determine whether the Company's proposal to forego cost-based power from the Joppa facility will result in just and reasonable rates for AmerenUE retail customers.

Q. How have Missouri retail customers played an important role in assuring the financial viability of the facility?

A. Since the Joppa plant's inception, its generation in excess of Federal purchase requirements has been sold on a cost-plus basis to EEInc.'s owners. Contractually, these sales have been in the form of "permanent" Joppa power and "excess" Joppa energy. "Permanent" Joppa power was subscribed to by each of EEInc.'s owners in proportion to their respective ownership shares. Accordingly, each of the plant's owners, including AmerenUE's predecessor, Union Electric Company, entered into long-term purchase obligations with EEInc. The most recent of these obligations, termed the Power Supply Agreement ("PSA"), stretched from September 2, 1987 to December 31, 2005. The PSA provides that the rate paid for "permanent" Joppa power was to recover interest expense, O&M expense, taxes, 110 percent of fuel expense,[6] and an after-tax return on equity of 15 percent. These costs were then passed on to retail customers as purchased power costs. This long-term obligation of ratepayer-funded power purchases helped ensure the financial viability of the EEInc. business venture. The right to purchase "excess" Joppa energy was also allocated in proportion to ownership.

[6] In an Amendment added in 1988, the 10 percent mark-up of fuel costs was changed to a demand charge adder of $1.53/MWH.

Q. Is there direct evidence that the long-term purchase obligations undertaken by the owners (as customers) helped ensure the financial viability of the Joppa plant?

A. Yes. This assurance of financial viability is readily apparent in reviewing a Commission Order issued in 1977 that approved the application of Union Electric Company for authority to guarantee certain financial obligations of EEInc. As discussed in the Order, EEInc. required financing to fund pollution control investments at the Joppa plant, and had arranged to issue $10 million in bonds to Metropolitan Life Insurance Company. The Order indicates that the owner-utilities ("Sponsoring Companies") and EEInc. were parties to an Amended Intercompany Agreement that, among other things, obligated the Sponsoring Companies to make payments for power purchased from EEInc. "in such amounts which, when added to EEI's other revenues, will be sufficient to enable EEI to pay all its operating and other costs and expenses, including taxes and interest and sinking fund charges on its bonds outstanding from time to time under the Mortgage." [Footnote omitted] [7] That is, Union Electric Company, as a Sponsoring Company, had entered into a long-term purchase obligation that helped ensure the financial viability of the EEInc. business venture.

This type of assurance was extended further as part of the "financial guarantee" that Union Electric Company sought to make on EEInc.'s behalf in 1977, which was the subject of the 1977 Order. As explained in the Order, Union

[7] Report and Order, *In The Matter Of The Application Of Union Electric Company For Authority To "Guaranty" Certain Financial Obligations Of Electric Energy, Inc., An Affiliate*, Case No. EF-77-197, 21 Mo. P.S.C. (N.S.) 425, 426, 1977 Mo. PSC LEXIS 23 (June 24, 1977).

Electric Company proposed a new amendment to the Amended Intercompany Agreement to cover the new $10 million bond issuance. The new amendment was intended to make unconditional the obligations of the Sponsoring Companies to make payments to EEInc. sufficient to enable EEInc. to pay its operating and other cost and expenses in the event that EEInc. was unable to generate or deliver any power to the Sponsoring Companies. In such a situation, the Sponsoring Companies would nonetheless be obligated to continue payments to EEInc. As stated in the Order, the obligations of the Sponsoring Companies were proposed to be "enlarged in order to induce the purchase of the 8½ percent Bonds by Metropolitan Life Insurance Company." [8] Put another way, the purchase obligations undertaken by Union Electric Company and the other Sponsoring Companies were necessary to secure the financing of EEInc.'s bonds.

Q. From a regulatory perspective, did Union Electric Company receive anything in return for providing a "guaranty" of EEInc.'s financial obligations?

A. Yes. According to the Order, in return for its "guaranty" of EEInc.'s financial obligations, Union Electric Company was "assured of a continuous source of economical power." It is worth noting here that in providing financial assurance to an entity of which it was an *owner*, Union Electric Company took on enlarged obligations in its role as a *customer* of that entity, and that, moreover, the benefit deriving from that enlarged obligation, as identified by the Commission, was a *customer* benefit.

Q. What are the ratemaking implications of these facts in this proceeding?

[8] Report and Order, Case No. EF-77-197, 21 Mo. P.S.C. (N.S.) at p. 427.

A. The core question here is whether the most reasonable and prudent course of action for AmerenUE, in its dual role as owner and customer of EEInc., facing expiration of the PSA, would have been to negotiate a replacement PSA with EEInc. under cost-based terms similar to those which existed for the previous 18 years, or to have allowed the contract to expire, and re-direct 100 percent of the benefit of AmerenUE's share of the Joppa plant to shareholders, with the consequent negative rate impact for AmerenUE customers. The ability to have extended the PSA was entirely within the control of AmerenUE and its corporate affiliates. As AmerenUE made the corporate decision to forego the opportunity to renew the PSA at cost-based rates, the Commission must then decide whether to approve AmerenUE's request to have customers pay the incremental cost of this decision as part of AmerenUE's $360 million rate increase request.

The history of the Joppa plant shows that the financial viability of the enterprise was assured through long-term contractual obligations in which the owners took on the role of customers. With the utility taking on the obligation of a long-term customer of its affiliate, AmerenUE ratepayers helped secure the financial viability of the Joppa plant as the EEInc. contract costs were recovered as purchased power expense. I submit that, in facing the expiration of the PSA, the most prudent course of action for AmerenUE as a regulated utility would have been to arrange to extend or renew the PSA on cost-based terms similar to those which had worked to the apparent mutual benefit of the Company and its ratepayers for the previous fifty years. Instead, AmerenUE has made a corporate decision to forego the opportunity to extend that arrangement. While the

Company may be free to make such a decision, it should not be allowed to pass the resulting incremental costs on to its ratepayers. I recommend that the Commission find that the incremental costs incurred as a result of that decision to be imprudent, and order that rates for retail customers should be established such that the incremental cost of serving AmerenUE's retail load absent the output of the Joppa facility are absorbed by the Company, and not by its customers.

Q. Are you aware of any situations in recent years in which other utilities that were in possession of "below-the-line" generation assets attempted to purchase power from those assets on a cost-of-service basis for the benefit of retail customers?

A. Yes. According to documents filed with the Kentucky Public Utilities Commission in July 2006, Kentucky Utilities – AmerenUE's partner in the EEInc. – stated that prior to the expiration of its PSA with EEInc., it had attempted to negotiate an extension of the PSA based on the previous cost-of-service terms.[9] Evidently, a utility facing circumstances similar to AmerenUE was willing to balance ratepayer interests with shareholder interests in addressing the disposition of power from a "below-the-line" resource which had had its financing secured through ratepayer-funded long-term purchase obligations. This approach is markedly different from that pursued by AmerenUE. We know that Kentucky Utilities' attempt to secure cost-based power was unsuccessful. We also know that, unlike AmerenUE and its affiliates, Kentucky Utilities does not have a controlling interest in EEInc.

Q. Are you aware of other examples in which a utility attempted to purchase power from "below-the-line" generation assets on a cost-of-service basis for the benefit of retail customers?

A. Yes. In 2002, I was a witness in a proceeding in Arizona that addressed a request by Arizona Public Service Company ("APS") to purchase power under a long-term contract at cost-based rates from a generation affiliate, Pinnacle West Energy Corporation ("PWEC"). PWEC had built several generation plants, the sales from which were not regulated by the state utility regulatory authority, the Arizona Corporation Commission ("ACC"). As explained in APS' testimony in that case, PWEC had built plants that were not in rate base, and had passed up opportunities for lucrative forward market sales to California based on the assessment of the parent company's president that the need to provide long-term resources to serve Arizona's retail load requirements was a higher priority.[10]

Unlike AmerenUE's ownership of EEInc., the PWEC units were not even directly owned by APS, yet its parent company's assessment of its obligation to retail customers resulted in the generation affiliate foregoing market sales opportunities. The actions taken by APS and its parent company demonstrate that

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[9] Kentucky Public Service Commission, Case No. 2006-00264, Kentucky Utilities Company Response to Information Requested in Appendix A of Commission's Order Dated July 6, 2006, Question No. 3, Witness: Keith Yocum. July 27, 2006.

[10] Arizona Corporation Commission, Docket No. E-01345A-0-0822. Rebuttal testimony of Jack E. Davis, President of Energy Delivery and Sales for APS and President of Pinnacle West Capital Corporation. On page 21 of his prefiled rebuttal testimony, Mr. Davis stated: "Redhawk, West Phoenix 4 and 5, and the Saguaro CT, all of which were constructed or are being constructed by PWEC, were not sized, sited or constructed by happenstance or on speculation. They were expressly built to serve APS load, and were planned and begun at a time when it looked as if nobody was willing to build for the Arizona, or more specifically, the APS market given the lucrative possibilities in California. In fact, I personally took part in discussions of whether PWEC should itself sell all or a portion of Redhawk's output forward to California. Despite the tremendous profit potential from such a transaction, I was unwilling to gamble that an unidentified "somebody else" would then meet APS' needs here in Arizona."

consideration of retail customer interests is a fundamental part of doing business prudently as a regulated utility. Clearly, APS and parent company management did not view itself as operating within a "straightjacket" in which only the short-run profits of shareholders could be considered when determining the appropriate disposition of power generated from "below-the-line" power plants.

Q. How should AmerenUE rates be adjusted to ensure that the incremental cost of serving AmerenUE's retail load absent the output of the Joppa facility are absorbed by the Company?

A. AmerenUE uses a system dispatch model called PROSYM to calculate its fuel and purchased power revenue requirement in this docket. The most accurate measure of the incremental cost of serving AmerenUE's retail load absent the output of the Joppa facility would be determined by running a dispatch model such as this to calculate the difference between the test year fuel and purchased power costs incurred by the Company and what would have been incurred had the PSA been extended under terms similar to what had been in place up to December 31, 2005. As part of a discovery request, I asked that AmerenUE perform this calculation using its PROSYM model, but the Company refused to do so.

In light of this refusal, I have estimated the revenue adjustment using other available information. To estimate the incremental fuel cost to serve retail load, I used the per-MWH plant costs and purchases associated with AmerenUE's off-system sales for the test year as a measure of AmerenUE's marginal energy cost. I then applied the difference between this unit cost and the unit costs that AmerenUE paid EEInc. for Joppa power in 2005, with the latter escalated by 5 percent to account for potentially higher fuel costs. I then applied this estimate of incremental unit cost to 40 percent of the output of the Joppa plant in 2005, which corresponds to AmerenUE's ownership share of the plant.[11] These calculations are shown in Schedule KCH-1 as Scenario 1. The result provides a conservative estimate of the incremental expense to serve retail load that is incurred as a result of Ameren's decision to forego the opportunity to renew the PSA under terms similar to what was in place in 2005. I estimate this incremental expense to be $21.8 million.

At the same time, AmerenUE's decision to forego cost-based purchases from the Joppa plant will also likely result in a reduced off-system sales margin credited to retail customers, as fewer low-cost resources will be available for off-system sales. (The Joppa facility will actually still be making sales into the market, but none of the sales will be credited to retail customers according to the Company's proposal.) I calculated the impact of reduced off-system sales margins in Schedule KCH-1 as Scenarios 2 and 3, discussed below.

In Scenario 2, I very conservatively assumed that the loss of the Joppa resource would result in a reduction in off-system sales credited to customers equal to 50 percent of AmerenUE's share of the plant. The rate impact on customers under this scenario – in which 50 percent of the foregone MWH results in a reduction in off-system sales margins and 50 percent of foregone MWH results in higher fuel and purchased power costs to serve retail load – is approximately $42.1 million. In making this calculation, I used a three-year

[11] I note that AmerenUE's actual purchase from the Joppa plant in 2005 amounted to 64 percent of the plant's output.

average market price of $38.11 per MWH to represent off-system sales prices. The three-year period used as the basis for this calculation was 2003 through 2005. These market prices were derived from the workpapers of AmerenUE witness Shawn E. Schukar, but did not include Mr. Schukar's adjustments to 2005 prices. Consequently, the market price used in my analysis is somewhat higher than the market price of $35.71 per MWH used by Mr. Schukar.

In Scenario 3, I assumed that the loss of the Joppa resource would result in a reduction of off-system sales margins for AmerenUE's full share of the plant. The rate impact on customers under this scenario is $62.6 million.

Q. Why did you use the per-MWH plant costs and purchases associated AmerenUE's off-system sales as a measure of AmerenUE's marginal energy cost?

A. Given the Company's refusal to provide a more accurate calculation of its incremental cost, it was necessary for me to identify a reasonable proxy. As, in any given hour, off-system sales should be transacted using the lowest-cost resources available to AmerenUE after retail load is served, I concluded that the Company's unit cost of making these sales was reasonable estimate of its marginal energy cost.

Q. Why did you use a three-year average market price covering 2003 through 2005 to represent off-system sales prices?

A. I used a three-year average price in order to reduce the potential scope of disagreement with the Company on this point. In his direct testimony, Mr. Schukar supports the use of a three-year average market price to avoid possible distortions in pricing that might otherwise occur if the prices for a single year, such as 2005, were used. The three-year average market price of $38.11 per MWH that I used was derived from the monthly prices in Mr. Schukar's workpapers. One difference I have with Mr. Schukar, however, is that prior to calculating the three-year average market price used in his analysis, Mr. Schukar adjusted 2005 prices downward to offset the pricing effects associated with Hurricane Katrina, MISO start-up, and rail transportation disruptions. In contrast, the three-year average I used is based on actual prices for all three years without the special adjustments to 2005 prices made by Mr. Schukar. In my view, the types of adjustments made by Mr. Schukar may be appropriate if 2005 prices alone were being used to estimate off-system sales margins; however, the use of a three-year average in the first instance is intended to compensate for volatility that may occur in any one year. Therefore, using both a three-year average AND adjusting 2005 prices prior to calculating the average is likely to introduce unwarranted downward bias into the market prices used for projecting off-system sales revenues.

Q. What is your recommendation to the Commission regarding the appropriate ratemaking treatment of AmerenUE's ownership share of the Joppa plant?

A. As I stated above, I recommend that the Commission find that the incremental costs incurred as a result of AmerenUE's actions with respect to the Joppa plant to be imprudent, and order that rates for retail customers be established such that the incremental cost of serving AmerenUE's retail load absent the output of the Joppa facility are absorbed by the Company, and not by customers. If an FAC is not adopted as part of this proceeding, this adjustment should be applied to base rates. The precise adjustment can be made as part of a compliance filing in response to a Commission order requiring that the necessary calculation be made using PROSYM. Alternatively, the adjustment can be made using the calculations I present in Schedule KCH-1 of up to $62.6 million.

If an FAC is adopted, then the adjustment can be implemented either through base rates or through the FAC charge. If the adjustment is made to base rates, then it would still be necessary to apply an equivalent adjustment to the FAC charge to ensure that the base rate disallowance is not overridden or "wiped out" by the subsequent FAC charge. That is, an FAC charge would typically recover all (prudent) fuel and purchased power costs incurred in excess of base fuel and purchased power rates. If actual costs are deemed to be too high as a result of imprudence, then the imprudence adjustment must be made to the FAC calculation – otherwise any base rate disallowance will be overridden in the calculation of the FAC charge and imprudent costs will be inadvertently recovered through the FAC. I will address the issue further as part of my direct testimony in the FAC phase of this proceeding.

In the alternative, the disallowance can be applied directly to the FAC charge as a credit, or offset component. The amount of the disallowance can be calculated as part of the FAC calculation by subtracting the incremental costs and/or reduction in off-system sales margins that are a result of AmerenUE's decision to forego purchasing cost-based power from its share of the Joppa plant.

This calculation can be updated with each successive determination of the FAC by applying a dispatch model such as PROSYM.

<u>Sharing of Off-System Sales Margins</u>

Q. Please describe the alternative proposal made by AmerenUE for sharing off-system sales margins between the Company and ratepayers.

A. AmerenUE's proposal for the treatment of off-system sales margins is discussed in the direct testimony of Mr. Baxter and Mr. Schukar, and in Mr. Shukar's supplemental direct testimony. The Company's primary proposal is to recognize $183 million in off-system sales margins as a credit against base rates. To the extent that the Company falls short of, or exceeds, this level of off-system sales margins, the full shortfall or gain would be experienced by the Company, with no impact on customers. This "fixed-credit" approach can be viewed as a traditional approach to treating off-system sales margins in rates.

Mr. Schukar's testimony also describes an alternative proposal that the Company stops short of fully endorsing. According to the alternative proposal, customers would receive 100 percent of the benefit from off-system sales for the first $120 million of annual margin, plus 80 percent of the benefit between $120 million and $180 million of annual margin, plus 50 percent of the benefit between $180 million and $360 million of annual margin, plus 100 percent of the benefit of any annual margins earned above $360 million.

Q. What is the purpose of such a sharing mechanism?

A. As discussed by Mr. Schukar, an off-system sales sharing mechanism reduces risk to the Company if actual off-system sales margins turn out to be lower than the pro-forma level (which, in this case, was initially proposed to be $180 million, but was later revised to $183 million). At the same time, the sharing mechanism can provide additional off-system sales benefits to customers if off-system sales levels turn out to be greater than the pro-forma level.

Q. What is your assessment of the Company's alternative sharing proposal?

A. I believe a properly-structured sharing mechanism for off-system sales can have merit and is worthy of adoption. The key lies in striking the proper balance between added risk and added potential reward for customers – and the reduced risk and reduced potential reward for the Company – vis-á-vis the fixed-credit approach. In my opinion, the specific sharing proposal put forward by the Company in this proceeding does <u>not</u> strike the necessary balance and should <u>not</u> be adopted.

Q. Please explain.

A. A comparison of the Company's sharing proposal relative to its fixed-credit proposal is shown in Table KCH-1, below. As shown in the table, if the Company's sharing proposal were adopted, it would free AmerenUE of all downside risk, relative to the fixed-credit approach, of failing to reach an off-system sales margin of $120 million – and it would free the Company of most of the risk associated with failing to reach an off-system sales margins of $180 million; instead, this risk would be transferred to customers. In addition, if the pro-forma margin of $183 million were reached, customers would receive a smaller benefit than under the fixed-credit approach. In fact, customers would receive a smaller benefit relative to the fixed-credit approach at all margins below $210 million. In exchange, customers would receive the potential to receive a share of increased off-system sales credit at off-system sales margins above $210 million.

Table KCH-1
Comparison of AmerenUE OSS Margin Proposals
($millions)

Margin	AmerenUE Fixed Proposal		AmerenUE Sharing Proposal		Impact on Customers of Sharing
	Customer Share	Co. Share	Customer Share	Co. Share	
$0	$183	($183)	$0	$0	($183)
$30	$183	($153)	$30	$0	($153)
$60	$183	($123)	$60	$0	($123)
$90	$183	($93)	$90	$0	($93)
$120	$183	($63)	$120	$0	($63)
$123	$183	($60)	$122	$1	($61)
$150	$183	($33)	$144	$6	($39)
$180	$183	($3)	$168	$12	($15)
$183	$183	$0	$170	$14	($14)
$210	$183	$27	$183	$27	$0
$240	$183	$57	$198	$42	$15
$243	$183	$60	$200	$44	$17
$270	$183	$87	$213	$57	$30
$300	$183	$117	$228	$72	$45
$330	$183	$147	$243	$87	$60
$360	$183	$177	$258	$102	$75
$390	$183	$207	$288	$102	$105

In my opinion, this risk-reward tradeoff is not reasonable for customers. For example, consider what would occur if off-system sales margins were to deviate by $60 million from the pro-forma margin of $183 million. At a $60 million deviation below $183 million, AmerenUE would experience $123 million in off-system sales margins, and under the Company's sharing proposal, customers would receive a credit of $122 million. This would represent a reduction in customer benefits of $61 million relative to the fixed-credit credit of

$183 million. Now consider a deviation of $60 million above the pro forma margin. In this case, AmerenUE would experience $243 million in margins and customers would receive a benefit of $200 million – an improvement of only $17 million relative to the fixed-credit approach. It is not a reasonable proposition for customers to accept the risk of a $61 million reduction in benefits if margins are $60 million below the pro-forma level in exchange for a $17 million increase in benefits if margins are $60 million above the pro-forma level.

Q. Do you recommend an alternative approach to margin sharing?

A. Yes. A preferred approach would be to design any sharing of off-system sales margins based on *deviations* from the pro-forma level of $183 million. In my opinion, it would not be unreasonable for customers and the Company to share on a 50/50 basis the impact of deviations in the off-system sales margin relative to the $183 million baseline. For example, in the aforementioned case of a $60 million deviation below $183 million, this approach would result in customers experiencing a reduction in benefits of $30 million, while in the case of a $60 million deviation above $183 million, customers would experience a $30 million increase in benefits. This risk/reward tradeoff is inherently more reasonable than that of the Company's sharing proposal for this same level of deviation, as discussed above. For purposes of this proceeding, I would recommend capping the 50/50 sharing at the $360 million margin proposed by the Company, after which any further improvements in the margin would flow 100 percent to customers.

A comparison of the Company's sharing proposal and my recommended approach is shown in Table KCH-2 below.

Table KCH-2
Comparison of AmerenUE and Commercial Group OSS Margin Proposals
($millions)

Margin	AmerenUE Sharing Proposal		Commercial Group Sharing Proposal		Change to Customer Ben. from CG Prop.
	Customer Share	Co. Share	Customer Share	Co. Share	
$0	$0	$0	$92	($92)	$92
$30	$30	$0	$107	($77)	$77
$60	$60	$0	$122	($62)	$62
$90	$90	$0	$137	($47)	$47
$120	$120	$0	$152	($32)	$32
$123	$122	$1	$153	($30)	$31
$150	$144	$6	$167	($17)	$23
$180	$168	$12	$182	($2)	$14
$183	$170	$14	$183	$0	$14
$210	$183	$27	$197	$14	$14
$240	$198	$42	$212	$29	$14
$243	$200	$44	$213	$30	$14
$270	$213	$57	$227	$44	$14
$300	$228	$72	$242	$59	$14
$330	$243	$87	$257	$74	$14
$360	$258	$102	$272	$89	$14
$390	$288	$102	$302	$89	$14

The column entitled "Change to Customer Benefit from CG Proposal" shows, at various margins, the improved benefit to customers from the sharing proposal I am recommending relative to the Company's sharing proposal. For example, if the margins turn out to be $243 million, the Company's approach would result in a customer credit of $199.5 (rounded to $200 million), whereas my proposal would credit customers with an additional 50 percent of the increase over $183 million, for a total benefit of $213 million.[12] This result is an improvement of $13.5 million (rounded to $14 million) relative to the Company's sharing proposal.

Similarly, if margins turn out to be \$123 million, the Company's approach would result in a customer credit of \$122 million, whereas my proposal would reduce the customer credit by 50 percent of the decrease from \$183 million, for a total credit from off-system sales margins of \$153 million – an improvement of \$31 million relative to the Company's sharing proposal. This result illustrates the significantly lower downside risk to customers incorporated into my margin sharing proposal relative to the Company's sharing proposal.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

[12] i.e., \$183 million + (50% x \$60 million) = \$183 million + \$30 million = \$213 million.

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-2007-0002

AFFIDAVIT OF KEVIN C. HIGGINS

STATE OF UTAH)
)
COUNTY OF SALT LAKE)

Kevin C. Higgins, being first duly sworn, deposes and states that:

1. He is a Principal with Energy Strategies, L.L.C., in Salt Lake City, Utah;

2. He is the witness who sponsors the accompanying testimony entitled "Direct Testimony of Kevin C. Higgins;"

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and schedules are true and correct to the best of his knowledge, information and belief.

Kevin C. Higgins

Subscribed and sworn to or affirmed before me this 12 ~~day~~ of December, 2006, by Kevin C. Higgins.

Notary Public

My Commission No.: ?
My Commission Expires: 3-28-10
(SEAL)

LORI FIKE
NOTARY PUBLIC • STATE of UTAH
505 E 200 S
SALT LAKE CITY, UT 84102
COMM. EXP. 03/28/2010

KEVIN C. HIGGINS
Principal, Energy Strategies, L.L.C.
215 South State St., Suite 200, Salt Lake City, UT 84111

Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of Application of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. for an Adjustment of Electric Rates," **Kentucky** Public Service Commission, Case No. 2006-00172. Direct testimony submitted September 13, 2006.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2006-00065. Direct testimony submitted September 1, 2006. Cross examined December 7, 2006.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744, **Arizona** Corporation Commission," Docket No. E-01345A-05-0816. Direct testimony submitted August 18, 2006 (Revenue Requirements) and September 1, 2006 (Cost-of-Service/Rate Design). Surrebuttal testimony submitted September 27, 2006. Cross examined November 7, 2006.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No 1454 – Electric," **Colorado** Public Utilities Commission, Docket No. 06S-234EG. Answer testimony submitted August 18, 2006.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-180. Direct testimony submitted August 9, 2006. Joint testimony regarding stipulation submitted August 22, 2006.

"2006 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006. Joint testimony regarding stipulation submitted August 23, 2006.

"In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE-179. Direct testimony submitted July 12, 2006. Joint testimony regarding stipulation submitted August 21, 2006.

"Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan," **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; "Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan," Docket Nos. P-0062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006. Surrebuttal testimony submitted August 18, 2006. Cross examined August 30, 2006.

"In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations," **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

"Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders," **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted May 15, 2006.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Power Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No. G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase," **Arizona** Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska**, Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company," **Kentucky** Public Service Commission, Case No. 2003-00434. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company," **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

"In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period," Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchased Power Contract," **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted

September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada,** PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01. Direct testimony submitted July 8, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to present. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

Incremental Cost of Discontinuing the Sale of Power from the EEInc. Joppa Plant to AmerenUE at Cost-based Rates

Scenario 1: Marginal Energy Costs

Line No.	Description	Amount	Source
1	2005 EEInc. Joppa Net Generation (MWh)	7,881,897	EEInc. 2005 FERC Form 1, p. 402, Line 12
2	AmerenUE Ownership Share of EEInc Joppa Output	40%	
3	AmerenUE Allocated Share of EEInc. Joppa Net Generation (MWh)	3,152,759	= Ln 1 x Ln 2
4	AmerenUE EEInc. Joppa 2005 Cost per MWh ($/MWh)	$17.40	See Note 1 for Derivation
5	CG Cost Escalation Allowance (%)	5%	CG Assumption
6	Estimated Test Year EEInc. Joppa Cost ($/MWh)	$18.27	= Ln 4 x [1 + Ln 5]
7	Replacement Power Avg. Cost (MWh)	$25.16	See Note 2 for Derivation
8	Incremental Cost	$\boxed{\$21,729,922}$	= [Ln 6 - Ln 7] x Ln 3

Note: EEInc. Joppa data based on Calendar Year 2005 Information

Note 1: Derivation of AmerenUE 2005 Cost per MWh

Line No.	Description	Amount	Source
9	Total Revenue Received from AmerenUE ($)	$86,547,136	See Note 1 "Data Source" below
10	Total Energy Sold to AmerenUE (MWh)	4,974,178	See Note 1 "Data Source" below
11	AmerenUE 2005 EEInc. Joppa Cost per MWh	$17.40	= Ln 9 ÷ Ln 10

Data Source: EEInc. 2005 FERC Form 1, p. 311, Ln 2

Note 2: Off-System Plant Costs and Purchases without Intercompany JDA Allocation Purchase from UEC (Amount $ = Total Off System Costs Less Intercompany JDA Allocation Purchase from UEC)

Line No.	Test Year Month	Amount ($)	Energy (MWh)	$/MWh	Source
12	Jul-05	$6,108,096	201,281	$30.35	See Note 2 "Data Source" below
13	Aug-05	$8,305,844	343,185	$24.20	See Note 2 "Data Source" below
14	Sep-05	$10,764,950	199,545	$53.95	See Note 2 "Data Source" below
15	Oct-05	$7,306,576	247,260	$29.55	See Note 2 "Data Source" below
16	Nov-05	$6,659,044	301,541	$22.08	See Note 2 "Data Source" below
17	Dec-05	$14,407,653	469,564	$30.68	See Note 2 "Data Source" below
18	Jan-06	$5,564,326	290,704	$19.14	See Note 2 "Data Source" below
19	Feb-06	$6,822,516	322,047	$21.18	See Note 2 "Data Source" below
20	Mar-06	$4,908,840	316,082	$15.53	See Note 2 "Data Source" below
21	Apr-06	$6,565,187	356,520	$18.41	See Note 2 "Data Source" below
22	May-06	$3,588,969	155,879	$23.02	See Note 2 "Data Source" below
23	Jun-06	$2,390,410	110,665	$21.60	See Note 2 "Data Source" below
24	Total	$83,392,410	3,314,273	$25.16	

Data Source: AmerenUE Response to Missouri PSC Data Request 0272

Incremental Cost of Discontinuing the Sale of Power from the EEInc. Joppa Plant to AmerenUE at Cost-based Rates

Scenario 2: 50% at Marginal Energy Costs & 50% at Wholesale Sales Margin

Line No.	Description	Amount	Source
1	2005 EEInc. Joppa Net Generation (MWh)	7,881,897	EEInc. 2005 FERC Form 1, p. 402, Line 12
2	AmerenUE Ownership Share of EEInc Joppa Output	40%	
3	AmerenUE Allocated Share of EEInc. Joppa Net Generation (MWh)	3,152,759	= Ln 1 x Ln 2
4	Portion of AmerenUE EEInc Generation Serving Retail Load (%)	50%	= 1 - Ln 6
5	Portion of AmerenUE EEInc Generation Serving Retail Load (MWh)	1,576,379	= Ln 3 x Ln 4
6	Portion of AmerenUE EEInc Generation Sold to Market (%)	50%	CG Assumption
7	Portion of AmerenUE EEInc Generation Sold to Market (MWh)	1,576,379	= Ln 3 x Ln 6
8	AmerenUE EEInc. Joppa 2005 Cost per MWh ($/MWh)	$17.40	See See KCH--1, p. 1, Note 1 for Derivation
5	CG Cost Escalation Allowance (%)	5%	CG Assumption
6	Estimated Test Year EEInc. Joppa Cost ($/MWh)	$18.27	= Ln 4 x [1 + Ln 5]
	Retail Portion of Disallowance		
7	Replacement Power Avg. Cost (MWh)	$25.16	See See KCH--1, p. 1, Note 2 for Derivation
8	Incremental Cost - Retail Portion	$10,864,961	= [Ln 6 - Ln 7] x Ln 5
	Wholesale Portion of Disallowance		
9	Three Year Avg. Market Price ($/MWh)	#REF!	See See KCH--1, p. 3, Note 3 for Derivation
10	Incremental Cost - Wholesale Portion	#REF!	= [Ln 6 - Ln 9] x Ln 5
	Total Disallowance		
11	Incremental Cost - Total	#REF!	= Ln 8 + Ln 10

Note: EEInc. Joppa data based on Calendar Year 2005 Information

Incremental Cost of Discontinuing the Sale of Power from the EEInc. Joppa Plant to AmerenUE at Cost-based Rates

Scenario 3: Wholesale Sales Margin

Line No.	Description	Amount	Source
1	2005 EEInc. Joppa Net Generation (MWh)	7,881,897	EEInc. 2005 FERC Form 1, p. 402, Line 12
2	AmerenUE Ownership Share of EEInc Joppa Output	40%	
3	AmerenUE Allocated Share of EEInc. Joppa Net Generation (MWh)	3,152,759	= Ln 1 x Ln 2
4	AmerenUE EEInc. Joppa 2005 Cost per MWh ($/MWh)	$17.40	See See KCH--1, p. 1, Note 1 for Derivation
5	CG Cost Escalation Allowance (%)	5%	CG Assumption
6	Estimated Test Year EEInc. Joppa Cost ($/MWh)	$18.27	= Ln 4 x [1 + Ln 5]
7	Three Year Avg. Market Price ($/MWh)	$38.11	See Note 3 for Derivation
8	Incremental Cost	$62,568,753	= [Ln 6 - Ln 7] x Ln 3

Note: EEInc. Joppa data based on Calendar Year 2005 Information

Note 3: AmerenUE's Three Year Average Market Price without the 2005 Price Adjustments

Line No.	Description	Amount	
	Weekly Weighting Factor		
9	Number of Hours in Year	8,760	
10	Number of Hours in Week	168	
11	Number of Weeks in Year	52.143	= Ln 9 ÷ Ln 10

Line No.	Description	$/MWh	Source
12	Three year average 5x16 market price	[redacted]	Schukar HC Workpaper (Confidential)
13	5x16 Annual Weighting	4,171	= 5 x 16 x Ln 11
14	5x16 Weighted Price	[redacted]	=Ln 12 x Ln 13
15	Three year average 2x16 market price	[redacted]	Schukar HC Workpaper (Confidential)
16	2x16 Annual Weighting	1,669	= 2 x 16 x Ln 11
17	2x16 Weighted Price	[redacted]	=Ln 15 x Ln 16
18	Three year average 7x8 market price	[redacted]	Schukar HC Workpaper (Confidential)
19	7x8 Annual Weighting	2,920	= 7 x 8 x Ln 11
20	7x8 Weighted Price	[redacted]	=Ln 18 x Ln 19
21	Total Weighted Price	$333,887	=Ln 14 + Ln 17 + Ln 20
22	Number of Hours in Year	8,760	
23	Three Year Average Market Price	$38.11	=Ln 21 ÷ Ln 22