DRAFT

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

PREHEARING BRIEF OF THE OFFICE OF THE PUBLIC COUNSEL

INTRODUCTION

On July 7, 2006, Union Electric Company d/b/a AmerenUE filed with the Missouri Public Service Commission tariffs seeking a general rate increase in its retail electric rates. The Commission suspended those tariffs on July 11, 2006, and set two weeks of evidentiary hearings to be held in this case during the weeks of March 12 and March 19, 2007.

On September 12, 2006, the Commission adopted a procedural schedule in this case, set the test year as the 12 months ending June 30, 2006, with a true-up for certain items as of January 1, 2007, and scheduled an additional week of evidentiary hearings during the week of March 26, 2007.

On September 29, 2006, AmerenUE filed Direct Testimony respecting its requested fuel adjustment clause ("FAC") and a related FAC tariff, together with Supplemental Direct Testimony to update the three-months of budgeted data included in its original filing to actual data for the last three months of the test year adopted by the Commission.

Pursuant to the Procedural Order, the Staff, with input from the other parties, assembled the statement of the issues. Not all parties agreed upon the phrasing of the issues, and the Staff was the final arbiter of disagreements over the wording of the issues (as well as the scheduling of issues and witnesses).

This brief will only address in detail the issues on which Public Counsel is sponsoring witnesses and testimony. As filed, dozens of issues were raised in the parties' testimony, and Public Counsel has not analyzed all of them in order to take a position. This brief will, on issues other than those of Public Counsel witnesses, indicate Public Counsel's position. On a number of issues, Public Counsel has not yet developed a position. Public Counsel reserves the right to support issues raised by other parties at the hearing or in post-hearing briefs.

ISSUES[1]

Overview and Policy*: In addition to "cost of service," what policy considerations should guide the Commission in deciding this case?*

Other than the sheer magnitude of the difference in revenue requirement between AmerenUE and the other parties, this case is not too terribly different from any other rate case. For instance, there are issues in which AmerenUE has acted to benefit itself to the detriment to its ratepayers, and the parties representing those ratepayers seek to have the Commission address those actions in this case. Electric Energy, Inc. (EEInc.) is an example of such an issue (it will be discussed in greater detail below). AmerenUE opted to not pursue renewal of the decades-old arrangement by which the owners of the Joppa plant received the available power from that plant at cost. Instead, it opted to allow its corporate parent, Ameren Corporation, to generate more profits by selling that power on the market. AmerenUE made an adjustment to its test year books to remove the benefits of the EEInc. power, and Public Counsel (and the Staff and the

[1] This brief was begun before the list of issues was finalized and filed. As a result, there may be some minor differences between the way the issues are defined in this brief and the way they are defined in Staff's March 6 filing of the list of issues. The issues are set forth in italics. Public Counsel's position on each of those issues is set forth in regular type.

State of Missouri) seek to have the Commission reverse that adjustment. This is typical of many of the issues in this case, and is typical of the types of issues generally raised in rate cases.

One new issue that has definite policy implications is the issue concerning the fuel adjustment clause (FAC). While there are policy considerations specific to the issues on the FAC, and the Commission should address them clearly in this case of first impression, there are no "overarching" policy considerations that should steer the Commission in this case in a direction different than it has historically taken.

The historical policy considerations, and the approach the Commission should take in this case, all involve the Commission's role as the protector of the public. AmerenUE is a monopoly, and the sole reason that the Commission exists is to protect the public from the power of monopoly utilities. "The Act establishing the Public Service Commission is indicative of a policy to protect the public. The protection given the utility is incidental." State ex rel. Dail v. Public Service Com., 240 Mo. App. 250, 251 (Mo. Ct. App. 1947). "[T]he guiding star of the public service commission law and the dominating purpose to be accomplished by such regulation is the promotion and conservation of the interests and convenience of the public." State ex rel. Crown Coach Co. v. Public Service Com., 238 Mo. App. 287, 298 (Mo. Ct. App. 1944). "The Commission's principal interest is to serve and protect ratepayers…" State ex rel. Capital City Water Co. v. Missouri Pub. Servs. Comm'n, 850 S.W.2d 903, 911 (Mo. Ct. App. 1993). It cannot be disputed that these cases set forth the policy considerations that should guide the Commission's decision in this case.

Pinckneyville and Kinmundy*: What amount should be included in rate base for AmerenUE's purchase of these CTG plants from affiliated companies?*

This issue pertains to the cost at which AmerenUE acquired from its affiliate Ameren Generating Resources (AEG) the gas-fired generating stations at Pinckneyville and Kinmundy.

This transaction was completed on May 2, 2005. AmerenUE acquired the Pinckneyville facility for $502/kW and acquired the Kinmundy facility for $412/kW. Both of these prices appear to be well above the market value of the facilities. Public Counsel, in the direct testimony of Ryan Kind at page 35, recommends using for ratemaking purposes the blended cost of $193.80/kW of the recently acquired Audrain, Goose Creek, and Raccoon Creek Plants.

***Peno Creek**: What amount should be included in rate base for AmerenUE's construction purchase of this CTG plant?*

Public Counsel recommends that the gross value of this plant reflected in AmerenUE's revenue requirement be reduced from the gross plant amount associated with the $550/kW all inclusive construction cost to $390/kW. (Kind Direct, p. 30). The source of the $390/kW figure is a benchmark figure presented by AmerenUE for the cost of constructing new gas-fired generation in Case No. EA-2000-37. Public Counsel witness Ryan Kind explains the rationale for applying this figure to the Peno Creek plant:

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

AmerenUE does not dispute that Peno Creek was built on an expedited basis. Common sense, as well as the evidence produced by Public Counsel, should convince the Commission that there are costs associated with a significant construction project built on a "hurry-up" basis. Those costs are clearly shown in the $550/kW that AmerenUE paid for the plant. The Commission should adopt Public Counsel's much more reasonable $390/kW figure.

Return on Equity: *What return on equity should be used in determining revenue requirement?*

Based on the analyses presented in the testimony of Public Counsel witness Charles King, the Commission should find that the appropriate return on equity (ROE) is 9.65 percent.

Mr. King's return on equity is based on his Discounted Cash Flow (DCF) analysis. The DCF analysis, in turn, is based on a group of comparable companies. Mr. King arrived at his list of comparable companies by starting with the companies examined by AmerenUE witnesses VanderWeide and McShane. Mr. King eliminated four companies on Dr. VanderWeide's electric utility list that were more heavily involved in gas distribution than electric service. He also eliminated MDU Resources because it is most heavily involved in non-utility activities, including construction, mining, and gas and oil production, and OGE Energy because it is predominantly a gas pipeline company (although it does have some electric utility operations). TXU was eliminated because it has written down its equity to the point that it displays unreasonable financial risk.

Mr. King then examined the proportion of revenue of each company derived from non-regulated activities. Because AmerenUE derives virtually all of its revenue from regulated services and predominantly its electric operations, Mr. King established a threshold of 60 percent regulated utility revenue as a basis for inclusion in the comparison groups to be used in his analysis. The end result of this effort is two comparison groups, an electric utility group of 25 companies and a gas distribution group of 16 companies. (King Direct Testimony, Schedule CWK-3). Mr. King's DCF analyses of the appropriate return on equity for AmerenUE's electric operations relied on the group of 25 electric utilities.

Mr. King's selection of comparable companies is far superior to those taken by the two AmerenUE witnesses. Dr. VanderWeide's group is way too broad. It includes several utilities which have only limited involvement in regulated utility activities and receive most of their revenue from unregulated activities. As Mr. King notes in his rebuttal testimony:

> Only regulated companies realize their profits through the application of an allowed rate of return to the book value of their assets. A [non-regulated or mostly non-regulated] company experiences a totally different profit dynamic, one driven by competitive markets, not by regulation.

The other AmerenUE witness, Ms. McShane, errs by straying too far in the other direction. Her group of proxy companies is too narrow, unnecessarily limited by her criterion that only utilities with nuclear generation be included. Twenty years ago, the ownership of nuclear plants was a very distinguishing characteristic because it usually meant that the utility had incurred very sizeable debt and had assumed a significant safety risk. The newest nuclear plant is now over 20 years old, and the debt obligations and perceived safety risks associated with nuclear generation have receded in importance.

Mr. King described his application of the DCF model as follows:

> In developing the equity returns for the comparison groups, I shall apply the Discounted Cash Flow ("DCF") procedure. I consider the DCF procedure to be the most credible test of a market return. I shall present two versions of this test. The first, which I shall describe as the "classic" DCF, employs the forecasts of investment analysts in estimating the growth component of the DCF formula. The other procedure employs both analysts' forecasts and a forecast of the annual growth of Gross Domestic Product in the "out" years beyond 2012. Additionally, I shall consider the Capital Asset Pricing Model ("CAPM") as a check on the DCF results. Finally, I shall examine the trend in rates of return allowed by public utility commissions to electric utilities during the past 16 years. (King Direct Testimony).

It is important to note that Mr. King does not rely on the CAPM model except as a "sanity check" for his DCF analyses. Both AmerenUE witnesses give the CAPM analysis weight equal to that of their DCF analyses. There is simply no justification for this undue reliance on the deeply-flawed CAPM. The AmerenUE witnesses also rely on risk premium analyses. These suffer from at least as many flaws as the CAPM, most notably in the ease with which they are manipulated to achieve a desired ROE recommendation. This manipulation can be done by the analysts' choice of risk premiums and return estimates. The AmerenUE witnesses appear to have chosen both components with the goal of producing the highest possible ROE. Mr. King points out:

> Even if one accepts the calculation of the historical risk premiums, the witnesses appear to have padded their return estimates. Ms. McShane does so by averaging the higher gas company risk premium with the electric company indicator. Dr. VanderWeide does so by averaging the risk premiums of electric companies with those of S&P's 500 companies. If either witness had accepted the historical electric utility premiums, their return indications would have been lower. (King Rebuttal Testimony).

The DCF approach is the exclusive method that Public Counsel witness King relied on in his calculation of AmerenUE's cost of equity. Mr. King offers an understandable translation of the DCF equation in his direct testimony:

> The formula says that the return that any investor expects from the purchase of a stock consists of two components. The first is the immediate cash flow in the form of a dividend. The second is the prospect for future growth in dividends. The sum of the rates of these two flows, present and future, equals the return that investors require. Investors adjust the price they are willing to pay for the stock until the sum of the dividend yield and the annual rate of expected future growth in dividends equals the rate of return they expect from other investments of comparable risk. The DCF test thus determines what the investing community requires from the company in terms of present and future dividends relative to the current market price. (King Direct Testimony).

None of the witnesses disagree with the basic formula or approach of the DCF model, and it will not be discussed in any detail herein. The nuances of its application, of course, are at the heart of the issue in this case – as they in most rate cases. Virtually all cost of capital witnesses set forth the DCF equation in their testimony in the same way, cite the same portions of Hope and Bluefield,[2] yet nonetheless arrive at ROE recommendations that are wildly

[2] Federal Power Commission et. al vs. Hope Natural Gas Company, 320 U.S. 592, at 601 (1944);

divergent – making ROE the biggest issue in most rate cases. Yet it is the issue that most regulatory commissions devote the least critical evaluation to, preferring to "pick" the testimony of the witness that sponsors an ROE closest to the regulators' preconceived notion of a proper return.

In this case, the ROE witness with the least-manipulated ROE analyses is Public Counsel witness King. The Commission should beware of witnesses whose testimony essentially amounts to: "I conducted an elaborate and apparently rigorous DCF analysis. Then, dissatisfied with the result, I made adjustments until the ROE ended up where my gut (or my client) told me it should be. To further the appearance of professionalism and impartiality, I averaged in the results of several discredited (but complicated and impressive) market-based or risk-based analyses." Mr. King, on the other hand, has shown the Commission in his prefiled testimony exactly how his DCF results are calculated, and he will stick by them. He performed other analyses (company-specific DCF, CAPM, and an examination of nationwide ROE awards), but despite the fact that he could use them to lower his ROE recommendation, he used them only as a very general check on his DCF results.

Mr. King used the least subjective approach and the least subjective components in deriving the growth factor in his classic DCF analysis:

> According to the DCF theory, the relevant measure of "g" should be the growth in dividends. Dividends, however, are largely a function of management discretion, and in the near term they do not necessarily reflect the underlying driver of earnings. In the long run, however, any rate of dividend growth that differs significantly from earnings growth is unlikely to be sustainable. For this reason, it is generally accepted that the growth rate of earnings per share ("EPS") is the most reliable indicator of the "g" factor.
> The classic DCF calculation employs predictions of EPS growth, usually in the three to five year time horizon. Investment analysts routinely attempt to forecast

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> the future earnings of traded companies. Value Line provides such forecasts based on the research of its own and other organizations' analysts. Another commonly cited source is the Institutional Brokers Estimation System, or I/B/E/S, now part of Thomson Financial's research program. I/B/E/S does not conduct independent research but surveys investment analysts for their predictions of future earnings growth. I have used the forecasts from these two sources for my development of the classic DCF return. (King Direct Testimony).

The results of Mr. King's classic DCF analysis is 9.9 percent.

Significantly, Mr. King could have arrived at a much lower ROE recommendation for AmerenUE if he relied on the company-specific DCF analysis of AmerenUE. That analysis resulted in an ROE of only 8.3 percent. Mr. King, without hyperbole, simply discards that result because it is principally due to Value Line's prediction that Ameren's earnings will increase only 1.5 percent on average over the coming five years. Rather than rely on the predictions of one source, Mr. King constructs his entire approach on the theory that the more data points from the more sources, the more robust the result will be.

Mr. King does not rely on the Capital Asset Pricing Model (CAPM) because, as the Interstate Commerce Commission has found, it is "conceptually and technically flawed." Like the company-specific DCF, including his CAPM results in Mr. King's final recommendation on ROE would have led to a significantly lower ROE recommendation. Mr. King does, however, rely on two variations of the DCF approach.

Because an arguable weakness in the "classic DCF" formulation is that it assumes that the rates of earnings growth predicted by investment analysts will continue indefinitely, Mr. King also performed a "two-step DCF" analysis. This type of analysis is relied upon by the Federal Energy Regulatory Commission. In this two-step DCF analysis:

> [t]he first step is the same analysts' forecasts used in the classic formulation. The second step is an estimate of long-term nominal rate of growth in Gross Domestic Product ("GDP"). This procedure acknowledges that disparities between the short-term rate of growth and the growth in the overall economy cannot last

> forever. Ultimately, earnings growth will trend toward the rate of increase in the total market.

The result of Mr. King's two step DCF analysis of AmerenUE's ROE is 9.4 percent. Because the two DCF analyses are by far the most reliable (and the most relied upon by state commissions), Mr. King weights the results equally. The result of the classic DCF was 9.9 percent, and the result of the two-step DCF was 9.4 percent. The average, and the best estimate of the required ROE for AmerenUE, is 9.65 percent.

Public Counsel witness King also made an adjustment to eliminate the double-leveraging effect of the way AmerenUE reflects its capital structure. As Mr. King discusses in his direct testimony:

> [AmerenUE's proposed] capital structure reflects the implicit assumption that the equity component is the proportion of capital that is held by the shareholders of AmerenUE's parent, the Ameren Corporation. That is not the case. A small proportion – 5.2 percent -- of AmerenUE's "equity" takes the form of long-term debt at the parent company level. And an even smaller portion – 0.5 percent – takes the form of parent company short-term debt. The effect is to overstate the equity portion of AmerenUE's capital as it ultimately reaches Ameren Corporation's shareholders. To correct for this "double leverage" effect, I adjust AmerenUE's capital structure in columns D and E of Schedule CWK-1.

In rebuttal testimony, AmerenUE witnesses Nickloy and VanderWeide try to discredit Mr. King's double-leveraging adjustment. In his rebuttal testimony, AmerenUE witness Nickloy implies that it is necessary to track funds across Ameren Corporation's balance sheet to justify the double-leverage adjustment. In his surrebuttal Schedule CWK-SR-1, Mr. King demonstrates that the double-leverage adjustment is thus necessary to ensure that the actual equity investors in AmerenUE receive only the authorized rate of return on their investment. Mr. King also refutes AmerenUE witness VanderWeide's unfounded criticism of Mr. King's adjustment.

Income Taxes*:*
Should net salvage be normalized?

Public Counsel has no position on this issue.

Metro East: *Should any adjustment to AmerenUE's revenue requirement be made for any alleged non-compliance with the conditions contained in the Commission's order approving the Metro East Transfer and if so, what should the adjustment be?*

This issue relates to the question of whether AmerenUE has complied with conditions in "the Metro East case."[3] On February 10, 2005, the Commission issued its "Report and Order on Rehearing" in that case, which contained the following conditions:

> [P]re-closing liabilities that are directly assignable to UE's Illinois retail operations, or to the transferred assets, must transfer to CIPS as a condition of the Commission's approval of the transfer.[4]
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> …
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> [T]he Commission will exclude 6-percent of any such liabilities arising from pre-closing events and conditions from UE's rates as a condition of its approval of the transfer, unless AmerenUE, in a future rate case where it seeks to recover 6-percent of such liabilities, is able to prove that benefits directly flowing from the Metro East transfer are greater than 6-percent of these liabilities … [I]n addition to unknown environmental and other liabilities, this includes general corporate liabilities and pre-closing natural gas costs not directly assignable to UE's Illinois retail operations.[5]
>
> …
>
> As a condition of its approval of the transfer, the Commission will exclude from rates 6-percent of any costs incurred by UE in the Sauget remediation unless, as with the other liabilities discussed above, UE can meet its burden to establish that such costs are outweighed by transfer-related benefits.[6]
>
> …
>
> AmerenUE may seek recovery in a future rate proceeding (a rate increase or an excess earnings complaint) of up to 6% of the unknown generation-related liabilities associated with the generation that was formerly allocated to AmerenUE's Metro East service territory, if it proves by a preponderance of the evidence that the sum of the Missouri ratepayer benefits attributable to the transfer in the applicable test year is greater than the 6% of such unknown generation-related liabilities sought to be recovered.[7]
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> …
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> Union Electric Company, doing business as AmerenUE, as a condition of the approval herein contained, shall not recover in rates any portion of any increased

[3] Case No. EO-2004-0108

[4] Case No. EO-2004-0108, Report and Order on Rehearing, page 61.

[5] Case No. EO-2004-0108, Report and Order on Rehearing, page 62.

[6] Case No. EO-2004-0108, Report and Order on Rehearing, page 63.

[7] Case No. EO-2004-0108, Report and Order on Rehearing, Ordered paragraph number 7.

> costs due solely to transmission charges for the use of the transmission facilities herein transferred to AmerenCIPS to the extent that the costs in question would not have been incurred had the facilities not been transferred.[8]

AmerenUE did not even address these conditions in its case-in-chief, even though it acknowledged that it is seeking to recover more than 94% of the unknown generation-related liabilities associated with the generation that was formerly allocated to AmerenUE's Metro East service territory (Response to Public Counsel DR Number 2018). AmerenUE also acknowledged that it is seeking to recover more than 94% of the test year costs incurred by UE that were related to the Sauget remediation (Response to Public Counsel DR Number 2022).

AmerenUE did belatedly put some testimony on this issue in the rebuttal testimony of Gary Weiss. Mr. Weiss' testimony fails to satisfy the Commission's condition in the Metro East case that AmerenUE prove that the benefits outweigh the costs.

Callaway Refueling Non-Labor Maintenance Expense*: Should Callaway refueling non-labor maintenance expense be based on an average of the last three refuelings or on the most recent refueling as the appropriate level to be included in the determination of the revenue requirement in this case?*

Public Counsel has no position on this issue.

Electric Energy, Inc.*: How should the expiration of the affiliate power supply agreement with EEInc. be treated for ratemaking purposes? Would it be lawful and proper for the Commission to impute to AmerenUE's revenue requirement the net effect on AmerenUE's variable production costs of power from EEInc.? Was the action taken by AmerenUE respecting the expiration of the affiliate power supply agreement with EEInc. prudent?*

This issue concerns the ratemaking treatment to be afforded AmerenUE's actions leading up to, and in response to, the expiration of a long-standing power supply arrangement that it had with EEInc., the owner of a coal-fired generation station near Joppa, Illinois (the Joppa plant). Pursuant to that arrangement, AmerenUE had been receiving available power from the Joppa

[8] Case No. EO-2004-0108, Report and Order on Rehearing, Ordered paragraph number 8.

plant at cost for many years until the arrangement expired at the end of 2005. This arrangement was formalized in a long series of Power Supply Agreements (PSAs) through the years. The PSAs had always been renewed or extended for fifty years, until AmerenUE decided not to continue the arrangement when the last PSA was due to expire at the end of 2005.

Public Counsel witness Kind summarizes Public Counsel's recommendation on the rateaking treatment for EEInc.:

> Any new rates that result from this case should reflect UE's entitlement to 40% of the output from the Joppa plant. Including 40% of the Joppa plant output as a resource available to serve UE's regulated Missouri retail load will lower UE's cost of service (revenue requirement) because the Joppa plant is one of the lowest cost plants in the U.S. The low production cost nature of the Joppa plant is illustrated in one of the workpapers for UE witness Warner Baxter's testimony which shows that the productions costs at Electric Energy, Inc. ($15.94/MWh) were well below the production costs at UE ($17.69/MWh) for the time period from 2002 through 2005. The first page of this 3 page workpaper is attached as Attachment 5. In addition to the low production costs of EEInc.'s generation facilities, the EEInc steam generation facilities are almost fully depreciated. Page 205 of the EEInc 2005 FERC Form 1 (see relevant excerpts from this report in Attachment 6) shows gross steam production plant of $370,618,403 and page 219 of the same report shows accumulated depreciation for this plant of $330,593,417.
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> …
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> UE's 40% share of the EEInc Joppa plant has been an important part of UE's generation portfolio for decades. UE's ownership interest in EEInc and the provision of power from the EEInc Joppa plant to UE's Missouri retail customers began about 50 years ago. (Kind Direct, pp. 22, 24).

For decades, AmerenUE's ratepayers have been paying their full share of the cost of service for the power they have been receiving from the Joppa plant. In addition to paying the full cost of service, AmerenUE's ratepayers have provided the following support to EEInc.:

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

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

- Cost responsibility for surplus capacity whether or not UE's ratepayers needed that capacity; and
- Responsibility for certain financial obligations extended by UE to EEInc. See the Commission approval, issued on June 24, 1977 in Case No. EF-77-197, of a request by UE, for the approval of the financial responsibility necessary to permit EEInc to proceed with improvements to the Joppa plant. In this decision, the MPSC stated that UE was "assured of a continuous source of economical power" in return for the guaranty of EEInc's financial obligations. See the Application of Union Electric Company for authority to "guaranty" certain financial obligations of Electric Energy, Inc., 1977 Mo. PSC LEXIS 23, 21 Mo.P.S.C. (N.S.) 425, 427 (1977). (Kind direct, pp. 25-26).

AmerenUE could have continued to receive power at cost-based rates had it been willing to put the interests of its ratepayers ahead of the interests of the shareholders of its corporate parent Ameren Corporation. As the last PSA was about to expire at the end of 2005, there were three shareholders in EEInc.: AmerenUE, its corporate parent Ameren Corporation, and Kentucky Utilities (KU). KU, wanting to continue providing the low-cost power from the Joppa plant to its customers, sought to continue the decades-old arrangement. Although KU owns only 20 percent of the stock in EEInc., it would have been successful of AmerenUE had taken the same interest in the welfare of its customers as KU did in its customers. But AmerenUE sided with its corporate parent rather than its fellow regulated utility in deciding how to follow up the expiring PSA. KU never had a chance with only 20 percent of the vote. Although it tried to continue the historical arrangement, it eventually had to throw in the towel. Had AmerenUE sided with KU, AmerenUE ratepayers as well as KU ratepayers would continue to receive power from the Joppa plant at cost.

Off-System Sales*: How should off-system sales be recognized in AmerenUE's revenue requirement and what amount of off-system sales margin is appropriate for the test year? Should any tracking or sharing of changes in off-systems sales margins be implemented?*

AmerenUE's revenue requirement should include a baseline amount of off-system sales margins at a level that reflects the best estimate of the ongoing level of off-system sales margins. A deferred accounting tracker mechanism should be used to accumulate variations from the baseline level between rate cases. The accumulated deferral amount should be reflected in the revenue requirement in AmerenUE's next rate case. In addition, the tracker must account for the Taum Sauk plant. Given AmerenUE's stated intention that its shareholders rather than its ratepayers should bear the costs of the Taum Sauk disaster, "it will be necessary to impute the revenues from margins on the additional sales of capacity and energy that would be possible if the Taum Sauk Plant was still operating." (Kind Rebuttal)

A tracking mechanism is necessary because of recent changes in the AmerenUE system and the environment in which it operates that have greatly increased the difficulty in estimating the expected future level of off-system sales margins. Public Counsel witness Ryan Kind lists many of these changes in his direct testimony:

> Recent generation resource changes include the following:
>
> - The addition of thousands of megawatts (MWs) of gas-fired peaking capacity to UE's generation portfolio over the last few years.
> - The announcement made by the Ameren Corporation (Ameren HoldCo) that it will terminate the Joint Dispatch Agreement (JDA) between UE and AEG at the end of this year.
> - The dispute over whether UE will continue to use its 40% share of the output from the 1,000 MW EEInc. Joppa plant to serve its native load customers.
> - The extra 6% share of UE's generation resources that are now available to serve UE customers in Missouri as a result of UE transferring the Illinois portion of its service territory to AmerenCIPS in the Metro East transfer case.
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> …
>
> Recent changes in the load that UE serves include the following:
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> - Removal of the load associated with UE's former Illinois service territory as a result of the Metro East transfer.
> - The addition of several hundred MWs of retail load as a result of adding Noranda as a retail customer.

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

…

Recent regional wholesale electric market changes include the following:

- The evolution of energy markets at the Midwest ISO (MISO) that has already occurred and further developments, including an ancillary services market, that are likely in the near future.
- Further opening of the Illinois retail market with the newly developed Illinois Auction process which offers new off-system sales opportunities for UE.
- Changes in regional electric market wholesale prices and margins related to changes in the fuel costs for gas-fired generation.

These changes are cumulative in nature; that is, rather than canceling each other out, they add to each other. Each increases the uncertainty in predicting the future and decreases the reliability of the past as an indicator of the future. Because of these uncertainties and because of the importance of the other issues in this case, it will be very difficult for the Commission to set a level of margins in base rates that is likely to accurate reflect actual future levels. A tracking mechanism will ensure that both ratepayers and shareholders will be treated fairly if actual results differ substantially from the projections made by production cost models.

Although Public Counsel generally opposes a FAC for AmerenUE in this case, if the Commission determines that UE should be permitted to have a fuel adjustment mechanism, the fuel adjustment mechanism should include off-system sales margins that vary from the baseline level included in base rates.

Fuel Adjustment Clause*: Should AmerenUE's proposed fuel adjustment clause be approved and, if so, with what modifications or conditions?*

Public Counsel does not support Commission approval of a FAC for AmerenUE. Senate Bill 179, the Commission's FAC rules, and case law all support Public Counsel's position that the Commission has discretion to approve, disapprove, or modify a utility's FAC proposal. In exercising that discretion, the Commission should consider at least the following factors:

- Will the rates resulting from the exercise of its discretion to approve, modify or reject applications to establish a FAC be "just and reasonable"?
- Does AmerenUE have a need for a FAC because it would face a substantial threat to its financial viability if it did not have the ability to recover any increased costs of fuel and purchased power in between rate cases without a FAC?
- Would permitting AmerenUE to use a FAC be consistent with the Commission's rules for FACs?
- Is AmerenUE's power supply cost structure vulnerable to changes in fuel and purchased power costs and if so, is this vulnerability due to factors beyond its control?
- Has AmerenUE taken prudent action to hedge its vulnerability to increases in fuel and purchased power costs through (1) appropriate planning and acquisition of supply and demand-side resources and (2) appropriate hedging of generation fuel costs?
- Are AmerenUE's fossil fuel prices and wholesale markets expected to have substantial volatility over the next few years ?

Upon consideration of all relevant factors, the Commission should determine that approving a FAC for AmerenUE will not be in the public interest.

If, despite Public Counsel's (and other parties') recommendation to the contrary, the Commission approves a FAC, it should not approve the AmerenUE proposal without significant modifications. Public Counsel opposes the implementation procedures and cost inclusions in the FAC proposed by AmerenUE for multiple reasons. The implementation procedures are not consistent with Commission rules, include costs that are not appropriate for inclusion in a FAC, and will not allow for adequate prudence reviews. Public Counsel witness Trippensee discusses the numerous problems with AmerenUE's proposal. The following list of significant flaws is from his rebuttal testimony (p. 4):

1. The proposed FAC implementation procedures are not consistent with 4 CSR 240-20.090.
2. The short length of the recovery period increases volatility in customer rates.
3. The timing of the recovery period increases volatility for customers during periods of high use.

4. The timing of the recovery period creates a mismatch between cost causer and cost payer.
5. Inclusion of costs that are not fuel or purchased power costs.
6. Inclusion of AmerenUE depreciation expense in FAC.
7. Inclusion of fly ash disposal costs net of revenues received for fly ash.
8. Inclusion of revenues and expense of buying and selling activities for fuel commodities that are not used to serve native load or purchased power.
9. Creates four mandatory FAC filings per year and decreases regulatory oversight resources.

In addition, the FAC proposed by AmerenUE would collect fuel related costs in both base tariffs and through the FAC's Fuel and Purchased Power Adjustment. AmerenUE's proposed FAC formula would not recognize the actual kWh revenues billed during the accumulation period but would use actual fuel costs incurred to produce those kWhs sold during the accumulation period.

Public Counsel has offered a thoughtful and thorough review of the policy considerations the Commission should evaluate in deciding whether to allow a utility a FAC. AmerenUE's position is that the Commission has no discretion to disapprove an application for a FAC, so long as the application follows the Commission's rule. The Commission's rule was not designed to be comprehensive. Nor was it designed to be a checklist such that, if all the boxes are checked, a proposed FAC is necessarily in the public interest. Nonetheless, that is AmerenUE's position in this case. The Commission should reject that position, and reject AmerenUE's proposed FAC.

If there is a fuel adjustment clause, should there be provisions to mitigate and limit retail rate impacts?

Although the concept of a cap on FAC increases has some surface appeal, Public Counsel is acutely aware of the TANSTAAFL[9] principle. Public Counsel's concern is that either in settlement negotiations or in the give-and-take of Commission decision making, a cap that offers very little real protection would be exchanged for something that has real benefit to consumers. The caps discussed by the electric utilities during the rulemaking proceedings all were some variation of a "soft cap;" that is, they would limit increases during a period to a certain percentage increase, but any amounts not recovered because of the cap would be deferred and recovered later. It is not hard to imagine scenarios where the rate shock impact of these deferrals would be much harder on customers than simply flowing through increases as they occur. This type of cap offers "protections" that are minimally helpful at best, and actually harmful at worst. In addition, it has serious "inter-generational equity" concerns. New customers could end up paying rates significantly higher than they would otherwise pay because of the deferred impact of fuel price spikes from years earlier, long before they were on the system.

Public Counsel would strongly support a "hard cap;" that is, one that actually limits FAC increases rather than deferring and accumulating them for later imposition on customers. AmerenUE has certainly not offered such a cap, and would be likely to appeal any Commission order that imposed one.

SO2 Allowances/SO2 Premiums/2006 Storm Costs*:* *Should revenues received from environmental allowance transactions be included in the revenue requirement and if so, what amount?*

The Commission should include a normalized level of revenues from SO2 allowance sales in the revenue requirement. Public Counsel recommends that the Commission use $23,993,951 as the normalized level of SO2 allowance sales in this case (Kind Surrebuttal, Attachment 1). This amount was derived by calculating a five-year average of the amount of annual net revenues that AmerenUE has received from emission allowance sales over the five-year period ending December 31, 2006.

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[9] "There ain't no such thing as a free lunch."

As with any revenue stream or expense that shows considerable volatility, the Commission should not rely on test year levels (or any short period of time) to establish rates that will be charged in the future. The best way to approximate going-forward revenue levels is to normalize past revenues from a representative past period. For AmerenUE's SO2 allowance sales, an appropriate representative period is five years. In order to get the most recent data, which will be most representative of going-forward levels, the Commission should look at a five year average of the five years ending December 31, 2006. As Public Counsel witness Kind noted in his surrebuttal testimony:

> The level of allowance sales that UE made in each of the five calendar years over the five year period varies considerably from the test year sales level ($3.9 million) so there was an obvious need to normalize the level of allowance sales to make the amount in the test year more representative of the level of sales that has occurred preceding the test year, and in the test year update period.

The actual test year level of less than $4 million is not even 20 percent of the five year average. The test year level is clearly not representative of the level that can be expected in the future when rates set in this case are in effect.

In addition to using a five year average level, certain adjustments to the booked level of SO2 allowance sales in those five years are necessary. Because the terms of one of the major transactions that took place during the test year of 2006 were negotiated in an improper context where considerations of the financial interests of one of UE's affiliates were intertwined with the financial interests of UE, adjustments to the actual booked amount of the transaction are necessary.

Mr. Kind's rebuttal testimony describes significant adjustments to annual SO2 allowance revenues for 2005 and 2006 in the calculation of his five-year average normalized sales level recommendation. As he explains in his surrebuttal testimony, Mr. Kind decided that there was no need to adjust 2006 SO2 sales revenues after he received UE's response to OPC DR No. 2225 in between the filing of rebuttal and surrebuttal testimony. (Kind Surrebuttal testimony, p. 17.) Mr. Kind adjusted the amount of 2005 SO2 revenues by imputing the difference between the amount of revenues that UE could have generated from a sale of SO2 allowances when the allowance market was at its peak in December of 2005 and the amount of revenue that UE actually generated from selling the same number of allowances in that month as part of a transaction with Dynegy where the financial interests of UE's affiliate, AmerenIP, were intertwined with the financial interests on UE. (Kind Rebuttal testimony, p. 9, and Kind Surrebuttal testimony, p. 18.)

Should the Company establish a regulatory liability to account for sales of environmental allowances sold by the Company?

No.

Should SO_2 premiums (net of discounts) be included in the regulatory liability account?

No.

Should the balance of SO_2 allowances less SO_2 Premiums paid be used to offset 2006 storm costs? If so, what is the proper storm cost level to include in the cost of service?

No.

Fuel and Purchased Power:

Diesel Fuel Hedge Costs: Should diesel fuel hedge costs be included in the cost of service?

Public Counsel supports the Staff position on this issue.

Nuclear Fuel Prices: Should nuclear fuel prices that exist beyond the 1/1/2007 true-up cutoff date be allowed in the cost of service? Should nuclear fuel prices to be included in the cost of service be determined using nuclear fuel prices that exist through the end of the 1/1/2007 true-up cutoff date?

Public Counsel supports the Staff position on this issue.

Nuclear Fuel Inventory: What is the appropriate nuclear fuel inventory to include in rate base? Should nuclear fuel inventory be based on projected inventory levels from May 2007 through

October 2008? Should nuclear fuel inventory be based on an 18 month average that exists at the end of the 1/1/2007 true-up cutoff date?

Public Counsel supports the Staff position on this issue.

Depreciation:

A. 4 CSR 240-10.020: Does 4 CSR 240-10.020 require any adjustment in this case for return on depreciation reserve? If so, what adjustment does 4 CSR 240-10.020 require? If AmerenUE is not in compliance with 4 CSR 240-10.020, what action should the Commission take as a consequence?

Public Counsel has no position on this issue.

B. Fossil-fueled and hydro powered generation plant depreciation rates: Should depreciation rates for the plant accounts for fossil-fueled and hydro powered generation plants be based on average service lives with no truncation or a service life that is truncated at an estimated future final retirement date of each generation plant (Life Span)?

Public Counsel has no position on this issue.

C. Should the Commission assume that the Callaway Plant will be relicensed for an additional 20 year term, or should the Commission assume that the Callaway Plant will not be relicensed for purposes of calculating depreciation rates for the Callaway Plant?

The Commission should assume that Callaway will be relicensed for an additional 20 year term. Depreciation rates are, by definition, set based on estimates of future events. The Commission should use the best estimate available to set depreciation rates for Callaway. If the Commission finds, based on the evidence in this case, that it is more likely than not that Callaway will be relicensed, then the Commission should set rates based on a 2024 retirement. On the other hand, if it finds that it is more likely that Callaway will be relicensed, it should set rates based on a 2044 retirement date.

Ameren UE asserts that no decision has been made to relicense the plant, but that fact is immaterial. Just because no decision has been made yet does not relieve the Commission of the obligation to make its best prediction of what that decision will be at the time it is made. All the evidence in the case points to the likelihood of relicensing; it is much more probable than not that Callaway will have its licensed renewed. In his direct testimony, Public Counsel witness William Dunkel summarizes the points weighing in favor of renewal as follows:

> (1) The vast majority of commercial nuclear production units do apply for the license renewal. 72 of the 104 active nuclear production units (almost 70%) already have a renewed license, have filed for a renewed license, or have filed a Letter of Intent to Apply for License Renewal for a named unit.
>
> (2) The NRC has never refused to renew a commercial nuclear power reactor's initial license for the additional twenty years.
>
> (3) A "sister" plant has already applied for a license renewal.
>
> (4) Unlike fossil fueled plants, Callaway does not emit greenhouse gases, and therefore does not contribute to global warming. AmerenUE has committed to reducing its carbon intensity; retiring Callaway would be a huge step in the opposite direction of that commitment.
>
> (5) [Highly Confidential information is omitted from this brief.]
>
> (6) AmerenUE's proposal that October 2024 should be used in the depreciation rate calculations as the final retirement date even if it expected that the license will be renewed, is unacceptable. Using an incorrect final retirement date produces incorrect depreciation rates. This would be a miscalculation of the depreciation rate that would overcharge current customers.

D. Should terminal net salvage and inflation costs relating to the future retirement of the Company's generating plants be included in depreciation rates, and if so, how should such costs be calculated?

Public Counsel has no position on this issue.

E. In the calculation of the Distribution, Transmission and General Plant depreciation rates, should the estimated Net Salvage Percents to be applied in the determination of depreciation rates be calculated to reflect historic inflation rates based on analyses of historic net salvage percents or should expected future inflation be used?

Expected future inflation should be used. This issue has to do with the calculation of the amount to be included in rates for future costs of removing plant at the end of its useful life. Because there is a lot of plant at issue, and because some of it will be removed far in the future, the choice of the inflation rate makes a big difference in the calculation of rates in this case. Public Counsel witness William Dunkel outlines the issue in his direct testimony:

> AmerenUE witness Mr. Wiedmayer estimated the future net salvage percents based primarily on his analysis of past net salvage percents. Unfortunately that past data includes some of the highest inflation in U.S. history. The U.S. inflation was over 11% in 1974, over 11% in 1979, over 13% in 1980, and over 10% in 1981. During the ten year period 1973-1982, the purchasing power of the dollar was cut in half. The past net salvage percents that Mr. Wiedmayer relied on have the impact of these high inflation rates built into them.
>
> However the forecasts for future inflation are much lower. According to the Survey of Professional Forecasters, a survey of 53 professional forecasters surveyed by the Federal Reserve Bank of Philadelphia, future inflation over the long-term is expected to be 2.5% per year.

For the distribution poles and fixtures account (Account 364), AmerenUE witness Wiedmayer proposes a future net salvage percent of -135%, meaning that Mr. Wiedmayer forecasts that in the future it will cost $1,350 net to remove each $1,000 of original cost pole investment. Mr. Dunkel explains how this illogical result is embodied in AmerenUE witness Wiedmayer's depreciation calculations:

> If all costs are measured on a consistent basis, the net cost-of-removal is generally much less than the investment (which includes installation labor and material costs). However the costs are not measured on a consistent basis. The "original cost" investment dollar amount is recorded when the investment is installed. The net cost-of- removal is determined later, often decades later, when the investment is removed. The decades of inflation between these two events greatly inflate the net cost-of-removal as compared to the "original cost" investment.
>
> …
>
> For an investment that lives 43 years, Schedule WWD-6 [to Mr. Dunkel's direct testimony] illustrates how inflation changes the Net Salvage percent over the decades. In 1962 the original cost of the pole investment (including both material and installation labor costs) is assumed to be $1,000, and the net salvage, if removed then, would be -$209, also in 1962 dollars. This produces a net salvage percent of -21% when everything is measured in consistent dollars from the same year.
>
> As time passes the $1,000 original cost does not change. It is still $1,000 "original cost" investment on the books 43 years later when the investment is retired.
>
> However the net salvage does change because of inflation, because the net salvage is not incurred until the investment retires. When the investment is retired 43 years later, in 2005, the cost of removal is paid in 2005 dollars. Because of the 43 years of inflation, the CPI-U index maintained by the United States Bureau of Labor Statistics shows it takes $6.47 in "year 2005" dollars to

> equal to one 1962 dollar. As a result, the net cost of removal that would cost \$209 in 1962 dollars costs \$1,350 in the year 2005 dollars. The \$1,350 negative net salvage (in year 2005 dollars), divided by the \$1,000 original cost (in year 1962 dollars) produces -135% net salvage.

Public Counsel recommends that the future Net Salvage percents be calculated based on a 2.5% annual future inflation rate.

F. In the calculation of the Transmission, Distribution and General Plant depreciation rates should the net salvage percents applied in the determination of depreciation rates be based on actual net salvage expense?

Public Counsel would not object to basing net salvage on actual net salvage costs, but to be in compliance with recent Commission Orders, Public Counsel has proposed that present customers pay for future inflation at a 2.5% per year future inflation rate. For example for the Distribution accounts, the current actual negative net salvage expense is \$6 million per year (Selecky Schedule JTS-10). The Staff and AmerenUE effectively propose current customers pay for 4% to 4.5% future annual inflation, which would result in \$42 to \$50 million per year being collected from current customers to pay for future Distribution net salvage costs (Wiedmayer Schedule JFW-E4-3 and E3-3). At Public Counsel's proposed rate of 2.5% future annual inflation, \$23 million would be collected from current customers to pay for future Distribution net salvage costs, which is still almost four times the current actual Distribution net salvage costs cost.

G. Is there a difference between the actual book accumulated depreciation and the theoretical accrued depreciation? If so, how should that difference be recovered from ratepayers?

Public Counsel has no position on this issue.

H. What net salvage percentage should be used in the depreciation rate calculation for assets in Account 322?

The net salvage percentage should be -13.7% (Dunkel Revised Rebuttal Schedule WWD-14). However it is acceptable to round this to –14%.

Wind Power*: Should AmerenUE include wind power in its generation portfolio? If so, how much?*

AmerenUE should certainly take a much more serious approach to the evaluation of wind resources than it has in the past. The details of how much, when, and where are best addressed in the context of integrated resource planning.

Demand Side Management*.*
Should AmerenUE set megawatt and megawatt hour goals for Demand Side Management? If so, what should those goals be?
Should AmerenUE fund Demand Side Management programs at minimum levels? If so, at what levels?
How should DSM programs be selected?

Public Counsel supports the Staff position as set forth in the rebuttal testimony of Staff witness Lena Mantle. Specifically, Public Counsel recommends that the Commission require AmerenUE to adopt the DSM goals proposed by the Missouri Industrial Energy Consumers, and also require that peak demand and energy reduction goals be revised after the Staff, Public Counsel, and other interested entities have had an opportunity to review AmerenUE's comprehensive resource plan filing scheduled for February 5, 2008.

Low-Income Programs*:*
Should AmerenUE continue to fund its current low-income weatherization program? If so, how should the program be funded?
Should AmerenUE fund low income programs at minimum levels? If so, at what levels?

Public Counsel supports the Staff position as set forth in the rebuttal testimony of Staff witness Lena Mantle. Specifically, Public Counsel recommends that the weatherization program should be continued at the annual funding level of $1.2 million. Funding should be split 50/50 between ratepayers and shareholders. The Commission should order AmerenUE to do a process and impact analysis of the weatherization program and file a tariff sheet to be placed in its tariff that describes the program funding and eligibility requirements for weatherization.

***Voluntary Green Power Program**: Should AmerenUE's Voluntary Green Power Program be approved?*

Public Counsel supports the Staff position as set forth in the rebuttal testimony of Staff witness Lena Mantle. Ms. Mantle objects to AmerenUE devoting its resources to developing a program for customers to purchase Renewable Energy Credits (RECs) rather than working to evaluate and include renewables in its portfolio of resources. Every other Missouri electric utility (except perhaps certain municipal utilities) has managed to evaluate and include renewables. Only AmerenUE, Missouri's largest electric utility, has not. Public Counsel agrees with Staff witness Mantle that there is a significant likelihood that customers purchasing a REC will believe that they are actually purchasing renewable energy.

***Class Cost of Service and Rate Design**:*

Class Cost of Service Issues: What should be the increase or decrease in the revenue responsibility of each customer class?

To what extent, if any, are current rates for each customer class generating revenues that are greater or less than the cost of service for that customer class?

The results of Public Counsel's Class COS studies show that the Residential and SPS classes are near class cost of service. The SGS and LGS are above costs. The SPS class is near cost. LPS is significantly below cost as is LTS to a lesser extent. The change in class revenue percentage that would be needed on a revenue neutral basis to achieve equalized rates of return are provided below. [10]

CCOS Indicated Revenue Neutral Shifts To Equalize ROR

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	Residential	SGS	LGS	SPS	LPS	LTS
TOU	-1.03%	-7.62%	-6.70%	3.47%	22.01%	11.22%
Non-TOU	3.53%	-6.19%	-8.92%	-1.30%	14.35%	1.68%

How should AmerenUE's cost of service be assigned to the customer classes?

CCOS study results provide the Commission with a general guide in setting the just and reasonable rate for the provision of service based on costs. In addition, other factors are also relevant considerations when setting rates including the value of a service, affordability, rate impact, rate continuity, etc. A determination as to the particular manner in which the results of a cost of service study and all the other factors are balanced in setting rates can only be determined on a case-by-case basis. [11] In this case, the Commission should use the results from the cost of service study methods presented by Public Counsel witness Meisenheimer in this case as a guide to identifying potential interclass shifts. In addition, the Commission should mitigate any adverse impact of a rate increase to a reasonable extent by insuring that no class faces an increase in rates when another would otherwise receive a decrease.[12] Ms. Meisenheimer's direct, rebuttal and surrebuttal testimonies in this case describe the cost and rate design methods recommended by Public Counsel.[13]

Should the Commission adopt AmerenUE's proposal to cap any residential class increase at no more than ten (10%) percent?

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[10] Meisenheimer Surrebuttal, page 6.
[11] Meisenheimer Direct, page 4.
[12] Meisenheimer Direct, page 3.
[13] Meisenheimer Direct, pages 3-13 and related schedules; Meisenheimer Rebuttal, pages 2-5 and related schedules; Meisenheimer Surrebuttal, pages 2-9 and related schedules.

Public Counsel's testimony shows that Residential is near cost on a revenue neutral basis.[14] In addition, based on the evidence related to revenue requirement, Public Counsel supports an overall reduction in this case. However, if contrary to Public Counsel's position, the Commission determines that Residential is more than 10% below cost, Public Counsel would support the 10% cap to avoid rate shock and improve affordability**.**

Should Staff's proposal to combine the Small Primary Service Class and the Large General Service Class in the Class Cost of Service Study be adopted?

Public Counsel has no position on this issue.

On what basis should production capacity be allocated to classes?

Public Counsel has developed a Time of Use (TOU) method and a A&3CP allocation method for assigning production capacity costs.[15] Both methods are consistent with production allocation methods described in the NARUC Manual.[16]

The A&3CP production allocator assigns production capacity costs according to a composite allocator that has (1) a demand related component and (2) an energy related component.[17] This method recognizes the importance of year-round energy demand as well as peak demand actually representative of AmerenUE's system in determining production costs.[18]

The Time Of Use method assigns demand related fixed plant investments and depreciation reserve to each hour. The method then sums each class' share of hourly investments based on only those hours when the class actually used the system. Since capacity

[14] Meisenheimer Surrebuttal, page 6.
[15] Meisenheimer Rebuttal, page 2.
[16] Meisenheimer Direct, page 7 and Meisenheimer Surrebuttal, page 7.
[17] Meisenheimer Direct, page 6.
[18] Meisenheimer Surrebuttal, page 3-4.

cost actually vary by hour depending on the plants in use. [19] The TOU allocator appropriately, for each hour, assigns the same capacity cost per hour to each class taking service during the hour based on the configuration of plants needed to serve the hour's total load. As a result, all customer classes pay the same higher level of costs when peaking plants are operating and the same lower level of cost when they are not running. The particular pattern of use by each class over different hours of the year appropriately leads to a difference in overall average cost by class. [20]

On what basis should transmission costs be allocated to classes?

Transmission facilities are installed to provide reliable service throughout the year including periods of scheduled maintenance. It can also, at times, substitute for generation and can minimize the cost of generation facilities through the sales or purchases of power. Therefore, Transmission Plant costs can be equitably allocated on the same basis as the Production Plant.[21]

On what basis should distribution costs be allocated to classes? Should the allocation of primary distribution costs include any customer-related component?

Public Counsel accepts and uses a customer related allocation for a portion of distribution costs for FERC Accounts 364-367 identified as related to secondary voltage. The portion of distribution costs for FERC Accounts 364-367 identified as related to primary voltage should be allocated as demand related.

Distribution Plant includes the cost of land, structures and equipment used in connection with distribution operations. Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of

[19] Meisenheimer Direct, page 7.
[20] Meisenheimer Surrebuttal, page 8.

energy used by the customer. With the exception of service drops and meters, most of the facilities between the utility customer's point-of-service and the distribution substation are shared facilities. Since no portion of such facilities are directly related to the number of customers, the associated costs are best classified as demand related, rather than customer related.[22] The Company method significantly over allocates distribution costs to small customers and the zero intercept method is flawed in that it does not prove a direct relationship between the number of customers and cost causation of facilities.[23]

On what basis should non-fuel generation expenses by allocated?

Consistent with the principle that "expenses follow plant", the allocators applied to the expenses accounts should be the same or similar to those applied to the related plant accounts. Specifically, the demand-related power production expenses should be allocated consistent with the demand related allocators in Public Counsel's CCOS studies. [24]

On what basis should off-system sales revenues be allocated among the customer classes?

Public Counsel does not oppose allocating net off-system sales on the basis of production capacity in this case.[25]

On what basis should credit and collection expenses be allocated?

Public Counsel witness Ms. Meisenheimer allocated credit and collection expenses on the basis of the number of customers.

Rate Design: *How should the Commission implement any revenue change it orders in this case and address proposed revisions to existing tariffs?*

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[21] Meisenheimer Direct, page 7-8.
[22] Meisenheimer Direct, page 8-9.
[23] Meisenheimer Rebuttal, page 10-14.
[24] Meisenheimer Direct, page 10.
[25] Meisenheimer Supplemental Rebuttal, page 2.

Should the Commission adopt AARP's proposal to recover less of the Company's demand related costs in the summer, and more of the demand related costs in the winter?

Public Counsel has no position on this issue.

Should the Commission adopt the Missouri Association for Social Welfare's proposal to create an "essential service rate"?

Public Counsel has no position on this issue.

Should the Commission adopt AmerenUE's proposal for economic development and retention riders?

Public Counsel has no position on this issue.

Should AmerenUE have an Industrial Demand Response program? If so, what should be the parameters of that program?

Public Counsel is generally supportive of the concept of an Industrial Demand Response program. The particulars of such a program should be developed in the context of integrated resource planning.

Does the Large Power Rate need to be changed? If so, should the Commission adopt AmerenUE's proposal for changes to the Large Power Service Rate?

Public Counsel has no position on this issue.

Does the Large Transmission Service Rate need to be changed? If so, should the Commission adopt AmerenUE's proposal for changes to the Large Transmission Service Rate?

Public Counsel has no position on this issue.

Should the Commission adopt AmerenUE's proposal for changes to miscellaneous tariff provisions?

Public Counsel has no position on this issue.

Should the Commission adopt Staff's proposal for changes to miscellaneous tariff provisions?

Public Counsel has no position on this issue.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been emailed to all parties this 6th day of March 2007.

By:____________________________