Exhibit No.

Issues: Customer Growth, Off-system Sales, Emission Allowances, Fuel & Purchased Power, Ash Handling, EEInc, Plant Retirement Assumptions, Osage Headwater Costs, Fuel Adjustment Clause

Witness: Michael L. Brosch

Type of Exhibit: Surrebuttal Testimony

Sponsoring Party: State of Missouri

Case No. ER-2007-0002

Date Testimony Prepared: February 27, 2007

BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF MISSOURI

SURREBUTTAL TESTIMONY

OF

MICHAEL L. BROSCH

ON BEHALF OF

STATE OF MISSOURI

NP

State Exhibit No. 504 - NP

Case No(s). ER-2007-0002

Date 3/27/07 Rptr MW

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 MICHAEL L. BROSCH

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Michael L. Brosch, being of lawful age, on his oath states: that he has participated in the preparation of the foregoing Surrebuttal Testimony in question and answer form to be presented in the above case; that the answers in said Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Michael L. Brosch

Michael L. Brosch

Subscribed and sworn to before me this 26th day of February, 2007.

Lori M. Rice

Notary

NOTARY PUBLIC STATE OF MISSOURI NOTARY SEAL

LORI M. RICE
My Commission Expires
June 7, 2010
Jackson County
Commission #06897298

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
SURREBUTTAL TESTIMONY OF MICHAEL L. BROSCH
ON BEHALF OF THE STATE OF MISSOURI
CASE NO. ER-2007-0002

Q. Please state your name and business address.

A. My name is Michael L. Brosch. My business address is 740 North Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. Are you the same Michael L. Brosch who submitted Direct Testimony in this Case on December 15, 2006 addressing revenue requirements and on December 29, 2006 addressing Fuel Adjustment Clause issues and Rebuttal Testimony on January 31, 2007?

A. Yes. My qualifications were described in the initial revenue requirement submission.

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

A. As before, I am appearing on behalf of the State of Missouri ("State"). My firm, Utilitech, Inc., was retained by the State of Missouri to examine the rate case filing of AmerenUE ("UE" or "Company") and to sponsor expert testimony resulting from this work.

Q. What is the purpose of your surrebuttal testimony at this time?

A. My rebuttal testimony is responsive to AmerenUE's rebuttal testimony on the following ratemaking issues:

ISSUE	COMPANY WITNESS	STATE ACCOUNTING SCHEDULE	SURREBUTTAL SCHEDULES ATTACHED
Customer Growth	Cooper	Revised C-1	MLB-7
Off-system Sales	Schukar	Revised C-2	MLB-8, MLB-9
Emission Allowances	Baxter	No Revision C-8	
Fuel & Purchased Power	Neff	Later Revision to C-3	
Ash Handling	Neff	Withdrawal of C-6	
Electric Energy Inc.	Moehn, Baxter, Svanda	Revised C-4	MLB-10, MLB-11 MLB-12
Retirement Assumptions	Naslund, Birk	N/A	
Osage Headwater Cost	Weiss	No Revision C-7	
Fuel Adjustment Clause	Neff, Lyons	N/A	

CUSTOMER GROWTH ADJUSTMENT

Q. Did AmerenUE submit Rebuttal testimony responding to the customer growth adjustments sponsored by Staff witness Mr. Hagemeyer and your adjustment at State Accounting Schedule C-1?

A. Yes. AmerenUE witness Mr. Cooper submitted Rebuttal Testimony. According to page 2 of Mr. Cooper's Rebuttal, the Staff and State's customer growth adjustments "...are not appropriate revenue adjustments, and the Commission should reject them for several reasons. First, these proposed revenue adjustments consist of imputed revenues from estimates of additional customers based upon the estimated kilowatthour usage of such customers. Second, absent fuel costs, neither Mr. Hagemeyer nor Mr. Brosch allowed any other direct or indirect Company operating costs associated with serving these proposed growth customers."

Q. Does the Company dispute that it continues to experience customer growth that creates new revenues and profit margins with the passage of time?

A. No. Mr. Cooper's Rebuttal does not dispute that growth is occurring. Instead, he implies at page 5 of his Rebuttal that accounting for such growth is inaccurate by referring to such calculations as creating, "...uncertain and speculative phantom test year customers, kilowatthours and revenues which are not applicable to the test year." He also expresses concern that customer growth contributes to expense growth beyond fuel costs that should be recognized.

Q. Is the adjustment you sponsor reflective of any "phantom" customers?

A. I don't know what a phantom customer is, but the adjustment I sponsor, after the updating described below, is based upon the actual number of customers being served by AmerenUE at December 31, 2006, according to its response to Data Request AG/UTI-285.

Q. Regarding incremental costs associated with customer growth, Mr. Cooper states at page 5 of his Rebuttal, "Costs relevant to serving customer growth were ignored altogether by

Mr. Hagemeyer and Mr. Brosch, including such obvious costs such as meter reading, billing and postage. How do you respond?

A. I agree that only a few relatively minor expenses vary directly with the number of customers served by AmerenUE. To address the concern raised by Mr. Cooper in this regard, I have added expenses for meter reading, billing and postage to the updated calculation of State Adjustment C-1 to recognize such incremental costs.

Q. Does Mr. Cooper suggest that other incremental costs, beyond postage, meter reading and billing will also increase as customers are added?

A. Yes. He argues at page 4 that all expenses are variable with the number of customers served, stating, "The Company's intermediate-term and long-term costs of serving additional customers are best reflected by the sum of the various functional components embedded within the Company's current class rate structures, which are comprised of the total cost of providing service to its customers. These costs include all operating and maintenance expenses,depreciation, taxes and a fair return on net plant investment."

Q. Is this a valid argument?

A. No. Many of a utility's costs are relatively fixed and do not vary as new customers are added. I think Mr. Cooper would agree that AmerenUE does not need to hire new officers and administrative employees or add to its transmission system or generating resources each time a new customer is added. His reference to "intermediate-term and long-term costs" is revealing in this regard, in reflecting an admission that only a few costs vary directly with the growth in customers in the short term. The Staff and State's customer growth adjustments are short-term adjustments, that simply annualize customer levels at the end of 2006, so as to match revenues and gross margins on sales to the simultaneous updating of Plant in Service,[1] Depreciation Expense, Fuel Costs and other major elements of the revenue requirement as of year-end 2006.

Q. Did you ask AmerenUE for additional information supporting Mr. Cooper's assertion at page 3 that other expenses vary directly as customers are added, where he stated, "Other less direct but obvious and real expenses that were omitted are allowances for the additional customer call center, credit and collection expenses and distribution operating expenses associated with serving a greater number of customers"?

A. Yes. I listed these expenses and asked for annual actual expense amounts for each item for the past five years in Data Request No. AG/UTI-338. In its response, the amounts provided indicated a good correlation between customer growth and Meter Reading costs, but no obvious correlation for the other expense elements. In its response, the Company admitted that such costs are not directly related to customer growth, stating, "AmerenUE does not believe that each of the listed expenses in part (a) of this data request varies directly with the number of customers served (i.e., as customer counts increase, these expenses increase proportionately). However, it is intuitive that over time, absent any increased efficiencies and/or technological advances, certain of the expense items in (a) that do not vary directly will increase as customer growth occurs if AmerenUE's existing service levels are to be maintained."

---

1 It should be noted that the Rate Base update planned in this proceeding would include within rate base all of the additional Plant in Service investment placed in service as of December 31, 2006, including investment made to connect and serve the new customers added through year-end.

Q. Should the Commission assume that AmerenUE will not avail itself of increased efficiencies or technological advances to control expense growth in the future?

A. No. Historical actual expense trends from 2002 through 2006 for Credit and Collection costs and for Customer Accounts expenses are favorable, even though customer growth has occurred since then.[2] There is no reason to believe that automation of these functions and improvements in methods and procedures will not continue to improve operational productivity.

Q. Have you revised State Joint Accounting Schedule C-1, to update your calculation of the appropriate adjustment for customer growth as of December 31, 2006?

A. Yes. This revised calculation appears at Schedule MLB-7 to this testimony. Two revisions are made to the calculation that I initially submitted. First, I updated the estimated customer count statistics at Line 1 to reflect actual data, based upon the Company's response to Data Request No. AG/UTI-285. AmerenUE added more residential customers and fewer general service customers than I had estimated in the initial calculations I sponsored. The other revision was to add at Line 11 a reduction to recognize incremental postage costs and meter reading/billing costs that would be incurred by AmerenUE to serve the additional customers that were added. This change is directly responsive to Mr. Cooper's criticisms in Rebuttal and are intended to recognize and account for expenses that vary directly with the number of customers that were added by AmerenUE in 2006.

[2] AmerenUE response to AG/UTI-338, part a.

OFF-SYSTEM SALES

Q. At page 32 of his Rebuttal Testimony, AmerenUE witness Mr. Schukar disputes your adjustment to update AmerenUE's off-system sales pricing, stating, "Mr. Brosch's approach reflects many of the same flaws that I discussed relating to Dr. Proctor's and Mr. Dauphanais' methodologies. First, the recommended prices reflect only average MISO energy prices and consequently fail to accurately reflect the prices that AmerenUE can actually realize for off-system sales at its generating stations. To correct this, Mr. Brosch would need to utilize the Gen LMPs from the units that are expected to make off-system sales. (These Gen LMP prices have been significantly below the MISO energy-only prices.) Second, Mr. Brosch recommends using a single year with abnormally high prices in the Summer and unusually low prices in September (Proctor direct testimony, p. 15) -- which creates the upwardly-skewed average price that I discussed earlier." How do you respond?

A. First, with regard to the claim that my "recommended prices reflect only average MISO energy prices and consequently fail to accurately reflect the prices that AmerenUE can actually realize", I relied upon the Company to provide pricing data that was comparable to that used by Mr. Schukar. I believed that such data was provided in response to Staff Data Request No. 269 and was, in fact, comparable. To confirm comparability, I then submitted Data Request No. AG/UTI-150 asking if the Staff 269 pricing data was "comparable to the input data utilized by Mr. Schukar to estimate normalized energy pricing based upon his earlier 2003-2005 analysis period" and the response provided by AmerenUE was "Yes". With such assurance from the Company, I relied upon this data in formulating the adjustment described in my Direct Testimony and State Accounting

Schedule C-2. If there is any problem with comparability of this information, it lies in the quality of the Company's responses to the referenced data requests.

Q. How do you respond to Mr. Schukar's other claim that using 2006 market energy prices is inappropriate because such prices are, "abnormally high prices in the Summer and unusually low prices in September -- which creates the upwardly-skewed average price"?

A. Because off-system sales prices fluctuate for many reasons, it is difficult to know that observed prices in a particular month are "abnormal". Mr. Schukar's answer to deal with the risk of anomalies within a particular month's pricing data is to rely upon a 36 month average of very old pricing data that vastly understates current market prices, as explained in my Direct Testimony at page 10. Mr. Schukar's pricing data dates back to January 2003, which is now up to four years old, and is clearly not reflective of ongoing, current market energy prices and increasing price trends. We need to look no further than AmerenUE's own internal forecast of off-system sales prices and margins to see that Mr. Schukar's pricing proposals are unreasonably low.

Q. What average price per MWH is assumed by AmerenUE within its official operating budget for calendar year 2007?

A. The "Margin Report" provided by the Company in support of its 2007 Fuel Budget assumes average revenue per MWH for off-system sales of *** ______ ***,[3] which is

[3] E-mailed file FB_REPORT_UE_Jan2_HC.xls from Tom Byrne received 2/16/2007 to supplement the response to AG/UTI-72 and AG/UTI-290. A formalized Supplemental Response to AG/UTI-72 was provided on February 23, 2007 and is included here as Highly Confidential Schedule MLB-8.

*** _______ *** than the average price of $35.71 that Mr. Schukar proposes, based upon his 2003-2005 averaging convention.[4]

Q. At its current estimate regarding off-system market prices, how much AmerenUE off-system sales margin is expected to be earned by AmerenUE in 2007?

A. The Company's recently approved Fuel Budget for 2007 includes gross margin on off-system sales of *** _________ ***, which is *** _______________ *** the $183 million amount Mr. Schukar is asking the Commission to include in setting the Company's base rates.[5] I have attached a copy of the Company's Highly Confidential Supplemental response to Data Request No AG/UTI-072 as Schedule MLB-8, including an excerpt of the electronic file summarizing off-system sales margins budgeted by the Company for calendar year 2007.

Q. What is your recommendation regarding an appropriate amount of off-system sales margins for calculation of the Company's revenue requirement?

A. I recommend that <u>no less than</u> the Company's budgeted 2007 margins be recognized. This amount should be reflective of the most recent available information regarding current and expected market conditions impacting AmerenUE at this time. Moreover, this Company-prepared estimate should be conservative for use in this rate case proceeding for the following reasons:

---

4 Direct Testimony of Shawn Schukar, page 9, line 2.
5 Id.

- Budgeted 2007 off-system sales margins would not reflect availability of Taum Sauk and when Taum Sauk is available, significant additional off-system sales margins are earned by AmerenUE.[6]
- Native loads should be higher in 2007 due to ongoing customer and load growth, reducing the amount of generation available to make off-system sales relative to test year levels.
- Average prices assumed in the AmerenUE Fuel Budget are considerably lower than the market energy prices assumed by Electric Energy Inc. in its 2007 Budget.[7]

Q. Have you updated State Accounting Schedule C-2 to reflect updated estimates of Calendar 2006 off-system sales prices?

A. I have revised State Accounting Schedule C-2, but <u>not</u> based upon the same 2006 pricing data that was initially used. While such an update was contemplated in my Direct Testimony[8] and would normally be performed using actual pricing information that is now available for months after September 2006, I have no confidence that the updated "comparable" pricing data being supplied by the Company is reflective of representative price data applicable to AmerenUE output.[9] Moreover, I have no access to dispatch simulation software that would enable a more precise estimate of off-system sales volumes and margins at current price levels. Therefore, I propose substituting the off-

---

6 The negative impact upon off-system sales margins was estimated to be $15 million annually in AmerenUE's response to AG/UTI-83. The impact should be larger at higher 2007 market energy prices.

7 See page 5.13 of Schedule MLB-12.

8 Direct Testimony of Michael Brosch, page 8, line 15.

9 The Company's response to AG/UTI-287 contains MISO energy pricing for the entire year of 2006, but in the response to Data Request No. AG/UTI-343, such data is now said by Mr. Schukar to no longer be "comparable".

system sales margin amount set forth in the Company's 2007 Fuel Budget, which results in a Revised State Accounting Schedule C-2 in the amount of *** ____ *** million increasing off-system sales margins from the *** ____ *** million value in AmerenUE's direct filing to the Companys' more current estimate of *** ____ *** million. This Revised State Accounting Schedule is attached as Schedule MLB-9.

Q. At page 36 of his Rebuttal on the subject of off-system sales tracking, Mr. Schukar argues that you and Office of Public Counsel witness Mr. Kind , "…seem to forget or possibly ignore that there are offsetting effects on the revenues that AmerenUE realizes or may realize from native load customers and the revenues from off-system sales. When native load sales are higher than the normalized sales utilized to determine base rates, the level of off-system sales goes down, and vice versa. Since the margins earned on off-system sales are generally below the margins earned on retail sales to native load customers, the use of a tracker mechanism for off-system sales would actually put the utility at greater risk than the risk it faces under existing ratemaking practice." Is this a valid concern if off-system sales margins are tracked without sharing as you propose?

A. No. Fluctuations in sales and revenues from native-load customers are primarily related to two issues, weather fluctuations in the short term and gradual customer growth in longer term. Weather fluctuations should be symmetrical around normal weather, such that offsetting weather-driven native load versus off-system sales demand changes would average out over time. In the longer term, as AmerenUE native load grows with retail customers being added, shareholders will retain the incremental margins from such native load growth between rate cases at the same time any off-system sales volume declines caused by such native load growth would be tracked through to customers. This longer-term effect is advantageous to shareholders and should be welcomed by Mr. Schukar.[10]

Q. According to Mr. Schukar at page 37 of his Rebuttal, "The second reason why a tracker on off-system sales would be poor public policy is that AmerenUE's proposed treatment of off-system sales margins provides the Company with strong incentives to maintain high plant performance and availability – particularly in the context of a fuel adjustment clause." How do you respond?

A. First, I would agree with Mr. Schukar that adopting a fuel adjustment clause creates a serious problem in blunting utility incentives to operate generation plant and acquire fuel supplies efficiently. This is one of the reasons why the State opposes adoption of a fuel adjustment clause ("FAC") for AmerenUE. By not implementing an FAC, the Commission can be sure that the Company will have every incentive to procure its fuel and operate and maintain its generation facilities in a cost effective manner.

Then, the remaining question becomes, **if** an FAC is implemented over the objections of the State, should any sharing of off-system sales be considered to replace the destruction of incentives caused by the FAC. On this point, I would suggest that only a very small sharing percentage of 5 to 10 percent of achieved off-system sales margins around the most probable expected ratemaking estimate of expected margins may be reasonable, if applied symmetrically both above and below the baseline level.[11]

---

10 At page 36 of his Rebuttal, Mr. Schukar notes that, "the margins earned on off-system sales are generally below the margins earned on retail sales to native load customers."

11 This alternative proposal will only produce reasonable results if the full amount of expected annual off-system sales margins serve as the baseline for symmetrical sharing above or below such amount. At the time, the State has adopted AmerenUE's internally projected forecast of such margins, based upon the 2007 Fuel Budget, as described herein.

EMISSION ALLOWANCE SALES

Q. At pages 10-15 of his Rebuttal Testimony, AmerenUE witness Mr. Baxter addresses the positions of the parties regarding regulatory treatment of emission allowance sales. Have you reviewed Mr. Baxter's proposed regulatory policies for emission allowances?

A. Yes. Several proposals for regulatory treatment of allowance sales are now advanced by Mr. Baxter:

- AmerenUE proposes that July and November/December storm-related O&M expenditures incurred by AmerenUE should be offset directly by the large amount of SO2 allowances sales revenues that the Company was realized during the second half of 2006.[12]
- If his proposed "offset" of allowance sales and storm costs is not adopted, then expensed storm costs should be recorded as a regulatory asset to be recovered over a four-year amortization period effective when rates to be set as a result of this case take effect.[13]
- Given the similarly extraordinary nature of the most recent ice storm, the proposed approach could also be considered for the January 2007 storm costs.[14]
- AmerenUE supports Staff's proposed concept of creating a regulatory liability for emission allowance sales revenues, but only on a going-forward basis and conditioned upon such regulatory liability being used

[12] Baxter Rebuttal, page 12.
[13] Id.
[14] Id. page 13.

for the sole purpose of offsetting the cost of future capital investment related to environmental compliance at the Company's generating plants.[15]

- If any emission allowance revenues are reflected in base rates (a position the Company does not support in the context of this proposal), then only the emission allowance sales revenues above these base rate amounts should be reflected in the regulatory liability.[16]

Q. Does Mr. Baxter oppose the inclusion of any emission allowance sales as a reduction to revenue requirement, as recommended by the State and Office of Public Counsel?

A. Yes. Three reasons are identified by Mr. Baxter for AmerenUE's opposition to recognizing emission allowance sales for ratemaking. First, he claims that past sales of allowances have varied greatly in amount, and are therefore a poor predictor of future sales levels. Second, that embedding a level of emission allowance sales in base rates will mean that for AmerenUE to recover its expected costs on a going forward basis AmerenUE would, on average, have to sell $16 to $20 million worth of SO2 allowances each year. Finally, Mr. Baxter states that the OPC's and State's proposals could also cause unnecessary rate changes by initially reducing rates through SO2 allowance revenue credits even though substantial environmental compliance investments with sizeable rate impacts are on the immediate horizon.[17]

Q. Did AmerenUE include any level of emission allowance sales in its own filing?

---

15 Id.

16 Id. page 14.

17 Rebuttal Testimony of Warner Baxter, pages 14-15.

A. Yes. Approximately $3.9 million of actual test year allowance sales were recorded on the books, and AmerenUE made no adjustment to modify or remove this amount. Thus, Mr. Baxter's criticism of embedding an amount of allowances sales in base rates would also apply to the Company's own prefiled case, but at a dollar level lower than the $20.3 million pro-forma level I sponsored in State Accounting Schedule C-8.[18]

Q. Did you, in your Direct Testimony, address the variability concern raised by Mr. Baxter in two of his three stated reasons for opposition of your proposal?

A. Yes. At page 39 I proposed that any Fuel Adjustment Clause ("FAC") that may be approved for AmerenUE, over the opposition of the State and other parties, be conditioned upon full crediting of all prospective sales of environmental allowances that may be made by the Company.

Q. If an FAC is <u>not</u> approved for AmerenUE, would you also support deferral accounting that would require the Company to record a regulatory liability for its actual prospective environmental allowance sales, reduced by the amount of emission allowance sales that are recognized in establishing the Company's base rates?

A. Yes. Using the State's position as an example, if $20.3 million of allowance sales are recognized in setting base rates, a regulatory asset or liability would be recorded in each month by AmerenUE in amount by which the retail portion of actual allowance sales in that month varied from $1.692 million (1/12 of $20.3 million). Amounts accumulated in

[18] State Accounting Schedule C-8 recognizes an average historical amount of SO_2 allowance sales of $20.6 million for ratemaking purposes, times a jurisdictional allocation factor of 98.46%, yielding a test year pro-forma level of $20.3 million.

this deferral account could be reviewed in the Company's next Missouri rate case and adjustments could then be made to increase or decrease the ratemaking allowance.

Q. Would the approach you described address the concerns mentioned by Mr. Baxter?

A. Full deferral accounting (with or without an FAC) should certainly address the concerns about quantification accuracy and any implied need to sell allowances in the future. Under this approach, the Company would be made "whole" for any differences between the ratemaking level of emission allowance sales and future actual allowance sales levels. Mr. Baxter's third concern about wanting to keep all of the allowance sales proceeds for shareholders. until future environmental costs begin to increase is <u>not</u> addressed by this proposal.

Q. With respect to Mr. Baxter's third concern, does your proposed inclusion of an average level of allowance sales in setting the Company's rates create a risk of causing "unnecessary rate changes by initially reducing rates through SO2 allowance revenue credits even though substantial environmental compliance investments with sizeable rate impacts are on the immediate horizon"?[19]

A. No. This argument is entirely speculative, as AmerenUE has made no showing regarding its future revenue requirements, or that such amounts would be significantly impacted by the Company's proposed denial of any ratepayer participation in emission allowance sales at this time. The Commission might reasonably wonder why AmerenUE has been actively selling emission allowances and reporting such sales as income historically, rather than approaching the Commission on its own motion in the past, if it really had any

[19] Rebuttal Testimony of Warner Baxter, page 15, line 8.

interest in building up a regulatory liability for the benefit of customers in an effort to offset future rate cases driven by environmental expenditures.

It is important to recognize that the State's proposed recognition of average SO2 sales proceeds at this time in setting rates, rather than letting the Company retain such cash flow, represents a change of less than 0.7 percent of test year operating revenues.[20]

Q. Why should the Commission not accept the Staff's proposal, that is apparently now supported by AmerenUE, that would prospectively defer all allowance sales proceeds and include no such transactions in setting the Company's base rates?

A. There are a number of reasons why this proposal should be rejected, including the following:

- AmerenUE has established a history of significant sales of environmental allowances, and such allowances are assets that are clearly utility-related and for which ratepayers have an undisputed claim to participate.[21]
- Ratepayers will bear significant costs as part of AmerenUE SO2 coal price adjustments in their present rate levels,[22] and allowance sales should be recognized as a source of revenue to offset these current period costs.
- The Staff's deferral proposal (and presumably AmerenUE's adoption of this proposal) would not accrue any interest to recognize the time value of large sums of money owed to ratepayers, but retained by the Company for future use.

---

[20] State Adjustment C-8 would reduce revenue requirement by $16.5 million, which is 0.7 percent of test year revenues of $2.352 billion per AmerenUE, as shown on State Schedule C, column B, line 1.

[21] See State Accounting Schedule C-8 for a history of such sales from 2003 through November 2006. According to the response to AG/UTI-307a, significant allowance sale transactions also occurred in 2001 and 2002.

[22] See Direct Testimony of Michael Brosch, page 38.

- AmerenUE has not defined or quantified any specific future need for special funding by ratepayers, through foregone participation in allowance sales proceeds, or explained how ratepayers would be any better off by waiting for economic benefit from allowance sales.
- AmerenUE has not indicated any inability to finance future environmental expenditures it may face,[23] to support a conclusion that funding from SO2 allowance sales is needed for such purposes.
- If allowance sales are retained by AmerenUE and deferred for future regulatory disposition, the Company will incur income tax expenses on such sales, reducing the net value of such sales that could otherwise be credited to ratepayers.
- A portion of Staff's proposal appears to constitute retroactive ratemaking, as suggested by Mr. Baxter at Rebuttal page 13, line 10.

Q. Do you agree with Mr. Baxter that if an amount of SO2 allowances are built into the determination of the Company's base rates, as you propose, then "only the SO2 allowance sales revenues above these base rate amounts should be reflected in the regulatory liability"?

A. Yes. In fact, I would suggest that the deferral accounting be symmetrical, accounting for variations both "above" or "below" the dollar amount recognized in setting utility rates.

Q. How do you respond to Mr. Baxter's proposal to use the large amounts of recent actual SO2 allowance sales to offset storm costs that AmerenUE has incurred?

---

[23] Mr. Baxter references Form 10-K estimates of possible future environmental costs at Rebuttal page 14.

A. The State of Missouri does not object to this proposal and agrees with Mr. Baxter that retroactive ratemaking should not be applied to defer either the past SO2 allowance proceeds, or to defer any past storm costs that have been experienced by the Company in 2006 or 2007, to date. However, in the event AmerenUE requests any Accounting Authority Order treatment to defer storm costs incurred prior to the effective date of new rates in this Case, an accounting for past SO2 allowance sales and possible deferral accounting for such historical transactions may need to be revisited.

FUEL AND PURCHASED POWER EXPENSES

Q. AmerenUE witness Mr. Neff explains at page 2 of his Rebuttal certain fuel expense hedging costs that he believes should be allowed in determining test year fuel expenses. Have you included these costs in your estimate of fuel expenses?

A. Yes. These hedging costs were included in the Company's response to Staff Data Request No. 310, that I relied upon as the starting point for my fuel expense calculations and adjustment.[24] I made no adjustment to exclude these hedging costs because recovery of such costs is reasonable in the absence of a fuel adjustment clause, when used to limit the risks to the utility of volatility in experienced fuel costs between rate cases. If an FAC is allowed for AmerenUE, over the objections of the State of Missouri, it may not be appropriate to allow recovery of such hedging costs.

Q. Have you revised and updated State Accounting Schedule C-3 to reflect actual fuel and purchased power costs as of January 2007?

---

[24] See Direct Testimony of Michael L. Brosch, page 16.

A. Not at this time. I understand that the Order Adopting Procedural Schedule and Test Year in this Case has established March 2, 2007 as the date when AmerenUE is to provide data supporting its position on true-up items. An updating of the State's estimated fuel and purchased power expenses will occur after receipt and review of this additional information from the Company.

ASH HANDLING

Q. At page 3 of his Rebuttal, AmerenUE witness Mr. Neff responds to your proposed ash handling expense adjustment by stating, "The wording of the business plan may have led Mr. Brosch to conclude that AmerenUE realized an immediate gain from avoiding ash disposal costs that were incurred in the test year. However, there are no ash disposal costs in the test year because these are costs that would be incurred in the future when the ash pond at the Labadie Plant is full and ash must be disposed of off-site." Did you conclude that imminent savings would result from the Pakmix Business Plan document?

A. Yes. After reviewing Mr. Neff's Rebuttal on this matter and conducting additional investigation, I have concluded that State Accounting Schedule C-6 should be withdrawn. In its response to Data Request AG/UTI-304, AmerenUE provided detailed Labadie Station ash disposal facts and revenue/expense amounts that support a conclusion that a ratemaking adjustment is not required.

ELECTRIC ENERGY, INC.

Q. At page 2 of his Rebuttal Testimony, AmerenUE witness Mr. Moehn states, "First, it is important to properly characterize this unique notion of 'support', sometimes also referred to in the various testimonies as financial support. Ratepayers no more provided 'support' to EEInc. than I have provided 'support, to Schnuck's or Target by shopping there over the years. When I shop there, I exchange money for goods. What occurred from 1954-2005 between EEInc. and AmerenUE was an unremarkable exchange of value seen in any sale of a commodity, pure and simple. As a result of AmerenUE's purchase of power from EEInc., its ratepayers received reliable, low cost power, including capacity (MW) and energy (MWh)." Do you agree with these characterizations of the historical relationship between EE Inc. and AmerenUE?

A. No. A quite remarkable and unique business arrangement has occurred between Union Electric, a regulated utility, and Electric Energy, Inc. ("EEInc."), an affiliated company, over the past fifty plus years. Union Electric, on behalf of its ratepayers and with the approval of the Commission, invested in EEInc., committed to take and pay for its share of the output of EEInc. facilities (beyond the requirements of the Federal government) and guaranteed certain financing for the benefit of EEInc. During this historical period, EEInc. was assured the sale of its plant output at full cost plus a guaranteed rate of return, effectively transferring the risks arising from ownership and operation of its facility to Union Electric and its other sponsoring utilities. This history is utterly and completely different from shopping at Schnuck's or Target, where customers pay market prices only if they want or need the products being offered and do not guarantee cost recovery, an assured return or the financial condition of the seller.

Q. At Rebuttal page 3, Mr. Moehn states that, "AmerenUE's equity investment in the stock of EEInc. was made as a below-the line investment with shareholder money, not with ratepayer money. The significance of this investment being below-the-line lies in the fact that for ratemaking purposes, below-the-line investments are excluded from any rate base, cost of capital, or other calculation relating to the utility's cost to serve its utility customers. Consequently, ratepayers do not bear any responsibility for potential losses on these non-regulated investments." Should these arguments be relied upon to deny ratepayers the economic value associated with the Joppa Power Plant?

A. No. Mr. Moehn chooses to focus upon narrowly construed observations regarding sources of money used by Union Electric to make an investment in EEInc. stock many years ago to support his arguments regarding EEInc. and the Joppa Plant:

- That EEInc.'s capital investment in the Joppa Plant has historically been treated as non-jurisdictional by the Commission.
- That historically, ratepayers were <u>not</u> financially responsible for the costs and risks of operating EEInc.'s Joppa Plant.
- That Union Electric Company, as an owner of common stock investment in the stock of EEInc., absorbed significant actual or potential losses in operation of the Joppa Plant.

However, when the historical regulatory treatment of the Joppa Plant is carefully considered, the facts are that ratepayers bore considerably more of the costs and risks of this investment than did EEInc. or Union Electric shareholders.

Q. What does it mean for an "investment" to be "below-the-line" in your experience with utility regulation?

A. The common reference to "below-the-line" that I am familiar with from my experience in utility regulation over the past 28 years has nothing to do with "investments" or common stock, but rather relates to expenses recorded on a utility's income statement that are excluded in determining operating income because they are recorded in accounts that align "below" the "Operating Income" line on the income statement. The below the line income statement accounts include non-operating income and expense accounts as well as interest expenses. Mr. Moehn does not define his use of the term "Below-the-line", except to conclude that, "...below-the-line investments are excluded from any rate base, cost of capital, or other calculation relating to the utility's cost to serve its utility customers."

Q. Would a utility's investment in the common stock of a subsidiary, such as Union Electric's investment in EEInc. common stock, ever be included by a regulator in "rate base, cost of capital or other calculations relating to the utility's cost to serve", as suggested by Mr. Moehn?

A. No. Utility rate base is made up of direct investments made by the utility <u>in its own</u> Plant in Service, inventories, prepayments and working capital, reduced by accumulated depreciation and accumulated deferred income taxes. Mr. Moehn's reference to EEInc. as an "investment" that could have been included in rate base is simply wrong. I am aware of no instance in my entire professional career when a utility's common stock investment in a subsidiary was judged by a regulator to be "included" or "excluded" in the manner described by Mr. Moehn.

Q. What is normally recognized and included in calculating a public utility's cost of capital for ratemaking purposes?

A. Utility cost of capital calculations normally are based upon the book cost of equity and debt capital invested <u>in the utility entity</u>, which capital balances are combined and used to weight the cost rates for such debt and equity to arrive at an overall rate of return for the utility. There would be no reason to consider including a utility's investment in the common stock of a subsidiary as part of the utility's overall cost of capital.

Q. Is Mr. Moehn correct in asserting that the investment in EEInc. was excluded in other rate case calculations relating to the utility's cost to serve?

A. No. Mr. Moehn is not correct in suggesting that Union Electric's investment in EEInc., which in turn represents 40 percent of the equity capital investment in the Joppa Power Plant, was "excluded" in the context of any "...other calculation relating to the utility's cost to serve its utility customers." As explained in my Direct Testimony at pages 19-21, Union Electric ratepayers have for many years paid electricity rates that included recovery of Joppa Plant costs that were booked as purchased power expenses within the "utility's cost to serve its customers."

Q. Has Mr. Moehn or any other Company witness identified any Missouri Commission Order in which Union Electric's investment in EEInc. common stock was said to be either included or excluded in calculating rate base?

A. No.

Q. Has Mr. Moehn or any other Company witness identified any Missouri Commission Order in which Union Electric's purchased power expenses paid to EEInc. were excluded in calculating utility operating income?

A. No. In fact, at page 4 of his Rebuttal, Mr. Moehn admits, "the cost of the PSA has always been ruled as a prudent expense incurred by AmerenUE on behalf of its customers." The significance of this fact goes to the heart of determining whether shareholders or ratepayers bore the majority of risks and costs associated with Joppa, and therefore whether shareholders or ratepayers are entitled to realize the current market value of the plant and its output.

Q. Why does it matter whether ratepayers versus shareholders have borne the costs and risks of operating the Joppa Plant historically?

A. Mr. Moehn seems to recognize the equity and fairness of attributing the benefit of the value of the Joppa Plant based upon who has borne the costs and risks of the Joppa Plant – ratepayers or shareholders. I agree with this principal and have explained how it should be applied in my Direct Testimony on this issue. Unfortunately, Mr. Moehn's apparent fixation upon common stock ownership and other formalities does not allow him to recognize that shareholders have <u>not</u> absorbed Joppa Plant cost and risks historically and that shareholders are <u>not</u> entitled to retain all Joppa financial benefits prospectively.

Q. After suggesting that the Joppa Plant investment was <u>not</u> treated as jurisdictional in past Missouri ratemaking, Moehn concludes at page 3 that, "It follows therefore, that any risk associated with this investment, had it been related to the construction of the Joppa Plant, or related to the ongoing operations of EEInc., falls clearly on AmerenUE's shareholders and not on AmerenUE's ratepayers. In sum, shareholders took the investment risk and are entitled to the investment rewards." Does this "follow" from any reasoned analysis of the history of costs, risks and ratemaking for the Joppa Plant?

A. No. The Joppa Plant was treated as jurisdictional by virtue of the Power Supply Agreements ("PSA") that embedded the cost of Joppa capacity and energy within Union Electric electricity rates. The PSA governing disposition of Joppa Plant output since 1987 provided for full recovery of 100 percent of the costs of production every year, plus a guaranteed return on investment equivalent to a 15 percent equity rate of return.[25] To the extent Joppa insurance costs were incurred to protect against casualty losses, the premiums for such insurance were includable in the cost of service formula within the PSA. If extraordinary repairs were needed due to equipment failure, the replacement costs of the equipment became recoverable under the PSA. If availability or operational performance at Joppa deteriorated and KWH output declined, Union Electric and the other sponsoring utilities remained obligated to pay all of the Joppa operating and maintenance expenses plus a 15 percent equity return. The owners of Joppa absorbed no risks associated with operating or maintaining the Joppa Plant during the term of the PSA.

Q. At page 4 of his Rebuttal, Mr. Moehn opines, "...if the Joppa Plant had experienced some type of catastrophic failure, had regulation made a coal plant undesirable, or had other equally bad and unforeseen events happened at EEInc., AmerenUE would not have sought recovery from ratepayers because AmerenUE's shareholders were at risk for this

[25] 1987 Power Supply Agreement between EE Inc. and the Sponsoring Companies, Article III "Rates".

unregulated investment." Are there any extant facts to support this hypothetical situation?

A. No. Mr. Moehn's hindsight is now 20/20, since no such events have occurred and it is now convenient for the Company to characterize Joppa as being an "at risk" plant to shareholders. Mr. Moehn wishes to now speculate that, "AmerenUE would not have sought recovery" upon an event of catastrophic (and presumably uninsured) failure at Joppa. This form of after-the-fact speculation is not credible for several reasons:

- According to Mr. Moehn, the PSA represented a "...great deal for AmerenUE, allowing it to provide low-cost power to its ratepayers."[26] If this is true, the Commission should have been very receptive to any request for ratepayer recovery of uninsured property losses in the interest of returning this low-cost source of power to service.
- The PSA obligated AmerenUE and the other sponsoring utilities to absolutely and unconditionally pay Joppa Station's cost of service, even if EEInc. was unable to generate or deliver electricity.[27]
- The cost-based PSA would have allowed EEInc. to invest in replacement facilities and to incur extraordinary expenses, with all such costs recoverable through the PSA formula pricing of plant output.[28]

Q. Has AmerenUE ever made any representation to the Missouri Commission in any filing or pleading that "If the Joppa Plant experienced some type of catastrophic failure, had

[26] Moehn Rebuttal, page 4, line 1.
[27] EE Inc. Annual Report 2005, page 13.
[28] Power Supply Agreement Between Electric Energy, Inc. and the Sponsoring Companies, 9/2/1987, Sections 3.01b and 3.07.

regulation made a coal plant undesirable, or had other equally bad and unforeseen events happened at EEInc.", recovery would not have been sought from ratepayers?

A. This question was asked of the Company in Data Request AG/UTI-332 and the Company responded, "AmerenUE has never had the occasion to make the specific statement set out in this data request."

Q. At page 5 of his Rebuttal, Mr. Moehn states, "In every year, AmerenUE received a level of power, be it capacity and/or energy, from EEInc. to serve its ratepayers that was commensurate with the charges paid by those ratepayers. Costs not associated with power or capacity purchased to serve ratepayers, or for any costs for power or capacity that the Commission determines to be imprudent, would be excluded from AmerenUE's rates, and those costs would be paid exclusively by AmerenUE's shareholders." Should the Commission conclude from this testimony that ratepayers "got what they paid for" and that the EEInc. shareholders were at risk for any significant amount of unrecoverable costs?

A. No. Again, in an absence of any facts to support his "shareholders at risk" hypothesis, Mr. Moehn is forced to speculate about what might have happened <u>if</u> a prudence disallowance had been ordered by the Commission or <u>if</u> EEInc. had fraudulently billed AmerenUE for costs "not associated with power or capacity to serve ratepayers." There has been no showing of any Commission determination that EEInc. billings to Union Electric for cost-based power were imprudent or unreasonable and therefore not fully recoverable from ratepayers. The important factual reality is that the Joppa Plant has been included in Union Electric's revenue requirement in prior years on a cost of service basis, with little or no risk of disallowance of cost recovery, because the PSA assured EEInc. of full cost recovery.

Q. At page 5 Mr. Moehn states, "In fact, over the roughly 50 years that AmerenUE had purchased power agreements with EEInc., none of the parties who now apparently want to recharacterize the below-the-line treatment of AmerenUE's investment in EEInc. ever questioned the terms, price, or structure of the agreements under which AmerenUE obtained power that it used to serve ratepayers." How do you respond?

A. I have not tried to "recharacterize" anything. The State's position is that the risks, costs and benefits of the Joppa Plant, to the extent not dedicated to Federal Government service, have historically been dedicated and charged to the sponsoring utilities on a full cost of service, guaranteed rate of return basis. It is AmerenUE's proposal to now recharacterize history so as to rationalize shifting the economic value of the Joppa Plant and its output for the sole benefit of shareholders, after ratepayers have supported the Union Electric share of costs and risks of the plant for roughly 50 years.

Q. At page 6 of his Rebuttal, Mr. Moehn references certain "subsidiaries" of EEInc. and asserts that the, "Midwest Electric Power generating subsidiary has experienced losses in recent years." Is this a point of any consequence?

A. No. Midwest Electric Power, Inc. ("MEPI") owns and operates two gas-fired combustion turbine generators with combined capacity of 76 megawatts. Additionally, MEPI operates three refurbished gas-fired combustion turbines for Ameren Energy Development Company with a combined capacity of 186 megawatts. Mr. Moehn does not explain or quantify what "losses in recent years" arose from the MEPI business, but the MEPI entity had total net plant investment of less than $40 million in 2006 and earned positive net income of $252 thousand and $244 thousand in both 2005 and 2006, respectively.[29] Of greater importance is the fact that these combustion turbine operations were added to the Joppa site much later than the steam units and were not included within the cost-based PSA,[30] making such operations irrelevant to the discussion of EEInc.'s Joppa Plant coal-fired capacity. It should be noted that I have excluded MEPI operations from the updated imputation adjustment that is described later in my testimony and that replaces and supersedes State Accounting Schedule C-4, the adjustment I propose to impute the realized ongoing market value of the EEInc. business operation for ratemaking purposes (See Schedule MLB-11).

Q. At page 5 of his Rebuttal, Mr. Moehn states, "I also understand that in recent years EEInc. wrote off approximately $1.7 million related to an abandoned project to construct a coal transfer terminal." Does this mean that shareholders have been borne all of the historical risks and costs of the Joppa Steam plant operations?

A. No. A single abandonment loss event in 50 years does not indicate any significant risk shifting. Mr. Moehn does not provide any factual details about this "write-off" event to explain when or why the abandonment occurred or whether any recognition of such costs was prohibited through the cost-of-service PSA calculations (if the event occurred during the term of the PSA). In any event, an isolated $1.7 million abandoned project represents

29 See AmerenUE response to AG/UTI-298, Entity ID: MEP, Income Statement Current Year 12ME and Prior Year 12 ME Activity.

30 Appendix "A" to the 1987 PSA defines the "Production Plant" facilities that are subject to the PSA pursuant to Section 1.01 as including "The Company's steam-electric generating station..." consisting of listed and described assets and features that do not include any combustion turbine generators.

less than one percent of annual EEInc. Operating Expenses, which totaled $233 million in 2006.[31]

Q. At page 6, Mr. Moehn also refers to, "Like any other cost not included in prudently incurred charges for capacity or energy bought by AmerenUE to serve ratepayers, the shareholders of EEInc. bore 100% of the earnings impact of these losses." Has Mr. Moehn identified any "other costs not included in prudently incurred charges for capacity" for which "shareholders of EEInc. bore 100%" of the costs?

A. No. It is potentially misleading to the Commission for Mr. Moehn to imply that "other costs" were <u>routinely</u> borne 100% by shareholders under the cost-based PSA between EEInc. and Union Electric that was effective for many years, without describing and quantifying each of such alleged shareholder-absorbed cost events. Perhaps the inference is that the abandoned coal transfer terminal event was, in fact, not a prudently incurred cost and EEInc. decided to have the sponsoring companies absorb the write-off as a reduction of their subsidiary income, rather than paying it as part of their PSA billings.

Q. After citing only two isolated cost events throughout the history of EEInc. that he believes to have been borne by EEInc. shareholders, Mr Moehn states conclusively at page 6, "Any risk associated with the operation or construction of the Joppa Plant has always been borne by AmerenUE shareholders." Is this true?

A. No. The PSA provided EEInc. with full cost recovery opportunities for all of the following costs incurred in connection with the Joppa steam plant, including without limitation or any showing of prudence by EEInc.:

[31] AmerenUE response to AG/UTI-298.

- Interest expenses and amortization of debt costs (Section 3.01, Component A, Section 3.02(a))
- Depreciation expenses (Section 3.01, Component A, Section 3.02(a) and Section 3.05)
- Total operating expenses for labor, maintenance, materials, supplies, services, administrative and generation expenses, etc. (Section 3.01, Component B, Section 3.02(a))
- Total expenses for taxes and insurance (Section 3.01, Component C, Section 3.02(a))
- Return on investment, adjusted to provide a return on equity after taxes of 15.0% (Section 3.01, Component C, Section 3.02(a) and Section 3.04)
- Actual Fuel Costs (Section 3.02(b) and Section 3.03)
- Replacements, extensions and improvements expenditures (Section 3.07)

By these terms, Union Electric and the other sponsoring companies had a very direct obligation to assure the financial viability of the Joppa Plant, as documented in the PSA. In the absence of any documented Missouri Commission disallowances of purchased power expenses paid pursuant to the PSA, all of Union Electric's share of Joppa Plant O&M and investment-related costs have been borne by UE's ratepayers, not shareholders.

Q. Does another document clearly state the nature of operating assurances received historically by EEInc. from AmerenUE and the other Sponsoring Companies?

A. Yes. This responsibility is summarized best by EEInc. in its own 2005 Annual Report, a copy of which is attached as Schedule MLB-10. This report states at page 13:

> Under the Power supply Agreement and Mod 16, 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 Power Supply Agreement and Mod 16 also provide the company the opportunity to earn a profit on other services provided to the Sponsoring Companies and to the DOE.
>
> The DOE was committed to 0% of Joppa Station's capacity for 2005 and 2004. For 2006, the DOE's commitment will again be 0% of Joppa Station's capacity.
>
> <u>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</u>. [emphasis added]

Q. At page 7 of his Rebuttal, Mr. Moehn states, "AmerenUE's retail customers played no more of a role in "assuring the financial viability" of the Joppa Plant than do customers of any business play a role in assuring the viability of that business by purchasing the goods and services of that business." Is this accurate?

A. No. This assertion is directly contradicted by the terms of the PSA that are summarized above by the statements of EEInc. in its 2005 Annual Report (as quoted above). The customers of EEInc. fully reimbursed all of the costs of operating, maintaining, insuring and improving the Joppa Plant for the initial decades of its existence and were contractually committed to take and pay for the output of the plant at such cost-based pricing terms. This is in stark contrast to virtually every other customer/provider business relationship in our market-based economy, where the buyer is under no compulsion to buy and if he/she elects to buy, the buyer has no obligation to pay any more than the fair market value of the product in question.

It is impossible to reconcile Mr. Moehn's admission at Rebuttal page 9 regarding, "The financial backstop provided by the PSA [that] allowed EEInc. to finance these bonds at more favorable terms" to his suggestion on page 7 that AmerenUE's customers have done nothing special to assure the viability of EEInc.'s business. AmerenUE on behalf of its customers most certainly provided financial security and guarantees for the benefit of EEInc. and this Commission was involved in reviewing and approving these transactions in Case No. 12,064 and Case No. EF-77-197, as noted in my Direct Testimony.

Q. At page 8 of his Rebuttal, Mr. Moehn states, "...over the period from 1954-2005, the average annual cost of EEInc.'s power to AmerenUE was $14.19/MWh, including costs for demand and energy. I think everyone will agree that this was a good price and good value." Do you agree with Mr. Moehn that $14.19 was a "good price and a good value" throughout this 51 year period?

A. I would not agree to this generalization without a market assessment of capacity transactions throughout this period. One might expect that the price of EEInc. output at Joppa was competitive with alternative new generating resources at the time the Joppa Plant was initially constructed in the 1950's. However, in the early 1980's, an apparent glut of base load generating capacity had developed in the Midwest and alternative base-load power supplies may have been available on better terms than the Joppa Plant cost-based rates in that time period.

At the present time, the market value of Joppa Plant output dramatically exceeds the costs of production at Joppa – which is why Ameren now desires extraction of this value for sole benefit of its shareholders. The important historical point is that Union Electric and its ratepayers, as well as the other Joppa Plant sponsors were committed to take and pay for Joppa output at cost-based rates, limiting their ability to take advantage of any market opportunities to purchase less costly capacity if and when it may have been available.

Q. At page 11 of his Rebuttal, Mr. Moehn states, "As I noted earlier, ratepayers were required to pay for, and did pay for, prudently incurred power costs. Since power costs from the Joppa Plant were so low there was never a question of whether they were prudently incurred." Did the PSA limit EEInc.'s costs that were recoverable from Union Electric to only "prudently incurred" costs and only when the result was prices that were "low"?

A. No. I have reviewed the PSA documents and see no restriction or limitation upon EEInc. ability to recover its costs based upon prudence or the reasonableness of resulting prices. The obligations of the Sponsoring Companies to pay the Joppa Station cost of service were said by EEInc. in its 2005 Annual Report to be "absolute and unconditional".

Q. Has Mr. Moehn identified any Missouri Commission Order that addresses prudence or alleged imprudence associated with EEInc. power supply billings to Union Electric pursuant to the PSA?

A. No. He seems to opine that Joppa Plant costs were so low that they must have been prudent, but this is an unsupported assumption. More importantly, there has been no showing that shareholders have borne any significant costs or risks associated with the Joppa Plant that now entitles shareholders to reap windfall profits by treating the market value of Joppa Plant output as non-jurisdictional for ratemaking purposes.

Q. Mr. Moehn disputes your conclusion at page 12, stating, "Had something happened at Joppa that made that power high cost power, consistent with the below-the-line character of the EEInc. investment, AmerenUE would not have sought to pass those costs through its cost of service as part of its purchased power expenses. In addition, there would be no reason to expect that the Commission would permit such costs, if imprudent, to be included in AmerenUE's cost of service. Shareholders bore that risk, just as shareholders bear the risk of financial losses at EEInc. today." How do your respond?

A. Of course, it is utterly impossible to prove today what AmerenUE "would not have sought" from the Commission if Joppa costs had been higher than actually occurred. It is equally impossible to prove any "shareholder borne risk" arising from mythically higher prior year Joppa Plant costs that might have been so unreasonable as to be found "imprudent" by the Commission. The known facts do not support such rank speculation. The more plausible scenario is to consider what really happened, Joppa was constructed and operated on a cost-basis for the benefit of ratepayers for about 50 years, until present market opportunities created an opening for management to attempt to capture the present value of the plant for its shareholders.

Q. Are there any parallel issues in this rate case that illustrate the Company's one-sided approach to jurisdictional inclusion or exclusion of specific generating resources?

A. Yes. I would encourage the Commission to consider another ratemaking issue in this case that disproves Mr. Moehn's suggestion that, "Had something happened at Joppa that made that power high cost power, consistent with the below-the-line character of the EEInc. investment, AmerenUE would not have sought to pass those costs through its cost of service." We need look no further than Pinckneyville and Kinmundy to observe another affiliate transaction representing the <u>reverse</u> situation we see with the Joppa Plant. Pinckneyville and Kinmundy were investments that were initially made outside of Missouri retail regulation, within separate non-regulated Ameren corporate affiliates, but these investments ultimately proved to be high-cost in relation to the declining market value of gas-fired peaking capacity and the affiliated companies had no cost-based PSA to fall back on to recover such high costs. Ameren is now seeking full regulatory recovery within AmerenUE rate base of the <u>book</u> cost of these uneconomic combustion turbine investments that were initially made outside of regulation, while simultaneously seeking to move the low-cost/high-value Joppa steam generating capacity outside of Commission regulatory jurisdiction.

Q. Is the Arkansas Power & Light ("APL") power supply agreement that Mr. Moehn cites at page 12 of his Rebuttal comparable to the PSA that existed between EEInc. and Union Electric?

A. No. The APL agreement was not an affiliate transaction, through which a common parent corporation can engage in self-dealing to the disadvantage of ratepayers. Mr.

Moehn notes that the APL agreement was part of a larger transaction in 1992 and it would be reasonable to assume that the economics of this power supply arrangement represented part of the consideration between the parties in that larger transaction. There has been no comparable transfer of utility service territories in connection with PSA arrangement that governed EEInc. Joppa Plant output.

Q. At page 16 of his Rebuttal, Mr. Moehn states, "the mere fact that there has been a history of financial transactions over an extended period of time does not give that consumer any ownership rights in, or other ongoing benefits from, the retailer." Is EEInc. simply a common retailer of electricity as Mr. Moehn would urge the Commission to believe?

A. No. To my knowledge, EEInc. has no retail customers. EEInc. is an affiliate of AmerenUE that has engaged in a long term, cost-based wholesale power supply arrangement, producing bulk power transactions that have been treated as jurisdictional by the Missouri Commission for many years. The Union Electric utility business was compelled to buy the Joppa Plant output that was not needed by DOE from EEInc., paying whatever costs were incurred by EEInc. to produce that output, along with a guaranteed return on equity. This arrangement is quite different from a typical "retailer" that has no guaranteed market for his products, no assurance that costs will be recovered at all, and certainly no contractual right to earn a 15 percent after tax return on equity in every year.

Q. At page 17, Mr. Moehn argues, "AmerenUE's ratepayers in the end only paid for, through prudent fuel and purchased power expense included in rates, roughly 20% of the total costs associated with EEInc.'s Joppa Plant, far less than the amount they would have paid had AmerenUE's 40% share of EEInc. been included in rate base over this same period." Does this indicate the existence of any shareholder risks or costs that justify removing the market value of the Joppa Plant from the Commission's jurisdiction?

A. No. The fact that the Federal Government also participated in the Joppa Plant on a cost of service basis for many years does not imply any unrecovered costs or operational risks were borne by shareholders. As noted above, EEInc. reported in its 2005 Annual Report that, "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."

Q. Does it matter that cost-based rates were influenced by EEInc. having a,"capital structure [that] was highly leveraged", as noted by Mr. Moehn at page 17?

A. Not really. The economic effect of higher debt leverage within EEInc. was a substitution of higher fixed costs (interest expense) recoverable through PSA cost-based pricing, in place of more equity return cost at the contractual 15 percent after-tax return rate. It is not unusual for project financing for power plants protected by long-term cost-based power supply agreements to be heavily leveraged, because higher levels of financial risk are acceptable when project operating risks are mitigated by the PSA cost recovery terms.

Q. At page 18, Mr. Moehn challenges your analogy to regulatory asset accounting by claiming, "In reality, we do operate in a legal and regulatory environment that does follow and apply traditional accounting definitions and rules. Operating in an environment with clear and specific accounting rules is a good thing. These rules provide clearly defined boundaries and limitations in order to avoid the type of confusion Mr. Brosch is attempting to introduce through his novel interpretation and definition of a "regulatory asset." Since we cannot arbitrarily change accounting definitions to suit our whims, there can be no argument for a regulatory asset no matter how much Mr. Brosch wishes to stretch the accounting definition." Do you need to stretch any "accounting definitions" to explain the equitable arguments in support of your adjustment?

A. No. My Direct Testimony is clear in stating that the Joppa Plant is reasonably considered to be a "regulatory asset", but "not in the traditional accounting definition of this term." Mr. Moehn wants to argue about "traditional accounting definitions and rules", but he doesn't cite any such rules in support of AmerenUE's proposal to remove the economic value of the Joppa Plant from regulatory jurisdiction of this Commission after contrary treatment of the plant and its costs for about 50 years.

Q. Have other regulatory agencies treated a non-jurisdictional business unit as if it were a "regulatory asset", in the manner you describe, when the utility engaged in unreasonable affiliate transactions seeking to create a windfall for shareholders?

A. Yes. As I mentioned in my Direct Testimony, regulators have for many years imputed telephone directory advertising profits into the revenue requirement of regulated telephone utility companies, in Missouri and in other states. This was done without regard to ownership of the directory publishing assets and in spite of affiliate contracts that were designed to produce unreasonable arrangements for sharing of directory publishing profits. My reference to the concept, rather than the accounting term, "regulatory asset" is not unusual in the context of regulatory remedies for abusive utility affiliate arrangements. For example, the Washington Supreme Court upheld imputation of directory publishing revenues by the Washington Utilities and Transportation Commission, stating at page 25 of its Opinion:

> The company also argues that it is being treated differently from other companies in the business and that the character of the asset as a "regulatory asset" does not give the Commission the right to impute income. The fact is that the company is different from other companies competing for the business. The record shows that US West did not develop this lucrative business by its initiative, skill, investment or risk-taking in a competitive market. Rather, it did so because it was the sole provider of local telephone service, and as such owned the underlying customer databases and had established business relationships with virtually all of the potential advertisers in the yellow pages. Therefore, the Commission reasonably concluded that the yellow pages business is quite unlike businesses of other unregulated companies which were developed in, or derive their profitability from, the competitive marketplace.[32]

Many other regulatory commissions and courts have found similarly in instances where utility affiliate arrangements were structured to unreasonably remove a valuable asset or profitable business segment from regulatory jurisdiction. Imputation is a widely recognized regulatory tool where an affiliate owns and operates an asset or business segment that should be treated as a "regulatory asset", in spite of utility holding company asset conveyances or affiliate contract terms to the contrary.[33]

---

[32] *U S WEST Comm. Inc. v. Wash. Util. & Transp. Comm.*, 134 Wn2d 74, 949 P.2d 1337 (1997), p,27

[33] Oklahoma Supreme Court, *Turpin v. Oklahoma Corporation Comm'n.* 769 P.2d 1309, 1327 (Okla. 1988); Utah Supreme Court, *US West Communications, Inc., Petitioner, v. Public Service Commission of Utah, Respondent.* No.980082 filed January 7, 2000. See also *State ex rel. Utils. Comm'n v. Southern Bell Tel. & Tel. Co.*, 299 S.E. 2d 763, 765 (N.C. 1983); *In re Rochester Tel. Corp. v. Public Serv. Comm'n*, 87 N.Y. 2d 17, 660 N.E. 2d 1112, 1116-18, 637 N.Y.S.2d 333 (1995); *In re Northwestern Bell Tel. Co.*, 367 N.W.2d 655, 660-61 (Minn. Ct. App. 1985). Other regulatory decisions include: *General Tel. Co. of the Northwest v. Idaho Pub. Utils. Comm'n*, 712 P.2d 643, 651 (Idaho 1986); *In re US West Communications, Inc.*, 165 Pub. Util. Rep. 4th (PUR) 235, 250-51 (Utah Pub. Serv. Comm'n Nov. 6, 1995); *Alabama Pub. Serv. Comm'n v. South Central Bell Tel. Co.*, 130 Pub. Util. Rep. 4th (PUR) 92, 93-96 (Ala. Pub. Serv. Comm'n Feb 13, 1992); *In re Rates & Charges of Mountain States Tel. & Tel. Co. v. Corporation Comm'n*, 99 N.M. 1, 653 P.2d 501, 505 (1982); *In re New England Tel. & Tel. Co.*, 157 Pub. Util. Rep. 4th (PUR) 112, 163-65 (Vt. Pub. Serv. Bd. Oct. 5, 1994); *In re South Central Bell Tel. Co.*, 121 Pub. Util. Rep. 4th (PUR) 338, 347-

Q. Mr. Baxter states the following in his Rebuttal regarding the EEInc. issue, "Stated bluntly, the Staff and the other parties seek to improperly and unlawfully take shareholder monies from this unregulated investment, and in the process they ignore a number of important facts, as discussed in the rebuttal testimony of Michael L. Moehn. They also ignore the controlling law relating to corporate governance, as discussed further in the rebuttal testimony of Professor Robert C. Downs, and similarly ignore regulatory principles, as discussed further in the rebuttal testimony of Former NARUC and MARC Chair David Svanda." Are you recommending that the Missouri Commission, "take monies from an unregulated investment" in your recommended imputation adjustment?

A. No. I am recommending that Ameren shareholders not be allowed to "take monies" associated with the market value of the Joppa Plant and its output for the sole benefit of shareholders, after many decades of jurisdictional treatment of the costs and risks associated with the Joppa Plant by this Commission. My recommendation is entirely consistent with the mainstream regulatory response to instances where utility holding companies have arranged their business affairs with non-regulated affiliated entities in an effort to distort regulatory outcomes for shareholder advantage, as noted in my reference to directory publishing imputation in the previous answer. Final resolution of whether or not Missouri ratepayers' historic cost support of the EEInc. power supply entitles them to the full value of the plant for its remaining life is an important issue before the Commission at this time, after this issue was found "not relevant" to the Federal Energy Regulatory Commission's review, when it granted EEInc. market-based rate

---

50 (La. Pub. Serv. Comm'n Apr. 1, 1991); *Pacific Northwest Bell Tel. Co. v. Katz*, 853 P.2d 1346, 1348-49 (Or. Ct. App. 1993); *In re New York Tel. Co. v. Public Serv. Comm'n*, 72 N.Y.2d 419, 530 N.E. 2d 843, 845, 534 N.Y.S.2d 136 (1988)

authorization in FERC Docket Nos. ER05-1482-000 and ER05-1482-001. In fact, the FERC found this specific matter to be, "...an issue that is better resolved at the state level."[34]

Q. Mr. Svanda states in his Rebuttal, "The critically important point for this rate case, though, is that AmerenUE put only shareholder dollars on the line in its investment in EEInc. Not one penny of ratepayer money was put at risk." Is this correct?

A. Not really. Only by choosing to focus upon legal ownership of the relatively small initial equity capital investments made by Union Electric more than 50 years ago can Mr. Svanda find "shareholder dollars" put "on the line". Much larger amounts of ratepayer money were "on the line" since then that were used by Union Electric to pay its share of the EEInc. power bills under the PSA during the entire useful life of the Joppa Plant, effectively guaranteeing full cost recovery plus an assured return on investment. If costs at Joppa went up or if plant performance declined, ratepayers were on the hook to pay all of the costs and EEInc. stated in its Annual Report that such obligations are "absolute and unconditional". Mr. Svanda's "critically important point" is not important at all in determining an equitable outcome, given how risks and costs associated with the Joppa Plant have been apportioned between shareholders and ratepayers for the past five decades.

Q. Mr. Svanda states in Rebuttal at page 10, "The price of any product must logically include all the costs that went into making that product. Labor and materials obviously are costs included in a price. In addition, the costs of the machinery and plant used to

[34] 113 FERC ¶61,245, paragraph 34.

make the product, along with the cost of money borrowed to finance that plant and machinery, are all included in the price of a product. In regulatory terms, a return on and return of the capital investment of the company that makes a product is part of the price of that product. That's why, in regulatory terms, we refer to the "cost of capital" in rate cases – that cost, the ROE component and debt component, is just as much a cost as are the wages paid to employees. When I buy a car or anything really, the price includes these costs. But paying those costs when I buy a Mustang does not mean I am buying Ford Motor Company or am acquiring any special rights regarding the operations of Ford. I got what I paid for and paid for what I got. That's the deal. Period." Do you agree with Mr. Svanda on these points?

A. No. In competitive markets, manufacturers <u>attempt</u> to recover all of their costs and the maximum achievable profit when selling their output. However, competitive market conditions dictate what price will be successful in moving any particular product, and that price may or may not recover all of the costs incurred by the company. If I were to buy a Mustang, I would be loath to pay more than the competitive market price for the car and, judging by the recent financial performance of Ford Motor Company, Mr. Svanda' selection of Ford to advance a view that "the price of any product must logically include all the costs that went into making that product" is not ideal. Ford Motor Company reported a full-year net <u>loss</u> of $12.7 billion, or $6.79 per share for 2006, indicating much of Ford's cost structure is not sustainable under current market conditions.[35]

In stark contrast to Ford, we should consider what ratepayers bought and paid for with regard to the Union Electric share of the Joppa Plant. Ratepayers were committed

---

[35] See "Ford Motor Company Reports 2006 Fourth-Quarter and Full-Year Results" at http://www.corporate-ir.net/ireye/ir_site.zhtml?ticker=F&script=412&layout=-6&item_id=954063.

by their utility through the terms of the PSA to take and pay for the UE share of Joppa capacity at whatever cost levels were incurred by EEInc., on an absolute and unconditional basis, even if no power was produced. This would be like approaching Ford and contracting to buy a fixed share of all of the vehicles they could produce for fifty years, committing to pay the actual costs incurred by Ford plus a 15 percent return on equity. Mustang drivers don't own Ford Motor Company because they actually bought only the cars they needed, at market prices rather than cost-based prices. Under present circumstances at Ford, it would probably be cheaper to acquire the entire Ford Corporation. than to contract to buy all of Ford's output at cost-based, rather than market-based prices.[36]

Q. At page 12 of his Rebuttal, Mr. Svanda states, "Finally, the "guarantee" that the Government or the Sponsoring Companies would purchase all of Joppa's power cannot support the other parties' position. No one has ever claimed that the purchase of power from EEInc. was ever uneconomic." Is that the point being made (i.e., purchase of uneconomic power) with regard to the referenced financial guarantees of EEInc.?

A. No. The unconditional guarantee of cost support for the Joppa Plant was not about the economics of Joppa Plant output or any "claims" about such economics. If the Plant failed to perform, there may have been no output at all, much less an "uneconomic" output. Obviously the Plant has performed and its costs have been paid, but the point to

[36] Id. Total Ford sales at market prices were $160.1 billion in 2006. Ford stock "F" presently trades at about $8.40 per share, with 1.82 billion shares outstanding, suggesting a market value of its equity of about $15 billion, less than 10% of annual sales. http://tools.thestreet.com/tsc/quotes.html?pg=qcn&ref=tscsearchbox&symb=f

be made is that by absolutely and unconditionally guaranteeing to pay Joppa costs without regard to output levels, shareholders were not at risk in any material way.

Q. Mr. Svanda claims at page 13, "If catastrophe happened, this was a below-the-line investment, and AmerenUE's shareholders would have borne the consequences, not the ratepayers." Is this an established fact?

A. No. First of all, one should expect that casualty insurance was maintained by EEInc. to protect against most insurable risks. Certainly the PSA provided for full cost recovery of any premiums paid to secure insurance coverage. In the absence of an actual "catastrophe" beyond the limits of insurance coverage, we cannot know what AmerenUE would have proposed in the way of regulatory treatment. However, after many decades of dependable service to Missouri retail electric customers, AmerenUE would certainly have been able to color an argument that it is entitled to equitable recovery of all prudently incurred costs needed to repair or reconstruct Joppa facilities in order to restore the plant to service.

Q. At page 18, Mr. Svanda states, "I find troubling the aspect of the other parties' position that effectively wants to punish a regulated entity for having done a good job in the past. By any measure, the power purchase contract between AmerenUE and EEInc. was a great deal for AmerenUE's ratepayers, giving them access to power at fabulously low rates. That, of course, is the reason the other parties have concocted their proposal in the first place. In the spirit of 'no good deed goes unpunished,' that proposal is profoundly unfair." How do you respond?

A. There is absolutely nothing "punitive" about a ratemaking adjustment in this case that maintains the status quo with respect to the value of the Joppa Plant. It is not clear what "regulated entity" Mr. Svanda is referring to when observing that such entity has "done a good job in the past", since he is careful throughout the rest of his testimony to characterize EEInc. as a completely separate corporation that has long been an unregulated, below-the-line entity. By his argument, AmerenUE is the "regulated entity" and AmerenUE has recently done a terrible job with respect to securing the current market value of the Joppa Plant for the benefit of itself and its ratepayers. Mr. Svanda claims this was "a great deal for AmerenUE's ratepayers", so one is left to wonder how, under common ownership and senior management, AmerenUE was unable to preserve its rights to participate in the costs and benefits of the Joppa Plant past 2005. The only "concocting" that has occurred would be the Company's unfair plan to gain a windfall for shareholders by removing the value of the Joppa Plant from the Commission's regulatory jurisdiction as of December 31, 2005.

Q. Referring to Schedule MLB-11 to this testimony, have you updated the calculation of the EEInc. Imputation Adjustment that you sponsor?

A. Yes. This document is a replacement calculation for the Schedule C-4 that was filed within the <u>State Joint Accounting Schedules</u> on December 15, 2006. In this updated calculation, I have substituted full calendar year Net Income of EEInc. at lines 1 and 2 for the years 2006 and 2005, respectively, in place of the partial year data that was available at the time the initial adjustment was calculated.

Q. In your updated calculation of EEInc. imputation, have you excluded the financial results associated with the EEInc. subsidiaries that are mentioned by AmerenUE witness Moehn in his Rebuttal testimony?

A. Yes. The amounts used in the imputation are stand-alone EEInc. financial results that exclude the earnings from MEPI and the other EEInc. subsidiaries, including the small amount of earnings arising from the MEPI combustion turbines.

Q. Was any termination accounting performed that resulted in unusual transactions between EEInc. and the sponsoring companies at the expiration of the PSA?

A. Yes. AmerenUE and the other sponsoring companies were billed a total of $9.2 million for certain regulatory assets that were recorded on EEInc.'s books, thereby avoiding any write-off of such assets when cessation of cost-based regulation of EEInc caused the discontinuation of FASB Statement No. 71 Accounting at EEInc.[37]

Q. When EEInc. sold emission allowances in 2005, prior to the expiration of the cost-based PSA, were the proceeds or income from such allowance sales credited back to AmerenUE and the other sponsoring companies?

A. No. According to the Company's response to Data Request AG/UTI-313, "AmerenUE did not receive any direct distribution back in connection with the sale by EEInc. of any emission allowances. Those sales would have contributed to EEInc.'s earnings/net income. AmerenUE, like all of EEInc.'s shareholders, records a proportionate share of EEI's earning in their net income." Thus, AmerenUE and its ratepayers bore an allocation of cost responsibility for all environmental compliance expenses incurred by

[37] Electric Energy Inc. Annual Report, 2005, page 12.

EEInc. prior to 2006, but when emission allowances owned by EEInc. were sold, AmerenUE ratepayers were denied participation in the earnings from such sales.

Q. Have significant emission allowances been sold by EEInc. historically?

A. Yes. I have attached as Schedule MLB-12 a package containing information attached to Notice for EEInc.'s October 27, 2006 Board of Directors Meeting. According to this information at page 3.1, EEInc., made "Past Sales" of emission allowances producing new allowance earnings of $49.3 million.

Q. In Schedule MLB-12, there is also a document titled, "2007-2009 Budget Presentation, October 27, 2006". Does this Budget Presentation include estimates of projected future EEInc. consolidated Cash Flow, Balance Sheets, Income Statements and Projected Revenues?

A. Yes. Pages 5.13 through 5.16 contain such projections.

Q. Does EEInc. project robust earnings, cash flow and dividends throughout this forecast horizon?

A. Yes. Starting with Cash Flow projections at page 5.13, EEInc. expects to continue to earn much higher net income in every year after 2005, the last year when its earnings were constrained to the 15 percent return on equity under cost-based pricing. The expansion in EEInc. earnings allows for the payment of significant projected dividends in all future years after 2005, as shown at line 11. While significant future capital expenditures are forecasted by EEInc., particularly with regard to pollution control (see line 13), there is projected to be ample cash flow to maintain dividends in all years, while drawing upon a projected "increase in Ameren loan". The Projected Balance Sheet grows throughout the projection period, largely as a result of investment in net plant that expands the investment in facilities significantly after 2007.

Q. What assumptions are reflected in the "Projected Income Statement 2005-2015" values and how do such assumptions impact anticipated Net Income levels?

A. The key assumption is stated at the bottom of the schedule, involving the assumed market prices for Joppa Plant energy output. Market prices are assumed to average $42.60 per MWH in 2006 and about $46 per MWH thereafter. In comparison to 2005, when the PSA was effective and Joppa output was priced at "cost", EEInc.'s realization of much higher market prices in 2006 and thereafter is predicted to more than double annual revenues and causes "Net Income Before Allowance Sales" to expand by a factor of about 10 times. These projected results clearly indicate why the Company seeks to avoid Missouri Commission jurisdiction over the value of Joppa Plant output and underscores the point made in my Direct Testimony that a profit windfall is planned for shareholders as a result of this change in Joppa Plant status. However, the EEInc. financial projections are heavily dependent upon projections of future market energy prices which are inherently uncertain. This is why I recommended regulatory deferral accounting to track changes in actual EEInc. imputation along with any changes in AmerenUE off-system sales in my Direct Testimony.

DEPRECIATION RETIREMENT ASSUMPTIONS

Q. At page 2 of his Rebuttal, AmerenUE witness Mr. Naslund observes that the Staff and several intervenor parties including the State of Missouri have rejected the Company's assumption that Callaway will not be re-licensed for use beyond 2024 and states that, "None" of the witnesses with such testimony "have participated in the license extension process for a nuclear plant." Is there any real dispute regarding the possibility of Callaway re-licensing?

A. No. To my knowledge neither AmerenUE, nor the other parties discussing Callaway re-licensing have ruled out this possibility. In fact, AmerenUE has spent large sums in recent years at Callaway to ensure that the re-licensing option remains open.

Q. At page 4 of his Rebuttal, Mr. Naslund states, "None of the capital or O&M expenses noted in Mr. Brosch's testimony were expended based on plant life extension beyond 40 years." Has AmerenUE been careful to specify that all replaced components at Callaway would be designed to survive an extended operating license period?

A. Yes. In his Deposition, Mr. Naslund noted that when Callaway's Steam Generators were replaced in 2005, and when other plant components have been replaced, the Company specified replacement materials with a 40-year life span.[38] Specifying long-lived replacement components ensures that the re-licensing option remains open.

---

[38] Deposition of Charles Naslund 1/23/2007, transcript pages 9-11 and at page 186, where he stated, "We have tried at every opportunity when a component has to be replaced because its at end of life, we've always tried to make sure that we specified materials that would maximize the ultimate life of Callaway. So at every turn we've tried to make very prudent decisions in that aspect."

Q. Mr. Naslund states at page 3 that, "No studies have been completed to investigate the technical issues or economic issues that would need to be evaluated to make a prudent decision on license extension." Does this mean that retirement of Callaway is more likely to occur in 2024 than in 2044?

A. No. It means that the ultimate retirement date is not determinable at this time. I am not advocating any decision at this time regarding whether Callaway will or will not ultimately be re-licensed. In matters impacting the Company's revenue requirement, I believe that the apparent uncertainty regarding this decision argues for no change to increase nuclear depreciation expense accrual rates until a decision has been made.

Q. In your Direct Testimony at pages 50-51, you expressed concern with the Company's assumption that its entire coal-fired generation fleet would be retired in 2026. Has AmerenUE revised this assumption?

A. Yes. AmerenUE witness Mr. Birk now sponsors, at page 2 of his Rebuttal, revised coal plant retirement dates of 2021 for Meramec, 2027 for Sioux Station, 2033 for Labadie Station and 2037 for Rush Island. After referring to these and other changes, AmerenUE witness Mr. Wiedmeyer states at page 26 of his Rebuttal, "The overall reduction in depreciation related to Steam Production Plant is approximately $5.17 million or approximately 5 percent."

OSAGE HEADWATER RETROACTIVE EXPENSES

Q. At page 4 of his Rebuttal, AmerenUE witness Mr. Weiss argues for an amortization of a special assessment of prior period costs related to the Osage headwater study, stating, "The Company believes that since the ratepayers have already received the increased benefits of additional low cost generation from the Osage Plant, a five-year amortization ($866,484 annually) of these additional Osage headwater benefits is appropriate. Recovering these costs over just the next five years will more closely match the costs associated with these benefits to the customers who have received the benefits. Since this additional payment is accruing during a rate case, the Company did not feel it was necessary to request an Accounting Authority Order." How do you respond?

A. The Company's request in this matter is admitted retroactive ratemaking, which is to be avoided in utility ratemaking. The assessment for prior years' headwater benefits was never established as an expense to be tracked for ratemaking purposes, as admitted by Mr. Weiss in stating that no "Accounting Authority Order" was requested or received. Osage headwater expenses have been set in past rate cases based upon the best available information at the time, with no expressed intention to later "true-up" or otherwise adjust for over or under-recoveries of such costs. No retroactive relief is now appropriate on this issue under such circumstances. These amounts pertain to periods occurring prior to the test year and should be disallowed as an inappropriately retroactive prior period adjustment, a common form of disallowance in utility ratemaking.

Q. In your Direct Testimony you referenced two other discrete transactions that were one-time events involving millions of dollars in benefits to AmerenUE that Mr. Weiss has not proposed to amortize to the benefit of ratepayers. If the retroactive adjustment of interim headwater charges requested by AmerenUE is approved, should it be offset by a five year amortization of these other transactions?

A. Yes. If the door is opened by the Commission to look backwards and adjust for unforeseen changes in costs that have occurred since the last rate case, the large unforeseen one-time transactions I referenced in my Direct Testimony should be amortized to customers over five years, reducing revenue requirement by $10.52 million.[39] However, my primary recommendation is to not engage in retroactive ratemaking for Osage Headwater assessments dating back over 25 years.

FUEL ADJUSTMENT CLAUSE

Q. At pages 2 and 3 of his Rebuttal, Mr. Neff provides graphs depicting spot market coal price volatility that he asserts is supportive of AmerenUE's need for an FAC. Does AmerenUE buy most of its coal on the spot market?

A. No. As I described in my Fuel Adjustment Clause Testimony filed on December 29 ("FAC Testimony"), most of AmerenUE's coal is procured using term contracts at fixed (rather than spot) prices. The Company's strategy is specifically designed to manage and reduce the exposure to fluctuations in spot market prices of the type depicted by Mr. Neff.

Q. Has Mr. Neff provided any graphs or other data illustrating whether the coal prices that AmerenUE actually pays have been volatile in the past?

A. No. His discussion at page 7 explains how AmerenUE works to mitigate the types of price fluctuation shown on pages 2 and 3, but he leaves the Commission with only the

---

39 See Direct Testimony of Michael Brosch at page 36, line 20 and page 37, line 2; with such amounts amortized over five years (divide by five).

spot market price graphs at page 2, and the implication that such spot prices are directly applicable to AmerenUE.

Q. At the bottom of page 7 and on page 8 of his Rebuttal, Mr. Neff refers to historical price increases that have been experienced by AmerenUE with regard to contract coal prices and freight rates. Do these historical increases indicate volatility in the prices of delivered coal being paid by AmerenUE?

A. No. Historical price increases do not indicate volatility, they indicate that certain price increases have occurred. It should be noted that these price increases will be captured for ratemaking purposes in this rate case, using data as of January 2007.

Q. Does the existence of railroad diesel fuel surcharges, as discussed by Mr. Neff at page 9 of his Rebuttal, justify granting an FAC for AmerenUE?

A. No. Even if the most dramatic full range impact he cites proves to be recurring and sustained in the future, the dollar cost impact he quotes represents only about *** __ *** percent of annual pretax operating income for the Company.[40] However, as noted above, AmerenUE engages in a hedging program to limit its exposure to even this amount of volatility and the costs of the hedging program have been included in test year fuel expense by the State.

Q. At page 10 of his Rebuttal, Mr. Neff quotes certain coal and transportation cost increases that he characterizes as "known and measurable". Do these statements support granting an FAC for AmerenUE?

[40] Neff Rebuttal Page 9, line 19 amount divided by State Accounting Schedule C, line 16, column D.

A. No. Fuel and transportation cost increases that are known and measurable are entirely consistent with traditional test period regulation. It is only when future costs are volatile and not known and measurable that an FAC is truly needed. The predictability of these costs is largely a result of the Company's risk mitigation strategy and term contracting approach to fuel procurement. This Company has limited exposure to fuel cost volatility and appears to desire a fuel adjustment clause primarily to secure piecemeal recovery of its predictable and gradually increasing fuel costs through an FAC without needing to file a rate case where offsetting productivity effects and customer growth would also be quantified..

Q. Do the known and measurable price increases described by Mr. Neff support his conclusion that, "Frequent rate cases will be necessary to seek recovery of variations in fuel costs if the Commission does not approve a Fuel Adjustment Clause for AmerenUE."?

A. No. Margins on normal annual customer growth alone can be expected to offset more than half of the expected "known and measurable" fuel price increases predicted for 2008 and 2009, as shown in State Accounting Schedule C-1. If Ameren achieves even modest productivity gains in managing its other non-fuel O&M expenses, it may be able to fully offset any remaining fuel price increases not "paid for" with ongoing customer growth. Absent an FAC, frequent rate cases are unlikely under such circumstances, because in a rate case AmerenUE would be required to account for its customer growth and its productivity gains as an offset to increased fuel costs. What is clearly desired by AmerenUE in the alternative is an FAC that would pass through expected fuel cost increases on a single-issue basis, while allowing the Company to retain for shareholders the benefits of customer growth and productivity gains.

Q. Turning to the FAC Rebuttal Testimony of Dr. Mayo, he describes how off-system sales opportunities tend to reinforce management incentives for generating plant that may otherwise be diminished under FAC regulation and then he refers to your off-system sales margin tracking proposal at page 11 and states, "...that adoption of such a proposal would effectively eliminate the firm's incentives for system improvements that could result in enhanced off-system sales. That is, if off-system sales margins were passed through in their entirety, any economic incentive for the firm to enhance its plants' availability and efficiency would be eliminated. Consequently, the beneficial effects of this incentive-based mechanism would be lost." How do you respond?

A. I propose avoidance of this incentive problem to begin with, by <u>not</u> adopting an FAC. Without an FAC, AmerenUE has every incentive to optimally maintain and operate its generating units so as to efficiently burn fuel as well as incentives to continue its risk mitigation approach to fuel procurement. This traditional regulatory lag incentive effect will also serve to optimize profitable off-system sales as a consequence of high generating unit availability, efficient heat rates and lowest possible fuel costs.

In contrast, AmerenUE and Dr. Mayo would put the cart before the horse, by first adopting an FAC to pass-through expected fuel price increases to customers on a piecemeal basis, and then trying to remedy the blunted incentives caused by an FAC through shareholder retention of significant amount of the off-system margins that should otherwise flow to customers.

Q. At page 19 of his Rebuttal, AmerenUE witness Mr. Lyons states, "...the proposed FAC should decrease the administrative burden on the Commission Staff and other parties by decreasing the frequency of full-fledged rate cases." Has AmerenUE had frequent rate cases in the past in the absence of an FAC?

A. No.

Q. Has AmerenUE made any commitment to <u>not</u> file future rate cases in the event its requested FAC for piecemeal recovery of fuel cost increases is granted?

A. No. In fact, the only commitment on this point is at page 6, line 13 of his September 29 testimony, Mr. Lyons notes that the Company "must file a new rate case every 37 months while its FAC is in effect."

Q. At pages 21 and 22 of his Rebuttal, Mr. Lyon's repeats the "offsetting effects" and "incentive" concerns voiced by Mr. Schukar regarding your proposed tracking off-system sales. Is this an inconsistency in your position?

A. No. As explained above, interactive effects between native load and off-system volumes that are caused by abnormal weather tend to be income neutral in the short term, while gradual long-term customer growth impacts upon native load are beneficial to shareholders, because native load growth benefits shareholders between rate cases while any declining off-system sales opportunity caused by customer growth would be tracked through to customers.

Q. At pages 30-34 of his Rebuttal, Mr. Lyons proposes an elaborate process involving ProSym simulation runs through which AmerenUE would attempt to hold harmless ratepayers from the adverse energy cost effects caused by the absence of Taum Sauk. Is this process consistent with the argument he makes at page 19 that the Company's proposed FAC "...formula used in the rider is simple and straightforward and does not require complex calculations or analyses"?

A. No. Considerable resources are involved in truly understanding and "auditing" all of the input values and results associated with production simulation modeling.

Q. At page 20 of his Rebuttal, Mr. Lyons opines, "I believe that fuel costs will, if anything, receive greater scrutiny if recovered in an FAC because the annual FAC reconciliation cases will allow the Commission and interested parties to focus exclusively on fuel (and purchased power) costs. A full rate case, by contrast, will tend to be less frequent and require the review of all of AmerenUE's costs, which means less attention will likely be paid to fuel costs." Is it consistent with your experience that FAC reconciliation cases receive greater regulatory scrutiny than fuel costs reviewed in rate cases?

A. No. While it is theoretically possible for the Staff or a party to attempt to "focus" upon fuel costs assuming each periodic FAC adjustment involves formal review proceedings with discovery rights and an opportunity for hearings in the event contested issues emerge, in my experience in other states, most FAC adjustments receive only limited regulatory oversight due to the demands of other proceedings and the limited amounts at issue in each proceeding. The only way that rigorous financial and management audits of fuel procurement processes, operational performance and accounting costs can be expected to occur to verify the Company's proposed FAC will be if the Commission directs its resources toward a formalized auditing process to achieve this result, which is again wholly inconsistent with the Company's argument that an FAC involves little administrative complexity.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

Witness: M. Brosch

AMEREN UE
CASE NO. ER-2007-0002
CUSTOMER GROWTH ANNUALIZATION
FOR THE TEST YEAR ENDED JUNE 30, 2006
(000's)

REVISED
Schedule C-1
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	RESIDENTIAL CLASS	SMALL GENERAL SVC.	LARGE GENERAL SVC.	TOTAL AMOUNT
	(A)	(B)	(C)	(D)	(E)	(F)
1	Estimated Number of Customers @ 12/31/2006	AG/UTI-285	1,024,559	138,743	9,619	1,172,921
2	Average Test Year Number of Customers	Brosch WP-C-1	1,015,547	137,289	9,470	1,162,306
3	Customer Growth Factor	Line 1/Line2	**100.887%**	**101.059%**	**101.573%**	10,615
4	Test Year Normalized MWH Sales per UE	UE Sch. JRP-E8	13,003,136	3,553,502	7,917,344	24,473,982
5	Test Year Normalized Sales Revenues per UE	"	$ 839,527	$ 225,063	$ 416,823	
6	Annualized MWH Sales for Customers at 12/31/06	Line 3 * Line 4	13,118,474	3,591,134	8,041,884	24,751,491
7	Annualized Revenue for Customers at 12/31/06	Line 3 * Line 5	$ 846,974	$ 227,446	$ 423,380	
8	MWH Adjustment for Customer Growth	Line 6 - Line 4	115,338	37,632	124,540	277,509
9	Revenue Adjustment for Customer Growth	Line 7 - Line 5	$ 7,447	$ 2,383	$ 6,557	$ 16,387
10	Less: Estimated Fuel/Energy Cost for Customer Growth - Additional MWH (Line 8 times energy rate - Note 1)					$ (3,593)
11	Estimated Incremental Postage and Meter Reading at $4.00 per Customer (Note 2)					$ (42)
12	**State of Missouri Adjustment to Sales Margins for Customer Growth (Line 9 - Line 10- Line 11)**					**$12,751**

Footnotes:

(1) Total Energy Cost per UE, with AG Adjustments as follows:

	Retail Amounts
Total Variable Fuel/Purchased Power per UE (AG/UTI-202)	$ 538,981
Plus: AG Adjustments to Fuel/Purchased Power (Schedule C-3)	(18,451)
Sub-total	520,530
Divide by Net Output MWH (AG/UTI-202)	40,203,930
Variable Energy Cost per MWH for Customers Added	$ 12.9472

(2) Postage at $.24 per month * 12 months and AMR at $1.12 per Customer (Staff DR #504)

Schedule MLB-8

4 pages

Designated HIGHLY CONFIDENTIAL

By AmerenUE

Schedule MLB-9

1 page

Designated HIGHLY CONFIDENTIAL

By AmerenUE

Electric Energy, Inc.

Annual Report - 2005

Electric Energy, Inc.

Annual Report - 2005

Table of Contents

To Our Shareholders and Employees

Our annual performance plan for 2005 focused on three areas:

- Performing our activities in a responsible and safe manner;
- Operating our facilities in an environmentally responsible manner;
- Managing our activities to reduce costs.

For the year 2005, we had two recordable injuries – both of which were lost time cases. We had no recordable injuries after February 27, 2005. These results were an improvement over the nine recordable and six lost time accidents that occurred in 2004. Performing our work safely must be our top priority at all times. We all need to accept the principle that working safely is the only acceptable approach at EEI.

In the environmental stewardship area, we had one reportable spill. However, we had no water discharge exceedances, and we achieved our nitrogen oxide (NO_x) emission target and our annual station opacity goal. We must continue to take necessary steps to assure continuing compliance with our environmental stewardship responsibilities.

Our operating results and costs are addressed below.

2005 Operating Results

Our 2005 net generation was below the 2004 generation. The year 2004 was the most successful year of power production in the history of the company, but there were no planned outages in 2004. Net generation and gross capacity factor were also less in 2005 due to measures taken to conserve coal. In addition, equivalent availability was impacted negatively by 0.32% because Unit 6 planned outage exceeded its schedule by seven days.

Fuel costs increased due to an increase in railcar lease expenses, increase in railcar repairs, and an increase in natural gas prices. This increase in fuel costs is the primary reason our overall costs exceeded budget by $0.39 per megawatt hour.

Our accomplishments included:

- A gross generation of 8,467,797 megawatt hours for an 89.0 percent gross capacity factor;
- A net generation of 7,881,897 megawatt hours for an 89.3 percent net capacity factor;
- Low total costs of $18.02 per megawatt hour based on net generation;
- Low fuel costs of $11.18 per net megawatt hour.

These achievements are the result of our prudent investments, our employees' willingness to make necessary change, and our collective teamwork approach to problem solving. We will continue to set high standards for our performance. It is essential to our future success that we continue to improve in our daily work, and most importantly, that we work safely. We must each set a personal standard to assure that everyone returns home to their families without injury each day. We can accomplish these challenging objectives by maintaining a daily focus on our mission statement and long-term strategies for success. (Please refer to page four for Electric Energy, Inc.'s (EEI) mission and strategies for success.)

EEI's 2005 earnings totaled $21.1 million, comprised of $10.3 million of EEI operating income and $10.8 million of income from sales of emission allowances. Operating income was in line with previous years. Emission allowance earnings were $9.6 million higher in 2005 than 2004 due to increases in the number of allowances sold and the price received per allowance.

Subsidiary Results

During 2005, Midwest Electric Power, Inc. completed its fifth full year of generating and selling electric energy. Midwest Electric Power, Inc. owns and operates two gas-fired combustion turbines with combined capacity of 76 megawatts. Additionally, Midwest Electric Power, Inc. operates three refurbished gas-fired combustion turbines for Ameren Energy Development Company with combined capacity of 186 megawatts. These units allow our owners to meet their higher demand levels during the peak summer months.

Massac Enterprises, LLC completed its seventh year of operations during 2005. This entity continues to provide certain tax savings, contributing directly to lower bus bar costs.

Our ash subsidiary, Met-South, Inc., showed a profit for the tenth consecutive year. In 2005, its after-tax earnings were approximately $562,000 compared to earnings of approximately $366,000 in 2004. We expect Met-South, Inc. to continue achieving profits in the future; however, downward pricing pressure is occurring in the ash market partially due to an increasing regional supply of ash. EEI expects to continue to sell or dispose of its ash in an environmentally acceptable and beneficial manner. This off-site use of our fly ash and bottom ash represents significant cost savings to all of our customers.

Our Joppa and Eastern Railroad subsidiary continues to allow EEI to achieve low transportation costs for our fuel. Operating results continue to meet our expectations.

Looking Ahead

We continue to experience fast-paced change and uncertainty in our industry, particularly in the area of environmental regulations. Additionally, beginning in 2006, EEI entered into a new contract with a third party for market-based sales of our energy. Our performance will be measured hourly in the marketplace by our ability to respond as promised. However, EEI's future need not be uncertain. The winning companies will be those who are highly reliable, low cost energy producers. We will achieve this result by having the best team that consistently performs at high levels. Our long-term strategies are directed at **protecting our resources, consistently performing at high levels, and preparing for a changing future.**

My congratulations to our employees for a job well done. Also, my thanks to our Board of Directors for their continuing support.

Robert L. Powers

Robert L. Powers

EEI Mission

Our mission is to maximize the value of our company by consistently operating in a safe, environmentally responsible, and cost-effective manner.

Strategies for Success

Protect Our Resources

We will protect the health and safety of everyone working at our plant through effective planning and safe work practices.

We will operate our plant in an environmentally responsible manner.

We will protect our plant equipment through sound operating and maintenance practices.

Perform at High Levels

We will set high expectations for our results that keep us among the best performers in our industry.

We will implement quality management systems and effective work processes that help us consistently achieve our objectives.

We will search for ways to improve our daily work.

Prepare for a Changing Future

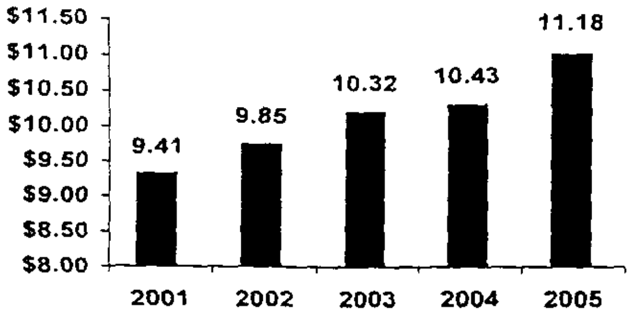
We will remain focused on our industry direction and customer expectations, be responsive to needed change, and be flexible in our methods of response.

We will promote a work environment where people treat each other with fairness and respect.

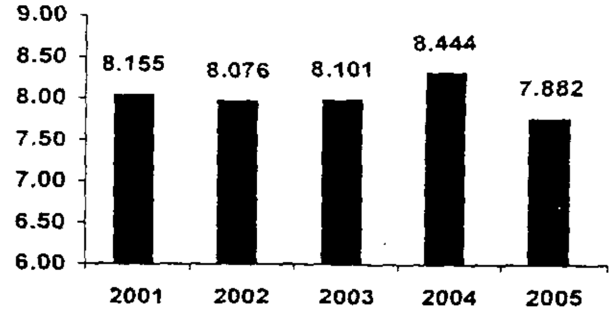
We will prepare ourselves to meet the challenges ahead through effective training and communication.

Joppa Steam Electric Station
2005 Results

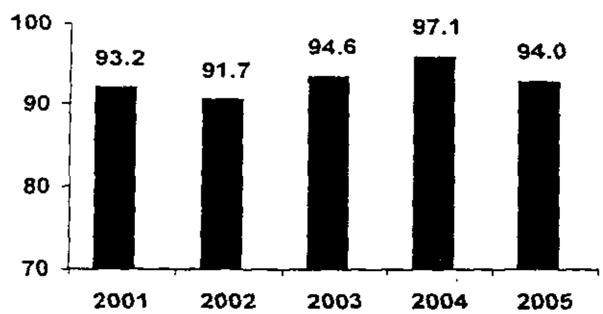
Fuel Costs
Per Net MWH



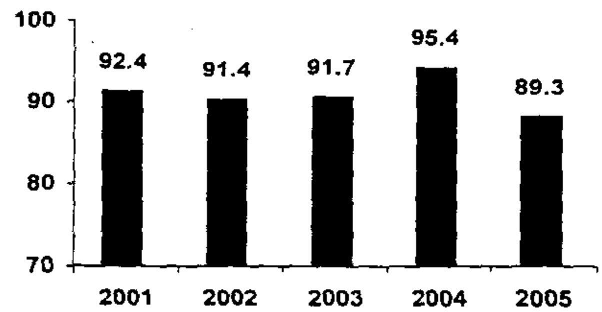
Net Generation
MWH (Millions)



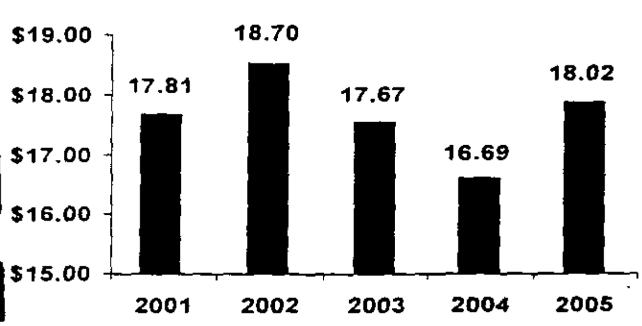
Plant Availability
%



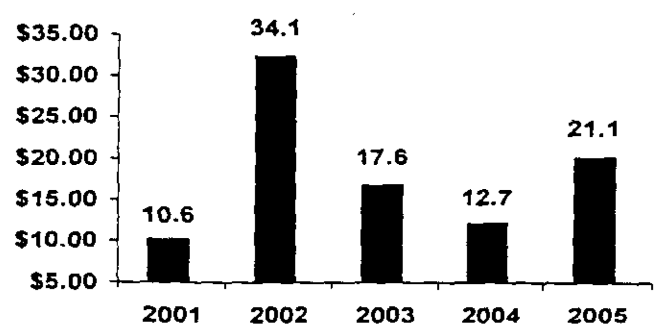
Net Capacity Factor
%



Total Operating Costs
Per Net MWH



Net Income
(Millions)



Electric Energy, Inc.

General Offices:
P. O. Box 165, Joppa, IL 62953

Company Profile

Electric Energy, Inc. received its charter from the State of Illinois on December 13, 1950, and is located on the north bank of the Ohio River, two miles west of Joppa, Illinois. The Company was organized for the purpose of constructing, owning, and operating electric power generating and transmission facilities to produce and supply electric power to a uranium processing plant located near Paducah, Kentucky. This uranium processing plant (the Paducah Project) was operated for the United States of America acting by and through the then-Atomic Energy Commission. The first generation of power by means of the facilities occurred on April 10, 1953, in the amount of 25 Megawatts (MW).

Electric Energy, Inc. was originally formed by five Sponsoring Companies. On May 1, 1957, one of the original Sponsoring Companies transferred its share to another Sponsor. On October 6, 1997, a second original Sponsoring Company transferred its share to another company, on April 30, 2002, a third original Sponsoring Company transferred its share to another company, and on September 30, 2004, one Sponsoring Company acquired another Sponsoring Company's shares of Electric Energy Inc.'s stock creating the ownership as it is today:

Ameren Energy Resources Company	40%
Kentucky Utilities Company	20%
Union Electric Company	40%

During 2005, the Company was obligated under contract with the Sponsoring Companies to deliver to them approximately 100 percent of the generating capacity of Joppa Steam Electric Station (Joppa Station). For 2006, approximately 100 percent of generating capacity will be delivered to Ameren Energy Marketing Company.

The original Power Supply Contract, dated May 4, 1951, provided for the delivery of 500 MW to the Atomic Energy Commission. This original contract has been modified several times. During 2005, the Company operated under Modification No. 16. Modification No. 16 and Modification No. 17 became effective on January 1, 2003 and January 1, 2006, respectively. In 2005, the Company sold approximately 0 percent of Joppa Station generating capacity to the Department of Energy. The Department of Energy is the successor of the Atomic Energy Commission. Although the Company's contract is with the Department of Energy, the United States Enrichment Corporation assumed responsibility for operation of the Paducah Project in 1992 and began direct operation of the plant during 1999.

The Company's present gross generating capacity is 1,162 MW. 1,086 MW of this capacity is steam generation from Joppa Station and 76 MW is combustion turbine generation from Midwest Electric Power, Inc. Transmission facilities of the Company are interconnected with those of its Sponsors by means of 230 kilovolt (KV) and 161 KV transmission lines. The Department of Energy's Paducah Project is connected by means of six 161 KV transmission lines.

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
800 Market Street
St. Louis MO 63101-2695
Telephone (314) 206 8500
Facsimile (314) 206 8514

Report of Independent Auditors

To the Board of Directors of
Electric Energy, Inc.:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, stockholders' equity, and cash flows present fairly, in all material respects, the financial position of Electric Energy, Inc. and its subsidiaries at December 31, 2005, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion. The financial statements of the Company as of December 31, 2004 and for the year then ended were audited by other auditors whose report dated March 31, 2005 expressed an unqualified opinion on those statements.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of December 31, 2005.

PricewaterhouseCoopers LLP
March 29, 2006

Consolidated Balance Sheets

Electric Energy, Inc.
And Its Subsidiaries
As of December 31,

	2005	2004
Assets		
Property, Plant, and Equipment:		
In service, at original cost	$ 468,781,342	$ 459,925,724
Construction work in progress	1,607,848	959,869
	470,389,190	460,885,593
Less - Accumulated provision for depreciation	379,736,745	370,623,470
	90,652,445	90,262,123
Current Assets:		
Cash and cash equivalents	354,121	222,130
Accounts receivable -		
Department of Energy	1,055,064	363,710
Sponsoring Companies and other	25,129,266	18,296,673
Fuel inventory, at average cost	10,449,164	10,638,921
Materials and supplies, at average cost	7,909,448	8,244,205
Prepayments and other current assets	823,372	1,556,974
	45,720,435	39,322,613
Other Assets:		
Prepaid and other benefit costs	1,456,175	4,404,018
Deferred charges and other assets	553,219	1,385,121
Deferred taxes	9,528,760	6,659,049
Unamortized debt costs	0	63,225
	11,538,154	12,511,413
Total Assets	$ 147,911,034	$ 142,096,149
Stockholders' Equity and Liabilities		
Stockholders' Equity:		
Common stock, $100 par, 62,000 shares authorized and outstanding	$ 6,200,000	$ 6,200,000
Retained earnings	82,573,661	61,457,689
	88,773,661	67,657,689
Current Liabilities:		
Notes payable	19,900,000	38,125,000
Long-term debt maturing within one year	0	14,444,443
Accounts payable	23,038,410	12,492,129
Accounts payable to Sponsoring Companies	3,681,521	3,071,062
Accrued interest	69,178	209,045
Other current liabilities	669,870	732,636
	47,358,979	69,074,315
Other Liabilities:		
Accrued and other benefit liabilities	4,489,705	4,404,018
Asset retirement obligations	5,852,726	0
Other liabilities	1,435,963	960,127
	11,778,394	5,364,145
Total Stockholders' Equity and Liabilities	$ 147,911,034	$ 142,096,149

Schedule MLB-10
Page 9 of 31

 The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Income

Electric Energy, Inc.
And Its Subsidiaries
For the Years Ended December 31,

	2005	2004
Operating Revenues:		
Power sales to Department of Energy	$ 2,728,615	$ 41,759,266
Power sales to Sponsoring Companies	169,775,605	162,013,009
Other revenues	1,855,068	1,570,716
	174,359,288	205,342,991
Operating Expenses:		
Fuel	91,625,582	89,494,269
Purchased power	1,852,450	40,063,329
Other operations	27,938,847	24,848,589
Maintenance	18,185,889	15,817,934
Depreciation and amortization	14,435,088	11,328,545
Taxes, other than income taxes	2,116,630	2,053,940
	156,154,486	183,606,606
Operating Income	18,204,802	21,736,385
Other (Income) and Expense:		
Interest income	(50,435)	(51,499)
Interest expense	2,247,337	3,064,590
Other, net	(17,870,119)	(2,447,853)
	(15,673,217)	565,238
Income Before Income Taxes	$ 33,878,019	$ 21,171,147
Income Taxes	12,762,047	8,425,439
Net Income	$ 21,115,972	$ 12,745,708
Earnings Per Share of Common Stock	$ 340.58	$ 205.58

Schedule MLB-10
Page 10 of 31

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Stockholders' Equity

Electric Energy, Inc.
And Its Subsidiaries
For the Years Ended
December 31, 2005 and 2004

	Common Stock	Retained Earnings	Total Stockholders' Equity
Balance, January 1, 2004	$ 6,200,000	$ 48,711,981	$ 54,911,981
Net Income	0	12,745,708	12,745,708
Balance, December 31, 2004	6,200,000	61,457,689	67,657,689
Net Income	0	21,115,972	21,115,972
Balance, December 31, 2005	$ 6,200,000	$ 82,573,661	$ 88,773,661

 The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

Electric Energy, Inc.
And Its Subsidiaries
For the Years Ended December 31,

	2005	2004
Cash Flows provided from Operating Activities:		
Net income	$ 21,115,972	$ 12,745,708
Adjustments to reconcile net income to net cash flow provided by operating activities:		
Depreciation and amortization	14,435,088	11,328,545
Amortization of debt issue costs	63,225	103,005
Loss on disposal of assets	33,724	26,408
Deferred income taxes	(2,865,047)	1,023,563
Net effect on cash flows of changes in:		
Accounts receivable	(7,523,947)	(1,053,805)
Fuel stock and materials inventory	889,647	(1,671,871)
Other assets	3,775,080	(988,242)
Accounts payable	10,248,109	6,195,316
Prepayments and accruals	1,092,492	1,365,309
Net cash flows provided from operating activities	41,264,343	29,073,936
Cash Flows used in Investing Activities:		
Proceeds from the disposal of property, plant and equipment	11,654	35,972
Additions and replacements of property, plant and equipment	(9,383,194)	(4,629,558)
Net cash flows used in investing activities	(9,371,540)	(4,593,586)
Cash Flows used from Financing Activities:		
Borrowings of notes payable	175,420,000	232,085,000
Repayments of notes payable	(193,645,000)	(202,010,000)
Repayments of long-term debt	(14,444,443)	(54,444,446)
Changes in checks written but not presented	908,631	(92,355)
Net cash flows used from financing activities	(31,760,812)	(24,461,801)
Increase in cash and cash equivalents	131,991	18,549
Cash and cash equivalents at beginning of year	222,130	203,581
Cash and cash equivalents at end of year	$ 354,121	$ 222,130

Supplemental Disclosure of Cash Flow Information

	2005	2004
Cash paid during the year for:		
Interest (net of amounts capitalized)	$ 2,212,260	$ 2,856,877
Income taxes	$ 7,538,000	$ 4,977,000

Schedule MLB-10
Page 12 of 31

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

1) Summary of Significant Accounting Policies

a) **Basis of Presentation** – The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the accounts of Electric Energy, Inc. (EEI or the Company) and its wholly-owned subsidiaries: Joppa and Eastern Railroad Company (J&E), Massac Enterprises, LLC, Met-South, Inc., and Midwest Electric Power, Inc. (Midwest). All intercompany transactions have been eliminated.

J&E operates a short line railroad with 3.9 miles of track and has access to four rail lines. J&E transports approximately five million tons of coal each year. As of December 2005, J&E owns 724 railcars and leases 135 railcars allowing for reduced rail freight rates.

Massac Enterprises, LLC is a captive retailer located in an Enterprise Zone in Illinois allowing EEI to achieve certain tax savings, contributing directly to lower bus bar costs.

Met-South, Inc. is an ash facility used to sell the Company's class "C" flyash. This facility allows for on-site storage of about 11,750 tons of fly ash with truck, barge, and rail loading capabilities. This company adds positive cash flow and earnings to EEI.

Midwest owns and operates two gas-fired combustion turbines with combined capacity of 76 megawatts. Additionally, Midwest operates three refurbished gas-fired combustion turbines for Ameren Energy Development Company with combined capacity of 186 megawatts. These units allow our owners to meet their higher demand levels during the peak summer months.

The Company complies with the rules, regulations and Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC). For the years ended December 31, 2005 and 2004, the Company applied the provisions of the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provided for the deferral of certain costs and benefits that are to be included in future rates as regulatory assets and liabilities on the Consolidated Balance Sheets. Regulatory assets represented the probable future revenue associated with certain costs that would be recovered through the rate-making process. Regulatory liabilities represented probable future reductions in revenues associated with amounts that would be refunded through the rate-making process.

Accounting for the Discontinuation of Application of FASB Statement No. 71 – As a result of the new Power Supply Agreement effective January 1, 2006, which is discussed below, management has concluded the Company can no longer apply the provisions of SFAS No. 71. Under the provisions of the previous contract, the net amount of the recorded regulatory assets and liabilities related to pension, postretirement, organizational and asset retirement costs were provided immediate revenue recovery and were billed to the Sponsoring Companies and the US Department of Energy (DOE) for the year ended December 31, 2005. As a result, regulatory assets related to the adoption of FASB Interpretation No. 47 (FIN 47), "Conditional Asset Retirement Obligations," of $5,237,519, the net of pension and postretirement regulatory assets and liabilities of $3,033,530 and the regulatory asset related to organizational costs of $887,479 were recorded as depreciation expense, other operations expense and other operations expense, respectively, on the Consolidated Statements of Income The total net amount of $9,158,528 is included in accounts receivable on the Consolidated Balance Sheet as of December 31, 2005. This amount was fully paid by the

Sponsoring Companies and the DOE in 2006. As of December 31, 2005, the effects of applying SFAS No. 71 have been removed from the Company's Consolidated Balance Sheet.

b) **Use of Estimates** – The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

c) **Cash and Cash Equivalents** – The Company considers highly liquid investments with a maturity of three months or less from the date of purchase to be cash equivalents.

The Company utilizes a cash management mechanism that funds certain bank accounts for checks as they are presented to the bank. The Company classified checks written but not presented to the bank, which amounted to approximately $2.8 million and $1.9 million at December 31, 2005 and 2004, respectively, in accounts payable. For cash flow reporting purposes, these amounts are classified as financing activities.

d) **Operating Revenues** – 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 (AER) (40%), Kentucky Utilities Company (20%) and Union Electric Company (40%) (Sponsoring Companies) and to the DOE. Through December 31, 2005, sales to the Sponsoring Companies are governed by the Power Supply Agreement, and sales to the DOE are made under the Modification No. 16 (Mod 16) of the Power Contract. Modification No. 17 (Mod 17) became effective January 1, 2006.

The Power Supply Agreement and Mod 16, 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 16 requires the Company to make available to the DOE a specified percentage of Joppa Station's capacity.

Under the Power Supply Agreement and Mod 16, 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 Power Supply Agreement and Mod 16 also provide the Company the opportunity to earn a profit on other services provided to the Sponsoring Companies and to the DOE.

The DOE was committed to 0% of Joppa Station's capacity for 2005 and 2004. For 2006, the DOE's commitment will again 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.

Mod 17 is effective through December 31, 2006, unless canceled, as provided under the terms. Effective January 1, 2006, the Company entered into a new Power Sales Agreement with Ameren Energy Marketing Company (AEM), which is a subsidiary of AER. Under the terms of the new Power Supply Agreement, all of the Company's Joppa Station capacity is under contract to AEM, and energy will be sold at hourly market-based rates as published by the MISO, a regional independent system operator.

Additional revenue is provided by sales of electricity from the Company's subsidiary, Midwest, to affiliates of the Sponsoring Companies. These sales are governed by Midwest's Power Supply Agreement (the Agreement). The Agreement was through December 31, 2004. However, the Agreement is subject to an annual extension as provided under its terms. Midwest continued to operate under the previous agreement through December 31, 2005.

The Agreement, and the rates established therein for the sale of electricity to affiliates of the Sponsoring Companies, has been accepted by the FERC. The Agreement provides that Midwest will sell all of its capacity to the Sponsoring Companies.

Under the Agreement, the Sponsoring Companies are required to make monthly payments for power which will enable Midwest to recover its cost-of-service, which includes all operating expenses, taxes, and interest plus generate a prescribed rate of return on equity capital, generally representing $15,000 annually.

Midwest has negotiated a new Power Supply Agreement with EEI that is effective January 1, 2006. This agreement is subject to annual extension as provided under its terms and allows EEI to purchase all of the capacity available from Midwest.

e) **Other (Income) and Expense** – Other income for 2005 included $16,802,350 of proceeds from the sale of banked emission allowances. Sulfur dioxide (SO_2) and nitrogen oxide (NO_x) allowances of 10,000 units and 426 units, respectively, were sold, contributing $10,512,597 of 2005 after-tax net income. The Company's remaining allowances banked at December 31, 2005, amounted to 48,695 SO_2 and 123 NO_x units. These allowances are held to meet future emission requirements and for possible sale as determined by management.

Other income for 2004 included $1,782,500 of proceeds from the sale of banked emission allowances. NO_x allowances of 800 units were sold, contributing $1,106,162 of 2004 after-tax net income. The Company's remaining allowances banked at December 31, 2004, amounted to 55,666 SO_2 and 79 NO_x units.

f) **Utility Plant** – Utility plant at and related to the Joppa Station is generally being depreciated over the periods provided under the Modified Accelerated Cost Recovery System for both book and tax purposes as prescribed under Mod 16. The Company charges the depreciation of rail cars to fuel inventory as transportation costs. The amount of such charges to fuel inventory was $305,748 and $609,247 in 2005 and 2004, respectively.

Expenditures for maintenance and repairs are expensed as incurred, while replacements and betterments which extend the useful lives of the assets are capitalized. Upon retirement or disposal, the cost of the assets and related accumulated depreciation are removed from the accounts and any resulting gain or loss is included in earnings.

The Company capitalized interest, in accordance with SFAS No. 34, "Capitalization of Interest Costs," in the amounts of $125,957 and $31,855 in 2005 and 2004, respectively, which related to construction work in progress.

g) **Impairment of Long-Lived Assets** – The Company assesses the recoverability of its long-lived assets when conditions are present which may indicate a potential impairment. The Company uses projected undiscounted cash flows of the related operations. These factors, along with management's plans with respect to operations, are considered in assessing the recoverability of long-lived assets. If the Company determines, based on such measures, that the carrying amount is impaired, the long-lived assets will be written down to their fair value with a corresponding charge to earnings.

h) **Materials and Supplies** – Materials and supplies are recorded at the lower of cost or market. Cost is determined using the weighted average cost method.

i) **Income Taxes** – Subsequent to September 30, 2004, the Company filed consolidated United States federal and state income tax returns and, for financial reporting purposes, provided income taxes for the difference in the tax and financial reporting bases of its assets and liabilities in accordance with SFAS No. 109, "Accounting for Income Taxes." Beginning on September 30, 2004, the Company is included in the consolidated federal and state income tax returns with Ameren Corporation. The Company and Ameren Corporation have entered into a tax sharing agreement. Under the terms of the tax sharing agreement, the Company pays taxes based on a separate company income tax return basis, as defined in the agreement. Separate company income taxes are defined as the income tax liability or refund, computed with respect to the corporate taxable income or loss of a member of the tax sharing group, as though the member were not a member of the group. The Company's allocation equals its separate return tax plus, in the event of Ameren Corporation having a negative separate return tax, a pro rata portion of Ameren Corporation's negative separate return tax. The pro rata portion is allocated to each member having a positive separate return tax, based on the ratio of the member's positive separate return tax to the sum of all members' positive separate return taxes. The tax allocated to any member shall not exceed the separate return tax of such member. The Company paid $7,538,000 in 2005 to Ameren Corporation for federal and state income taxes. Taxes payable to Ameren Corporation for 2005 and 2004 were $10,416,499 and $2,327,412, respectively. In accordance with the tax sharing agreement and SFAS No. 109, the Company records deferred income taxes for the difference in the tax and financial reporting bases of its assets and liabilities.

j) **Impact of Accounting Standards**

Accounting for Asset Retirement Obligations (ARO) – SFAS No. 143, "Accounting for Asset Retirement Obligations," provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and was effective January 1, 2003. This statement requires that the fair value of asset retirement costs, for which the Company has a legal obligation to expend, be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability.

The Company adopted SFAS No. 143 on January 1, 2003. No asset retirement obligations were recorded upon adoption as management concluded that no obligations existed at that date. Accordingly, no ARO liabilities are recorded on the Company's Consolidated Balance Sheet as of December 31, 2004.

FIN 47 clarified that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability's fair value can be reasonably estimated. FIN 47 also clarified when an entity would have sufficient information to reasonably estimate the fair value of an ARO. This interpretation was effective for the Company on December 31, 2005.

The Company adopted FIN 47 on December 31, 2005, and recorded asset retirement obligations of $5,852,726 for asbestos and river structure removal as well as ash pond closures related to the Company's Joppa Station. As part of the adoption, the Company capitalized asset retirement obligations of $1,098,922 as property, plant and equipment. The difference between the recorded asset and ARO liability related to the adoption of FIN 47 was recorded as a regulatory asset. See discussion above related to the Company's discontinuation of applying SFAS No. 71.

The following table shows what the Company's AROs would have been if FIN 47 had been in effect in 2004:

	Asset Retirement Obligation
January 1, 2004	$5,250,156
December 31, 2004	$5,543,253

The adoption of FIN 47 would not have had an income statement impact on the Company if adopted in 2004 because a regulatory asset would have been recorded as an offset to the AROs and the related net capitalized asset retirement costs.

k) **Regulatory Assets and Liabilities**

Regulatory assets and (liabilities) reflected in the Consolidated Balance Sheets as of December 31, relate to the following:

	2005	2004
Regulatory Assets:		
Income taxes, net (a)	$ 0	$ 7,520
Pension benefit costs (b)	0	2,979,735
Organizational costs (a)	0	864,370
Total Regulatory Assets	$ 0	$ 3,851,625
Regulatory Liabilities:		
Postretirement benefit costs (c)	$ 0	$ (1,424,283)
Total Regulatory Liabilities	$ 0	$ (1,424,283)

The above are recorded in the Consolidated Balance Sheets as:
(a) Deferred charges and other assets.
(b) Prepaid and other benefit costs.
(c) Accrued and other benefit liabilities.

Please refer to footnote 1, Summary of Significant Accounting Policies, for a discussion of the Company's discontinuation of the application of SFAS No. 71.

l) **Reclassifications** – Certain reclassifications have been made to the 2004 financial statements to conform with 2005 reporting.

2) Notes Payable

The Company had two revolving credit agreements, which allowed borrowings of up to $45,000,000. A $25,000,000 revolving credit agreement expired on June 10, 2005. A $20,000,000 revolving credit agreement will expire on April 25, 2006. The $25,000,000 agreement provided for interest to be charged on outstanding borrowings at LIBOR (London InterBank Offering Rate) plus a margin ranging from 0.55% to 0.75%, depending on utilization. The $20,000,000 agreement provides for interest charges on outstanding borrowings at a rate per annum equal to (i) the eurodollar rate plus fifty-five hundredths of one percent (0.55%), (ii) the base rate, or (iii) the overnight rate plus fifty-five hundredths of one percent (0.55%). No compensating balances are required for either credit agreement. There were no borrowings outstanding under these revolving credit agreements at December 31, 2005.

In June 2004, the Company secured an additional credit agreement with Ameren Corporation, which allows borrowings up to $50,000,000. Interest shall accrue monthly on the unpaid principal balance of each loan from the date of such loan until such principal amount shall be paid in full. If only funds from the Lender's treasury ("Internal Funds") are used to fund the loan, the daily interest rate applicable to such loan shall be the CD yield equivalent of the 30-day Federal Reserve "AA" Non-Financial Commercial Paper Composite Rate ("Composite Rate") published for such day, or, if no such Composite Rate was established for that day, then the applicable rate shall be the Composite Rate for the next preceding day for which such Composite Rate was established. If only funds borrowed by the Lender ("External Funds") are used to fund the loan, the daily interest rate applicable to such loan shall equal the Lender's daily cost for such funds. If both Internal Funds and External Funds are used to fund the loan, the daily rate applicable to such loan shall be a "blended" rate equal to the weighted average of the cost of Internal Funds and the cost of External Funds used to fund such a loan. During 2005, the credit agreement was revised to allow borrowings up to $75,000,000.

At December 31:

	2005	2004
Available lines of credit	$ 95,000,000	$ 95,000,000
Notes outstanding	19,900,000	38,125,000
Weighted average interest rate	4.3%	2.7%

During the year:

	2005	2004
Maximum short-term borrowings	$ 45,780,000	$ 48,600,000
Average short-term borrowings	32,859,000	20,348,000
Weighted average interest rate	3.6%	2.2%

3) **Long-Term Debt**

	2005	2004
1991 Senior medium-term notes 8.60%	$ 0	$ 6,666,666
1994 Senior medium-term notes 6.61%	0	7,777,777
Maturities due within one year	0	(14,444,443)
Total Long-Term Debt	$ 0	$ 0

For the 1991 and 1994 notes above, annual principal payments were due December 15 through 2005. Interest was paid semiannually. These notes were paid in full on December 14, 2005.

4) **Financial Instruments and Financings**

The carrying amounts of cash and cash equivalents and short-term receivables and obligations approximate their fair value due to the short maturities of these instruments. The estimated fair value of the Company's senior medium-term notes on December 31, 2004, which is based on current market rates of issues with similar remaining maturities, was approximately $15,060,926.

5) **Related Party Transactions**

Transactions with the Sponsoring Companies and their affiliates during 2005 and 2004 included the sale of generated power to them, the purchase of power from them in order to supplement generated power to meet the DOE's demand, and other transactions for general services and materials. The amount of power purchased from the Sponsoring Companies was $1,852,450 and $39,724,809 in 2005 and 2004, respectively. The Company also has a Facilities Use Agreement with Central Illinois Public Service Company and Union Electric Company. The total amount paid in 2005 and 2004 related to this agreement was $315,649.

During 2005 and 2004, the Company purchased coal through a pooling arrangement from Ameren Energy Fuels and Services Company, a subsidiary of AER. These purchases amounted to $33,522,213 and $33,007,190 for 2005 and 2004, respectively.

In June 2004, the Company secured a credit agreement with Ameren Corporation, which allows borrowings up to $50,000,000. During 2005, the credit agreement was revised to allow borrowings up to $75,000,000. See Note 2 for additional discussion.

See Note 1 for additional related party income tax transactions.

) **Concentration of Credit Risk**

Credit risk is the exposure to economic loss that would occur as a result of nonperformance by counterparties, pursuant to the terms of their contractual obligations. Specific components of credit risk include counterparty default risk, collateral risk, concentration risk, and settlement risk. Substantially all of the Company's revenues are from the sale of electricity to its Sponsoring Companies.

Exposure to credit risk with accounts receivable is not significant because the receivables are from traditional investor-owned utilities and the United States government. Also, because financial instruments are transacted only with highly-rated financial institutions, nonperformance by any of the counterparties is not anticipated.

7) **Income Taxes**

The components of the net deferred income tax assets at December 31 are as follows:

	2005	2004
Deferred Tax Assets:		
Property related differences	$ 2,244,721	$ 1,677,085
Employee benefits	5,592,529	4,015,679
Other, net	1,691,510	966,285
Net deferred income tax assets	$ 9,528,760	$ 6,659,049

The components of current and deferred income tax expense for the years ended December 31 are as follows:

	2005	2004
Current:		
Federal	$ 12,881,204	$ 5,973,462
State	2,745,890	1,428,414
Deferred, net:		
Federal	(2,452,474)	918,828
State	(412,573)	104,735
Total income tax expense	$ 12,762,047	$ 8,425,439

	2005	2004
Statutory federal rate	35.0%	35.0%
State income taxes	4.5	4.7
Other	(1.8)	0.1
Effective tax rate	37.7%	39.8%

8) **Pension Costs and Postretirement Benefits**

The Company has a defined benefit pension plan that covers all employees. Benefits under the plan reflect each employee's compensation, years of service, and age at retirement. The plan's assets are invested primarily in bond and equity funds with a trust company.

Pension contributions are actuarially determined using the entry age normal cost method. The Company accounts for pension plan activity pursuant to the provisions of SFAS No. 87, "Employers' Accounting for Pensions." For the years ended December 31, 2005 and 2004, the Company recovered pension costs in rates on a cash funded basis in accordance with Mod 16. Accordingly, the difference between SFAS No. 87 pension costs and cash funding of the Plan were deferred as a regulatory asset. See Note 1 for additional discussion.

The Company provides certain life insurance and health care benefits for substantially all retired employees. The Company has various defined benefit postretirement health care plans which pay stated percentages of most necessary medical expenses incurred by retirees after subtracting payments by Medicare and after a stated deductible has been met. Retired employees are eligible for certain postretirement benefits in accordance with plan documents. The Company reserves the right to amend or modify the plan documents, in whole or in part, at any time.

The Company records its expense for postretirement benefits other than pensions during each employee's years of service in accordance with SFAS No. 106, "Employers Accounting for Postretirement Benefits Other Than Pensions." For the years ended December 31, 2005 and 2004, the Company recovered postretirement costs in rates on a cash funded basis in accordance with Mod 16. Accordingly, the difference between SFAS No. 106 postretirement costs and cash funding of the Plan were deferred as a regulatory liability. See Note 1 for additional discussion.

The primary objective of the Company's retirement plan and postretirement benefit plans is to provide eligible employees with pension and postretirement healthcare/life oenefits. The Company manages plan assets in accordance with the "prudent investor" guidelines contained in the Employee Retirement Income Security Act of 1974 (ERISA), as amended. The Company's goal is to earn the highest possible return on plan assets consistent with its tolerance for risk. The Company delegates investment management to specialists in each asset class and where appropriate, provides the investment manager with specific guidelines which include allowable and/or prohibited investment types. The Company regularly monitors manager performance and compliance with investment guidelines.

The expected return on plan assets for the Company's retirement plan and postretirement benefit plans is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns and volatility of the various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolio was developed and adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

The changes in the pension benefit obligation and plan assets are as follows:

	2005	2004
Benefit obligation, beginning of year	$ 58,579,648	$ 52,836,522
Service cost, net of expense	1,901,115	1,761,480
Interest cost on projected benefit obligation	3,515,536	3,222,591
Plan amendments	1,944,091	0
Benefits paid	(1,755,235)	(1,593,995)
Changes in actuarial assumptions	3,279,861	2,353,050
Benefit obligation, end of year	$ 67,465,016	$ 58,579,648
Fair value of plan assets, beginning of year	$ 53,506,639	$ 49,983,062
Actual return on plan assets	2,754,529	5,365,495
Benefits paid	(1,755,235)	(1,593,995)
Administrative expenses	(218,331)	(247,923)
Fair value of plan assets, end of year	$ 54,287,602	$ 53,506,639

A reconciliation of the funded status of the pension plan under SFAS No. 87 to the amount recognized in the Consolidated Balance Sheets at December 31, 2005 and 2004, is as follows:

	2005	2004
Funded status - deficiency of plan assets over projected benefit obligation	$ (13,177,414)	$ (5,073,009)
Unrecognized net loss	6,670,581	1,785,297
Unrecognized prior service cost	2,017,128	307,977
Accrued pension cost	$ (4,489,705)	$ (2,979,735)

The pension plan was amended in 2005, which resulted in an additional $5 per month per employee for each year of credited service.

The weighted-average assumptions used to determine benefit obligations at December 31 are as follows:

	2005	2004
Discount rate	5.50%	5.90%
Rate of compensation increase	4.00%	4.00%
Measurement date	12/31/2005	12/31/2004

The weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31 are as follows:

	2005	2004
Discount rate	5.90%	6.25%
Expected long-term rate of return on plan assets	8.00%	8.00%
Rate of compensation increase	4.00%	4.00%
Measurement date	12/31/2004	12/31/2003

The information for pension plans with an accumulated benefit obligation in excess of plan assets is as follows:

	2005	2004
Projected benefit obligation	$ 67,465,016	$ 58,579,648
Accumulated benefit obligation	55,570,626	47,430,529
Fair value of plan assets	54,287,602	53,506,639

The accumulated benefit obligation in 2004 did not exceed the fair value of plan assets.

The components of net periodic pension cost are as follows:

	2005	2004
Service cost-benefits earned during the year	$ 1,959,912	$ 1,815,959
Interest cost on projected benefit obligation	3,515,536	3,222,591
Expected return on plan assets	(4,200,418)	(3,935,031)
Amortization of unrecognized prior service cost	234,940	141,947
Net periodic pension cost per SFAS No. 87	1,509,970	1,245,466
Adjustment to funding level	(1,509,970)	(1,245,466)
Net periodic pension cost recognized	$ 0	$ 0

The weighted average asset allocations as of December 31, 2005 and 2004, by asset category, are as follows:

	Target Allocation	Plan Assets 2005	Plan Assets 2004
Equity Securities	60.0%	59.3%	60.4%
Debt Securities	40.0	40.4	39.3
Other	0.0	0.3	0.3
Total	100.0%	100.0%	100.0%

The Company did not contribute to the pension plan during 2005. The Company expects to contribute $2,000,000 to its pension plan during 2006.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

2006	$ 1,986,979
2007	2,160,549
2008	2,380,731
2009	2,623,632
2010	3,035,254
Years 2011-2015	21,319,464

The changes in postretirement benefit (other than pensions) obligation and plan assets are as follows:

	2005	2004
Benefit obligation, beginning of year	$ 55,685,576	$ 50,150,456
Service cost-benefits earned during the period	1,437,760	1,476,379
Interest cost on accumulated benefit obligation	3,321,022	3,306,961
Changes in actuarial assumptions	1,082,362	2,587,794
Benefits and expenses paid	(1,864,749)	(1,877,370)
Retiree contributions	75,920	41,356
Benefit obligation, end of year	$ 59,737,891	$ 55,685,576
Fair value of plan assets, beginning of year	$ 56,158,812	$ 52,911,311
Actual return on plan assets	5,445,731	5,083,515
Retiree contributions	75,920	41,356
Benefits paid	(1,673,279)	(1,669,108)
Administrative expenses	(191,470)	(208,262)
Fair value of plan assets, end of year	$ 59,815,714	$ 56,158,812

A reconciliation of the accumulated postretirement benefit obligation to the prepaid postretirement benefit cost at December 31 is as follows:

	2005	2004
Plan assets in excess of projected benefit obligation	$ 77,823	$ 473,236
Unrecognized net loss	12,315,581	13,624,344
Unrecognized prior service cost	(10,937,229)	(12,673,297)
Prepaid postretirement benefit cost	$ 1,456,175	$ 1,424,283

The components of the net periodic other postretirement benefit cost are as follows:

	2005	2004
Service cost-benefits earned during the year	$ 1,437,760	$ 1,476,379
Interest cost on accumulated benefit obligation	3,321,022	3,306,961
Expected return on plan assets	(3,694,187)	(3,696,726)
Amortization of unrecognized prior service cost	(1,736,068)	(1,736,068)
Amortization of unrecognized net loss	639,581	596,624
Net periodic postretirement benefit cost per SFAS No. 106	(31,892)	(52,830)
Adjustment to funding level	31,892	52,830
Net periodic postretirement benefit cost recognized	$ 0	$ 0

The weighted average asset allocations as of December 31, 2005 and 2004, by asset category, are as follows:

	Target Allocation	Plan Assets 2005	Plan Assets 2004
U.S. Equity Securities	50.0%	52.1%	52.2%
U.S. Debt Securities	40.0	36.6	35.8
Other	10.0	11.3	12.0
Total	100.0%	100.0%	100.0%

The Company did not contribute to the postretirement plan during 2005 and does not expect to contribute to the funded postretirement plan during 2006.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

2006	$ 1,863,194
2007	1,991,056
2008	2,082,083
2009	2,232,292
2010	2,445,329
Years 2011-2015	16,288,935

The weighted-average assumptions used to determine benefit obligations at December 31 are as follows:

	2005	2004
Discount rate	5.50%	5.90%
Rate of compensation increase (life insurance benefit)	4.00%	4.00%
Measurement date	10/1/2005	10/1/2004

The weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31 are as follows:

	2005	2004
Discount rate	5.90%	6.50%
Expected long-term rate of return on plan assets-Management	4.80%	4.72%
Expected long-term rate of return on plan assets-Bargaining Unit	8.00%	8.00%
Rate of compensation increase (life insurance benefit)	4.00%	5.00%
Measurement date	10/1/2004	10/1/2003

The estimated cost of these future benefits could be significantly impacted by future changes in health care costs, work force demographics, interest rates, or plan changes. A 1% increase in the assumed health care cost trend rate each year would increase the aggregate service and interest costs for 2005 by $918,002 and the accumulated postretirement benefit obligation at December 31, 2005, by $9,359,790. A 1% decrease in the assumed health care cost trend rate each year would decrease the aggregate service and interest costs for 2005 by $720,055 and the accumulated postretirement benefit obligation at December 31, 2005, by $7,532,911. The 2005 assumptions included a health care cost trend rate of 10.0% declining to 5.5% in 2015. The 2004 assumptions included a health care cost trend rate of 10.5% declining to 5.5% in 2015.

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 was enacted. Among other features, the Act introduces a prescription drug benefit under Medicare Part D and a federal subsidy to sponsors of retiree health care plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. FASB Staff Position FAS 106-2 provides guidance on accounting for the effects of the Act, and is effective for interim periods beginning after June 15, 2004. The Company adopted FASB Staff Position FAS 106-2 during the quarter ended September 30, 2004. This adoption did not have a material impact on the financial statements.

9) **Environmental Matters**

The Company is subject to various environmental regulations by federal, state, and local authorities. As new laws or regulations are developed, the Company assesses their applicability and implements the necessary modifications to the facility as required for compliance. The more significant matters are discussed below.

The 1997 Kyoto Protocol requires participating countries to return to 1990 levels of greenhouse gas (GHG) emissions (primarily carbon dioxide (CO_2)). Under the treaty, the US would have an overall reduction target of 7% in GHG emissions from 1990 levels by 2008-2012. On November 12, 1998, the US signed the treaty. However, for the treaty to enter into force within the US, it will have to be ratified by a two-thirds vote of the US Senate. The treaty, in its present form, is unlikely to be ratified by the US Senate since it does not contain provisions requiring participation of developing countries.

The Bush Administration continues to resist mandatory emission reductions for CO_2. Since burning anything that contains carbon produces CO_2, the Company's options to meet the reduction requirements would be limited.

Beginning in 1994, the United States Environmental Protection Agency (USEPA) required specific states to reduce ozone season NO_x emissions through a cap and trade program known as the NO_x State Implementation Plan (SIP) Call. The ozone season is from May 1 to September 30. The Company was in compliance with the NO_x emission levels required in 2005 and 2004 and has sufficient NO_x allowances for 2006 through 2007. It is expected that additional NO_x emission reductions may be required in 2008 and 2009 when the Illinois EPA (IEPA) reallocates the amount of NO_x each utility can emit. Management has studied compliance alternatives and has developed several options to meet various NO_x levels of compliance.

In March 2005, the USEPA issued the Clean Air Interstate Rule (CAIR) which created a new annual NO_x cap and trade program, a new ozone season cap and trade program, and reductions in the emission value of SO_2 allowances allocated under the existing Acid Rain Program.

The CAIR Annual and Ozone Season NO_x Program will require NO_x reductions in 2009 and additional NO_x reductions in 2015. The Company modified the existing low NO_x burner system by installing Separated Over Fire Air on unit six in 2005 and is planning to install Separated Over Fire Air on unit five in 2006. The Company will continue to evaluate the effect that Separated Over Fire Air low NO_x burners have on the reduction of NO_x emissions.

Under the CAIR SO_2 Program, each allowance issued after 2010 allows 0.5 tons of emissions and each allowance issued after 2015 allows 0.35 tons of emissions. The Company is evaluating the installation of SO_2 removal controls to achieve these reductions.

In March 2005, USEPA issued the Clean Air Mercury Rule (CAMR) which created a mercury cap and trade program. This program will require reductions in mercury emissions beginning in 2010 with additional reductions in 2018. The Company is evaluating mercury control options to be installed to meet these dates.

Congress continues to consider bills for multi-pollutant legislation that would require reductions in SO_2, NO_x, and mercury (Hg) similar to the CAIR and CAMR rules. Some of these bills also require reductions in CO_2 emissions. Management is monitoring the multi-pollutant bills and their effect on the Company.

In February 2004, USEPA finalized new requirements under the Clean Water Act (316(b) legislation) to reduce impingement and entrainment of aquatic organisms in cooling water intake systems. The Company has developed a corporate strategy and a "Proposal for Information Collection" (PIC) plan. This PIC plan has been submitted to the IEPA for approval. Bio-monitoring began in 2005, and compliance options will be evaluated in 2006 or 2007. The required equipment changes, if any, must be installed in 2009.

On April 19, 2005, the Company received an information request by USEPA to evaluate compliance with the Illinois State Implementation Plan and New Source Performance Standards. The Company complied with the information request and has not received any additional correspondence from USEPA.

10) Commitments and Contingencies

As a result of issues generated in the course of daily business, the Company is involved in legal, tax, and regulatory proceedings. The Company believes that the final disposition of these proceedings, except as otherwise disclosed in these notes to our financial statements, will not have an adverse material effect on the Company's results of operations, financial position, or liquidity.

11) Leases

Sales of power generated by Midwest are governed by the Power Supply Agreement between Midwest and the Sponsor Companies. This Agreement was executed during 2000 and amended during 2002 to continue in force through December 31, 2004 (see Note 1d). Midwest has negotiated a new Power Supply Agreement with EEI to be effective January 1, 2006. During 2005, Midwest continued to operate under the previous agreement. As of December 31, 2005, the Agreement is classified as an operating lease of Midwest's facilities to affiliates of the Sponsors. These facilities are included in property, plant, and equipment at a cost of $38,193,819, with accumulated depreciation of $8,615,062. Minimum annual lease payments to Midwest are based on the operating costs of the facilities. For 2005 and 2004, these payments amounted to $2,998,577 and $2,403,746, respectively. These payments are included in the rental expense mentioned below for 2005 and 2004.

The Company leases certain facilities, railcars, and other equipment under operating leases. Total rental expense under operating leases for the years ended December 31, 2005 and 2004, was approximately $4.6 million and $3.4 million, respectively. Future minimum lease payments under operating leases that have initial or remaining noncancelable lease terms in excess of one year are as follows:

2006	$ 3,657,682
2007	3,653,821
2008	3,482,051
2009	3,288,379
2010 +	13,902,221
	$ 27,984,154

Selected Financial and Statistical Data

	2005	2004	2003	2002	2001
Net Generation (mwh)	7,881,897	8,444,487	8,101,001	8,075,551	8,154,549
Energy Sales (mwh) to:					
DOE	51,495	1,157,166	2,428,691	3,775,525	3,147,567
Sponsors	7,807,373	8,360,896	7,178,675	6,478,936	5,776,535
Power Sales to:					
DOE	$ 2,728,615	$ 41,759,266	$ 68,499,312	$ 85,192,866	$ 54,017,251
Sponsors	$ 163,780,493	$ 157,862,984	$ 141,641,247	$ 134,232,348	$ 113,956,309
Operating Revenues	$ 168,364,176	$ 201,192,967	$ 212,356,792	$ 221,280,270	$ 169,773,399
Operating Expenses (including income taxes)	$ 163,031,357	$ 187,991,674	$ 199,702,758	$ 216,667,022	$ 153,814,140
Cost of Fuel Consumed	$ 88,149,444	$ 88,098,800	$ 83,625,197	$ 79,543,205	$ 76,747,986
Total Fuel Burned (tons equivalent for gas and oil)	4,924,100	5,188,354	4,883,306	4,846,671	4,935,145
Coal Burned (tons)	4,912,455	5,176,823	4,871,839	4,834,669	4,924,351
Average Cost of Fuel Burned per MMBTU	$ 1.09	$ 1.02	$ 1.00	$ 0.96	$ 0.92
Heat Rate (Btu per kwh, net generation)	10,420	10,405	10,335	10,333	10,352
Taxes (Federal, state and local)	$ 14,681,767	$ 10,267,098	$ 13,541,124	$ 23,858,425	$ 8,345,747
Payroll	$ 17,865,590	$ 17,601,623	$ 17,346,785	$ 17,068,104	$ 16,738,978
Employees (year end)	260	257	262	258	261

Electric Energy, Inc.

Directors

Daniel F. Cole
Senior Vice President, Administration
Ameren Corporation
St. Louis, Missouri

R. Alan Kelley
Chairman of the Board
Electric Energy, Inc.
Joppa, Illinois

Charles D. Naslund
Senior Vice President and
Chief Nuclear Officer
AmerenUE
Fulton, Missouri

Paul W. Thompson
Senior Vice President, Energy Services
LG&E Energy LLC
Louisville, Kentucky

Thomas R. Voss
Executive Vice President and
Chief Operating Officer
Ameren Corporation
St. Louis, Missouri

John N. Voyles, Jr.
Vice President, Regulated Generation
LG&E Energy Corporation
Louisville, Kentucky

David A. Whiteley
Senior Vice President, Energy Delivery
Ameren Services
St. Louis, Missouri

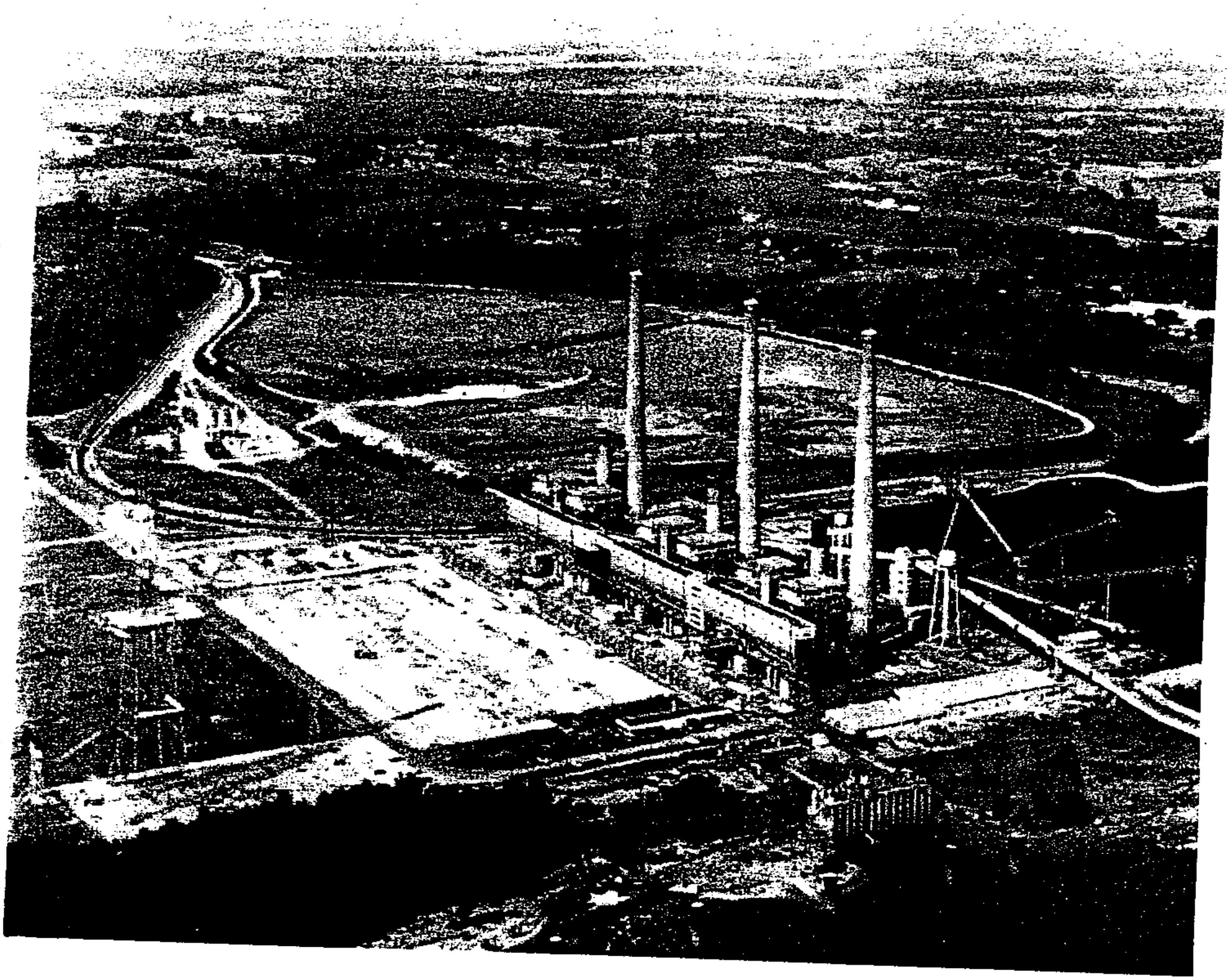
Officers

R. Alan Kelley
Chairman of the Board

James M. Helm
Secretary-Treasurer

Robert L. Powers
President

William H. Sheppard
Vice President



Joppa Steam Electric Station
We Provide Energy for a Strong America©

Schedule MLB-11

1 page

Designated HIGHLY CONFIDENTIAL

By AmerenUE

Electric Energy, Inc.

October 23, 2006

RECEIVED

OCT 2 4 2006

SENIOR VICE PRESIDENT & CNO

Messrs. D. F. Cole
R. A. Kelley
C. D. Naslund
P. W. Thompson
T. R. Voss
J. N. Voyles, Jr.
D. A. Whiteley

Gentlemen:

Enclosed is a Notice and booklet containing reference information for our Board of Directors' Meeting scheduled for **10 a.m. Central Time, October 27, 2006**, at the **Ameren General Office Building** in **St. Louis, Missouri**.

Remember to bring your 2007 calendars. We will schedule meeting dates for next year.

If you have any questions, please feel free to contact me at your convenience.

Yours very truly,

James M. Helm

James M. Helm
Secretary-Treasurer

JMH/adb
Enclosures
xc: R. L. Powers
W. H. Sheppard

Post Office Box 165 Joppa, Illinois 62953 (618) 543-7531 Fax (618) 543-7420

Electric Energy, Inc.

(An Illinois Corporation)

Notice of Meeting of Board of Directors

To the Members of the Board of Directors
of Electric Energy, Inc.

YOU ARE HEREBY NOTIFIED that a meeting of the Board of Directors of Electric Energy, Inc., will be held at the **Ameren General Office Building in St. Louis, Missouri**, for the transaction of such business as may properly come before the meeting on **Friday, October 27, 2006,** at **10:00 a.m. Central Time**.

James M. Helm
Secretary

Date: October 23, 2006

Copies sent to Messrs: D. F. Cole
R. A. Kelley
C. D. Naslund
T. R. Voss
J. N. Voyles, Jr.
P. W. Thompson
D. A. Whiteley

Post Office Box 165 Joppa, Illinois 62953 (618) 543-7531 Fax: (618) 543-7420

At the request of Electric Energy, Inc. –

I suggest the following charitable organization(s) be contributed cash during 2006:

First Choice

____
____
____
____

Suggested Amount: _______________

Second Choice

____
____
____
____

Suggested Amount: _______________

____
Signature

____
Title

____
Date

Fax Number: 618-543-7420 Attention: Jim Helm

Electric Energy, Inc.

Board of Directors' Meeting

October 27, 2006

Agenda

October 27, 2006

1.	Approve Minutes of Meeting Held July 21, 2006	Approval
2.	Earnings Report	Information
3.	Status Report of Emission Allowance Sales	Information
4.	Proposed Revision to Power Supply Agreement	Approval
5.	2007-2009 Operating Budget Presentation	Information
6.	2007-2009 Capital Budget Presentation	Approval
7.	Suggested Meeting Dates for 2007:	Information

1st Meeting (Phone)	2nd Meeting (St. Louis)	3rd Meeting (Phone)	4th Meeting (St. Louis)
February 2	May 4	July 20	October 26
February 9	May 11	July 27	November 2
February 16	May 18	August 3	November 16

8.	Officers' Salary Recommendation	Approval
9.	Other	

Electric Energy, Inc.

Minutes of Meeting of Board of Directors

Held July 21, 2006

A meeting of the Board of Directors of Electric Energy, Inc. convened via teleconference on Friday, July 21, 2006, at 10:00 a.m., subsequent to the following notice which had been previously sent to each member of the Board:

"Electric Energy, Inc.

(An Illinois Corporation)

Notice of Meeting of Board of Directors

To the Members of the Board of Directors
of Electric Energy, Inc.

YOU ARE HEREBY NOTIFIED that a meeting of the Board of Directors of Electric Energy, Inc., will be held via teleconference with said calls originating from Electric Energy, Inc., at Joppa, Illinois, for the transaction of such business as may properly come before the meeting on Friday, July 21, 2006, at 10:00 a.m. Central Time.

Date: July 14, 2006"

There were present the following, constituting a majority of the Board of Directors:

Messrs.
D. F. Cole
R. A. Kelley
P. W. Thompson
T. R. Voss
J. N. Voyles, Jr.
D. A. Whiteley

Mr. R. Alan Kelley, as Chairman of the Corporation, presided at the meeting and Mr. James M. Helm, Secretary of the Corporation, acted as

Secretary. Also attending were Mr. Robert L. Powers, President of the Corporation, and Mr. William H. Sheppard, Vice President of the Corporation.

The minutes of the meeting of the Board of Directors held on May 17, 2006, copies of which had been sent previously to each member, were approved. The Chairman introduced Mr. James M. Helm who presented the earnings report for the second quarter 2006. After discussion, upon motion duly made and seconded, it was unanimously;

> RESOLVED, that there be paid out of surplus on September 27, 2006, to stockholders of record at the close of business on July 21, 2006, dividends of $554.44 per share on 62,000 shares of common stock, totaling $34,375,000.00 for the third quarter 2006.

Mr. James M. Helm entered into a discussion of the Company's pension fund assets managed by Mellon Trust. Mr. Helm reported the financial results for the six months ended June 30, 2006, and reviewed the asset management strategy for the fund.

Mr. Helm then provided a status report on the VEBA Trusts managed by NISA Investment Advisors and the International Equity Funds. Mr. Helm reported the financial results of the Management and Bargaining Unit Trusts for the six months ended June 30, 2006. Mr. Helm also reviewed the asset strategy for each fund.

The Chairman introduced Mr. William H. Sheppard who updated the Board with the projected 2006 Capital expenditures of $9,327,000.00. Mr. Sheppard further reported that capital expenditures would be within the spending guidelines previously authorized by the Board.

Mr. Sheppard provided a report on the Company's incentive compensation plan for 2006. Mr. Sheppard reviewed each of the incentive categories and the projection for each category.

Mr. Sheppard then entered into a discussion of the Company's multi-pollution capital expenditure plan. He first reviewed the 2006 Capital plan presented in the October 2005 board meeting. Mr. Sheppard reported the current plan has been modified to support recent regulatory requirements as required by the Illinois Environmental Protection Agency. Mr. Sheppard discussed in detail the boiler optimization controls and separated over fire air projects previously installed by the Company and the proposed future projects consisting of mercury controls, scrubbers, fabric filters, and land fill projects to meet regulatory requirements. Mr. Sheppard concluded the presentation by reporting the Company has a multi-pollution control plan, and it is his expectation that the plan will firm up in the near future. Mr. Robert L. Powers entered into a general discussion regarding the Company's collective bargaining agreement. Mr. Powers reported the Company would like to extend the existing labor contract for a period of one to two years.

It was agreed that the next Board of Directors' meeting would be held on Friday, October 27, 2006, at the St. Louis Airport Hilton Hotel in St. Louis, Missouri, at 10:00 a.m. Central Time.

There being no further business, upon motion duly made and seconded, the meeting was adjourned.

____
Secretary

Electric Energy, Inc.

Minutes of Meeting of Board of Directors

Held July 21, 2006

A meeting of the Board of Directors of Electric Energy, Inc. convened via teleconference on Friday, July 21, 2006, at 10:00 a.m., subsequent to the following notice which had been previously sent to each member of the Board:

"Electric Energy, Inc.

(An Illinois Corporation)

Notice of Meeting of Board of Directors

To the Members of the Board of Directors
of Electric Energy, Inc.

YOU ARE HEREBY NOTIFIED that a meeting of the Board of Directors of Electric Energy, Inc., will be held via teleconference with said calls originating from Electric Energy, Inc., at Joppa, Illinois, for the transaction of such business as may properly come before the meeting on Friday, July 21, 2006, at 10:00 a.m. Central Time.

Date: July 14, 2006"

There were present the following, constituting a majority of the Board of Directors:

Messrs. D. F. Cole
R. A. Kelley
P. W. Thompson
T. R. Voss
J. N. Voyles, Jr.
D. A. Whiteley

Mr. R. Alan Kelley, as Chairman of the Corporation, presided at the meeting and Mr. James M. Helm, Secretary of the Corporation, acted as Secretary. Also attending were Mr. Robert L. Powers, President of the Corporation, and Mr. William H. Sheppard, Vice President of the Corporation.

The minutes of the meeting of the Board of Directors held on May 17, 2006, copies of which had been sent previously to each member, were approved.

The Chairman introduced Mr. James M. Helm who presented the earnings report for the second quarter 2006.

Mr. James M. Helm entered into a discussion of the Company's pension fund assets managed by Mellon Trust. Mr. Helm reported the financial results for the six months ended June 30, 2006, and reviewed the asset management strategy for the fund.

Mr. Helm then provided a status report on the VEBA Trusts managed by NISA Investment Advisors and the International Equity Funds. Mr. Helm reported the financial results of the Management and Bargaining Unit Trusts for the six months ended June 30, 2006. Mr. Helm also reviewed the asset strategy for each fund.

The Chairman introduced Mr. William H. Sheppard who updated the Board with the projected 2006 Capital expenditures of $9,327,000.00. Mr. Sheppard further reported that capital expenditures would be within the spending guidelines previously authorized by the Board.

Mr. Sheppard provided a report on the Company's incentive compensation plan for 2006. Mr. Sheppard reviewed each of the incentive categories and the projection for each category.

Mr. Sheppard then entered into a discussion of the Company's multi-pollution capital expenditure plan. He first reviewed the 2006 Capital plan presented in the October 2005 board meeting. Mr. Sheppard reported the current plan has been modified to support recent regulatory requirements as required by the Illinois Environmental Protection Agency. Mr. Sheppard discussed in detail the boiler optimization controls and separated over fire air projects previously installed by the Company and the proposed future projects consisting of mercury controls, scrubbers, fabric filters, and land fill projects to meet regulatory requirements. Mr. Sheppard concluded the presentation by reporting the Company has a multi-pollution control plan, and it is his expectation that the plan will firm up in the near future.

Mr. Robert L. Powers entered into a general discussion regarding the Company's collective bargaining agreement. Mr. Powers reported the Company would like to extend the existing labor contract for a period of one to two years.

It was agreed that the next Board of Directors' meeting would be held on Friday, October 27, 2006, at the St. Louis Airport Hilton Hotel in St. Louis, Missouri, at 10:00 a.m. Central Time.

There being no further business, upon motion duly made and seconded, the meeting was adjourned.

Secretary

Electric Energy, Inc.

Earnings Report

October 27, 2006

	Earnings Per Share	3rd Qtr. 2006	YTD 2006	October 2005 Through September 2006	3rd Qtr. 2005
Component D	$ 0.00	$ 0	$ 0	$ 331,293	$ 331,293
Met-South, Inc.	1.44	88,998	334,497	414,830	110,363
Midwest Electric Power, Inc.	0.06	3,750	11,250	244,026	3,750
Excess Energy	0.00	0	0	0	0
Additional Power	0.00	0	0	11,659	0
Permanent Joppa Power	0.00	0	0	1,971,926	2,169,314
Emission Allowances	291.63	18,081,132	18,373,929	28,886,526	0
Contract Sales	613.45	38,034,388	92,983,560	92,983,560	0
Total	$ 906.58	$ 56,208,268	$ 111,703,236	$ 124,843,820	$ 2,614,720

Met South, Inc. - EEI's ash subsidiary.

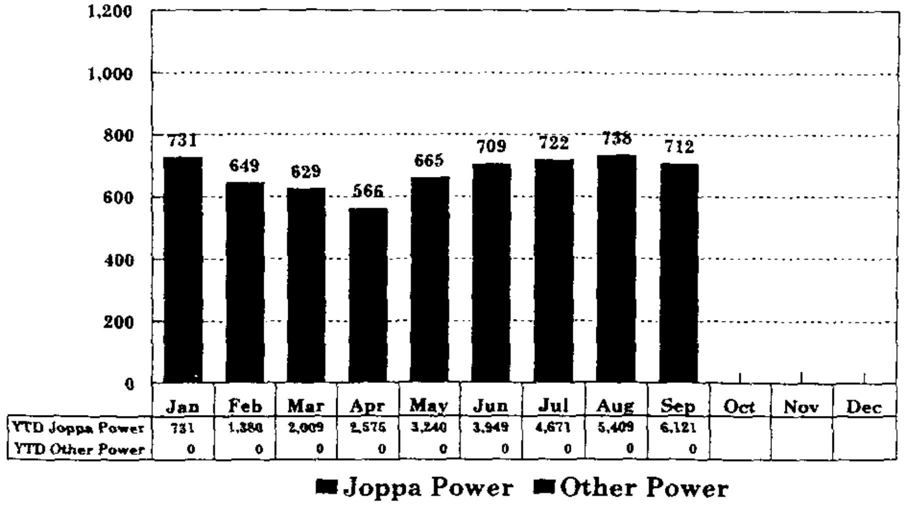
Midwest Electric Power, Inc. - EEI's gas-fired combustion turbine facility.

Contract Sales - New Power Supply Agreement (PSA) beginning 01/01/06.

2006 Sales

MWH

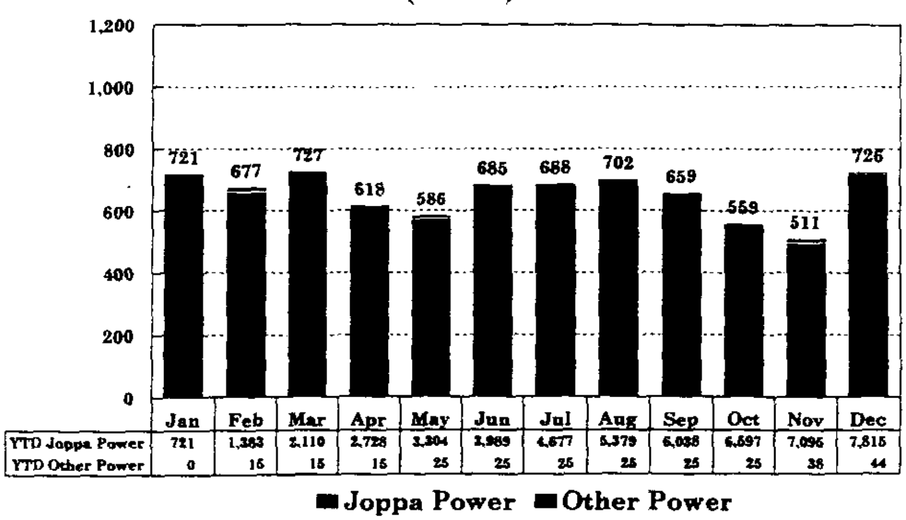
(000's)



2005 Sales

MWH

(000's)



Electric Energy, Inc.

Emission Allowances

Past Sales

	SO_2		NO_X		Total	
Year	Number of Allowances	Net Allowance Earnings *	Number of Allowances	Net Allowance Earnings *	Number of Allowances	Net Allowance Earnings *
2006	49,714	$17,956,964.57	400	$416,964.60	50,114	$18,373,929.17
2005	825	$262,711.67	0	$0.00	825	$262,711.67
2004	839	$105,300.63	800	$1,106,161.98	1,639	$1,211,462.61
2003	30,339	$2,969,390.32	1,095	$3,124,183.92	31,434	$6,093,574.24
2002	150,839	$15,435,824.59	2,500	$7,540,000.00	153,339	$22,975,824.59
2001	839	$72,338.67	0	$0.00	839	$72,338.67
2000	839	$50,598.46	0	$0.00	839	$50,598.46
1999	2,235	$272,976.07	0	$0.00	2,235	$272,976.07
Total	236,469	$37,126,104.98	4,795	$12,187,310.50	241,264	$49,313,415.48

Current Bank of Allowances

	SO_2	NO_X
2006 Beginning Balance	48,695	123
Allowance Allocations	28,992	2,804
Estimated Emissions	(26,240)	(2,392)
Allowance Sales	(48,875)	(400)
Estimated 2006 Ending Balance	2,572	135

Summary of 3rd Quarter 2006 Sales (included above)

	SO_2		NO_X		Total	
	Number of Allowances	Net Allowance Earnings *	Number of Allowances	Net Allowance Earnings *	Number of Allowances	Net Allowance Earnings *
ctual	48,875	$17,664,167.20	400	$416,964.60	49,275	$18,081,131.80

Net Allowance Earnings = Gross Amount less Taxes & Commission Fees

10/23/06
9:55 AM
3.1

Proposed Power Supply Amendment

Background:

- EEI entered into Power Supply Amendment (PSA) December 22, 2005 with Ameren Energy Marketing

- EEI entered into PSA Amendment 1 on July 20, 2006, to clarify pricing mechanism for forward pricing from megawatt Cenergy Index to the Intercontinental Exchange (ICE)

- Historically power contracts have been authorized by the Board of Directors

Discussion:

- Proposed PSA Amendment 2 and Board Resolution to:
    - Increase forward contract amount
    - Increase contract duration – 18 months ⇒ 4 years
    - Lengthen the time of the termination clause
    - Clarify pricing provision for forward contract
    - Clarify energy allocation, i.e. schedule reduction
    - Document amendment

- Proposed Board Resolution
    - Documents for the record Amendment 1, previously entered into on July 20, 2006
    - Approves and authorizes the execution of Amendment 2

- Authorizes officer(s) to enter into current Amendment

Resolution of the Board of Directors

of Electric Energy, Inc.

WHEREAS, Electric Energy, Inc. is the Seller in that certain Power Sales Agreement dated December 22, 2005 (hereinafter "Agreement") by and between Electric Energy, Inc. and Ameren Energy Marketing Company; and,

WHEREAS, the Parties amended the Agreement on the 20th day of July, 2006, to codify new terms and conditions under which Seller shall price Energy purchased by Buyer under the Agreement for purposes of supplying Forward Contracts; and

WHEREAS, the Parties desire to further amend the Agreement in order to codify new terms and conditions in accordance with the terms set forth in the proposed Second Amendment to the Agreement, which has been presented to Board; and

WHEREAS, it is the determination of the Board that such amendment is to the benefit of Electric Energy, Inc.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of Electric Energy, Inc. that the terms substantially set forth in Second Amendment to the Power Sales Agreement are hereby APPROVED; and,

BE IT FURTHER RESOLVED that the Chairman, the President, and any other officers of the Company, are authorized and directed to execute any documents or instruments, to deliver and file or record any such documents or instruments, and to take all action necessary or convenient to effect the purposes thereof; and,

BE IT FURTHER RESOLVED that the Secretary of the Company shall place this resolution in the minutes of the Meeting at which it was adopted, and shall place such minutes on file with the corporate book of the Company.

10/27/06
4.2

2007 - 2009

Budget Presentation

October 27, 2006

Presentation Summary

2007 Budget Now Compared to 2005 Submittal

- 2007 O&M less fuel costs are now slightly less than stated in 2005.

- 2007 capital costs increased by $3.082M, primarily because changes in the IEPA Mercury rules. Projects added for Mercury equal $2.927M.

- 2007 fuel consumed increased by $9M due to higher plant utilization projections.
    - In 2007, Fuel will be 67% of the total budget.
    - In 2005, Fuel will be 62% of the total budget.

- Total busbar cost for 2007 increased from $21.67/MWH (2005 submittal) to $22.20/MWH.

Capital Ten Year Plan for 2007 Budget

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Ten Year Total
Unit Outage	3	1	4	2	6	5	3	1	4	2	
Number of Days	43	80	75	70	77	77	85	70	70	70	

Environmental Projects

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Ten Year Total
2069	Air Pollution Control for SO2	$500,000	$6,375,000	$25,711,000	$52,964,000	$81,830,000	$77,261,000	$28,938,000	$0	$0	$0	$273,579,000
2030	Air Pollution Control for Mercury	700,000	5,200,000	3,528,000	0	0	0	20,662,000	49,657,000	0	0	79,747,000
2983	NOx Reduction Boiler Modifications	2,652,714	2,731,735	2,812,825	2,897,150	0	0	0	0	0	0	11,094,424
2084	Landfill for Multipollutant Waste	360,000	500,000	2,840,000	4,800,000	0	0	0	0	0	0	8,500,000
2995	Cooling Water Intake 316(b) Study	100,000	2,800,000	100,000	0	0	0	0	0	0	0	3,000,000
2107	Mercury Control with MinPlus Sorbent Injection	2,017,043	0	0	0	0	0	0	0	0	0	2,017,043
2108	Install Mercury Monitoring Equipment	250,000	150,000	0	0	0	0	0	0	0	0	400,000
2100	Purchase Mercury Analysis Equipment for the Lab	87,335	0	0	0	0	0	0	0	0	0	87,335
	Subtotal	$6,667,092	$17,756,735	$34,991,825	$60,661,150	$81,830,000	$77,261,000	$49,600,000	$49,657,000	$0	$0	$378,424,802

Major Projects

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Ten Year Total
3118	Replace Air Pre-heaters	$0	$6,700,000	$7,080,000	$7,470,000	$7,910,000	$8,360,000	$8,850,000	$0	$0	$0	$46,370,000
[redacted]	[redacted]	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	43,312,000
[redacted]	[redacted]	0	[redacted]	[redacted]	[redacted]	0	0	[redacted]	0	0	0	22,980,000
3119	Replace Economizer Hoppers	0	1,860,000	1,993,000	2,132,000	2,283,000	2,446,000	2,621,000	0	0	0	13,335,000
[redacted]	[redacted]	0	[redacted]	[redacted]	[redacted]	0	0	0	0	0	0	10,682,000
3039	Repair Bottom Ash Hopper	0	0	0	0	1,479,000	1,585,000	1,702,000	1,829,000	1,956,000	2,104,000	10,655,000
2101	Main Power Transformer Replacements	0	0	237,500	855,500	1,150,300	1,184,700	1,218,900	1,254,100	1,293,400	1,334,600	8,529,000
3029	Hydrojets	0	1,165,000	1,165,000	225,000	1,165,000	1,165,000	1,165,000	0	0	0	6,050,000
2058	Rail Crossing Overpass	0	0	0	4,500,000	0	0	0	0	0	0	4,500,000
3048	DCS(Distributed Control System) Upgrade to Ovation	900,000	870,000	870,000	870,000	0	0	0	0	0	0	3,510,000
3995	iring Replacement	100,000	250,000	1,511,568	1,467,510	0	0	0	0	0	0	3,329,078
2113	Expansion	200,000	1,000,000	0	0	0	0	0	0	0	0	1,200,000
	Subtotal	$1,200,000	$20,245,000	$21,801,068	$27,058,010	$20,067,300	$21,230,700	$29,266,900	$10,492,100	$11,173,400	$11,917,600	$174,452,078

Schedule MLB-12
Page 21 of 35

5.4

Fuel

2007 - 2009 Budget
Line Item Categories

Area	2005 Actual	2006 Projection	2007 Budget	2008 Budget	2009 Budget
A) Net Generation MWH	7,881,897	8,207,136	8,235,000	8,092,000	8,075,000
B) Cost of coal consumed	$36,435,572	$41,209,122	$47,824,225	$52,935,854	$53,197,450
$/MWH	$4.62	$5.02	$5.81	$6.54	$6.59
Freight	44,092,068	60,145,187	66,733,270	67,541,260	82,146,607
$/MWH	$5.59	$7.32	$8.10	$8.35	$10.16
C) Labor	983,909	1,126,772	1,177,651	1,193,662	1,240,487
$/MWH	$0.12	$0.14	$0.14	$0.15	$0.15
D) Supplies	638,443	781,346	779,328	784,116	788,090
$/MWH	$0.08	$0.10	$0.09	$0.10	$0.10
E) Railcar & Track Depr.	281,968	4,286	2,990	2,724	2,368
$/MWH	$0.04	$0.00	$0.00	$0.00	$0.00
F) Gas Line Depreciation	44,528	44,491	44,496	44,568	44,491
$/MWH	$0.01	$0.01	$0.01	$0.01	$0.01
G) Equipment Lease*	233,571	435,800	522,504	525,004	527,500
$/MWH	$0.03	$0.05	$0.06	$0.06	$0.07
H) Other J&E Expenses **	3,403,485	4,566,500	4,672,204	4,739,500	4,808,700
$/MWH	$0.43	$0.56	$0.57	$0.59	$0.60
I) Oil and Gas	2,035,900	1,634,698	2,211,450	2,219,204	2,150,489
$/MWH	$0.26	$0.20	$0.27	$0.26	$0.27
Total	$88,149,444	$109,948,202	$123,968,118	$129,985,892	$144,906,182
$/MWH	$11.18	$13.40	$15.05	$16.06	$17.95

2005 Equipment Lease reflects a $90k maintenance rebate on lease equipment, 2006-2008 includes additional leased equipment needed to support the increased coal inventory levels.
Leased 214 additional GE cars and additional cars are leased from Ameren as needed.

10/27/06

Operations

- Mercury sorbent injection for testing purposes begins 7/1/07 ($780k.) This amount will increase to $5.5M in 2009 when we begin sorbent injection on all units.

- Salaried labor increased due to:
  - Promotion of two supervisors to superintendents
  - Hiring an additional training supervisor
  - Hiring an additional Fuel Processing Supervisor to train for a retirement
  - Hiring three additional Operations Supervisors to strengthen performance assessment program, prepare for scrubber operations, and to train for future personnel retirements.

Maintenance

- Additional work in 2007 on Unit 3 outage compared to similar work on Unit 5 in 2006.
    - Guardian packing & spill strips costing $527k, for a difference of $466k.
    - Boiler tie-back repairs +$332k.
    - Boiler stationary coal nozzles and elbows +$220k.
    - Chemical cleaning +$145k.
    - DMW FSH rows 2 & 3 +$227k.
    - Other boiler outage work +$196k.
    - Other turbine outage work +$252k.
    - Air heater baskets +$350k.

A&G

- Healthcare increased 36% from the 2005 Actual.
- Pension increased 39% from the 2005 Actual.
- Property Insurance premium increased 76% from the 2005 Actual (61% premium increase, 15% new terrorism policy).
- New insurance policy in 2007 for Generation Loss ($150k).

Note: Source of cash is positive, use of cash is in ( )

Electric Energy, Inc. (Consolidated)
Statement of Projected Cash Flow 2006-2015

($ in 000's)

	Actual 2005	Projected 2006	Budget 2007	Budget 2008	Budget 2009	Est. 2010	Est. 2011	Est. 2012	Est. 2013	Est. 2014	Est. 2015
Beginning Cash	222	354	500	500	500	500	500	500	500	500	500
Net Cash Inflows:											
(1) **Net income**	**21,116**	**135,818**	**125,788**	**121,174**	**102,753**	**95,502**	**98,726**	**88,817**	**101,137**	**118,239**	86,728
(2) Tax benefit trans. improv.	263	243	227	223	223	223	223	223	223	223	223
(3) Tax benefit CT depreciation	326	278	275	275	275	276	276	276	276	276	(140)
(4) Tax benefit S'line depreciation	0	150	400	912	1,714	2,374	2,516	5,827	12,186	14,992	16,094
(5) Tax benefit turbine rotor expense	763	541	406	1,409	(97)	235	753	(136)	184	1,519	4,759
(6) Short-term borrowings	0	0	0	0	0	0	0	0	0	0	0
(7) Increase in Ameren loan	19,900	25,613	0	8,393	36,960	61,307	74,573	66,700	41,834	16,235	0
(8) **Depreciation (less removal)**	**7,616**	**5,616**	**5,983**	**6,701**	**7,440**	**8,013**	**9,086**	**11,327**	**15,832**	**18,217**	19,529
(9) Depreciation CT's	1,560	1,558	1,541	1,535	1,530	1,528	1,528	1,528	1,528	1,528	1,526
(10) Depreciation rail cars	306	4	3	3	0	0	0	0	0	0	0
Total Inflows	51,850	169,821	134,623	140,626	150,798	169,458	187,682	174,563	173,200	171,231	128,719
Net Cash Outflows:											
(11) Dividends	0	(137,500)	(107,000)	(103,000)	(87,000)	(81,000)	(84,000)	(75,000)	(86,000)	(100,000)	(74,000)
(12) Capital expenditures EEI	(7,617)	(6,804)	(5,808)	(26,365)	(24,008)	(31,412)	(23,669)	(22,592)	(32,182)	(15,804)	(24,919)
(13) **Capital exp./Multi. pollutant control**	**(2,230)**	**(2,849)**	**(6,667)**	**(17,757)**	**(34,992)**	**(60,661)**	**(81,830)**	**(77,261)**	**(49,600)**	**(49,657)**	0
(15) Capital expend. subsidiaries	(26)	(7)	(266)	(200)	(25)	0	0	0	0	0	0
(15) Tax cost trans. improv.	0	0	0	0	0	0	0	0	0	0	0
(16) Chngs in curr assets & liab.	10,724	(22,514)	(1,811)	6,696	(4,773)	3,615	1,817	290	(5,418)	(5,770)	(3,663)
(17) Repayments of s.t. debt	(38,125)	0	0	0	0	0	0	0	0	0	0
(18) Repayments of Ameren loan	0	0	(13,071)	0	0	0	0	0	0	0	(26,137)
(19) Repayments of l.t. principal	(14,444)	0	0	0	0	0	0	0	0	0	0
(20) Repayment of add'l l.t. financing	0	0	0	0	0	0	0	0	0	0	0
Total Outflows	(51,718)	(169,674)	(134,623)	(140,626)	(150,798)	(169,458)	(187,682)	(174,563)	(173,200)	(171,231)	(128,719)
Net Cash Flow	132	146	0	(0)	(0)	(0)	(0)	0	0	(0)	(0)
Ending Cash Balance	**354**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**

ASSUMPTIONS: After 2005, sales are at market rates: 2006 $42.60/MWH, 2007 $46.47/MWH, 2008 $46.93/MWH, and 2009 $46.30/MWH.
Beginning in 2007, dividends are declared and paid quarterly, at approximately 85 percent of earnings.
Ameren loan increases to $338M max in 2014.
MACRS depreciation in '05 (50% bonus '04; half-year convention), then straight-line, generally over 33 years.

5.13

ud07-08 10-23 10/23/2006

Electric Energy, Inc. (Consolidated)
Projected Balance Sheet 2005-2015

($ in 000's)

	Actual 2005	Projected 2006	Budget 2007	Budget 2008	Budget 2009	Est. 2010	Est. 2011	Est. 2012	Est. 2013	Est. 2014	Est. 2015
Assets											
(1) Plant In Service,CWIP	470,389	480,049	492,790	537,112	596,137	688,210	793,709	893,562	975,344	1,040,805	1,065,724
(2) Less Accum. Depr.	(379,737)	(386,915)	(394,442)	(402,682)	(411,652)	(421,193)	(431,807)	(444,662)	(462,022)	(481,767)	(502,822)
Net Plant	90,652	93,134	98,348	134,430	184,485	267,017	361,902	448,900	513,322	559,038	562,902
(3) Cash & Cash Equivalents	354	500	500	500	500	500	500	500	500	500	500
(4) Accounts Receivable	26,184	30,461	31,477	31,481	32,411	32,983	34,079	33,440	36,321	39,692	36,197
(5) Fuel Inventory	**10,449**	**14,722**	**18,684**	**18,755**	**26,639**	**27,438**	**28,261**	**29,109**	**29,982**	**30,881**	**31,807**
(6) Material Inventory-EEI	7,645	7,000	7,000	7,000	7,000	9,000	9,000	9,000	9,000	9,000	9,000
(7) Material Inventory-Subs.	264	272	280	288	297	306	315	324	334	344	355
(8) Prepayments,Other Assets	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834
(9) Deferred Tax Trans. Improv.	3,246	3,003	2,776	2,553	2,330	2,107	1,884	1,661	1,438	1,215	992
(10) Deferred Tax CT Deprec.	(3,184)	(3,462)	(3,737)	(4,012)	(4,287)	(4,563)	(4,839)	(5,115)	(5,391)	(5,667)	(5,527)
(11) Deferred Tax S'line Deprec.	0	(150)	(550)	(1,462)	(3,176)	(5,550)	(8,066)	(13,893)	(26,079)	(41,071)	(57,165)
(12) Deferred Tax Turbine Rotors	(768)	(1,309)	(1,715)	(3,124)	(3,025)	(3,260)	(4,013)	(3,877)	(4,061)	(5,580)	(10,339)
(13) Deferred Tax Asset	10,235	9,723	9,237	8,775	8,336	7,920	7,524	7,148	6,790	6,451	6,128
Total Assets	147,911	156,729	165,133	198,018	254,345	336,732	429,381	510,032	564,991	597,636	577,684
Liabilities											
(14) Short Term Loan	0	0	0	0	0	0	0	0	0	0	0
(15) Accounts Payable	27,390	11,913	14,249	20,055	23,068	28,943	31,553	30,997	28,380	26,068	19,731
(16) Accrued Interest	69	106	113	262	476	774	1,083	1,320	1,447	1,426	685
(17) Dividends Payable	0	0	0	0	0	0	0	0	0	0	0
(18) Ameren Loan	**19,900**	**45,513**	**32,442**	**40,835**	**77,795**	**139,102**	**213,675**	**280,375**	**322,209**	**338,444**	**312,307**
(19) 1991 Senior Notes (8.6%)	0	0	0	0	0	0	0	0	0	0	0
(20) 1994 Senior Notes (6.61%)	0	0	0	0	0	0	0	0	0	0	0
(21) Add'l Senior Notes	0	0	0	0	0	0	0	0	0	0	0
(22) Other Liabilities	11,778	12,105	12,450	12,814	13,199	13,605	14,034	14,487	14,965	15,470	16,003
Total Liabilities	59,137	69,637	59,254	73,965	114,539	182,423	260,345	327,179	367,002	381,408	348,726
Stockholders' Equity											
(22) Common Stock	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200
(23) Retained Earnings	**82,574**	**80,892**	**99,680**	**117,854**	**133,607**	**148,109**	**162,836**	**176,653**	**191,790**	**210,029**	**222,758**
	88,774	87,092	105,880	124,054	139,807	154,309	169,036	182,853	197,990	216,229	228,958
Total Liabilities & Stockholders Equity	147,911	156,729	165,133	198,018	254,345	336,732	429,381	510,032	564,991	597,636	577,684

ASSUMPTIONS: After 2005, sales are at market rates: 2006 $42.60/MWH, 2007 $46.47/MWH, 2008 $46.93/MWH, and 2009 $46.30/MWH.
Beginning in 2007, dividends are declared and paid quarterly, at approximately 85 percent of earnings.
Ameren loan increases to $338M max in 2014.
MACRS depreciation in '05 (50% bonus '04; half-year convention), then straight-line, generally over 33 years.

Electric Energy, Inc. (Consolidated)
Projected Income Statement 2005-2015

($ in 000's)

		Actual 2005	Projected 2006	Budget 2007	Budget 2008	Projected 2009	Est. 2010	Est. 2011	Est. 2012	Est. 2013	Est. 2014	Est. 2015
Operating Revenues		174,779	369,696	403,490	400,571	394,370	401,232	414,386	406,727	441,297	481,740	439,801
Operating Expenses												
(1)	Fuel Costs	91,626	110,447	124,693	130,697	145,617	149,964	154,442	159,054	163,804	168,697	173,737
(2)	Purchased Power	1,852	5,442	5,442	5,442	5,442	5,442	5,442	5,442	5,442	5,442	5,442
(3)	Operations	8,371	9,810	11,241	11,201	16,364	20,978	21,349	21,210	20,652	20,248	20,763
(4)	SO_2 Allowance Purchases	0	0	0	0	0	7,800	7,800	5,400	420	0	540
(5)	NO_X Allowance Purchases	0	0	0	0	1,066	918	918	918	918	918	2,296
(6)	A&G	18,295	16,414	18,118	18,555	19,526	20,111	20,714	21,336	21,975	22,634	23,313
(7)	Maintenance	17,708	18,448	21,322	19,364	19,834	20,574	21,191	22,664	25,065	26,705	27,506
(8)	Trans. & Sys.	1,751	2,349	2,254	2,218	2,247	2,314	2,384	2,455	2,529	2,605	2,683
(9)	Depreciation Expense	14,435	7,716	7,627	8,397	9,167	9,761	10,834	13,075	17,580	19,946	21,223
(10)	Interest Expense	2,247	1,083	1,154	687	1,714	1,968	2,437	4,713	11,813	14,833	14,992
(11)	Other Expenses	(713)	(417)	(301)	(305)	(278)	(256)	(231)	(205)	(178)	(149)	(119)
(12)	Taxes Besides Income Taxes	2,117	2,174	2,294	2,358	2,416	2,487	2,561	2,637	2,715	2,795	2,878
(13)	Income Taxes @ 40% Effective Rate	6,487	78,492	83,858	80,783	68,502	63,668	65,818	59,211	67,425	78,826	57,819
	Total Expenses	164,176	251,958	277,702	279,397	291,617	305,730	315,660	317,910	340,160	363,501	353,073
Net Income Before Allowance Sales		10,603	117,738	125,788	121,174	102,753	95,502	98,726	88,817	101,137	118,239	86,728
Proceeds - SO_2 sales (net of income taxes)		9,789	17,663									
Proceeds - NOx sales (net of income taxes)		724	417									
Net Income After Allowance Sales		21,116	135,818	125,788	121,174	102,753	95,502	98,726	88,817	101,137	118,239	86,728

ASSUMPTIONS:

After 2005, sales are at market rates: 2006 $42.60/MWH, 2007 $46.47/MWH, 2008 $46.93/MWH, and 2009 $46.30/MWH.

Beginning in 2007, dividends are declared and paid quarterly, at approximately 85 percent of earnings.

Ameren loan increases to $338M max in 2014.

MACRS depreciation in '05 (50% bonus '04; half-year convention), then straight-line, generally over 33 years.

Electric Energy, Inc. (Consolidated)
Projected Revenue 2005-2015
($ in 000's)

	Projected 2006	Budget 2007	Budget 2008	Budget 2009	Est. 2010	Est. 2011	Est. 2012	Est. 2013	Est. 2014	Est. 2015
EEI Market Based:										
Net Generation MWH	8,211	8,239	8,096	8,079	8,072	8,071	8,099	8,013	8,047	8,068
Rate per MWH	$42.60	$46.47	$46.93	$46.30	$47.17	$48.80	$47.68	$52.50	$57.29	$51.94
EEI Market Based Revenue $	349,762	382,900	379,960	374,058	380,756	393,865	386,160	420,683	461,013	419,052
Capacity Revenue, New Contract	12,024	12,024	12,024	12,024	12,024	12,024	12,024	12,024	12,024	12,024
Additional Power	0	0	0	0	0	0	0	0	0	0
Facilities Use Charge, DOE	315	315	315	315	315	315	315	315	315	315
Coal Inv. Adj. from 2005 to Sponsors	(655)	0	0	0	0	0	0	0	0	0
Met South	1,600	1,578	1,578	1,262	1,407	1,433	1,460	1,487	1,578	1,578
Midwest Electric Power	721	744	765	782	801	820	839	859	881	903
Emission Allowances Auction	487	487	487	487	487	487	487	487	487	487
Open Access Transmission (offset in exp.)	5,442	5,442	5,442	5,442	5,442	5,442	5,442	5,442	5,442	5,442
Total Revenue	369,696	403,490	400,571	394,370	401,232	414,386	406,727	441,297	481,740	439,801

Revenue above excludes EEI initiated sales of emission allowances that are reported separately, net of tax, on the income statement.

CFLW bud07-08 10-23 10/23/2006

Electric Energy, Inc.
Projected Capital Expenditures

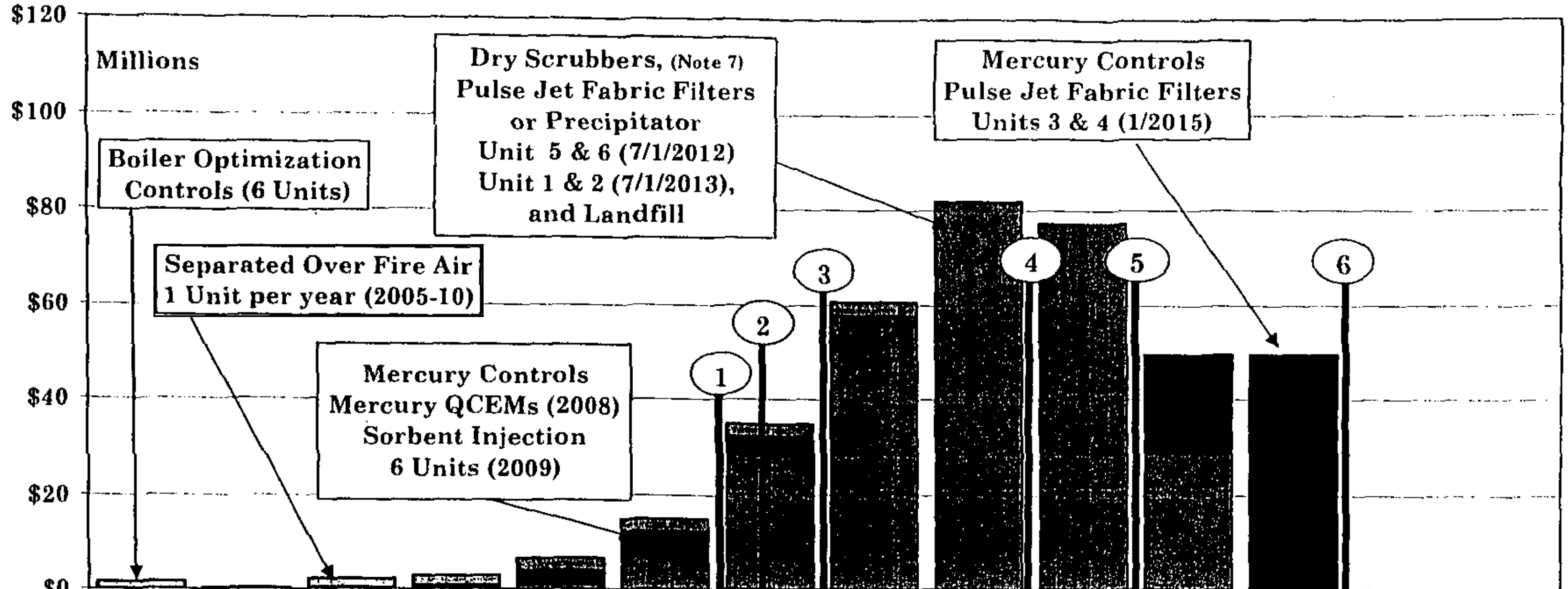
	2006	2007	2008	2009
2006 Budget	$9,372,000	$9,393,000	$20,379,000	$34,500,000
2006 Projected	$10,226,000			
2007 Budget		$12,475,000	$44,122,000	$59,000,000
Difference	$854,000	$3,082,000	$23,743,000	$24,500,000

Changes from 2006 budget

	2007	2008	2009
Mercury schedule moved up from 1/2010 to 7/2009 and additional sorbent testing	$2,654,000	$729,000	($3,782,000)
Studies for permiting and developing future landfill	$360,000	$275,000	($660,000)
Scrubber installation moved from 2011, 2012, 2014 and 2016 to 2 in 2012 and 2 in 2013 to meet rates stipulated in the Ameren/IEPA agreement	$200,000	$5,875,000	$19,154,000
Total MPC project change	$3,214,000	$6,879,000	$14,712,000
Replace LPDF rotor, Unit 5	$500,000	$1,800,000	
Air Pre-heaters (1 per year)		$6,700,000	$7,080,000
Penthouse Links (1 per year)		$5,100,000	$5,390,000
Backpass casing (1 per year)		$3,300,000	$3,554,000
Economizer Hoppers (1 per year)		$1,860,000	$1,993,000
Rail crossing overpass			($1,000,000)
Total	$3,714,000	$25,639,000	$31,729,000

Multi-Pollutant Capital Expenditure Plan

(2007 Budget Plan)



	2001-3	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Total	Cost per KW-net
☐ NOx	$1.6	$0.0	$2.0	$2.3	$2.7	$2.7	$2.8	$2.9	$0.0	$0.0	$0.0	$0.0	$16.9	$16.7
■ Mercury		$0.3	$0.2	$0.4	$3.1	$5.4	$3.5	$0.0	$0.0	$0.0	$20.7	$49.7	$83.2	$82.2
⊟ SO2		$0.0	$0.0	$0.2	$0.9	$6.9	$28.6	$57.8	$81.8	$77.3	$28.9	$0.0	$282.3	$278.9
Total	$1.6	$0.3	$2.2	$2.9	$6.6	$15.0	$34.9	$60.7	$81.8	$77.3	$49.6	$49.7	$382.4	$377.8

Estimated Clean Air Interstate (CAIR) with IEPA/Ameren Mercury Rule and 30% NOx Set Aside Emission Limits

1. 2009 NOx Ozone Season 1,815 tons (0.093 lb/mmbtu); NOx Annual Limit 4,619 tons (0.104 lb/mmbtu).
2. 2009 July Mercury Halogenated Activated Carbon Injection (minimum 5 lb/macf)
3. 2010 SO2 50% reduction (0.5 ton/1 ton allowance)
4. 2012 Ameren Group NOx average emission rate of 0.11 lb/mmbtu
5. 2013 Ameren Group SO2 average emission rate of 0.33 lb/mmbtu
6. 2015 NOx Ozone Season 1,713 tons (0.088 lb/mmbtu); NOx Annual Limit 3,850 tons (0.087 lb/mmbtu); SO2 65% reduction (.35 ton/1 ton allowance); Mercury 90% reduction or less than 0.008 lb/GWh; and Ameren Group SO2 average emission rate of 0.25 lb/mmbtu
7. Based on current analysis, dry scrubbing may be the lowest overall cost. Wet scrubbing is still an option and under consideration in our evaluation. Scrubbing of additional units may be considered based on economic evaluation.

Suggested Meeting Dates for 2007

1st Meeting (Phone)	2nd Meeting (St. Louis)	3rd Meeting (Phone)	4th Meeting (St. Louis)
February 2 - No	May 4 - Yes	July 20 - Yes	October 26 - Yes
February 9 - Ameren BoD - Yes	May 11 - Yes	July 27 - Yes	November 2 - Yes
February 16 - No	May 18 - Yes	August 3 - Yes	November 16 - Yes

2007

JANUARY

S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30	31			

FEBRUARY

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28			

MARCH

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

APRIL

S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30					

MAY

S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30	31		

JUNE

S	M	T	W	T	F	S
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30

JULY

S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30	31				

AUGUST

S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30	31	

SEPTEMBER

S	M	T	W	T	F	S
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30						

OCTOBER

S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30	31			

NOVEMBER

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	

DECEMBER

S	M	T	W	T	F	S
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30	31					

Officers' Salary

Recommendation

Other

Agenda

October 27, 2006

1.	Approve Minutes of Meeting Held July 21, 2006	Approval
2.	Earnings Report	Information
3.	Status Report of Emission Allowance Sales	Information
4.	Proposed Revision to Power Supply Agreement	Approval
5.	2007-2009 Operating Budget Presentation	Information
6.	2007-2009 Capital Budget Presentation	Approval
7.	Suggested Meeting Dates for 2007:	Information

1st Meeting (Phone)	2nd Meeting (St. Louis)	3rd Meeting (Phone)	4th Meeting (St. Louis)
February 2	May 4	July 20	October 26
February 9	May 11	July 27	November 2
February 16	May 18	August 3	November 16

8.	Officers' Salary Recommendation	Approval
9.	Other	