EXHIBIT

Exhibit No.: 404
Issue(s): Off System Sales/
Conditions Ordered in Case No. EO-2004-0108/
SO_2 Sales Revenues/
Electric Energy, Inc. Joppa Plant/
Peno Creek, Pinckneyville and
Kindmundy Generation Facilities
Witness/Type of Exhibit: Kind/Direct
Sponsoring Party: Public Counsel
Case No.: ER-2007-0002

DIRECT TESTIMONY

OF

RYAN KIND

Submitted on Behalf of
the Office of the Public Counsel

UNION ELECTRIC COMPANY D/B/A AMERENUE

** **denotes highly confidential information****

NP

Case No. ER-2007-0002

OPC Exhibit No. 404-NP
Case No(s). ER-2007-0002
Date 3/14/07 Rptr MV

December 15, 2006

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	)	**Case No. ER-2007-0002**
Rates for Electric Service Provided to Customers	)	Tariff No. YE-2007-0007
in the Company's Missouri Service Area.	)	

AFFIDAVIT OF RYAN KIND

STATE OF MISSOURI	)	
	)	ss
COUNTY OF COLE	)	

Ryan Kind, of lawful age and being first duly sworn, deposes and states:

1. My name is Ryan Kind. I am a Chief Utility Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached affidavit are true and correct to the best of my knowledge and belief.

Ryan Kind

Subscribed and sworn to me this 15th day of December 2006.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

JERENE A. BUCKMAN
My Commission Expires
August 10, 2009
Cole County
Commission #05754036

Jerene A. Buckman
Notary Public

My commission expires August 10, 2009.

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DIRECT TESTIMONY

OF

RYAN KIND

UNION ELECTRIC COMPANY

CASE NO. ER-2007-0002

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Ryan Kind, Chief Energy Economist, Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND.

A. I have a B.S.B.A. in Economics and a M.A. in Economics from the University of Missouri-Columbia (UMC). While I was a graduate student at UMC, I was employed as a Teaching Assistant with the Department of Economics, and taught classes in Introductory Economics, and Money and Banking, in which I served as a Lab Instructor for Discussion Sections.

My previous work experience includes several years of employment with the Missouri Division of Transportation as a Financial Analyst. My responsibilities at the Division of Transportation included preparing transportation rate proposals and testimony for rate cases involving various segments of the trucking industry. I have been employed as an economist at the Office of the Public Counsel (Public Counsel or OPC) since 1991.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION?

A. Yes, prior to this case I submitted written testimony in numerous gas rate cases, several electric rate design cases and rate cases, as well as other miscellaneous gas, water, electric, and telephone cases.

Q. HAVE YOU PROVIDED COMMENTS OR TESTIMONY TO OTHER REGULATORY OR LEGISLATIVE BODIES ON THE SUBJECT OF ELECTRIC UTILITY REGULATION AND RESTRUCTURING?

A. Yes, I have provided comments and testimony to the Federal Energy Regulatory Commission (FERC), the Missouri House of Representatives Utility Regulation Committee, the Missouri Senate's Commerce & Environment Committee and the Missouri Legislature's Joint Interim Committee on Telecommunications and Energy.

Q. HAVE YOU BEEN A MEMBER OF, OR PARTICIPANT IN, ANY WORK GROUPS, COMMITTEES, OR OTHER GROUPS THAT HAVE ADRESSED ELECTRIC UTILITY REGULATION AND RESTRUCTURING ISSUES?

A. Yes. I was a member of the Missouri Public Service Commission's (the Commission's) Stranded Cost Working Group and participated extensively in the Commission's Market Structure Work Group. I am currently a member of the Missouri Department of Natural Resources Weatherization Policy Advisory Committee, the National Association of State Consumer Advocates (NASUCA) Electric Committee, and the Standards Authorization Committee of the North American Electric Reliability Council (NERC). I have served as the small customer representative on the NERC Operating Committee and as the public consumer group representative to the Midwest ISO's (MISO's) Advisory Committee. During the early 1990s, I served as a Staff Liaison to the Energy and Transportation Task Force of the President's Council on Sustainable Development.

I. INTRODUCTION

Q. PLEASE IDENTIFY THE MAJOR ISSUES THAT YOU WILL BE ADDRESSING IN YOUR TESTIMONY.

A. The major issues that are addressed in this testimony include:

- Off-system sales margins,
- Ratemaking impacts of the conditions in the Commission's order approving the Union Electric Company (UE or Company) Metro East Transfer in Case No. EO-2004-0108,
- Normalization of SO_2 emission allowance sales revenues,
- UE's entitlement to 40% of the capacity and output from the Electric Energy, Inc. (EEInc) plant in Joppa, Illinois,
- Revenue requirement impacts of UE's construction of the Peno Creek gas-fired generating facility; and
- Revenue requirement impacts of UE's acquisition of the Pinckneyville and Kinmundy gas-fired generating facilities from its affiliate, Ameren Energy Generating Company (AEG or Genco).

II. OFF-SYSTEM SALES MARGINS

Q. WHAT IS PUBLIC COUNSEL'S RECOMMENDATION FOR THE RATEMAKNG TREATMENT OF OFF-SYSTEM SALES MARGINS IN THIS CASE?

A. Public Counsel's recommendation consists of the following two elements:

- UE's revenue requirement should include a baseline amount of off-system sales margins at a level that reflects the best estimate of the ongoing level of off-system sales margins; and
- A deferred accounting tracker mechanism should be used to accumulate variations from the baseline level between rate cases. The accumulated deferral amount should be reflected in the revenue requirement in UE's next rate case.

Q. PLEASE EXPLAIN WHY OPC'S RECOMMENDATION INCLUDES THE TRACKING MECHANISM.

A. There have been a large number of changes in the UE system and the environment that UE operates in during the last couple of years that have increased the difficulty in estimating the expected future level of off-system sales margins. There have been major changes in the generating resources that UE uses to serve its load and in the load that these resources must serve. In addition, the wholesale electric market where off-system sales are made has changed over the last couple years and further changes in this market are being proposed and implemented at this time.

Q. WHAT CHANGES HAVE OCCURRED RECENTLY IN THE GENERATION RESOURCES RELIED UPON BY UE TO SERVE ITS LOADS?

A. Recent generation resource changes include the following:

- The addition of thousands of megawatts (MWs) of gas-fired peaking capacity to UE's generation portfolio over the last few years.

- The announcement made by the Ameren Corporation (Ameren HoldCo) that it will terminate the Joint Dispatch Agreement (JDA) between UE and AEG at the end of this year.

- The dispute over whether UE will continue to use its 40% share of the output from the 1,000 MW EEInc. Joppa plant to serve its native load customers.

- The extra 6% share of UE's generation resources that are now available to serve UE customers in Missouri as a result of UE transferring the Illinois portion of its service territory to AmerenCIPS in the Metro East transfer case.

Q. WHAT CHANGES HAVE OCCURRED RECENTLY IN THE LOAD THAT UE MUST SERVE WITH ITS GENERATION RESOURCES?

A. Recent changes in the load that UE serves include the following:

- Removal of the load associated with UE's former Illinois service territory as a result of the Metro East transfer.

- The addition of several hundred MWs of retail load as a result of adding Noranda as a retail customer.

- Ameren HoldCo's announcement that it will terminate the Joint Dispatch Agreement at the end of this year.

Q. WHAT CHANGES HAVE OCCURRED RECENTLY IN THE WHOLESALE ELECTRIC MARKETS IN WHICH UE PARTICIPATES?

A. Recent regional wholesale electric market changes include the following:

- The evolution of energy markets at the Midwest ISO (MISO) that has already occurred and further developments, including an ancillary services market, that are likely in the near future.

- Further opening of the Illinois retail market with the newly developed Illinois Auction process which offers new off-system sales opportunities for UE.

- Changes in regional electric market wholesale prices and margins related to changes in the fuel costs for gas-fired generation.

Q. WHY DO THESE CHANGES ADD COMPLEXITY TO THE TASK OF ESTIMATING THE FUTURE ONGOING LEVEL OF OFF-SYSTEM SALES MARGINS?

A. UE's recent historical experience with off-system sales is not likely to be representative of the level of off-system sales margins that will occur after the new rates resulting from this rate case go into effect in the middle of 2007 due to the many changes that have occurred in the recent past or will occur in the near future. While it is possible to simulate the operation of UE's system and its interactions with wholesale electric markets with sophisticated production cost models, OPC would need to closely examine such models to assess the likelihood that the model's output provides a realistic portrayal of the future level of off-system sales margins. Because of all the other important issues in this case, it may be difficult for the Commission to be comfortable with setting a level of margins in base rates unless there is a tracking mechanism to ensure that both ratepayers and shareholders will be treated fairly if actual results differ substantially from the projections made by production cost models.

Q. DOES PUBLIC COUNSEL HAVE AN ALTERNATIVE SECONDARY RECOMMENDATION FOR THE TREATMENT OF OFF-SYSTEM SALES MARGINS IF THE COMMISSION REJECTS THE PRIMARY OPC RECOMMENDATION OUTLINED ABOVE?

A. Yes. First I should note that Public Counsel will recommend in our testimony on December 29, 2006 that UE should not be permitted to have a fuel adjustment mechanism. If the Commission determines that UE should be permitted to have a fuel adjustment mechanism, despite OPC's recommendation to the contrary, then Public Counsel recommends that the fuel adjustment mechanism should include off-system sales margins that vary from the baseline level included in base rates.

III. RATEMAKING IMPACTS OF CONDITIONS IN THE COMMISSION'S ORDER IN THE UE METRO EAST TRANSFER CASE

Q. PLEASE IDENTIFY THE CONDITIONS THAT THE COMMISSION IMPOSED ON THE RECOVERY OF COSTS RELATED TO UE'S FORMER ILLINOIS OPERATIONS WHEN IT ISSUED ITS ORDER APPROVING THE METRO EAST TRANSFER.

A. On February 10, 2005, the Commission issued its "Report and Order on Rehearing" in Case No. EO-2004-0108. This order contained the following conditions:

- The last full paragraph on page 61 of the Commission's "Report and Order on Rehearing" states that "**pre-closing liabilities that are directly assignable to UE's Illinois retail operations, or to the transferred assets**, must transfer to CIPS as a condition of the Commission's approval of the transfer." (Emphasis added)

- Ordered paragraph number 7 in the Commission's "Report and Order on Rehearing" states that "AmerenUE may seek recovery in a future rate proceeding (a rate increase or an excess earnings complaint) of up to 6% of the **unknown**

generation-related liabilities associated with the generation that was formerly allocated to AmerenUE's Metro East service territory, if it proves by a preponderance of the evidence that the sum of the Missouri ratepayer benefits attributable to the transfer in the applicable test year is greater than the 6% of such unknown generation-related liabilities sought to be recovered." (Emphasis added)

- Ordered paragraph number 8 in the Commission's "Report and Order on Rehearing" states that "Union Electric Company, doing business as AmerenUE, as a condition of the approval herein contained, shall not recover in rates any portion of any **increased costs due solely to transmission charges for the use of the transmission facilities herein transferred to AmerenCIPS** to the extent that the costs in question would not have been incurred had the facilities not been transferred." (Emphasis added)

- The first partial paragraph on page 63 of the Commission's "Report and Order on Rehearing" states that "as a condition of its approval of the transfer, the Commission will **exclude from rates 6-percent of any costs incurred by UE in the Sauget remediation** unless, as with the other liabilities discussed above, UE can meet its burden to establish that such costs are outweighed by transfer-related benefits." (Emphasis added)

- The first partial paragraph on page 62 of the Commission's "Report and Order on Rehearing" states that "the Commission will **exclude 6-percent of any such liabilities arising from pre-closing events and conditions** from UE's rates as a condition of its approval of the transfer, unless AmerenUE, in a future rate case where it seeks to recover 6-percent of such liabilities, is able to prove that benefits directly flowing from the Metro East transfer are greater than 6-percent of these liabilities" and also states "in addition to unknown environmental and other liabilities, this includes general corporate liabilities and pre-closing natural gas costs not directly assignable to UE's Illinois retail operations."

Q. HAS UE ADDRESSED THESE CONDITIONS IN ITS DIRECT TESTIMONY?

A. Not to my knowledge.

Q. WHAT HAVE YOU DONE TO DETERMINE WHETHER THERE NEED TO BE SOME ADJUSTMENTS TO UE'S REVENUE REQUIREMENT IN THIS CASE BECAUSE OF THE CONDITIONS LISTED ABOVE?

A. I sent OPC DR Nos. 2017 through 2024 to UE in an attempt to discover the extent to which UE's rate request in this case has complied with the 5 conditions listed above that were set forth by the Commission in its "Report and Order on Rehearing" in Case No. EO-2004-0108. These DRs were sent to UE on November 14, 2006 and the Company has still not responded fully to all of these DRs as of December 14, 2006.

Q. PLEASE REVIEW THE KNOWLEDGE THAT YOU HAVE OF UE'S COMPLIANCE WITH THESE CONDITIONS AS OF DECEMBER 14, 2006 STARTING WITH THE FIRST CONDITION LISTED ABOVE.

A. OPC DR No. 2017 asked UE to verify that it had complied with this condition regarding the transfer to CIPS of pre-closing liabilities that are directly assignable to UE's Illinois retail operations, or to the transferred assets. UE's response did not contain a clear statement verifying that it was in compliance with this condition. OPC has informed UE that its answer did not clearly affirm or deny compliance with this condition but no additional clarification has been forthcoming from UE thus far. UE's response to the DR described the process it was using to transfer "identifiable" assets and liabilities but it was not clear to OPC that the process described by UE would result in full compliance with this condition. UE's use of the word "identifiable" in its DR response raises the question of whether the Company is capable of identifying all such assets and liabilities.

Q. IS UE IN COMPLIANCE WITH THE SECOND CONDITON LISTED ABOVE REGARDING THE UNKNOWN GENERATION-RELATED LIABILITIES ASSOCIATED WITH THE GENERATION THAT WAS FORMERLY ALLOCATED TO AMERENUE'S METRO EAST SERVICE TERRITORY?

A. No. UE's response to OPC DR No. 2018 (See Attachment 1) acknowledged that it is seeking to recover more than 94% of the unknown generation-related liabilities associated with the generation that was formerly allocated to AmerenUE's Metro East service territory. Seeking to do so without providing evidence in its Direct testimony which "proves by a preponderance of the evidence that the sum of the Missouri ratepayer benefits attributable to the transfer in the applicable test year is greater than the 6% of such unknown generation-related liabilities sought to be recovered" is not consistent with the Commission's order so UE should not be permitted to recover these costs. It would not be appropriate for UE to attempt to supplement its direct case with additional evidence on this subject at this late date since the Commission's order in the Metro East case was very clear about the evidence UE needed to provide in order to justify including these costs, so the **__________** identified in UE's response to OPC DR No. 2019 should not be reflected in any new rates that may result from this case.

Q. IS UE IN COMPLIANCE WITH THE THIRD CONDITON LISTED ABOVE REGARDING ANY INCREASED COSTS DUE SOLELY TO TRANSMISSION CHARGES FOR THE USE OF THE TRANSMISSION FACILITIES HEREIN TRANSFERRED TO AMERENCIPS?

A. I have not been able to begin making a determination of UE's compliance with this condition at this time since UE has failed to provide timely responses to OPC DR Nos. 2020 and 2021 regarding this condition. Because of UE's failure to provide timely DR responses on this subject, I reserve the right to address this issue again in additional testimony in this case.

Q. IS UE IN COMPLIANCE WITH THE FOURTH CONDITON LISTED ABOVE REGARDING ANY COSTS INCURRED BY UE IN THE SAUGET REMEDIATION?

A. No. UE's response to OPC DR No. 2022 (See Attachment 2) acknowledged that it is seeking to recover more than 94% of the test year costs incurred by UE that were related to the Sauget remediation. Seeking to do so without providing evidence in its Direct testimony in which UE meets "its burden to establish that such costs are outweighed by transfer-related benefits" is not consistent with the Commission's order so UE should not be permitted to recover these costs. It would not be appropriate for UE to attempt to supplement its direct case with additional evidence on this subject at this late date since the Commission's order in the Metro East case was very clear about the evidence UE needed to provide in order to justify including these costs, so the $413 identified in UE's response to OPC DR No. 2023 should not be reflected in any new rates that may result from this case.

Q. IS UE IN COMPLIANCE WITH THE FIFTH CONDITON LISTED ABOVE REGARDING 6 PERCENT OF ANY SUCH LIABILITIES ARISING FROM PRE-CLOSING EVENTS AND CONDITIONS PLUS GENERAL CORPORATE LIABILITIES AND PRE-CLOSING NATURAL GAS COSTS NOT DIRECTLY ASSIGNABLE TO UE'S ILLINOIS RETAIL OPERATIONS?

A. UE's response to OPC DR No. 2024 asserts that the Company "did not include pre-closing general corporate liabilities related to the Metro-East or pre-closing natural gas costs in the test year" but I have not yet determined whether the Company also excluded 6 percent of any such liabilities arising from pre-closing events and conditions as stated in the first partial paragraph on page 62 of the Commission's order.

IV. NORMALIZATION OF SO_2 EMISSION SALES ALLOWANCE REVENUES

Q. BEFORE TURNING TO A MORE COMPLETE EXPLANTION OF THE BASIS FOR PUBLIC COUNSEL'S RECOMMENDATIONS REGARDING THE NORMALIZED LEVEL OF SO_2 EMISSION ALLOWANCE REVENUES TO INCLUDE IN THE UE COST OF SERVICE, PLEASE PROVIDE SOME BACKGROUND INFORMATION ABOUT THE FEDERAL ENVIRONMENTAL LAWS THAT CAUSED UE TO RECEIVE AN ANNUAL ALLOCATION OF SO_2 EMISSION ALLOWANCES.

A. On November 15, 1990, President Bush authorized major revisions to the Clean Air Act (CAA) that included a requirement for substantial reductions in power plant emissions (both SO_2 and NOx) intended to control acid rain. Title 4 of the CAA amendments of 1990 created a new market-based system for reducing SO_2 emissions below 1980 levels. In this system, owners of power plants like UE received their allocation of the emission allowances through an allocation process based primarily on historic fuel consumption from 1985 through 1987. Power plant owners use this allocation of allowances for their own compliance and any excess allowances can be either sold in the market or banked for future use or sale. Those power plant owners that do not have sufficient allowances can buy allowances in the market to achieve compliance. Different amounts of allowances were allocated to power plant owners during Phase I (1995-1999) and Phase II. Each allowance permits a generating unit to emit one ton of SO_2 during or after a specified year. Unused allowances can be banked for future use or sale.

The market-based system for regulating SO_2 emissions, where allowances could be traded, was intended to minimize the cost of reducing SO_2 emissions to the desired level. The system of tradable allowances encourages utilities to over-comply with emissions reductions targets when they can do so at a cost that is less than the market value of allowances while at the same time, allowing utilities to under-comply with the reduction targets when they can buy allowances at a cost that is less than their own cost of compliance. The most common strategies for lowering SO_2 emissions are converting to low sulfur coal or scrubbing power plant emissions. UE has reduced its emissions by converting many of its power plants to permit the burning of low sulfur coal from sources in the West like the Powder River Basin.

Q. DO THE ALLOWANCES THAT UE RECIEVES EVERY YEAR FROM THE ENVIRONMENTAL PROTECTION AGENCY (EPA) HAVE ANY VALUE AT THE TIME UE RECIEVES THEM?

A. The answer to this question is both yes and no, depending on what is meant by the word "value." If the word "value" is interpreted to mean "market value", then these allowances have value at the time they are received by UE because the Company could find a willing buyer to purchase the allowances at the time UE receives its allocation. On the other hand, it is my understanding that from a strict accounting point of view, allowances are reflected on the Company's balance sheet as having a zero value since the Company did not make any direct payments to receive the allowances. However, if a Company purchases allowances in the market and saves them for future use, instead of just receiving an annual allowance allocation from the EPA, then these allowances would be reflected on a Company's balance sheet at the market price.

Q. NOW LET'S TURN TO THE SUBJECT OF THE COMMISSION'S OVERSIGHT OF UE'S ALLOWANCE TRANSACTIONS. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN THE SO_2 EMISSION ALLOWANCES THAT UE RECEIVES EVERY YEAR AND THE SERVICE THAT

THE COMPANY PROVIDES TO MISSOURI RATEPAYERS AS A REGULATED ELECTRIC UTILITY.

A. I already mentioned that the quantity of allowances that UE receives every year from the EPA is based largely on the amount of fuel that was consumed at its generating plants during the 1985 through 1987 time period. The generating plants to which the allowances were allocated were built to serve the native load of UE. The electric rates paid by UE's customers have been set at a level high enough to provide UE with a reasonable opportunity to recover from its customers the costs associated with the financing and operation of these power plants. UE has not needed to pay for any costs that are not recoverable in rates in order to receive its annual allocation of emission allowances for the plants that it uses to serve its regulated utility service customers.

Q. HOW DID THIS COMMISSION FIRST GET INVOLVED IN OVERSEEING UE'S SO_2 EMISSIONS ALLOWANCES TRANSACTIONS?

A. On March 23, 1998, UE filed an application with the Commission wherein it sought authorization to manage its SO_2 emission allowance inventory. On December 15, 1998 the Commission issued an order approving a Stipulation and Agreement which granted UE limited authority to manage its SO_2 allowance inventory.

Q. WHAT WERE SOME OF THE MAIN PROVISIONS OF THE STIPULATION & AGREEMENT APPROVED BY THE COMMISSION IN CASE NO. EO-98-401?

A. The Stipulation & Agreement in Case No. EO-98-401, which gave UE limited flexibility to manage its SO_2 allowances, included the following four key provisions:

> 1. AmerenUE will have the authority to manage its allowance inventory, with the restrictions discussed below. The Staff and the Office of Public Counsel reserve the right to reexamine and modify their positions respecting the Commission granting AmerenUE the authority to manage its sulfur dioxide emission allowance inventory, when the

New Experimental Alternative Regulation Plan resulting from the Union Electric Company- CIPSCO, Inc. merger Case No. EM-96-149 expires on June 30, 2001. Any profits or losses that are realized from the sales or any other transactions associated with allowances, will be booked to utility operating income according to generally accepted accounting principles. **The regulatory treatment of these profits and losses as well as the prudence of any allowance transaction is subject to review and adjustment as part of any audit and/or examination in a future sharing calculation or future rate case.** (emphasis added)

2. **The Company is authorized to manage the entire allowance inventory, but may sell only up to one-half of all Phase I allowances without seeking specific Commission approval.** This includes sales to AmerenCIPS and other utilities. AmerenUE may request authorization to sell additional allowances, above this level, through a filing with the Commission. (emphasis added)

3. Sales in combination with other transactions, such as power contracts, are also authorized as a portion of the level discussed above. However, the Company must book a profit from the sale of the allowances at least equal to the current market value as established by the monthly price index published by Cantor Fitzgerald Environmental Brokerage Service. Should either the Staff, the Office of the Public Counsel or the Company wish to use a different index for this purpose in the future, notice will be given to the other parties and all parties will negotiate in good faith to agree on a substitute. The Commission will be asked to resolve the matter if no agreement is reached in a reasonable time period.

4. The Company will be required to provide detailed reporting of all the transactions involving allowances once each year. The reporting date will be August 31 for the previous twelve months ending on June 30. The database to support allowance transactions and inventory balances will be maintained and available to the Staff upon request during the year.

Q. THE LAST SENTENCE OF THE FIRST ITEM IN THE ABOVE STIPULATION AND AGREEMENT CONCERNS THE RATEMAKING TREATMENT ASSOCIATED WITH THE ALLOWANCE TRANSACTIONS THAT WERE PERMITTED BY THE COMMISSION'S ORDER IN CASE NO. EO-98-401. HOW DOES THAT SENTENCE IMPACT THE SO_2 ALLOWANCE REVENUE ADJUSTMENT THAT PUBLIC COUNSEL IS PROPOSING?

A. The Commission's decision in Case No. EO-98-401 to permit UE certain flexibility to engage in SO_2 allowance sales and otherwise manage its SO_2 allowance inventory preserved for a later date any Commission determinations regarding the ratemaking treatment of UE's SO_2 allowance transactions. From a layman's perspective, the statement in the stipulation that:

> The regulatory treatment of these profits and losses as well as the prudence of any allowance transaction is subject to review and adjustment as part of any audit and/or examination in a future sharing calculation or future rate case.

appears to be very straightforward and self-explanatory in its applicability to this general rate proceeding.

Q. CAN YOU QUANTIFY THE EFFECT OF THE SECOND ITEM FROM THE STIPULATION AND AGREEMENT SHOWN ABOVE WHICH STATES THAT "THE COMPANY IS AUTHORIZED TO MANAGE THE ENTIRE ALLOWANCE INVENTORY, BUT MAY SELL ONLY UP TO ONE-HALF OF ALL PHASE I ALLOWANCES WITHOUT SEEKING SPECIFIC COMMISSION APPROVAL?"

A. Yes. Its my understanding that UE received **________** Phase I SO_2 emission allowances and that the Commission order allowed it to sell one-half, or **________** of these allowances without seeking additional Commission approval.

Q. ARE YOU AWARE OF ANY ADDITIONAL COMMISSION ORDERS THAT PERTAIN TO UE'S MANAGEMENT OF ITS SO_2 ALLOWANCE INVENTORY?

A. Yes. Section 7 of the Stipulation and Agreement approved by the Commission's Report and Order issued on February 21, 1997 in Case No. EM-96-149 contains terms that the parties agreed to regarding the New Experimental Alternative Regulation Plan (2nd EARP). Attachment C to the Stipulation and Agreement contains additional details about implementation of the 2nd EARP. Item 2.a. on page 1 of Attachment C states that:

> the earnings report will reflect the following:...Any sale of emission allowances shall be reflected above-the line in the ROE calculation.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE COMMISSION'S ORDERS IN THE TWO CASES DISCUSSED ABOVE, CASE NOS. EO-98-401 AND EM-96-149 TO THE SO_2 ALLOWANCE REVENUES ADJUSTMENT THAT OPC IS RECOMMENDING IN THIS CASE.

A. The Commission order in Case No. EO-98-401 gave UE limited flexibility to engage in SO_2 transactions while preserving Commission ratemaking treatment of the transactions until future rate cases or cases where sharing calculations are made in the context of the second EARP. The Commission order in Case No. EM-96-149 provided the guideline that allowance sales "shall be reflected above-the line in the ROE calculation." While the Commission's order in Case No. EO-98-401 explicitly preserved the Commission's authority to make future determinations regarding the prudence and ratemaking treatment for UE's allowance transactions, the earlier order in Case No. EM-96-149 gave UE specific guidance about how it should report allowance transactions to the Commission when it filed its earnings reports under the EARP.

Regrettably, UE and its affiliates within Ameren holding company structure reacted to the signal that the proceeds from allowance transactions would have to be shared with consumers in accordance with the sharing grid set forth in the EARP by altering their decisions about the magnitude, type, and timing of its SO_2 allowance transactions while the EARP was still in effect. In addition to reacting to the ratemaking incentives under the EARP in their decisions regarding allowance transactions, UE and its affiliates were guided by other improper considerations including: (1) the present and potential future needs of UE's non-regulated affiliates for SO_2 emission allowances and (2) the impact that allowance transactions between UE and its affiliates would have on the financial performance of UE's unregulated affiliates and the overall financial performance of Ameren.

Q. PLEASE EXPLAIN HOW YOU FORMULATED PUBLIC COUNSEL'S RECOMMENDATION FOR A NORMALIZED LEVEL OF SO_2 ALLOWANCE SALES TO REFLECT IN THE REVENUE REQUIREMENT FOR THIS CASE.

A. I performed my review and analysis of UE's SO_2 sales activities for this case by reviewing materials on this subject from prior cases, reviewing copies of the "Annual Report of SO_2 Allowance Transactions" (SO_2 Annual Reports) that UE began submitting to the Staff and OPC in 1999 pursuant to the Commission's order in Case No. EO-98-401, and sending data requests to UE about this subject. UE has not provided timely responses to the data requests that I sent regarding its SO_2 activities so I am relying on information from prior cases and the SO_2 Annual reports for the normalization that OPC is proposing at this time. Because of UE's failure to provide timely DR responses on this subject, I reserve the right to revise the normalization recommendation and address this issue again in additional testimony in this case.

Q. WHAT IS PUBLIC COUNSEL'S RECOMMENDATION FOR A NORMALIZED LEVEL OF SO_2 ALLOWANCE SALES TO REFLECT IN THE REVENUE REQUIREMENT FOR THIS CASE AND HOW DID YOU ARRIVE AT THAT RECOMMENDATION?

A. Public Counsel recommends that the Commission use **______________** as the normalized level of SO_2 allowance sales in this case. As shown in Attachment 3, I arrived at this figure by calculating a five-year average of the amount of annual revenues that UE has received from emission allowance sales over the five year period that ends on June 30, 2006. The last year of the five year period coincides with the test year that the Commission has ordered in this case. The last year of the five year period was by far the lowest level of allowance sales that UE made over the five year period so there was an obvious need to normalize the level of allowance sales to make the amount in the test year more representative of the level of sales that has occurred since the time that UE's rates were last reviewed in Case No. EC-2002-1.

Q. IS THERE GENERALLY A TRADE-OFF BETWEEN A UTILITY'S ABILITY TO GENERATE REVENUES AND EARNINGS FROM ALLOWANCE SALES AND ITS ABILITY TO USE BANKED ALLOWANCES TO DEFER FUTURE INVESTMENTS IN POLLUTION CONTOL EQUIPMENT?

A. Yes. Utilities like UE, which had a very substantial bank of excess allowances (at least such a bank existed prior to the aggressive SO_2 sales that UE has engaged in over the last 5 years), have (perhaps "had" in UE's case) the ability to use their excess allowances to defer large investments in pollution control equipment for considerable periods of time. Therefore, there is a trade-off between selling excess allowances now (which would help keep current rates low for customers if the sales are reflected in rates) and preserving allowances for the future where they can be used over time to comply with environmental regulations instead of investing large amounts of money in pollution control equipment that will facilitate compliance by lowering emissions.

On page 40 of its "Report and Order on Rehearing" in Case No. EO-2004-0108, the Commission recognized this tradeoff when it referred to the potential "debacle" that could result occur because "UE aggressively markets its SO_2 allowances to other utilities" which creates the concern by some that "the company would have to install expensive pollution-control equipment at its plants sooner than would otherwise be necessary."

Q. HAVE YOU REVIEWED ANY AMEREN DOCUMENTS THAT SHOW UE IS AWARE OF THIS TRADE-OFF AND POTENTIAL FINANCIAL IMPACTS THAT AGGRESSIVE SO_2 SALES COULD HAVE ON FUTURE COSTS OF ENVIRONMENTAL COMPLIANCE?

A. ** [redacted] ** Vintage swaps are typically made for the purpose of essentially loaning allowances from your bank to another entity so you can earn interest on them. ** [redacted] **

Q. ** **

A. ** **

Q. HOW SHOULD THE COMMISSION USE THE INFORMATION THAT YOU HAVE PROVIDED ABOUT UE'S ALLOWANCE SALES ACTIVITIES AND THE TRADE-OFFS BETWEEN USING ALLOWANCES TO ENHANCE CURRENT REVENUES AND EARNING AGAINST USING BANKED EXCESSS ALLOWANCES TO DEFER MASSIVE EXPENDITURES ON POLLUTION CONTROL EQUIPMENT?

A. I believe it is essential for the Commission to take this information into account as it makes a determination about the reasonableness of OPC's proposed normalized level of SO_2 allowance sales revenues. Ameren's current projections of future environmental investments at UE show that UE will be investing between $365 million and $505 million for pollution control equipment over the next 4 years and investing another $750 million to $1.040 billion for pollution control equipment from 2011-2016. (See page 20 of the November 29, 2006 Ameren Investor Presentation at http://library.corporate-ir.net/library/91/918/91845/items/222932/IP_1106.pdf.) Because of the potential for much of these future costs to be borne by ratepayers, it would be grossly unfair to deprive ratepayers of the benefits (by not normalizing SO_2 sales revenues) of the aggressive SO_2

sales practices that are partly responsible for the need to make these huge investments on the presently projected timetable.

V. UE'S ENTITLEMENT TO 40% OF THE OUTPUT FROM THE ELECTRIC ENERGY, INC. JOPPA PLANT

Q. WHAT IS THE CURRENT STATUS OF UE'S RELATIONSHIP WITH ELECTRIC ENERGY, INC (EEINC.)?

A. UE still owns 40% of EEInc. UE was utilizing 40% of the low cost output and capacity (approximately 400 MWs) from the EEInc coal-fired generating to serve its regulated retail customer load up until the end of 2005. At that time, Ameren chose to divert UE's share of the Joppa plant output and capacity to the non-regulated part of Ameren's operations.

Q. WHAT IS PUBLIC COUNSEL'S RECOMMEDATION REGARDING THE TREATMENT OF THE 40% SHARE OF THE JOPPA PLANT OUTPUT AND CAPACITY THAT UE HAS RELIED UPON TO SERVE ITS REGULATED RETAIL CUSTOMERS?

A. Any new rates that result from this case should reflect UE's entitlement to 40% of the output from the Joppa plant. Including 40% of the Joppa plant output as a resource available to serve UE's regulated Missouri retail load will lower UE's cost of service (revenue requirement) because the Joppa plant is one of the lowest cost plants in the U.S. The low production cost nature of the Joppa plant is illustrated in one of the workpapers for UE witness Warner Baxter's testimony which shows that the productions costs at Electric Energy, Inc. ($15.94/MWh) were well below the production costs at UE ($17.69/MWh) for the time period from 2002 through 2005. The first page of this 3 page workpaper is attached as Attachment 5. In addition to the low production costs of EEInc.'s generation facilities, the EEInc steam generation facilities are almost fully depreciated. Page 205 of the EEInc 2005 FERC Form 1 (see relevant excerpts from this report in Attachment 6) shows gross steam production plant of $370,618,403 and page 219 of the same report shows accumulated depreciation for this plant of $330,593,417.

Q. HAVE YOU BEEN ABLE TO QUANTIFY THE AMOUNT BY WHICH UE'S REVENUE REQUIREMENT IN THIS CASE SHOULD BE REDUCED DUE TO THE INCLUSION OF THE JOPPA PLANT OUTPUT AS A RESOURCE AVAILABLE TO SERVE UE'S REGULATED MISSOURI RETAIL LOAD?

A. No I have not. Public Counsel does not have sufficient resources to quantify the impact of the EEInc. Joppa plant on UE's cost of service through production cost modeling. I sent OPC DR No. 2033 to UE which requested UE to perform an additional fuel run so that I could obtain a quantification of the impact of including the Joppa plant as a resource but UE has objected to this DR. OPC DR No. 2033 stated:

> With respect to the direct testimony of Warner L. Baxter, using the PROSYM model that is the basis of AmerenUE's fuel expense calculations, please identify the change in fuel expense and revenue requirement that would occur relative to the Company's filed case if it were assumed that 40% of the total output from the EEInc. plant was available to AmerenUE under the same cost-based pricing provisions that were in effect in the last year of the power sales agreement between EEInc. and AmerenUE. Please identify the price used in this analysis.

Q. HOW DID UE RESPOND TO THIS DATA REQUEST?

A. UE's December 4, 2006 response to this DR stated:

> The Company objects because this DR is unduly burdensome, oppressive and beyond the scope of discovery to the extent it seeks to require the Company to perform analyses, do research, or compile data instead of seeking facts known, opinions, or existing data, analyses or documents.

OPC's Counsel has been in touch with UE's Counsel regarding this objection and we are currently trying to resolve this issue. If our efforts to resolve this issue are not successful, OPC will file a motion to compel with the Commission.

Q. PLEASE PROVIDE ADDITIONAL BACKGROUND INFORMATION ABOUT THE EEINC. JOPPA PLANT AND UE'S RELATIONSHIP WITH EEINC.

A. UE's 40% share of the EEInc Joppa plant has been an important part of UE's generation portfolio for decades. UE's ownership interest in EEInc and the provision of power from the EEInc Joppa plant to UE's Missouri retail customers began about 50 years ago. EEInc's 2004 FERC Form 1 describes the Power Supply Agreement (PSA) under which UE served its Missouri retail customers for decades as follows:

> The Company's principal source of operating revenue is sales of electricity from Joppa Steam Electric Station (Joppa Station) to the Company's three electric utility shareholders, Ameren Energy Resources Company (40%), Kentucky Utilities Company (20%) and Union Electric Company (40%) (Sponsoring Companies) and to the United States (US) Department of Energy (DOE). Sales to the Sponsoring Companies are governed by the Power Supply Agreement. Sales to the DOE are made under the Modification 15 Power Contract (Mod 15). The Power Supply Agreement and Mod 15 continue in force through December 31, 2005, unless canceled, as provided under their terms.
>
> The Power Supply Agreement and Mod 15, and the rates established therein for the sale of electricity to the Sponsoring Companies and DOE, have been accepted by the FERC. In general, the Power Supply Agreement provides that the Company will sell the remaining power capacity to the Sponsoring Companies. Mod 15 requires the Company to make available to the DOE a specified percentage of Joppa Station's capacity until the termination date of December 31, 2005.
>
> Under the Power Supply Agreement and Mod 15, the Sponsoring Companies and the DOE are required to make monthly payments for power which will enable the Company to recover all of Joppa Station's cost-of-service, which includes operating expenses, taxes, and interest plus generate a prescribed rate of return on equity capital of 15% net of federal income tax.
>
> The DOE was committed to 0% and 10% of Joppa Station's capacity for 2004 and 2003, respectively. For 2005, the DOE's commitment will be 0% of Joppa Station's capacity.

> The obligations of each of the Sponsoring Companies and the DOE are absolute and unconditional and shall not be discharged or affected by the failure, impossibility or impracticability of the Company to generate or deliver electricity.[1]

As the above narrative from EEInc's FERC Form 1 indicates, UE's ratepayers have been paying their full share of the cost of service for the power they have been receiving from the Joppa plant under the PSA. In addition to paying the full cost of service, UE's ratepayers have borne the risk that UE may be obligated to make payments under the PSA regardless of whether EEInc was able to generate and deliver energy from the Joppa Plant to UE's Missouri customers.

Q. PLEASE PROVIDE AN OVERVIEW OF THE FINANCIAL SUPPORT THAT UE'S RATEPAYERS HAVE PROVIDED TO EEINC. AND THE JOPPA PLANT?

A. UE's ratepayers have provided a steady stream of financial support to EEInc over the last 50 years. That financial support has included the following:

- Full payment of UE's share of all capital costs, on a front-loaded basis over the life of the plant, through the point of nearly full amortization (even if the payments were levelized rather than front-loaded during the amortization period, now that the investment is almost fully amortized the effect is still "front-loaded" in that full payment was made before the plant's useful life has ended);
- Payment for pollution control and other modernization investments which extend the life of the plant and help maintain the plant's ability to generate low cost

[1] EEInc FERC Form 1 for the year ending December 31, 2004, pp. 123.1, 123.2.

energy for many years to come (ratepayers should not be paying for life extensions and then not receiving the benefits thereof);

- Cost responsibility for surplus capacity whether or not UE's ratepayers needed that capacity; and

- Responsibility for certain financial obligations extended by UE to EEInc. See the Commission approval, issued on June 24, 1977 in Case No. EF-77-197, of a request by UE, for the approval of the financial responsibility necessary to permit EEInc to proceed with improvements to the Joppa plant. In this decision, the MPSC stated that UE was "assured of a continuous source of economical power" in return for the guaranty of EEInc's financial obligations. See the Application of Union Electric Company for authority to "guaranty" certain financial obligations of Electric Energy, Inc., 1977 Mo. PSC LEXIS 23, 21 Mo.P.S.C. (N.S.) 425, 427 (1977).

Q. How did UE's IRP filings during the 1990s treat the future availability of the EEInc. Joppa plant as a resource that could be Utilized by UE in the future?

A. In UE's Electric Utility Resource Plan filings to the Commission in the 1990s, UE indicated that the capacity and energy to which its 40% share of EEInc entitles it would continue to be available to serve the loads of its Missouri customers well past when the current EEInc power purchase contract expires in 2005. UE's June 1995 Energy Resource Plan indicated that capacity from the Joppa plant would be available for the entire 20 planning period (1995 – 2014) and that additional energy from the Joppa plant may be available in 2007. [2] This same 1995 Energy Resource Plan indicated that the continued purchase of 405 MW from EEInc through 2014 (the end of the planning period) was part of UE's "Preferred Resource Plan."[3] One of UE's last Resource Plan submissions in Missouri prior to the Commission's May 20, 1999 order[4] granting variances (temporary suspension of filing requirements) from the rule for Missouri electric utilities was a document entitled "Risk and Uncertainly Analysis Briefing – October 1997." This document indicated that UE's share of the Joppa plant continued to be part of its resource plan for the planning period ending in 2014.[5]

Q. AT WHAT POINT DID IT BECOME CLEAR THAT UE AND ITS PARENT, AMEREN HOLDCO, DID NOT INTEND TO PERMIT UE'S RATEPAYERS TO CONTINUE BENEFITTING FROM THE EEINC. JOPPA PLANT THAT RATEPAYERS HAD BEEN SUPPORTING FINANCIALLY FOR DECADES?

A. UE's and Ameren's intentions to divert UE's 40% share of the low cost output from the Joppa plant from serving its captive customers to benefiting the shareholders of Ameren HoldCo beginning in 2006 became clear during 2004 in Case No. EO-2004-0108. In that case, UE's Vice President of Corporate Planning, Craig Nelson (Mr. Nelson is also a Vice-President of Ameren Services Company and Central Illinois Public Service Company), essentially stated in both his written[6] and oral testimony that UE would not continue to receive cost-based power from EEInc once the current PPA between UE and

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[2] UE's June 1995 Energy Resource Plan, p. 36, Table 4-3.

[3] UE's June 1995 Energy Resource Plan, p. 54, Table 6-7.

[4] MPSC "Order Granting Variance" in Case No. EO-99-544.

[5] Union Electric Risk & Uncertainty Analysis Briefing, Resource Planning, October 1997, p. 2, Table entitled "Optimized Expansion Plans for Various Sensitivities."

[6] Surrebuttal Testimony of Craig D. Nelson on behalf of Union Electric Company in MPSC Case No. EO-2004-0108, March 1, 2004, pp. 24, 25.

EEInc expires on December 31, 2005. In his oral testimony in that case, he stated that he did not believe that UE would continue to purchase power from EEInc because he had discussed the issue with the Chairman of the EEInc Board of Directors, R. Alan Kelley, and "he's not interested in selling at the lower of cost or market."[7] According to Ameren HoldCo's 2004 annual report to the SEC, in addition to being the Board Chairman at EEInc and a Senior Vice-President at UE, Mr. Kelley also held a number of other important positions at Ameren affiliates at that time.[8]

A. Please briefly describe the rights that UE has to the output from the EEInc. Joppa plant.

A. Craig Nelson acknowledged, in his oral testimony in Case No. EO-2004-0108,that the then current EEInc Bylaws contain provisions that entitle UE to 40% of the output from the EEInc Joppa plant.[9] UE witness Nelson also stated that the EEInc board has the right to alter UE's entitlement and sell the power to some other entity if 75% of the EEInc Board agrees to do so.[10] The Federal Energy Regulatory Commission's (FERC's) approval of the Joint Application for Approval of the Disposition of Jurisdictional Facilities Under Section 203 of the Federal Power Act in FERC Docket No. EC04-81-000 enabled the combined ownership shares of Ameren affiliates in EEInc to increase from 60% to 80%. KU still owns the remaining 20%. Public Counsel does not know

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[7] MPSC Case No. EO-2004-0108, Transcript p. 495, lines 22-25.

[8] AmerenEnergy Development Company – Director and Vice President, AmerenEnergy Generating Company – Director and President, AmerenEnergy Resources Company - Vice President, AmerenEnergy Medina Valley Cogen, (No. 2) L.L.C. – Manager and Senior Vice-President, AmerenEnergy Medina Valley Cogen, (No. 4) L.L.C. – Manager and Senior Vice-President, AmerenEnergy Medina Valley Cogen, L.L.C. – Manager and Senior Vice-President, AmerenEnergy Medina Valley Operations, L.L.C – Manager and Senior Vice-President, AmerenEnergy Resources Generating Company – Director and President, Ameren Services Co. - Senior Vice-President, Central Illinois Light Company - Senior Vice-President, Coffeen and Western Railroad Company – Director, Illinois Materials Supply Co. - Vice-President, and Missouri Central Railroad Company – Director.

[9] MPSC Case No. EO-2004-0108, Transcript p. 1575, line 24 - p. 1576, line 9.

[10] MPSC Case No. EO-2004-0108, Transcript p. 1576, lines 9-11.

whether the EEInc Board has acted to alter UE's entitlement. However, since UE still owns a 40% share of EEInc, UE's entitlement could not have been altered without the acquiescence of UE's representatives on the EEInc Board.

Q. WHAT HAVE UE AND AMEREN HOLDCO EXECUTIVES SAID IN PRIOR CASES ABOUT UE'S AND AMEREN HOLDCO'S RATIONALE FOR NOT CONTINUEING TO UTILIZE THE LOW COST JOPPA OUTPUT AND CAPACITY TO SERVE UE'S REGULATED MISSOURI RETAIL LOAD AFTER 2005?

A. In his oral testimony in Case No. EO-2004-0108, Craig Nelson described some of the affiliate considerations that were leading UE to not take advantage of its entitlement to 40% of the low cost Joppa output for its Missouri retail customers after 2005. He stated that if the EEInc Board has a choice between selling power from the Joppa plant at cost or selling it to another entity at whatever the market would bear, then the EEInc Board has an obligation to its shareholders to select the option that would maximize the profit on the sale of power.[11] This statement by Mr. Nelson ignores (1) UE's obligation as a regulated public utility to provide service at just and reasonable rates and (2) UE's obligations under the IRP rules to select a preferred plan that minimizes PVRR subject to risk and rate impact considerations (and any other considerations that are explicitly identified by the Company).

VI. NEW PENO CREEK GENERATING FACILLITY

Q. WHAT IS PUBLIC COUNSEL'S PROPOSAL REGARDING THE PENO CREEK GENERATING FACILITY?

[11] MPSC Case No. EO-2004-0108, Transcript p. 1578, lines 6-15.

A. Public Counsel recommends that the gross value of this plant reflected in UE's revenue requirement be reduced from the gross plant amount associated with the $550/kW (See Attachment 7) all inclusive construction cost to $390/kW.

Q. WHAT IS THE SOURCE OF THE $390/KW FIGURE?

A. This was a benchmark figure that UE presented for the cost of constructing new gas-fired generation in Case No. EA-2000-37. This figure appeared at the bottom of page 15 in UE's application in that case. (See Attachment 9)

Q. WHY DOES OPC PROPOSE USING THE LOWER FIGURE FOR THE COST/KW?

A. At the time UE added the Peno Creek units they were building this new generation facility in a rush make up for a generating capacity deficit at UE that they had created due to their pursuit of the Ameren HoldCo strategic objective of building all new generation in AEG (Genco) and attempting to get Missouri legislation passed that would permit them to transfer UE's generation to the Genco. UE's ratepayers should not be forced to absorb higher generation costs because of the pursuit of non-regulated strategic initiatives by UE' parent company, Ameren HoldCo.

Q. WHAT EVIDENCE CAN YOU CITE TO SUPPORT YOUR CONTENTION THAT A GENERATION DEFICIT DEVELOPED AT UE DUE TO THE PURSUIT OF NON-REGULATED STRATEGIC OBJECTIVES AT AMEREN HOLDCO?

A. The UE/CIPS merger was the first of a series of structural changes at UE and its affiliates that precipitated the UE generation deficit. A couple years after the merger, Illinois began to restructure its electric industry. UE's holding company, Ameren, responded to this restructuring by creating a non-regulated generation company, Ameren Energy

Generating (AEG). Once AEG was created, UE essentially stopped building new plants in Missouri to keep up with UE's load growth because it was decided at the holding company level that generation expansion would take place at AEG.

AEG proceeded to install more capacity than was needed by Ameren's utility operating companies in Illinois (in the hopes of marketing the power (via Ameren Energy Marketing) to retail customers in states with electric retail competition) and ended up with excess peaking capacity that it could not sell profitably into competitive markets. Information (see http://www.icc.state.il.us/ec/docs/020515relameren.pdf) that Ameren provided to the Illinois Commerce Commission (ICC) indicated that, for the summer of 2002, AmerenCIPS (supplied by Ameren Energy Marketing (AEM)) had a reserve margin of 29% while UE's reserve margin was only 17%. Presumably, AmerenCIPS' reserve margin for 2002 would have been even higher (and UE's would have been even lower) if AEM had not made a significant capacity sale to UE for that summer.

Within the last few of years, Ameren decided that it would move some of its excess non-regulated generating capacity from AEG to UE, even though it had constructed most of this capacity in Illinois. When Ameren sought permission from the Illinois Commerce Commission (ICC) to transfer generating capacity from AEG to UE, it received substantial opposition. (It also was receiving substantial opposition at FERC to this proposal.) Ameren responded to the opposition at the ICC by withdrawing its application and attempting to get approval from the ICC and this Commission to transfer all of its UE operations in Illinois to AmerenCIPS since doing so would eliminate the need for ICC approval of the transfer of AEG generating units to UE.

Q. IN YOUR ANSWER ABOVE YOU MENTION THAT "AEG PROCEEDED TO INSTALL MORE CAPACITY THAN WAS NEEDED BY AMEREN'S UTILITY OPERATING COMPANIES IN ILLINOIS (IN THE HOPES OF MARKETING THE POWER (VIA AEM) TO RETAIL

CUSTOMERS IN STATES WITH ELECTRIC RETAIL COMPETITION) AND ENDED UP WITH EXCESS PEAKING CAPACITY THAT IT COULD NOT SELL PROFITABLY INTO COMPETITIVE MARKETS." CAN YOU PROVIDE SOME REFERENCES FROM SEVERAL YEARS AGO WHICH ILLUSTRATE THE VIEWS THAT AMEREN HELD AT THAT TIME ABOUT FOCUSING ON THE ADDITION OF NON-REGULATED GENERATING FACILLITITES?

A. Yes. Ameren's employee newsletter, Ameren Journal, had several articles in the years 2000 and 2001 that illustrated the philosophy of focusing on non-regulated generation that was held by Ameren's senior management at that time. In the May 2000 issue of Ameren Journal, Ameren's current CEO Gary Rainwater stated on page 2 that:

> We're competing with companies that have 30,000 or 40,000 megawatts of capacity, so **we'll either have to move the AmerenUE plants into the genco [Ameren's non-regulated generating subsidiary] at some point or gain control of additional capacity in other ways**. We don't know if the state of Missouri will allow us to do that in the future, but that's the most critical issue we'll face in the years to come. (emphasis added)

In the July 2000 issue of Ameren Journal, Ameren's current CEO Gary Rainwater stated on page 3 that:

> AmerenEnergy Resource's mission is to be the growth engine of the corporation. Therefore, a prime financial KPI [key performance indicator] for us will be to achieve high earnings growth rates. That is not an appropriate indicator for regulated generation because it's virtually impossible to grow earnings at returns that justify new generation investment. **We need to put our investment on the non-regulated side of the generation business**, so we can't expect regulated generation to achieve earnings growth. (emphasis added)

In the May 2001 issue of Ameren Journal, Ameren's current CEO Gary Rainwater stated on page 10 that:

> We have proposed legislation that would allow utilities to move their generating assets into affiliated companies....Until legislation is enacted, **AmerenUE could face years of growing dependence on purchased power. The company currently plans to add a 45 MW peaking unit at its [AmerenUE] Meramec Plant next summer, while Ameren's non-regulated generation subsidiary, Ameren Energy Generating**

> **(AEG) plans to add about 850 MW of capacity this summer alone.** (emphasis added)

In addition to the statements made in Ameren Journal articles, the former Senior Vice-President of Ameren Services, Paul Agathen, addressed this issue in May 2001 in a guest editorial in the Joplin Globe where he stated that "Missouri's state regulated utilities have no plans to build new generating plants."

VII. TRANSFER OF PINCKNEYVILLE AND KINMUNDY GENERATING FACILLITIES FROM AEG TO UE

Q. WAS UE'S ACQUISITION OF THE PINCKNEYVILLE AND KINMUNDY PLANTS FROM ITS AFFILIATE, AEG, SUBJECT TO THE REQUIREMENTS OF THE MISSOURI AFFILIATE TRANSACTIONS RULE (4 CSR 240-20.015)?

A. Yes. This rule would apply to this transaction since the rule became effective for UE during 2003 and the Pinckneyville/Kinmundy transaction was completed on May 2, 2005. The Pinckneyville/Kinmundy transaction involved the acquisition of gas-fired generating units at the Pinckneyville and Kinmundy sites from AEG (an affiliated entity) to UE (a regulated Missouri electrical corporation).

Q. HAS UE COMPLIED WITH THE AFFILIATE RULE WITH RESPECT TO THE PINCKNEYVILLE/KINMUNDY TRANSACTION?

A. No. UE made not attempted to comply with several sections of the rule with respect to this transaction. I have reviewed the annual affiliate rule informational filing for calendar year 2005 that UE provided to Public Counsel on March 15, 2006 pursuant to the requirement in 4 CSR 240-20.015(4)(B) and followed up on this filing with several data requests. The annual filing provided by UE was entitled "AmerenUE Cost Allocation Manual, March 2006" I am not aware of any efforts that UE has made to have this purported "CAM" approved by the Commission as provided for in 4 CSR 240-20.015(3 (D).

Q. WHAT STANDARD FROM THE AFFILIATE TRANSACTIONS RULE WOULD APPLY TO THE PINCKNEYVILLE/KINMUNDY TRANSACTION?

A. Section (2) of 4 CSR 240-20.015 states:

> (2) Standards.
>
> (A) A regulated electrical corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated electrical corporation shall be deemed to provide a financial advantage to an affiliated entity if—
>
> 1. It compensates an affiliated entity for goods or services above the lesser of—
>
> A. The fair market price; or
>
> B. The fully distributed cost to the regulated electrical corporation to provide the goods or services for itself; or
>
> 2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of—
>
> A. The fair market price; or
>
> B. The fully distributed cost to the regulated electrical corporation.

Q. HAS UE PROVIDED THE DOCUMENTATION REQUIRED BY THE AFFILIATE RULE TO DEMONSTRATE THAT IT DID NOT PROVIDE A FINANCIAL ADVANTAGE TO AEG BECAUSE OF THE LEVEL OF COMPENSATION THAT IT PROVIDED TO AEG FOR THE PINCKNEYVILLE AND KINMUNDY GENERATION FACILLITIES?

A. No. UE also has not sought a variance from any requirements of the Affiliate Rule with respect to the Pinckneyville/Kinmundy transaction.

Q. PLEASE DESCRIBE SOME OF THE SPECIFIC PROVISIONS OF THE AFFILIATE RULE THAT UE FAILED TO COMPLY WITH FOR THE PINCKNEYVILLE/KINMUNDY TRANSACTION.

A. Section (3)(A) and (3) (B) of 4 CSR 240-20.015 state:

> (A) When a regulated electrical corporation purchases information, assets, goods or services from an affiliated entity, the regulated electrical corporation shall either obtain competitive bids for such information, assets, goods or services or demonstrate why competitive bids were neither necessary nor appropriate.
>
> (B) In transactions that involve either the purchase or receipt of information, assets, goods or services by a regulated electrical corporation from an affiliated entity, the regulated electrical corporation shall document both the fair market price of such information, assets, goods and services and the FDC to the regulated electrical corporation to pro-duce the information, assets, goods or ser-vices for itself.

UE has failed to comply with both of the above provisions.

Q. GIVEN UE'S FAILUTE TO COMPLY WITH THE AFFILIATE RULE AND PROVIDE SUFFICIENT DATA TO DOCUMENT THE "FAIR MARKET PRICE" OF THE ASSETS THAT IT ACQUIRED FROM ITS AFFILIATE, WHAT IS PUBLIC COUNSEL'S RECOMMENDATION FOR THE VALUE OF GROSS PLANT THAT SHOULD BE REFLECTED IN UE'S REVENUE REQUIREMENT FOR THE PINCKNEYVILLE AND KINMUNDY GENERATION FACILLITIES?

A. As Attachment 7 shows, UE acquired the Pinckneyville facility for \$502/kW and acquired the Kinmundy facility for \$412/kW. Both of these prices appear to be well above the market value of the facilities. Therefore, Public Counsel recommends using the blended price/kW of the recently acquired Audrain, Goose Creek, and Raccoon Creek Plants for ratemaking purposes. As shown on Attachment 7, this blended cost is \$193.80/kW. As a secondary recommendation, OPC recommends using the 2002 Audrain offer price of \$312.50/kW. The \$200,000,000 (\$200,000,000 /640mWs= \$312.50) initial offer price of NRG to UE is shown towards the bottom of the first page of the letter included in Attachment 8.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AmerenUE's Response to
OPC Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Ryan Kind

Data Request No. OPC 2018

Ordered paragraph number 7 in the Commission's ¿Report and Order on Rehearing¿ issued February 10, 2005 in Case No. EO-2004-0108 states that ¿AmerenUE may seek recovery in a future rate proceeding (a rate increase or an excess earnings complaint) of up to 6% of the unknown generation-related liabilities associated with the generation that was formerly allocated to AmerenUE's Metro East service territory, if it proves by a preponderance of the evidence that the sum of the Missouri ratepayer benefits attributable to the transfer in the applicable test year is greater than the 6% of such unknown generation-related liabilities sought to be recovered.¿ Is UE seeking to recover more than 94% of ¿the unknown generation-related liabilities associated with the generation that was formerly allocated to AmerenUE's Metro East service territory¿ that were referenced in the preceding sentence? If UE's answer is negative, please provide documentation that supports this answer.

Response:

Yes. See response to OPC DR 2019 for quantification.

Prepared By: Gary Weiss

Title: Manager Regulatory Accounting

Date: December 11, 2006

Attachment 1

AmerenUE's Response to
OPC Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Ryan Kind

Data Request No. OPC 2022

The first partial paragraph on page 63 of the Commission's ¿Report and Order on Rehearing¿ issued February 10, 2005 in Case No. EO-2004-0108 states that ¿as a condition of its approval of the transfer, the Commission will exclude from rates 6-percent of any costs incurred by UE in the Sauget remediation unless, as with the other liabilities discussed above, UE can meet its burden to establish that such costs are outweighed by transfer-related benefits.¿ Is UE seeking to recover more than 94% of any costs associated with the Sauget remediation? If UE's answer is negative, please provide documentation that supports this answer.

Response:

Yes. See Response to OPC DR 2023 for quantification.

Prepared By: Gary Weiss
Title: Manager Regulatory Accounting
Date: December 11, 2006

Attachment 2

Attachment 3

has been deemed

“Highly Confidential”

in its entirety.

Attachment 4

has been deemed

“Proprietary”

in its entirety.

Total Production O&M Costs Per Unit of Output Reported in FERC Form 1

Total Production Costs Defined to Include Fuel and Non-Fuel O&M for Generation + Purchased Power Expenses*

(Average Performance, 2002 - 2005)

Utility Reporting Output or Purchased Power	Region	Total Generation and Purchased Power Over 4-Yr Period (GWh)	Total Production Cost O&M $ / MWh	Rank
KeySpan Generation LLC	NPCC	46,505	4.96	1
PSEG Fossil LLC	MAAC	67,414	10.73	2
Texas New Mexico Power Co	ERCOT	30,345	10.81	3
Electric Energy Inc	MAIN	37,507	15.97	4
Indianapolis Power & Light	ECAR	67,758	16.94	5
AmerenUE	MAIN	206,057	17.69	6
Kansas City Power & Light Co	SPP	82,339	17.73	7
PSEG Nuclear LLC	MAAC	105,799	18.51	8
Duke Energy	SERC	368,208	18.74	9
Ohio Power Co	ECAR	236,991	19.04	10
Indiana Kentucky Electric Corp	ECAR	32,312	19.20	11
Westar Energy Inc	SPP	61,901	19.47	12
Southern Indiana Gas & Electric Co	ECAR	47,318	19.73	13
MidAmerican Energy Co	MRO US	113,535	19.85	14
Louisville Gas & Electric Co	ECAR	81,571	19.86	15
Appalachian Power Co	ECAR	207,329	20.21	16
South Carolina Generating Co Inc	SERC	16,467	21.12	17
AmerenEnergy Generating Co	MAIN	95,604	21.16	18
PacifiCorp	WECC	292,237	21.26	19
Kentucky Utilities Co	ECAR	100,104	21.43	20
Southern Electric Generating Co	SERC	27,013	21.78	21
Kentucky Power Co	ECAR	49,756	22.14	22
Indiana Michigan Power Co	ECAR	174,976	22.20	23
Ohio Valley Electric Corp	ECAR	62,176	22.33	24
Kansas Gas & Electric Co	SPP	54,425	22.42	25
Dayton Power & Light Co (The)	ECAR	79,153	22.68	26
AEP Generating Co	ECAR	34,789	22.75	27
Allete Inc	MRO US	47,639	23.19	28
Columbus Southern Power Co	ECAR	112,872	23.92	29
Duke Energy Indiana	ECAR	173,460	24.16	30
Alabama Power Co	SERC	317,853	24.18	31
Consumers Energy Co	ECAR	165,869	24.26	32
Idaho Power Co	WECC	67,671	24.62	33
Pennsylvania Power Co	MAAC	44,027	24.90	34
Northern Indiana Public Service Co	ECAR	74,931	25.02	35
Interstate Power & Light Co	MAIN	72,066	25.18	36
Detroit Edison Co (The)	ECAR	226,434	25.20	37
Southwestern Electric Power Co	SPP	99,173	25.63	38
South Carolina Electric & Gas Co	SERC	104,391	25.72	39
Wisconsin Public Service Corp	MAIN	57,763	26.12	40
Progress Energy Carolinas	SERC	240,373	26.20	41
Entergy Arkansas Inc	SERC	132,742	26.30	42
Duquesne Light Co	ECAR	58,789	26.84	43
Wisconsin Electric Power Co	MAIN	130,433	27.34	44
Empire District Electric Co (The)	SPP	21,775	27.44	45
Rochester Gas & Electric Corp	NPCC	40,431	27.65	46
Monongahela Power Co	ECAR	61,025	28.03	47
AmerenCILCO	MAIN	32,561	28.11	48
Puget Sound Energy Inc	WECC	101,855	28.17	49
Northern States Power Co (Minnesota)	MRO US	196,241	28.45	50
Otter Tail Power Co	MRO US	21,617	28.45	51
Georgia Power Co	SERC	382,044	28.66	52

Attachment 5

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Electric Energy, Inc.	End of 2005/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
[redacted]					1
			55,287		2
			1,381		3
					4
			56,668		5
[redacted]					6
					7
			1,517,462		8
24,109			52,678,228		9
113,820	-7,799	-43,458	222,867,838		10
					11
99,268			54,386,105		12
8,566	7,799	43,458	18,401,156		13
652,348			19,668,692		14
			1,098,922		15
898,111			370,618,403		16
[redacted]					17
					18
					19
					20
					21
					22
					23
					24
					25
[redacted]					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
[redacted]					36
					37
					38
					39
					40
					41
					42
					43

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Electric Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	323,376,783	323,376,783		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	12,858,051	12,858,051		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	12,858,051	12,858,051		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	852,734	852,734		
13	Cost of Removal	4,834,211	4,834,211		
14	Salvage (Credit)				
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	5,686,945	5,686,945		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	Depreciation on gas line	44,528	44,528		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	330,592,417	330,592,417		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	330,592,417	330,592,417		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission				
26	Distribution				
27	General				
28	TOTAL (Enter Total of lines 20 thru 27)	330,592,417	330,592,417		

Attachment 7

has been deemed

"Highly Confidential"

in its entirety.

NRG Power Marketing Inc.
901 Marquette Avenue
Suite 2300
Minneapolis, MN 55402-3265

Main Phone: (612) 373-5300
Main Fax: (612) 373-8686
Telephone: (800) 241-4NRG

an NRG Energy company

August 15, 2002

Mr. Clarence "Joe" Hopf, Jr.
Senior Vice President
Ameren Energy
400 South Fourth Street
St. Louis, MO 63102

RE: Audrain Proposal

Dear Joe:

We appreciated meeting with you and your team to discuss opportunities for the Audrain facility. As requested, NRG is pleased to present an indicative proposal to sell the Audrain facility to Ameren.

Executive Summary

NRG Energy, Inc. (NRG) acquired a 100% undivided interest in Duke Energy Audrain, LLC from Duke Energy North America on May 10, 2001. NRG's interests in the Audrain project are held by its direct, wholly owned subsidiary, NRG Audrain Holding LLC (Audrain). Audrain's operations are carried out through its wholly owned subsidiaries NRG Audrain BondCo LLC and NRG Audrain Generating LLC (Audrain Generating, formerly known as Duke Energy Audrain, LLC). Audrain Generating was established to develop, construct, lease and operate the 640MW gas-fired simple cycle merchant generation facility located in Vandalia, Missouri, approximately 105 miles northwest of St. Louis (the "Project").

This letter and information memorandum are being supplied confidentially for use by Ameren for the sole purpose of evaluating the potential purchase of Audrain. Contingent upon appropriate approvals, and delivery and execution of definitive agreements, NRG would consider selling 100% of its undivided interest in Audrain for $200 million.

In order to provide you with the information that you will require to submit a counterproposal, we will provide you with certain information regarding the Audrain generating facility, the industrial revenue bonds owned by NRG Audrain BondCo LLC, and the current facility lease structure with Audrain County. The information will include a preliminary information memorandum (included with this letter), a financial information supplement (upon signing a confidentiality agreement governing further disclosures and the sale process), and a Purchase Agreement (the "Agreement").

Proposal Guidelines

Your counterproposal must include all material terms on which it is based, specifically including the following:

a) **Price**. The purchase price you will pay in cash for NRG's interest in NRG Audrain Holding LLC. Our expectation is that the purchase price will be $200 million
b) **Financing Sources.** The form and source(s) of financing of the purchase price. If financing will involve third party source(s), please provide an indication of the timing and committed nature of those sources;
c) **Required Approvals and Consents.** A statement as to any applicable approvals and consents (shareholder, board, regulatory or otherwise) required by you to complete the transaction and the estimated timing to obtain such approvals (if they have not yet been obtained);
d) **Timing.** A statement regarding the proposed timing of a transaction and any requirements that you might have regarding the closing date of a transaction;
e) **Purchase Agreement.** By the time of your counterproposal, a Purchase Agreement will have been provided to you. NRG requests that you provide comments to the Agreement when you submit your proposal.

Statements

This indicative proposal is valid through August 30, 2002, unless extended by NRG. The submission of this proposal by NRG is not deemed an acceptance of all of the terms, conditions and requirements of Ameren's request for an indicative offer. Any counterproposal must be submitted in written form by 1:00 pm CST on August 30, 2002.

No agreement will be deemed to be reached, and unless the parties agree otherwise in writing, neither Ameren nor NRG will be obligated to the other in any manner until the execution and delivery of definitive agreements setting forth the understanding of the parties.

Audrain appears to be particularly well suited to meeting your planned generation needs. We look forward to discussing our offer with you. If you have any questions regarding this indicative proposal, please call me at (303) 308-2741 or David Duran at (303) 308-2822.

Regards,

Connie L. Paoletti
Origination

Encl.

AUDRAIN INFORMATION MEMORANDUM

Overview

NRG Energy, Inc. (NRG) acquired a 100% undivided interest in Duke Energy Audrain, LLC from Duke Energy North America on May 10, 2001. NRG's interests in the Audrain project are held by its direct, wholly owned subsidiary, NRG Audrain Holding LLC (Audrain). Audrain's operations are carried out through its wholly owned subsidiaries NRG Audrain BondCo LLC and NRG Audrain Generating LLC (Audrain Generating, formerly known as Duke Energy Audrain, LLC). Audrain Generating was established to develop, construct, lease and operate the 640MW gas-fired simple cycle merchant generation facility located in Vandalia, Missouri, approximately 105 miles northwest of St. Louis (the "Project").

Project History

Audrain was designed and constructed by Duke Energy Audrain under a turnkey, lump sum Engineering & Construction (E&C) Contract. Audrain achieved Substantial Completion and met performance guarantee requirements under the E&C Contract on May 9, 2001.

Site Description

Audrain and related equipment are situated on a site totaling approximately 105 acres at an elevation of just over 762 feet. The site is located 60 miles north of Interstate 70, 105 miles from St. Louis. The site was previously used for agriculture.

Electricity Interconnection

Ameren completed the appropriate interconnection and system studies. Ameren designed, procured, and constructed the switchyard as well as other system upgrades needed to interconnect Audrain to Ameren. Ameren operates and maintains the new switchyard as necessary to reliably and safely interconnect the facility to the electric transmission system.

Audrain has an Interconnection Agreement with Ameren dated January 2001. The Interconnection Agreement established and defined the respective responsibilities regarding the provisions of the installed equipment and facilities, and Audrain interconnecting equipment, and all that was necessary to interconnect the plant to the Ameren electric transmission system. These facilities include protection and controls, metering equipment, and all necessary connection, switching, transmission, distribution, safety engineering, communication and protective equipment. The interconnection facility was designed in accordance with the findings from the Ameren Facility Study, dated September 19, 2001. Ameren has completed construction and testing of its installed facilities.

Under the Interconnection Agreement, Duke paid Ameren for actual costs incurred to design,. construct, modify, test and install its facilities, and for easements, right of way, permits, and the like, to connect the plant to the electric system. Each company operates, maintains, repairs and inspects its respective interconnection facilities at Audrain's expense.

In addition, the Interconnect Agreement specifies the responsibilities of either party for billing, dispute resolution, insurance, limitation of liability, indemnification, warranties, default and termination.

Fuel Supply and Transportation

Panhandle Eastern Pipeline Company (PEPL) owns and operates the natural gas interconnection under a 20-year interruptible natural gas agreement. The natural gas fuel supply to the facility is transported by way of a PEPL interconnection. The interconnection is designed to supply a minimum flow rate of 500 dekatherm per hour at the delivery point at the site. A pressure regulating station reduces the gas pressure to 350 psig operating pressure as required by GE specifications.

Long-Term Power Purchase Agreement

At this time, NRG does not have any long-term power purchase agreements in place for its interest in Audrain. NRG Power Marketing (NPM) sells and markets the offtake produced by Audrain.

Equipment Configuration

Audrain's power train includes eight General Electric MS7001EA turbines and Brush generators. The CTGs are fired exclusively by natural gas. Electrical generators connected to the eight CTGs are connected to the switchyard through 4 individual generator step-up transformers (two generators per transformer). These transformers raise the generated voltage to 345 kV for connection into the AmerenUE electrical system under the terms of the 30-year Interconnection Agreement.

The CTGs are equipped with inlet air fogger systems and dry low NOx (DLN) combustion systems. The Audrain Project's combustor is guaranteed to meet a NOx emissions limit of 9 ppm and the facility's NOx levels were guaranteed by DFD under the Environment & Compliance Contract at 9 ppm. Since Commercial Operation, the CTGs have averaged NOx emissions below 8.5 ppm during base load operations.

Circulating Water System

Audrain Station CTGs have a closed loop circulating water system that is treated with ethylene glycol for freeze protection.

Plant Control System

Audrain has a central control room which houses modern state-of-the-art computer equipment including a Mark V turbine control system, distributed control system (DCS), vibration monitoring system, and CEMS. The CTGs are controlled by independent GE Speedtronic Mark V turbine control systems that provide primary control and engineering functions for the turbine generators. The Fisher-Rosemount Delta V DCS system provides plant process control, including Balance of Plant. A Bentley-Nevada 3300 Vibration Monitoring system monitors the turbine generator units.

Emissions Control System

Cisco hardware and VIM Technical software are included as part of the 8 fully automated and redundant CEMS to continuously monitor air pollution concentrations in flue gas from the CTGs. Audrain currently meets emission permit requirements.

Water Treatment System

Audrain utilizes potable water from the Monroe County Water District as makeup water for the fire main and demineralized water service for the CTGs. The treatment system is provided, as required, under contract with Ecolo Chem Inc. for demineralized water makeup to the demineralized storage tank, two demineralized water feed pumps, three demineralized forwarding pumps, and a 380,000 gallon demineralized water storage tank are permanent plant equipment.

Operations and Maintenance

The O&M agreement between Audrain and NRG Operations dated October 12, 2001 provides for the administration, operations, and maintenance of Audrain and will remain in effect for a term of ten years after the effective date, with subsequent five-year renewals at Audrain's discretion.

A Duke Energy Audrain Contract and Procurement Agreement provides warranties for all machinery, engineering and design, and for situations involving corrections, additions, repairs or replacements, excluding defects attributable to the manufacture of the turbines, which are provided in the Turbine Contract with GE.

Water Supply and Waste Water Disposal Management

The water supply for firewater and demineralized water service is provided from the Monroe County Water District as described above. The portable, trailer mounted system is a single train system sized for 215 gallons per minute makeup requirement.

Property Taxes

Under the financing structure for the Audrain generating facility, the project is exempt from real and personal property taxes in exchange for annual grant payments by NRG Audrain Holding LLC to the local taxing authorities. The annual grant payments are $350,000 through 2006. Beginning in 2007, the annual grant payments increase annually by the increase in the Consumer Price Index, but not more than 3% per year.

Financial Information

Available upon execution of a Confidentially Agreement.

Insurance

NRG maintains insurance coverage that for Audrain is sufficiently comprehensive in scope and amount. Audrain's insurance is on a full replacement value basis. Audrain is included in NRG's corporate policy for third party liability.

Employees

Audrain has 10 employees.

Permits and Regulatory Approvals

Audrain has obtained all permits, licenses and approvals required for operations and is operating in compliance with its emissions permit.

Environmental Matters

Similar to other gas-fired plants using GE-7EA technology, Audrain is significantly more environmentally friendly than other fossil fuel based generation such as coal or oil. Audrain has been designed and constructed to comply with all current environmental rules and regulations.

STATE OF MISSOURI
MISSOURI PUBLIC SERVICE COMMISSION

FILE COPY

In the matter of the Application of Union Electric Company, d/b/a AmerenUE, for approval of the transfer of generating assets by an affiliate to another affiliate	)))))	Case No. EA-2000-37

APPLICATION FOR FINDINGS PURSUANT TO 15 U.S.C.A. §79z-5a

COMES NOW, Union Electric Company, d/b/a AmerenUE ("AmerenUE"), and submits this verified Application requesting that this Commission make certain findings pursuant to 15 U.S.C.A. §79z-5a(c) ("Section 32") of the federal Public Utilities Holding Company Act ("PUHCA") in connection with a proposed transfer by AmerenUE's affiliate, Central Illinois Public Service Company, d/b/a AmerenCIPS ("AmerenCIPS"), of all of AmerenCIPS' generating assets and associated liabilities to another Ameren affiliate, presently known as "Genco." AmerenCIPS is a wholly-owned subsidiary of Ameren Corporation which provides electric and gas service to the public in Illinois. AmerenUE herein requests that the Commission find that AmerenCIPS' proposed transfer of its generating assets to Genco will benefit consumers, is in the public interest and does not violate Missouri law.

AmerenUE is a Missouri corporation, in good standing in all respects, with its principal office and place of business located at 1901 Chouteau Avenue, St. Louis, Missouri 63103. It is also a wholly-owned subsidiary of Ameren. AmerenUE is engaged in providing electric, gas and steam heating utility services in portions of Missouri as a public utility under the jurisdiction of the Missouri Commission. AmerenUE is also engaged in providing electric and gas service in portions of Illinois.

expenses associated with the new gas fired generating units. Under the JDA, AmerenUE's retail ratepayers would pay only the marginal production costs associated with energy from the new units. Of course, AmerenUE's ratepayers would also continue to have the rights to energy from the generation presently owned by AmerenCIPS as those rights are defined in the JDA. The formation of Genco would only expand the pool from which AmerenUE can draw energy.

37. In addition to the above, AmerenUE anticipates that Ameren will seek to serve certain of AmerenUE's current wholesale customers through the new Genco and Marketing Company in the future. This will result in an increase in existing AmerenUE capacity available to serve its retail customers. Five contracts representing 1998 demand of 260 mw of capacity are expiring at the end of the year 2000. Three contracts, representing 1998 demand of 37 mw of capacity, expire during 2003. If a successful bidder, Ameren intends to serve this load out of the Marketing Company and use existing AmerenUE generation facilities that were formerly dedicated to supplying wholesale customers to supply AmerenUE's retail load. With these demands on the AmerenUE system released, remaining regulated customers will enjoy a lower average fuel price and the need to buy less energy during periods of peak demand. AmerenUE anticipates that this will result in a decrease in fuel costs to its regulated customers of $14 million to $18 million dollars per year. Further, this reduction in peak demand defers the need for additional generating units to be constructed and brought into AmerenUE's rate base. This allows the current retail customers of AmerenUE to achieve greater benefits from an installed generating asset base currently valued at $322/kW, rather than constructing additional gas-fired capacity at an estimated cost of $390/kW. A reduction of 297 MW peak demand along with a 15% capacity margin would defer the construction of $133 million of new plants, with a savings of $23 million in fixed costs.