Exhibit No.: ______________
Issue(s): Callaway Nuclear Plant License Extension/
Past Retirement of Steam Production Plants
Depreciation Reserve-The Missing $159 Million/
Future Net Salvage of the Distribution and
Transmission (“Mass”) Accounts
Witness: William Dunkel
Type of Exhibit: Direct
Sponsoring Party: Public Counsel
Case No.: ER-2007-0002
Date Testimony Prepared: December 15, 2006

DIRECT TESTIMONY

OF

WILLIAM DUNKEL

Submitted on Behalf of
the Office of the Public Counsel

UNION ELECTRIC COMPANY, D/B/A AMERENUE

Case No. ER-2007-0002

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

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December 15, 2006

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))	**Case No. ER-2007-0002** Tariff No. YE-2007-0007

AFFIDAVIT OF WILLIAM DUNKEL

COUNTY OF SANGAMON)
) ss
STATE OF ILLINOIS)

William Dunkel, of lawful age and being first duly sworn, deposes and states:

1. My name is William Dunkel. I am a Consultant for the Office of the Public Counsel.

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

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

William Dunkel
William Dunkel
Consultant

Subscribed and sworn to me this 12th day of December 2006.

Sarah J Williams
Notary Public

My commission expires 2/27/2010.

"OFFICIAL SEAL"
Sarah J. Williams
Notary Public, State of Illinois
My Commission Exp. 02/27/2010

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DIRECT TESTIMONY

OF

WILLIAM W. DUNKEL

On Behalf of the Office of Public Counsel

Pertaining to AmerenUE

CASE NO. ER-2007-0002

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is William W. Dunkel. My business address is 8625 Farmington Cemetery Road, Pleasant Plains Illinois, 62677.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a consultant providing services in utility regulatory proceedings. I am the principal of William Dunkel and Associates, which was established in 1980. Since that time, I have regularly provided consulting services in utility regulatory proceedings throughout the country. I have participated in over 200 state utility regulatory proceedings before over one-half of the state commissions in the United States, as listed on Schedule WWD-1 attached hereto.

Q. PLEASE BRIEFLY DESCRIBE YOUR EXPERIENCE PERTAINING TO THE ELECTRIC UTILITY INDUSTRY.

A. I have participated in over 40 regulatory proceedings pertaining to electric utilities. I have worked in the electric engineering section of the Illinois Commerce Commission (ICC). The ICC regulates utilities in Illinois. I have also been design engineer for a company that manufactured equipment for the electric utility industry. I was granted patent No. 3822440 entitled a Solid State Pulse Initiator. This initiator was used by electric companies for certain electric energy metering purposes.

I have a Bachelor's of Science Degree from the University of Illinois.

Since becoming an independent consultant in July of 1980, I have participated in various regulatory proceedings pertaining to electric, telephone, and natural gas utility companies.

I am a member of the Society of Depreciation Professionals.

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY?

A. I am providing this Testimony on behalf of the Missouri Office of the Public Counsel (OPC).

Q. HAVE YOU PREVIOUSLY PARTICIPATED IN PROCEEDINGS IN MISSOURI?

A. Yes. I testified on behalf of the OPC in Case No. TR-2001-65, which was the Investigation of Exchange Access Service proceeding. I testified on behalf of the Staff of the Missouri Public Service Commission in Docket Nos. TR-79-213, which was a Southwestern Bell Telephone Company (SWBT) general rate case; TR-80-256, which was a SWBT general rate case; and TR-82-199, which was a SWBT general rate case. I have also testified on behalf of the Office of the Public Counsel (OPC) in Docket Nos. TC-93-224/TO-93-192, which was a Southwestern Bell Telephone Company general rate case, TR-93-181, which was a United Telephone Company of Missouri case, TR-86-84, which was a SWBT general rate case; TC-89-14; TO-86-8, which was an Extended Area Service (EAS) case involving all companies in Missouri; and TO-87-131, which was an EMS investigation involving all companies in Missouri.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to address to certain issue pertaining to depreciation.

CALLAWAY NUCLEAR PLANT LICENSE EXTENSION

Q. WHAT DOES THE COMPANY PROPOSE PERTAINING TO THE FINAL RETIREMENT DATE FOR THE CALLAWAY NUCLEAR PRODUCTION PLANT?

A. AmerenUE proposes that it be assumed that the final retirement of Callaway will be in October, 2024, which is the end of the initial Callaway forty year operating license.

The Nuclear Regulatory Commission (NRC) grants an initial operating license of forty years for commercial nuclear power reactors, and utilities are allowed to request a license renewal for an additional twenty years, all as is discussed in the NRC web site.[1]

Q. IN THIS PROCEEDING CHARLES D. NASLUND, SENIOR VICE PRESIDENT AND CHIEF NUCLEAR OFFICER WITH AMEREN SERVICES PRESENTS TESTIMONY PERTAINING TO CALLAWAY. IN LATE 2005, WHAT DID MR. NASLUND STATE PERTAINING TO THE REJUVENATION OF CALLAWAY?

A. Mr. Naslund stated

> "After the first 20 years of operation we have rejuvenated the plant. It's basically ready for the next 20 and the 20 beyond that."

The article containing this quotation is attached here to Schedule WWD-13 and can also be found at the KOMU website. The KOMU web site also contains a video which shows Mr. Naslund making that statement.[2]

Q. HAVE YOU REVIEWED OTHER EVIDENCE PERTAINING TO WHETHER OR NOT CALLAWAY WILL PROBABLY RETIRE IN OCTOBER OF 2024?

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[1] http://www.nrc.gov/ visited on 12/12/2006.

A. Yes. **

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Q. WHAT REASONS DO AMERENUE WITNESSES PRESENT FOR ASSUMING CALLAWAY WILL RETIRE IN OCTOBER 2024, WHICH IS THE END OF THE INITIAL FORTY YEAR LICENSE?

A. One argument AmerenUE presents is:

> First, there is a possibility that the license will not be extended. … AmerenUE will not decide on whether to apply for such an extension for a number of years.[3]

Q. PLEASE RESPOND TO THE ARGUMENT THAT "THERE IS A POSSIBILITY THAT THE LICENSE WILL NOT BE EXTENDED."

A. First of all, when dealing with the future, anything is "possible." However, the NRC has never refused to renew a commercial nuclear power reactor's initial license for the additional twenty years.[4]

[2] http://www.komu.com/satellite/SatelliteRender/KOMU.com/eca45b91-c0a8-2f11-01de-3a27bf72dd9e/9b25df3f-c0a8-2f11-0039-82b82f471b47. Visited 12/14/2006. In the video, Mr Naslund puts "and" between the two sentences. "...rejuvenated the plant, and it's basically ready for the next 20 and the 20 beyond that."

[3] Direct Testimony of William Stout, Page 30, lines 3-8.

[4] Of the 23 applications received prior to March 2005, including the Monticello application received March, 2005, all 23 have been issued a renewal license (some applications involving more than one plant, and/or plants with more than one unit). http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/license-renewal-bg.pdf visited on 12/12/2006.

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Based on this fact, it reasonable to expect that is much more probable than not that AmerenUE could obtain a license renewal if it properly applied for it.

Q. PLEASE RESPOND TO THE ARGUMENT THAT "AMERENUE WILL NOT DECIDE ON WHETHER TO APPLY FOR SUCH AN EXTENSION FOR A NUMBER OF YEARS."

A. The fact that it is not yet time for AmerenUE to make this decision, does not imply that AmerenUE will retire Callaway at the end of the initial license. Experience shows that when it is time to make that decision, the vast majority of nuclear plant owners do apply for a license renewal. Of the 104 operating commercial nuclear production units in the United States,[5] the NRC has already renewed the license for 47 units, is reviewing applications for 9 additional units,[6] and Letters of Intent to Apply for License Renewal, with expected submittal dates, have been received for 16 other named units. 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. Since the 104 figure includes all operating commercial nuclear production units, that means the 104 figure even includes those units that have not reached the time at which the decision to apply for re-licensing must be made.[7]

Q. HAS AMERENUE MADE A COMMITMENT THAT IS RELEVANT TO THIS ISSUE?

A. Yes. In response to Federal Government concerns about greenhouse gases and global warming, AmerenUE has made a commitment to the U.S. Department of Energy (DOE) in which AmerenUE committed to **decrease** its carbon intensity in the future. The ways that AmerenUE is considering

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[5] http://www.nrc.gov/reactors/operating/list-power-reactor-units.html visited on 12/12/2006.
[6] http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/license-renewal-bg.html visited on 12/12/2006.

meeting its commitment includes "...increased generation at our nuclear and hydroelectric power plants, ..."[8] This Ameren commitment is shown on page 3 of Schedule WWD-3, which is from the AmerenUE Form 10-K for the year 2005. In this document AmerenUE also states that "Coal-fired power plants, however, are significant sources of carbon dioxide, a principal greenhouse gas."[9]

AmerenUE's reference to "our nuclear" power plant clearly refers to Callaway, because that is the only Ameren nuclear plant. As Ameren stated in response to a data request "Callaway Unit 1 is the only nuclear facility owned, or partially owned, by Ameren and any of its affiliates.[10]

Q. THIS COMMITMENT MENTIONS OTHER POSSIBILITIES FOR AMERENUE TO REDUCE ITS CARBON INTENSITY, SUCH AS INCREASED PRODUCTION FROM THE HYDROELECTRIC PLANTS. PLEASE COMMENT.

A. Callaway produces a significant portion of the total AmerenUE production, and it does so without producing carbon dioxide or other greenhouse gasses. If Callaway is retired early, that would eliminate a large amount of production that does **not** now emit carbon gases. It would be difficult for AmerenUE to reduce its carbon intensity if Calloway was retired early. Callaway produces 26% of AmerenUE's power generation.[11] The amount of power produced by the hydroelectric plants is tiny compared to the power produced by Callaway. The hydroelectric plants produce 4% of AmerenUE's power generation.

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[7] http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html visited on 12/12/2006.
[8] From page 18 and 19, "Form 10-K, Union Electric Company-UEP, Filed: March 07, 2006 (period: December 31, 2005)"
[9] Schedule WWD 3-2. If should be noted that any fossil fuel plant produces carbon dioxide. It is a product of combustion.
[10] "Callaway Unit 1 is the only nuclear facility owned or partially owned by Ameren and any of its affiliates." From AmerenUE response to OPC Data Request number 5007.
[11] Ameren website: http://www.ameren.com/aboutus/adc_au_AmerenUE_Plants.asp visited on 11/14/2006. The 4% hydroelectric includes Keokuk, Osage, and Taum Sauk.

Q. HAS AN APPLICATION FOR A LICENSE RENEWAL BEEN FILED FOR "SISTER" NUCLEAR UNIT?

A. Yes. In October 2006, an application to renew the license of the Wolf Creek nuclear production unit was filed with the NRC.[12] Wolf Creek is a "sister" plant to Callaway. In response to a discovery request, AmerenUE acknowledged that the reactor in the Callaway plant is of a similar design, of similar output, and designed by the same firm as the reactor in the Wolf Creek plant.[13]

Q. WHAT IS THE SECOND REASON AMERENUE PRESENTED FOR USING OCTOBER 2024 AS THE FINAL CALLAWAY RETIREMENT DATE IN THE DEPRECIATION CALCULATIONS?

A. AmerenUE argued:

> Second, even if the license is extended, it may come with a price. That is, AmerenUE may be required to expend significant sums in order to comply with the terms of the extended license. ... Rather than lengthening the license now and decreasing depreciation expense, only to later increase depreciation expense as potentially significant new plant is added, it would be more prudent to continue depreciation at its current levels by using the October, 2024 retirement date.[14]

Q. PLEASE RESPOND TO THIS ARGUMENT.

A. Using an incorrect retirement date does not produce the correct depreciation rate. October 2024 is not the appropriate date "if the license is extended." In depreciation rate calculations a longer life tends to produce a lower depreciation rate, as compared to a shorter life. The above AmerenUE argument

[12] http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/license-renewal-bg.pdf visited on 12/12/2006.
[13] AmerenUE response to OPC Request Number 5025
[14] Page 30, Direct Testimony of William Stout.

incorrectly assumes the depreciation rates calculated on a 60 year life would be as high as the depreciation rates calculated on a 40 years life.[15] That is not a reasonable assumption.

In addition AmerenUE has just recently completed the refurbishment of Callaway. "About 3,000 people worked on the project."[16] In late 2005, among other things, AmerenUE replaced the four huge steam generators with new steam generators that "feature the latest technology for efficiency and reliability." They also replace "all four turbine rotors with new, more-efficient models." "Like the replacement steam generators, the new turbines rotors are designed to provide increased efficiency and durability compared to the original units manufactured in the 1970s."[17] Ameren has just completed the refurbishment of Callaway.

After the refurbishment of Callaway in late 2005, the Ameren Board of Directors informed the Ameren shareholders that for other nuclear plants that had already applied for license renewal, the operators of those plants did not identify the need for any "major plant refurbishment" for license renewal.[18] This statement from the Board appears on page 5 of Schedule WWD-12, which is from the "Notice of Annual Meeting of Shareholder and Proxy Statement of Ameren Corporation" for the May, 2006 annual meeting of shareholders.

In addition, any such future investment is not known or measurable.

[15] Life before final retirement.
[16] Ameren Media Release, dated November 21, 2005.
[17] Ameren Media Release, dated November 21, 2005.
[18] Earlier the Board had stated "At this time, Ameren has not yet decided whether it will pursue renewal of the operating license for the Callaway Plant."

Another issue is proper depreciation occurs over that life of the investment. For example, even if we assume an investment will be made a decade from now, the depreciation of that investment would start then. That assumed future investment would not be depreciating now.

One last point, adding 20 years to the life has a major impact on the depreciation rate; it would take an incredibly high additional investment to offset the impact of the additional 20 years of life.

Q. HAVE YOU RECENTLY PARTICIPATED IN A CASE IN WHICH THE DEPRECIATION RATES FOR A NUCLEAR PLANT HAD BEEN CALCULATED ON THE 40 YEAR LIFE, THEN THE LICENSE WAS RENEWED FOR AN ADDITIONAL 20 YEARS, AND THE UTILITY THEN FILED NEW DEPRECIATION RATES BASED ON THE 60 YEAR LIFE?

A. Yes. In the State of Indiana, I recently was involved in an Indiana-Michigan Power Company (I&M) case in which the existing depreciation rates for the Cook nuclear production plant had been calculated on the 40 year life of the initial license. The license was then renewed for an additional 20 years, and the utility then filed new depreciation rates based on the 60 year life. As expected, the new nuclear plant depreciation rates based on the 60 year life were much lower than the prior depreciation rates that had been based on the 40 year life. In the I&M utility witness's own words:[19]

Q. PLEASE EXPLAIN THE RESULTS OF YOUR STUDY FOR NUCLEAR PLANT?

A In August 2005, the NRC granted I&M a 20-year extension of the operating license for the plant. This increase in life is the major reason that the depreciation rate decreased from 3.37% to 1.16%.

[19] Page 19, Lines 6-9, Direct Testimony of James E. Henderson on behalf of Indiana Michigan power Company, filed 12/01/2005 in Indiana Cause Number 42959.

Q. COULD YOU PLEASE SUMMARIZE THE INFORMATION PERTAINING TO THE FINAL RETIREMENT DATE THAT SHOULD BE USED TO CALCULATE THE DEPRECIATION RATES FOR THE CALLAWAY NUCLEAR PRODUCTION UNIT?

A. Yes. Based on the above discussions, it is much more probable than not that Callaway will have its licensed renewed. As discussed above in more detail, these reasons include:

(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) **

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(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.

In summary, the Callaway depreciation rates should be calculated using a 60 year life to the final retirement date. It is much more probable than not that Callaway will have its licensed renewed.

PAST RETIREMENT OF STEAM PRODUCTION PLANTS

Q. WHAT ISSUE WILL YOU ADDRESS IN THIS AREA?

A. On this issue I will only respond to page 14 of the Direct Testimony of William M. Stout, in which he points out that

> AmerenUE has retired the Mound, Cahokia, and Venice I power plants, consisting of 17 units, and it also has retired Units 1 and 2 of the Venice II station.

Q. WHEN WERE THE CAHOKIA AND VENICE POWER PLANTS BUILT?

A. According to the Ameren web site, the Cahokia Plant "was built in 1928," and the first Venice unit was built in 1942.[20]

Q. WHAT WAS ONE CHARACTERISTIC OF PLANTS IN THE EARLY 1900S?

A. They were very fuel inefficient. Fuel efficiency is measured by the "heat rate." A steam production unit with a lower "heat rate" is more fuel efficient. A unit with a heat rate of 20,000 Btu/kWh will consume twice as much fuel to produce the same amount of electricity as a unit with a heat rate of 10,000 Btu/kWh.

The early plants had low efficiency. Below is a table of the average utility central power station heat rates by years, according to the U.S. Department of Energy:[21]

Year	Heat Rate, Btu per kWh
1902	92,500
1932	20,700
1941	18,600
1949	15,033
1955	11,699
1960	10,760
1970	10,494
1980	10,338
1990	10,402
2000	10,201
2005	10,241

The sources for this information are shown on Schedule WWD-4.

A typical plant in service in 1932 would require almost twice as much fuel as a typical 1960 plant for the same output of electricity.[22]

The average fuel efficiency almost doubled in the 28 years between 1932 and 1960.

[20] http://www.ameren.com/centennial/electricity.html visited on 11/24/2006.
[21] Table 6, Approximate Heat Rates for Electricity, 1949-2005, http://www.eia.doe.gov/Aer/Txt/stb1306.xls and Appendix A, History of the U.S. Electric Power Industry, 1882-1991 http://www.eia.doe.gov/cneaf/electricity/page/electric_kid/append_a.html visited on 11/16/2006
[22] 20,700/10,760=1.9

Q. IF THE AVERAGE FUEL EFFICIENCY ALMOST DOUBLED IN THE 28 YEARS BETWEEN 1932 AND 1960, DID IT DOUBLE AGAIN IN THE 28 YEARS 1960 TO 1988?

A. No. As the above chart shows, the rate of improvement in the average heat rates started to level out in the mid 1950s to 1960s. The average heat rates of the plants in service have improved only slightly in the 45 years after 1960.

Q. WHAT SIGNIFICANT DOES THIS HAVE?

A. In 2006, a 30 year old, 40 year old, or even older steam production unit can have close to the same fuel efficiency as a new steam production plant. The incentive now to retire an efficient "old" plant is less than it was to retire the inefficient plants from the early 1900s to which Mr. Stout refers.

DEPRECIATION RESERVE-THE MISSING $159 MILLION

Q. WHAT IS THE ISSUE YOU WILL ADDRESS ON THE DEPRECIATION RESERVE CALCULATION?

A. In their Pro Forma calculations, the Company updated the Plant in Service to be at the expected December 31, 2006 level, but it omitted over $159 million that would be added to the Depreciation Reserve in the last 6 month of 2006. Specifically, the Company did not update the Depreciation Reserve for the depreciation accrual during the last six months of 2006 that result from the depreciation of the existing investments.[23] Since the Depreciation Reserve is a deduction when calculating net rate base, the Pro Forma net rate base is overstated by many millions of dollars.

[23] The Company adjusted for the difference created by the Company proposed change in the depreciation rates, but did not include the depreciation expense at the current rates for the existing plant.

Q. ON THE SCHEDULES ATTACHED TO THE SUPPLEMENTAL DIRECT TESTIMONY OF GARY S. WEISS, WHAT WERE THE PRO FORMA ADJUSTMENTS INTENDED TO SHOW?

A. AmerenUE had the actual "PER BOOKS" amounts as of June 30, 2006. In the "PRO FORMA ADJUSTMENTS" column AmerenUE adjusted for what it expected to occur in the last six months of 2006. The final column is meant to be the level it expected as of December 31, 2006.[24]

Q. DID AMERENUE PROPERLY ADJUST THE DEPRECIATION RESERVES (ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT) TO THE DECEMBER 31, 2006 LEVEL?

A. No. As of June 30, 2006 the Company had over $10 billion dollars in investment.[25] I will call the investment that existed at June 30, 2006 the "existing" investment. The depreciation on that "existing" investment would be over $159.6 million in the last six months of 2006, as shown on Schedule WWD 5-1.[26] AmerenUE made no addition to the Pro Forma Depreciation Reserve for the depreciation of the "existing" investment in the last six months of 2006.[27]

Q. WHAT IMPACT DOES DEPRECIATION EXPENSE HAVE ON THE DEPRECIATION RESERVE?

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[24] For example, for Plant in Service, column (B) on Schedule GSW-E20-1, which was attached to the Supplemental Direct Testimony of Gary S. Weiss, shows the actual Plant in Service as of June 30, 2006. In the next column (the "Pro Forma" column) the Company makes adjustments that include adding all Plant is Service they expect to add in the last six months of 2006. The final column is their estimate of the Plant in Service as of December 31, 2006.
[25] Schedule GSW-E20-1.
[26] As an additional source, see Schedule GSW-E30-1 which shows that the annual depreciation at existing depreciation rates is over $300 million per year, which equates to over $150 million depreciation expense in six months.
[27] The Company adjusted for the difference created by the Company proposed change in the depreciation rates, but did not include the depreciation expense at the current rates for the existing plant.

A. The depreciation expense is credited into the Depreciation Reserve. The Uniform System of Accounts (USOA)[28] requires:

> **108 Accumulated provision for depreciation of electric utility plant (Major only).**
> A. This account shall be credited with the following:
> (1) Amounts charged to account 403, Depreciation Expense, or to clearing accounts for current depreciation expense for electric plant in service.

Therefore the $159.6 million of depreciation expense for the existing plant in the last six months of 2006 would result in $159.6 million being credited into the Depreciation Reserve (Account 108, the Accumulated provision for depreciation of electric utility plant). In its Pro Forma adjustments, AmerenUE failed to credit these depreciation expenses into the Depreciation Reserve (account 108) in the last six months of 2006.[29]

Q. HAS AMERENUE NOW ACKNOWLEDGED THAT THIS EXISTING PLANT WOULD BE DEPRECIATING IN THE LAST SIX MONTHS OF 2006, BUT THAT IT FAILED TO ADD THESE DEPRECIATION EXPENSES INTO THE RESERVES?

A. Yes. Below is request OPC 5042 (a) and (b) and the AmerenUE responses:

> Request OPC 5042:
>
> (a) Please state where in these Supplemental Direct Schedules or underlying workpapers, a Proforma additions to the Depreciation and Amortization Reserves was made for the accruals expected in

[28] Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Part 101, CFR Title 18, Volume 1.

[29] Retirements remove money from the Depreciation Reserve. However, AmerenUE's Pro Forma adjustments assumed no retirements in the last six months of 2006 (AmerenUE response to OPC Request 5028). Even if retirement were assumed, the net rate base would still be overstated by approximately $150 million, because retirements remove dollars from the Reserve, but retirements also remove similar dollars from the Plant is Service. Since the Reserve is deducted from the Plant in service when calculating the net rate base, reducing both as the result of a retirement has little impact on the net rate base, the only significant difference being the treatment of the net salvage of the retirement.

> the periods 7/2006 to 12/2006 that result from the depreciation accruals on the existing plant.
>
> (b) Schedule GSW-E30-1 (Weiss Supplemental Direct) on line 14 shows the existing annual depreciation and amortization accruals are $307,844,000, which is in excess of $25 million per month. Is it correct that the existing plant (the plant that existed as of June 30, 2006) would continue to have depreciation accruals well in excess of $20 million per month in the period 7/2006 to 12/2006? If "no" explain the answer and provide a corrected answer.
>
> AmerenUE response:
>
> (a) No adjustment was made.
>
> (b) The monthly electric depreciation expense is currently in excess of $20 million per month.

Q. ON SCHEDULE GSW-E21-1 THE COMPANY DID INCLUDE SOME ADJUSTMENT TO THE PRO FORMA RESERVES FOR DEPRECIATION AND AMORTIZATION. CAN YOU SHOW THAT THE COMPANY DID NOT ADJUST THE DEPRECIATION RESERVE FOR DEPRECIATION ON THE EXISTING PLANT?

A. Yes. Assuming, for the sake of argument, that the Pro Forma adjustments AmerenUE made were otherwise valid,[30] here is what the Pro Forma adjustments to the Depreciation and Amortizations Reserves should have been for the last six months of 2006:

[30] This statement is not an endorsement of these AmerenUE adjustments or calculations.

(1)	Credit into the Depreciation Reserve for the depreciation expense of the existing investments (investments as of 6/30/2006) at the current depreciation rates:	$159,596,000
(2)	Adjustment for the depreciation on **only** the **new** Plant additions (the Plant added after 6/30/2006), at the proposed depreciation rates:	$18,468,000
(3)	Unrelated adjustments:	
	Hydraulic account 355	-$51,000
	Venice Power Reserve	$198,000
	FAS 143 Adjustment	-$81,090,000
	Used for Gas operations	-$2,084,000
	Total Pro Forma Adjustment	+$95,037,000

The above is **positive** $95.0 million. However the Company total Pro Forma adjustment is **negative** -$64,559,000, as shown on Schedule GSW-E21-1. The $159.6 million difference between these two figures ($95.0 million **-** (-64.6 million = $159.6 million) is because the Company did not include the addition to the Depreciation Reserve that result from the depreciation of the existing plant during the last six month of 2006.

Q. WHAT DO YOU RECOMMEND ON THIS DEPRECIATION RESERVE ISSUE?

A. The Pro Forma Depreciation Reserve (Account 108) has to be increased by $159,596,349 for the depreciation accruals on the existing plant in the period 7/2006 to 12/2006. After applying the 99.05% allocation for the Missouri jurisdiction, the Missouri jurisdictional amount is $158,081,873,[31] as shown on Schedule WWD-5. Since the Depreciation Reserve is a deduction when calculating net rate base, this will significantly reduce the net rate base.

FUTURE NET SALVAGE OF THE DISTRIBUTION AND TRANSMISSION ("MASS") ACCOUNTS

Q. WHAT PROBLEM WITH THE AMERENUE FUTURE NET SALVAGE ESTIMATES WILL BE DISCUSSED IN THIS SECTION OF YOUR TESTIMONY?

A. 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.[32]

In this section I will present the future net salvage percents that incorporate future inflation at this 2.5% annual rate, instead of the much higher inflation rates that are built into the future net salvage percents proposed by Mr. Wiedmayer.

Q. WHAT IS NET SALVAGE?

A. Net salvage occurs at the time an investment is retired, or soon after. The retired investment may have a scrap or other salvage value, which is called "gross salvage." However there is also the labor

[31] This is the correct figure after the 99.05% allocation to Missouri jurisdiction, as shown on Schedule WWD 5-1.
[32] Federal Reserve Bank of Philadelphia – Economic Research – Survey of Professional Forecasters, Release Date: November 13, 2006. This document was obtained at the Federal Reserve Bank of Philadelphia website http://www.phil.frb.org/files/spf/survq406.html, visited December 4, 2006.

and other costs incurred to remove the investment from service, which is called "cost of removal." The "gross salvage" less the "cost of removal" is called the "net salvage." In recent decades in many accounts, the cost of removal is larger than the gross salvage, which results in a "negative" net salvage. "Negative" net salvage can also be called "net cost of removal." For example a –$1000 net salvage would be a $1000 net cost of removal.

Q. WHAT IS FUTURE NET SALVAGE?

A. Future net salvage is the net salvage that is expected to occur in the future. Page 54 of the Commission Report and Order[33] in the Empire District Electric case indicates that the net salvage costs of an asset in a mass account should be spread over the customers that benefit from that asset during its life. Since the net salvage costs do not occur until that asset retires, the net salvage that must be determined for the investments currently in service is the **future** net salvage.

The **past** net salvage can be determined from company records, but the **future** net salvage is in the future, and is therefore more difficult to determine.

Q. BASED PRIMARILY ON PAST NET SALVAGE RATIOS, FOR THE DISTRIBUTION POLES AND FIXTURES ACCOUNT ("DISTRIBUTION POLES" ACCOUNT 364), MR. WIEDMAYER PROPOSES A FUTURE NET SALVAGE PERCENT OF -135%.[34] WHAT DOES THE -135% FUTURE NET SALVAGE PERCENT RECOMMENDED BY MR. WIEDMAYER MEAN?

A. The -135% means Mr. Wiedmayer forecasts that in the future it will cost $1,350 net to remove each $1,000 of original cost pole investment.

[33] Case No. ER-2004-0570, Report and Order Issued March 10, 2005.
[34] Page III-7, of the Company Depreciation Study, Schedule JFW-E1.

Q. WHEN THE FUTURE NET SALVAGE PERCENT IS BASED ON THE PAST NET SALVAGE PERCENT, DOES THAT IMPLY THAT THE FUTURE INFLATION IS EXPECTED TO BE THE SAME AS THE PAST INFLATION?

A. Yes. Mr. Wiedmayer acknowledged this is the assumption in the following discovery response:

> OPC 5006 (c)
> If the Future Net Salvage percent is set equal to the historic net salvage percent as determined from the historic data shown on pages B-81,B-82, and B-83, does that effectively assume that future inflation will be the same as past inflation? If not, explain why not.
>
> AmerenUE/Mr. Wiedmayer's Response:
>
> c) Yes, that is the assumption when viewed over a long term period of 30 to 40 years.

These responses are attached as Schedule WWD-7.

Q. THE "ORIGINAL COST" POLE INVESTMENT INCLUDES BOTH THE LABOR TO INSTALL THE POLE AND THE MATERIAL COST OF THE POLE. SINCE THE COST-OF-REMOVAL IS ONLY LABOR, BUT NO SIGNIFICANT MATERIAL COST, HOW CAN IT COST MORE JUST TO REMOVE A POLE, THAN IT COSTS TO BUY AND INSTALL A POLE?

A. 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 those accounts in which the investment has a long average life, the amount of inflation that occurs between the time the investment is installed and the time it is removed increase the net salvage percent. Mr. Wiedmayer acknowledged this in response to a data request:

> OPC 5006 (b)
> Is it a correct statement that, everything else being equal, the greater the inflation between the time the investment went into service, and the time it was retired, the higher the cost of removal percent would be? If this is not a correct statement, provide the corrected statement.
>
> AmerenUE/Mr. Wiedmayer's Response:
>
> b) Yes, that is correct.

Q. CAN YOU EXPLAIN FURTHER WHY THE INFLATION THAT OCCURS BETWEEN THE INSTALLATION OF THE INVESTMENT AND THE REMOVAL OF THE INVESTMENT IMPACTS THE NET SALVAGE PERCENT?

A. Yes. The Company Depreciation Study determined that the investments in the Distribution Pole account (Account 364) live an average of 43 years.[35] For a pole installed in the year 1962, and retired 43 years later, in the year 2005, the net salvage percent would be:

$$\text{Net Salvage Percent} = \frac{\text{Net Salvage (paid in } \textbf{year 2005 dollars)}}{\text{Original Cost investment (paid in } \textbf{year 1962 dollars)}}.$$

The numerator is written in year 2005 dollars, but the denominator is written in year 1962 dollars. Inflation between these two years has a major impact on the net salvage percent calculated.

Q. DOES MR. WIEDMAYER ACKNOWLEDGE THAT IN HIS CALCULATION OF THE HISTORIC NET SALVAGE RATIO, THAT FOR A POLE INSTALLED IN 1965

[35] Page III-7, of the Company Depreciation Study, Schedule JFW-E1.

AND RETIRED IN 2005, THE "ORIGINAL COST" WOULD BE IN YEAR 1965 DOLLARS, AND THE "COST OF REMOVAL" WOULD BE IN YEAR 2005 DOLLARS?

A. Yes. In response to OPC request 5005, Mr. Wiedmayer acknowledge that in his calculation of the historic net salvage ratio for a pole installed in 1965 and retired in 2005, the original cost "would be in year 1965 dollars", and the cost of removal would be "in year 2005 dollars." A copy of that request and the AmerenUE response is attached hereto as Schedule WWD-8.

Q. CAN YOU ILLUSTRATE WHAT IMPACT INFLATION BETWEEN THE TIME OF INSTALLATION AND THE TIME OF REMOVAL HAS ON THE NET SALVAGE PERCENT?

A. Yes. For an investment that lives 43 years, Schedule WWD-6 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%[36] 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

[36] -$209/$1,000= -21%

one 1962 dollar.[37] 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.[38]

The vast majority of the -135% figure is the result of the inflation that occurred over the 43 years between installation and removal, including the extremely high inflation that occurred in the years 1973-1982. The inflation over the decades changed the -21% net salvage percent to -135%, as shown on Schedule WWD-6.

I am not suggesting there will be no future inflation, but the **level** of inflation assumed in the future is a very significant item in the determination of the future net salvage percent.

Q. IS IT REASONABLE TO EXPECT THAT THE AVERAGE INFLATION IN THE FUTURE WILL BE AS HIGH AS THE INFLATION WAS DURING THE AVERAGE LIFE OF THE POLES THAT HAVE RECENTLY RETIRED?

A. No. The lives of the poles that have recently retired include a time period when the U.S. experienced unusually high inflation. Schedule WWD-9 shows the Consumer Price Index-Urban index (CPI-U) and the U.S. rates of inflation from 1914 through 2005, as measured by the CPI-U. The CPI-U is maintained by the U.S. Bureau of Labor Statistics. As this Schedule shows, the U.S. inflation was over 11% in 1974, over 11% in 1979, over 13% in 1980, and over 10% in 1981. During that 10 year period 1973-1982, the purchasing power of the dollar was cut more than in half. When all 43 years of

[37] The CPI-u index was 195.30 in 2005, divided by the CPI-U index in 1962 of 30.20 =6.47
[38] Net salvage ratio= net salvage/ original cost of investment retired= -$1350/$1000= -135%.

their average life is considered, inflation over their life has average 4.3% per year, for the poles that have retired in the last ten years, as shown on page 3 of Schedule WWD-10.[39]

These very high historical rates of inflation are incorporated into the historic net salvage data Mr. Wiedmayer used as the basis for his Future Net Salvage proposals in this proceeding. As a result, Mr. Wiedmayer's proposed Future Net Salvage recommendations have the built-in assumption that in the future, the U.S. will experience extremely high rates of inflation.

However, 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.[40]

For another source of future inflation, for a different purpose Mr. Wiedmayer's Depreciation Study uses 2.0% as the estimate of future annual inflation, as can be seen in footnote (a) on page II-29 of the AmerenUE Depreciation Study filed in this proceeding (Schedule JFW-E1).

Future annual inflation is not forecast to be anywhere near as high as the average annual inflation that occurred during the past life of an average life pole that has recently retired.

Q. ON PAGE 54 OF THE COMMISSION REPORT AND ORDER[41] IN EMPIRE DISTRICT ELECTRIC CASE THE COMMISSION INDICATES THAT A TRADITIONAL APPROACH TO THE NET SALVAGE SHOULD BE USED FOR

[39] For example, for a pole installed in 1962, the CPI-U index was 30.20 in 1962. When retired 43 years later the CPI-U index was 195.30. The ratio is 195.30/30.20=6.5 times. This is an average annual inflation rate of 4.44% (check: (1.044)^43=6.5). The other years are similar, as shown on page 3 of Schedule WWD-5.

[40] Federal Reserve Bank of Philadelphia – Economic Research – Survey of Professional Forecasters, Release Date: November 13, 2006. This document was obtained at the Federal Reserve Bank of Philadelphia website http://www.phil.frb.org/files/spf/survq406.html, visited December 4, 2006. This 2.5% is the forecast future annual inflation measured in CPI-U.

THESE ACCOUNTS. WHAT IS INCLUDED IN A PROPER TRADITIONAL ANALYSIS?

A. The "Public Utility Depreciation Practices," published by NARUC states the analyst is expected to examine past data. However the analyst is also expected to be "cognizant of the factors that may cause future cost of removal experience to differ from that of the past" and if there are significant differences, the analyst is expected to "modify the results of the historical analysis." [42]

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the future Net Salvage percents include 2.5% annual future inflation. 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.[43]

2.5% annual future inflation is a conservative recommendation. In fact, Mr. Wiedmayer used 2.0% as his estimate of future annual inflation, for other purposes.[44] My recommendation of 2.5% future annual inflation produces a higher depreciation expense than would be produce using 2.0% for the future annual inflation rate. My recommendation of 2.5% annual future inflation rate is very reasonable, is supported by the survey of 53 professional forecasters surveyed by the Federal Reserve Bank of Philadelphia, and is conservative compared to the 2.0% annual future inflation rate Mr. Wiedmayer himself used for other purposes.

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[41] Case No. ER-2004-0570, Report and Order Issued March 10, 2005.
[42] "Public Utility Depreciation Practices", published by NARUC p.161 (1996).
[43] Federal Reserve Bank of Philadelphia – Economic Research – Survey of Professional Forecasters, Release Date: November 13, 2006. This document was obtained at the Federal Reserve Bank of Philadelphia website http://www.phil.frb.org/files/spf/survq406.html, visited December 4, 2006.
[44] Footnote (a) on page II-29 of the AmerenUE Depreciation Study filed in this proceeding (Schedule JFW-E1).

Q. WHAT IMPACT DOES USING A 2.5% FUTURE ANNUAL INFLATION HAVE ON THE FUTURE NET SALVAGE FOR THE DISTRIBUTION POLES ACCOUNT (ACCOUNT 364)?

A. With no other changes, the -135% future net salvage percent that Mr. Wiedmayer has proposed becomes -74% at a 2.5% annual future inflation rate, as shown on Schedule WWD-10. The $20,544,469 of annual net salvage cost that Mr. Wiedmayer has proposed for this account[45] becomes $11,207,874, as shown on Schedule WWD-11.[46] This is a reduction of over $9.2 million in annual expense in this one account.

Q. HAVE YOU ADJUSTED THE NET SALVAGE PERCENT IN THE OTHER TRANSMISSION AND DISTRIBUTION ACCOUNTS FOR A FUTURE ANNUAL INFLATION RATE 2.5%?

A. Yes. The results are shown on Schedule WWD-11. As shown on that Schedule, when 2.5% future annual inflation is used, the total annual depreciation expense is $20,060,630 less than the AmerenUE proposal, with no other changes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[45] Page C-96 of Company Depreciation Study, AmerenUE Schedule JFW-E1.
[46] $15,218,126 as shown on page C-96, times -74% future net salvage. Of course other adjustments may also impact this account.

William Dunkel, Consultant
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Qualifications

The Consultant is a consulting engineer specializing in utility regulatory proceedings. He has participated in over 200 state regulatory proceedings as listed on the attached Relevant Work Experience.

The Consultant has provided cost analysis, rate design, jurisdictional separations, depreciation, expert testimony and other related services to state agencies throughout the country in numerous state regulatory proceedings.

The Consultant provides services almost exclusively to public agencies, including the Public Utilities Commission, the Public Counsel, or the State Department of Administration in various states.

William Dunkel currently provides, or in the past has provided, services in state utility regulatory proceedings to the following clients:

The Public Utility Commission or the Staffs in the States of:

Arkansas	Mississippi
Arizona	Missouri
Delaware	New Mexico
Georgia	Utah
Guam	Virginia
Illinois	Washington
Maryland	U.S. Virgin Islands
Kansas	

The Office of the Public Advocate, or its equivalent, in the States of:

Colorado	Maryland
District of Columbia	Missouri
Georgia	New Jersey
Hawaii	New Mexico
Illinois	Ohio
Indiana	Pennsylvania
Iowa	Utah
Maine	Washington

The Department of Administration in the States of:

Illinois	South Dakota
Minnesota	Wisconsin

The Consultant graduated from the University of Illinois in February, 1970 with a Bachelor's of Science Degree in Engineering Physics with emphasis on economics and other business-related subjects. The Consultant has taken several post-graduate courses since graduation.

From 1970 to 1974, the Consultant was a design engineer for Sangamo Electric Company (Sangamo was later purchased by Schlumberger) designing electric watt-hour meters used in the electric utility industry. The Consultant was granted patent No. 3822400 for a solid state meter pulse initiator which was used in metering.

Between April, 1974 and July, 1980 the Consultant was employed by the Illinois Commerce Commission as a Utility Engineer in the Electric and Telephone Sections. During that period, he testified as an expert witness in numerous rate design cases and tariff filings in the areas of rate design, cost studies and separations. During the period 1975-1980, he was the Separations and Settlements expert for the Staff of the Illinois Commerce Commission.

From July, 1977 until July, 1980, he was a Staff member of the FCC-State Joint Board on Separations, concerning the "Impact of Customer Provision of Terminal Equipment on Jurisdictional Separations" in FCC Docket No. 20981 on behalf of the Illinois Commerce Commission. The FCC-State Joint Board is the national board that specifies the rules for separations in the telephone industry.

The Consultant has completed an advanced depreciation program entitles "Forecasting Life and Salvage" offered by Depreciation Programs, Inc.

Mr. Dunkel is a Senior member of the Society of Depreciation Professionals.

Since July, 1980 he has been regularly employed as an independent consultant in state utility regulatory proceedings across the nation.

He has testified before the Illinois House of Representatives Subcommittee on Communications, as well as participating in numerous other schools and conferences pertaining to the utility industry.

RELEVANT WORK EXPERIENCE OF WILLIAM DUNKEL

ALASKA

- ML&P	Docket No. U-06-006
- ACS of Anchorage	Docket No. U-01-34
- ACS	
General rate case	Docket Nos. U-01-83, U-01-85, U-01-87
AFOR proceeding	Docket No. R-03-003
- All Companies	
Access charge proceeding	Docket No. R-01-001
- Interior Telephone Company	Docket No. U-07-75
- OTZ Telephone Cooperative	Docket No. U-03-85

ARIZONA

- U.S. West Communications (Qwest)	Cost of Service Study
Wholesale cost/UNE case	Docket No. T-00000A-00-0194
General rate case	Docket No. E-1051-93-183
Depreciation case	Docket No. T-01051B-97-0689
General rate case/AFOR proceeding	Docket No. T-01051B-99-0105
AFOR proceeding	Docket No. T-01051B-03-0454

ARKANSAS

- Southwestern Bell Telephone Company	Docket No. 83-045-U

CALIFORNIA

(on behalf of the Office of Ratepayer Advocates (ORA))

- Kerman Telephone General Rate Case	A.02-01-004

(on behalf of the California Cable Television Association)

- General Telephone of California	I.87-11-033
- Pacific Bell	
Fiber Beyond the Feeder Pre-Approval Requirement	

COLORADO

- Mountain Bell Telephone Company	
General Rate Case	Docket No. 96A-218T et al.
Call Trace Case	Docket No. 92S-040T
Caller ID Case	Docket No. 91A-462T
General Rate Case	Docket No. 90S-544T
Local Calling Area Case	Docket No. 1766
General Rate Case	Docket No. 1720
General Rate Case	Docket No. 1700

General Rate Case	Docket No. 1655
General Rate Case	Docket No. 1575
Measured Services Case	Docket No. 1620
- Independent Telephone Companies	
Cost Allocation Methods Case	Docket No. 89R-608T

<u>DELAWARE</u>

- Diamond State Telephone Company	
General Rate Case	PSC Docket No. 82-32
General Rate Case	PSC Docket No. 84-33
Report on Small Centrex	PSC Docket No. 85-32T
General Rate Case	PSC Docket No. 86-20
Centrex Cost Proceeding	PSC Docket No. 86-34

<u>DISTRICT OF COLUMBIA</u>

- C&P Telephone Company of D.C.	
Depreciation issues	Formal Case No. 926

<u>FCC</u>

- Review of jurisdictional separations	FCC Docket No. 96-45
- Developing a Unified Intercarrier Compensation Regime	CC Docket No. 01-92

<u>FLORIDA</u>

- BellSouth, GTE, and Sprint	
Fair and reasonable rates	Undocketed Special Project

<u>GEORGIA</u>

- Southern Bell Telephone & Telegraph Co.	
General Rate Proceeding	Docket No. 3231-U
General Rate Proceeding	Docket No. 3465-U
General Rate Proceeding	Docket No. 3286-U
General Rate Proceeding	Docket No. 3393-U

<u>HAWAII</u>

- GTE Hawaiian Telephone Company	
Depreciation/separations issues	Docket No. 94-0298
Resale case	Docket No. 7702

<u>ILLINOIS</u>

- Commonwealth Edison Company	
General Rate Proceeding	Docket No. 80-0546
General Rate Proceeding	Docket No. 82-0026

Section 50	Docket No. 59008
Section 55	Docket No. 59064
Section 50	Docket No. 59314
Section 55	Docket No. 59704
- Central Illinois Public Service	
Section 55	Docket No. 58953
Section 55	Docket No. 58999
Section 55	Docket No. 59000
Exchange of Facilities (Illinois Power)	Docket No. 59497
General Rate Increase	Docket No. 59784
Section 55	Docket No. 59677
- South Beloit	
General Rate Case	Docket No. 59078
- Illinois Power	
Section 55	Docket No. 59281
Interconnection	Docket No. 59435
- Verizon North Inc. and Verizon South Inc.	Docket No. 02-0560
DSL Waiver Petition Proceeding	
- Geneseo Telephone Company	
EAS case	Docket No. 99-0412
- Central Telephone Company	
(Staunton merger)	Docket No. 78-0595
- General Telephone & Electronics Co.	
Usage sensitive service case	Docket Nos. 98-0200/98-0537
General rate case (on behalf of CUB)	Docket No. 93-0301
(Usage sensitive rates)	Docket No. 79-0141
(Data Service)	Docket No. 79-0310
(Certificate)	Docket No. 79-0499
(Certificate)	Docket No. 79-0500
- General Telephone Co.	Docket No. 80-0389
- SBC	
Imputation Requirement	Docket No. 04-0461
Implement UNE Law	Docket No. 03-0323
UNE Rate Case	Docket No. 02-0864
Alternative Regulation Review	Docket No. 98-0252
- Ameritech (Illinois Bell Telephone Company)	
Area code split case	Docket No. 94-0315
General Rate Case	Docket No. 83-0005
(Centrex filing)	Docket No. 84-0111
General Rate Proceeding	Docket No. 81-0478
(Call Lamp Indicator)	Docket No. 77-0755
(Com Key 1434)	Docket No. 77-0756
(Card dialers)	Docket No. 77-0757
(Concentration Identifier)	Docket No. 78-0005

(Voice of the People)	Docket No. 78-0028
(General rate increase)	Docket No. 78-0034
(Dimension)	Docket No. 78-0086
(Customer controlled Centrex)	Docket No. 78-0243
(TAS)	Docket No. 78-0031
(Ill. Consolidated Lease)	Docket No. 78-0473
(EAS Inquiry)	Docket No. 78-0531
(Dispute with GTE)	Docket No. 78-0576
(WUI vs. Continental Tel.)	Docket No. 79-0041
(Carle Clinic)	Docket No. 79-0132
(Private line rates)	Docket No. 79-0143
(Toll data)	Docket No. 79-0234
(Dataphone)	Docket No. 79-0237
(Com Key 718)	Docket No. 79-0365
(Complaint - switchboard)	Docket No. 79-0380
(Porta printer)	Docket No. 79-0381
(General rate case)	Docket No. 79-0438
(Certificate)	Docket No. 79-0501
(General rate case)	Docket No. 80-0010
(Other minor proceedings)	Docket No. various
- Home Telephone Company	Docket No. 80-0220
- Northwestern Telephone Company	
Local and EAS rates	Docket No. 79-0142
EAS	Docket No. 79-0519

INDIANA

- Indiana Michigan Power Company (I&M)	Cause No. 42959
- Public Service of Indiana (PSI)	
Depreciation issues	Cause No. 39584
- Indianapolis Power and Light Company	
Depreciation issues	Cause No. 39938

IOWA

- U S West Communications, Inc.	
Local Exchange Competition	Docket No. RMU-95-5
Local Network Interconnection	Docket No. RPU-95-10
General Rate Case	Docket No. RPU-95-11

KANSAS

- Southwestern Bell Telephone Company	
Commission Investigation of the KUSF	Docket No. 98-SWBT-677-GIT
- Rural Telephone Service Company	
Audit and General rate proceeding	Docket No. 00-RRLT-083-AUD
Request for supplemental KUSF	Docket No. 00-RRLT-518-KSF

- Southern Kansas Telephone Company	
Audit and General rate proceeding	Docket No. 01-SNKT-544-AUD
- Pioneer Telephone Company	
Audit and General rate proceeding	Docket No. 01-PNRT-929-AUD
- Craw-Kan Telephone Cooperative, Inc.	
Audit and General rate proceeding	Docket No. 01-CRKT-713-AUD
- Sunflower Telephone Company, Inc.	
Audit and General rate proceeding	Docket No. 01-SFLT-879-AUD
- Bluestem Telephone Company, Inc.	
Audit and General rate proceeding	Docket No. 01-BSST-878-AUD
- Home Telephone Company, Inc.	
Audit and General rate proceeding	Docket No. 02-HOMT-209-AUD
- Wilson Telephone Company, Inc.	
Audit and General rate proceeding	Docket No. 02-WLST-210-AUD
- S&T Telephone Cooperative Association, Inc.	
Audit and General rate proceeding	Docket No. 02-S&TT-390-AUD
- Blue Valley Telephone Company, Inc.	
Audit and General rate proceeding	Docket No. 02-BLVT-377-AUD
- JBN Telephone Company	
Audit and General rate proceeding	Docket No. 02-JBNT-846-AUD
- S&A Telephone Company	
Audit and General rate proceeding	Docket No. 03-S&AT-160-AUD
- Wheat State Telephone Company, Inc.	
Audit and General rate proceeding	Docket No. 03-WHST-503-AUD
- Haviland Telephone Company, Inc.	
Audit and General rate proceeding	Docket No. 03-HVDT-664-RTS

MAINE

- New England Telephone Company	
General rate proceeding	Docket No. 92-130
- Verizon	
AFOR investigation	Docket No. 2005-155

MARYLAND

- Chesapeake and Potomac Telephone Company	
General rate proceeding	Docket No. 7851
Cost Allocation Manual Case	Case No. 8333
Cost Allocation Issues Case	Case No. 8462
- Verizon Maryland	
PICC rate case	Case No. 8862
USF case	Case No. 8745
- Washington Gas Light Company	
Depreciation Rate Case	Case No. 8960

-	Chesapeake Utilities Corporation	
	General rate proceeding	Case No. 9062

MINNESOTA

-	Access charge (all companies)	Docket No. P-321/CI-83-203
-	U. S. West Communications, Inc. (Northwestern Bell Telephone Co.)	
	Centrex/Centron proceeding	Docket No. P-421/91-EM-1002
	General rate proceeding	Docket No. P-321/M-80-306
	Centrex Dockets	MPUC No. P-421/M-83-466
		MPUC No. P-421/M-84-24
		MPUC No. P-421/M-84-25
		MPUC No. P-421/M-84-26
	General rate proceeding	MPUC No. P-421/GR-80-911
	General rate proceeding	MPUC No. P-421/GR-82-203
	General rate case	MPUC No. P-421/GR-83-600
	WATS investigation	MPUC No. P-421/CI-84-454
	Access charge case	MPUC No. P-421/CI-85-352
	Access charge case	MPUC No. P-421/M-86-53
	Toll Compensation case	MPUC No. P-999/CI-85-582
	Private Line proceeding	Docket No. P-421/M-86-508
-	AT&T	
	Intrastate Interexchange	Docket No. P-442/M-87-54

MISSISSIPPI

-	South Central Bell	
	General rate filing	Docket No. U-4415

MISSOURI

-	Southwestern Bell	
	General rate proceeding	TR-79-213
	General rate proceeding	TR-80-256
	General rate proceeding	TR-82-199
	General rate proceeding	TR-86-84
	General rate proceeding	TC-89-14, et al.
	Alternative Regulation	TC-93-224/TO-93-192
-	United Telephone Company	
	Depreciation proceeding	TR-93-181
-	All companies	
	Extended Area Service	TO-86-8
	EMS investigation	TO-87-131
	Cost of Access Proceeding	TR-2001-65

NEW JERSEY

-	New Jersey Bell Telephone Company	
	General rate proceeding	Docket No. 802-135
	General rate proceeding	BPU No. 815-458
		OAL No. 3073-81
	Phase I - General rate case	BPU No. 8211-1030
		OAL No. PUC10506-82
	General rate case	BPU No. 848-856
		OAL No. PUC06250-84
	Division of regulated	BPU No. TO87050398
	from competitive services	OAL No. PUC 08557-87
	Customer Request Interrupt	Docket No. TT 90060604

NEW MEXICO

-	U.S. West Communications, Inc.	
	E-911 proceeding	Docket No. 92-79-TC
	General rate proceeding	Docket No. 92-227-TC
	General rate/depreciation proceeding	Case No. 3008
	Subsidy Case	Case No. 3325
	USF Case	Case No. 3223
-	VALOR Communications	
	Subsidy Case	Case No. 3300
	Interconnection Arbitration	Case No. 3495

OHIO

-	Ohio Bell Telephone Company	
	General rate proceeding	Docket No. 79-1184-TP-AIR
	General rate increase	Docket No. 81-1433-TP-AIR
	General rate increase	Docket No. 83-300-TP-AIR
	Access charges	Docket No. 83-464-TP-AIR
-	General Telephone of Ohio	
	General rate proceeding	Docket No. 81-383-TP-AIR
-	United Telephone Company	
	General rate proceeding	Docket No. 81-627-TP-AIR

OKLAHOMA

-	Public Service of Oklahoma	
	Depreciation case	Cause No. 96-0000214

PENNSYLVANIA

-	GTE North, Inc.	
	Interconnection proceeding	Docket No. A-310125F002
-	Bell Telephone Company of Pennsylvania	
	Alternative Regulation proceeding	Docket No. P-00930715
	Automatic Savings	Docket No. R-953409

Rate Rebalance	Docket No. R-00963550
- Enterprise Telephone Company	
General rate proceeding	Docket No. R-922317
- All companies	
InterLATA Toll Service Invest.	Docket No. I-910010
Joint Petition for Global Resolution of Telecommunications Proceedings	Docket Nos. P-00991649, P-00991648, M-00021596
- GTE North and United Telephone Company	
Local Calling Area Case	Docket No. C-902815
- Verizon	
Joint Application of Bell Atlantic and GTE for Approval of Agreement and Plan of Merger	Docket Nos. A-310200F0002, A-311350F0002, A-310222F0002, A-310291F0003
Access Charge Complaint Proceeding	Docket No. C-200271905

<u>SOUTH DAKOTA</u>

- Northwestern Bell Telephone Company	
General rate proceeding	Docket No. F-3375

<u>TENNESSEE</u>
(on behalf of Time Warner Communications)

- BellSouth Telephone Company	
Avoidable costs case	Docket No. 96-00067

<u>UTAH</u>

- U.S. West Communications (Mountain Bell Telephone Company)	
General rate case	Docket No. 84-049-01
General rate case	Docket No. 88-049-07
800 Services case	Docket No. 90-049-05
General rate case/ incentive regulation	Docket No. 90-049-06/90-049-03
General rate case	Docket No. 92-049-07
General rate case	Docket No. 95-049-05
General rate case	Docket No. 97-049-08
Qwest Price Flexibility-Residence	Docket No. 01-2383-01
Qwest Price Flexibility-Business	Docket No. 02-049-82
Qwest Price Flexibility-Residence	Docket No. 03-049-49
Qwest Price Flexibility-Business	Docket No. 03-049-50

<u>VIRGIN ISLANDS, U.S.</u>

- Virgin Islands Telephone Company	
General rate case	Docket No. 264
General rate case	Docket No. 277
General rate case	Docket No. 314

General rate case	Docket No. 316

<u>VIRGINIA</u>

- General Telephone Company of the South

Jurisdictional allocations	Case No. PUC870029
Separations	Case No. PUC950019

<u>WASHINGTON</u>

- US West Communications, Inc.

Interconnection case	Docket No. UT-960369
General rate case	Docket No. UT-950200

- All Companies- Analyzed the local calling areas in the State

<u>WISCONSIN</u>

- Wisconsin Bell Telephone Company

Private line rate proceeding	Docket No. 6720-TR-21
General rate proceeding	Docket No. 6720-TR-34

SCHEDULE WWD 2

IS DEEMED HIGHLY CONFIDENTIAL

Form 10-K

UNION ELECTRIC CO - UEP

Filed: March 07, 2006 (period: December 31, 2005)

Annual report which provides a comprehensive overview of the company for the past year

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regulatory actions, strategies and alternatives that Ameren and the Ameren Illinois utilities are considering will be successful.

In December 2005, the Ameren Illinois utilities filed with the ICC proposed new tariffs that would increase revenues from electric delivery services, effective January 2, 2007, based on a proposed residential rate phase-in plan, by $156 million (CIPS – $14 million, CILCO – $33 million, IP – $109 million) per year commencing in 2007 and an additional $46 million (CILCO – $10 million, IP – $36 million) per year commencing in 2008. These proposed tariffs are subject to approval of, and reduction by, the ICC, which is expected to rule by November 2006. We cannot predict the outcome of these proceedings.

As a part of the settlement of UE's Missouri electric rate case in 2002, UE undertook to use commercially reasonable efforts to make critical energy infrastructure investments of $2.25 billion to $2.75 billion from January 1, 2002, through June 30, 2006. Ameren also committed IP to make between $275 million and $325 million in energy infrastructure investments over its first two years of ownership, in conjunction with the ICC's approval of Ameren's acquisition of IP. UE's agreement to a rate moratorium in Missouri and CIPS', CILCO's and IP's rate freezes mean that capital expenditures will not become recoverable in rates and will not earn a return before at least July 1, 2006, for UE and January 2, 2007, for CIPS, CILCO and IP. In the current climate of rate reductions and rate moratoriums, any new energy infrastructure and new programs could result in increased financing requirements for UE, CIPS, CILCO and IP. This could have a material impact on our results of operations, financial position, and liquidity.

As of December 31, 2005, the Ameren Companies did not have, in either Missouri or Illinois, a rate adjustment clause for their electric operations that would allow them to recover the costs for purchased power or increased fuel costs from customers. Therefore, in so far as we have not hedged our fuel and power costs, we are exposed to changes in fuel and power prices to the extent that fuel for our electric generating facilities and power must be purchased on the open market. See the Outlook section in Management's Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Note 3 – Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for a discussion of Missouri legislation enabling a fuel and purchased power adjustment clause and an ICC order allowing for the recovery of power costs, effective January 2, 2007.

Steps taken and being considered at the federal and state levels continue to change the structure of the electric industry and utility regulation. At the federal level, FERC has been mandating changes in the regulatory framework for transmission-owning public utilities such as UE, CIPS, CILCO and IP.

Principally because of rate reductions and rate moratoriums that affect certain Ameren Companies, increased costs and investments have caused decreased returns in Ameren's distribution utility businesses. See Note 3 – Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report. In response to competitive, economic, political, legislative and regulatory pressures, we may be subject to further rate moratoriums, rate refunds, limits on rate increases or rate reductions, including phase-in plans. Any or all of these could have a significant adverse effect on our results of operations, financial position, or liquidity.

Increased federal and state environmental regulation will require UE, Genco, CILCO (primarily through AERG) and EEI to incur large capital expenditures and to increase operating costs.

About 61% of Ameren's generating capacity is coal-fired. The rest is nuclear, gas-fired, hydroelectric, and oil-fired. In May 2005, the EPA issued final regulations with respect to SO_2, NO_x, and mercury emissions from coal-fired power plants. The new rules require significant additional reductions in these emissions from UE, Genco, AERG and EEI power plants in phases, beginning in 2009. Preliminary estimates of capital compliance costs for Ameren, UE, Genco and AERG range from $2.1 billion to $2.9 billion by 2016.

State regulators are required to submit state implementation plans for SO_2, NO_x and mercury emissions controls in 2006. In January 2006, the governor of Illinois recommended that the Illinois EPA adopt rules for limitations on mercury emissions which would be significantly stricter than the federal rules. The drafting of state rules is still in its early stages, but should stricter rules be adopted, they would change the overall environmental compliance strategy for UE's, Genco's, AERG's and EEI's coal-fired power plants and increase related costs from previous estimates.

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies among our generating facilities. Coal-fired power plants, however, are significant sources of carbon dioxide, a principal greenhouse gas. The related Kyoto Protocol was signed by the United States but has since been rejected by the president, who instead has asked for an 18% decrease in carbon intensity

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on a voluntary basis. In response to the administration's request, six electric power sector trade associations, including the Edison Electric Institute, of which Ameren is a member, and the TVA, signed a Memorandum of Understanding (MOU) with the DOE in December 2004 calling for a 3% to 5% voluntary decrease in carbon intensity by the utility sector between 2002 and 2012. Currently, Ameren is considering various initiatives to comply with the MOU, including increased generation at our nuclear and hydroelectric power plants, increased efficiency measures at our coal-fired units, and investing in renewable energy and carbon sequestration projects.

The EPA has been conducting an enforcement initiative to determine whether modifications at a number of coal-fired power plants owned by electric utilities in the United States are subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. The EPA's inquiries focus on whether the best available emission control technology was or should have been used at such power plants when major maintenance or capital improvements were made.

In April 2005, Genco received a request from the EPA for information pursuant to Section 114(a) of the Clean Air Act, seeking detailed operating and maintenance history data with respect to its Meredosia, Hutsonville, Coffeen and Newton facilities, EEI's Joppa facility, and AERG's E.D. Edwards and Duck Creek facilities. All of these facilities are coal-fired plants. The information request requires Genco to respond to specific EPA questions about certain projects and maintenance activities in order to determine its compliance with certain Illinois air pollution and emissions rules and with the New Source Performance Standards required by the Clean Air Act. This information request is being complied with, but we cannot predict the outcome of this matter.

We are unable to predict the ultimate effect of any new environmental regulations, voluntary compliance guidelines, enforcement initiatives, or legislation on our results of operations, financial position, or liquidity. Any of these factors could result in a significant increase in capital expenditures, penalties and operating costs for UE, Genco, CILCO (primarily through AERG) and EEI. Therefore, such factors could also result in increased financing requirements for these Ameren companies. Although costs incurred by UE would be eligible for recovery in rates over time, subject to MoPSC approval in a rate proceeding, there is no similar mechanism for recovery of costs by Genco, AERG or EEI in Illinois.

UE's, CIPS', CILCO's and IP's participation in the MISO could continue to increase costs, reduce revenues, and reduce UE's, CIPS', CILCO's and IP's control over their transmission assets. Genco could also incur increased costs or reduced revenues by its participation in the MISO Day Two Energy Market.

On May 1, 2004, functional control of the UE and CIPS transmission systems was transferred to the MISO. On September 30, 2004, IP transferred functional control of its transmission system to the MISO. CILCO had transferred functional control of its transmission system to the MISO before its acquisition by Ameren. UE, CIPS, CILCO and IP may be required to incur expenses or expand their transmission systems according to decisions made by MISO rather than according to their internal planning process. See Note 3 – Rate and Regulatory Matters, to our financial statements under Part II, Item 8, of this report.

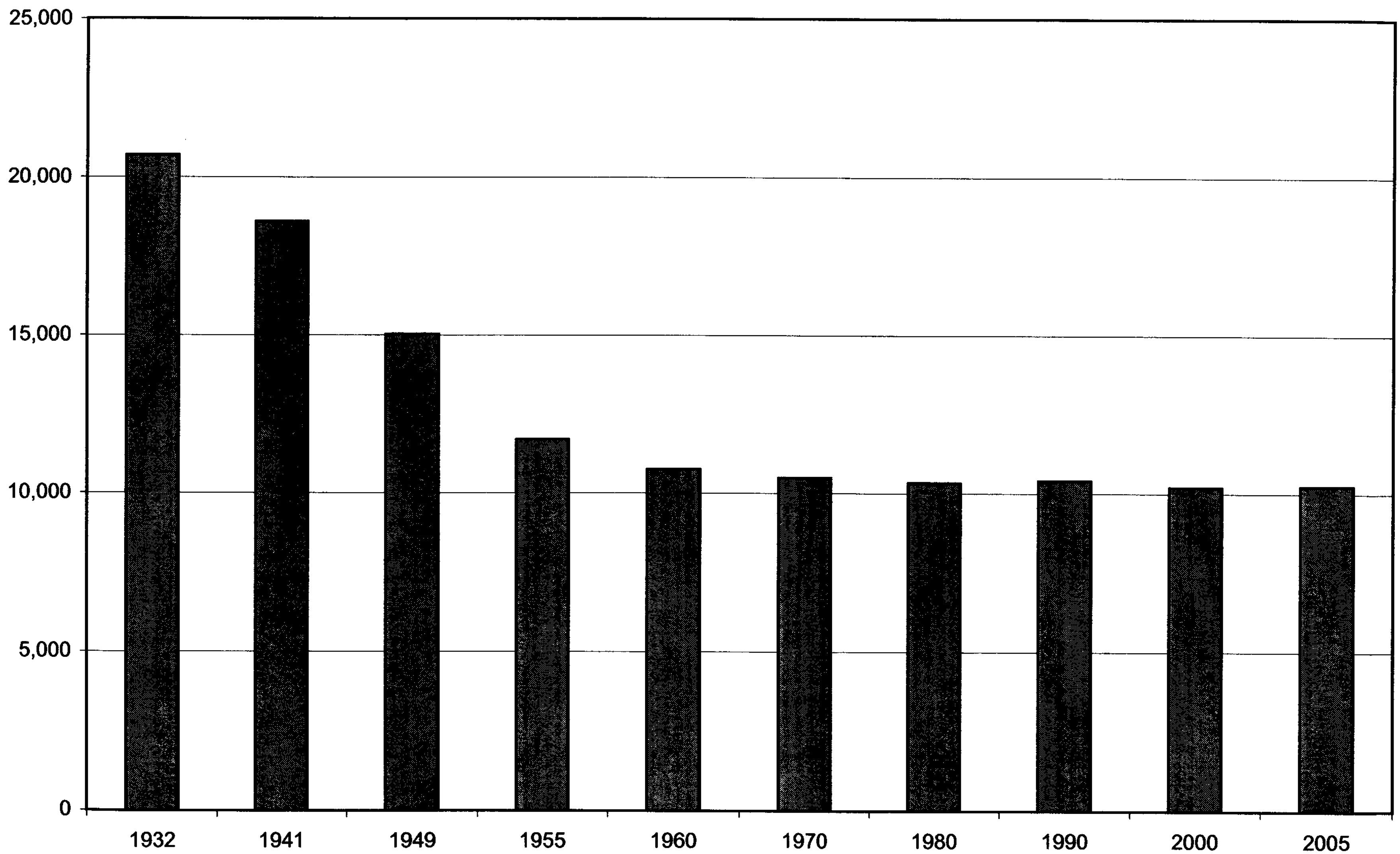
The MISO Day Two Energy Market, which began operation on April 1, 2005, is designed to improve transparency of power pricing and efficiency in generation dispatch. This is a new and complex market, which has incurred significant price volatility and suboptimal dispatching of power plants. In addition, the sale of power in this market-based environment has resulted in unanticipated transmission congestion and other settlement charges.

Until we achieve a greater degree of operational experience participating in the MISO, including the MISO Day Two Energy Market, there is considerable uncertainty as to the impact of our MISO participation. In addition, there is uncertainty regarding whether we will continue to participate in MISO, as well as the impact of ongoing RTO developments at FERC. We are unable to predict the impact these issues could have on our results of operations, financial position, or liquidity.

Increasing costs associated with our defined benefit retirement plans, health care plans, and other employee-related benefits may adversely affect our results of operations, financial position, or liquidity.

We offer defined benefit and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, returns on investments, interest rates, and other actuarial assumptions have a significant impact on our earnings and funding requirements. At December 31, 2005, assuming continuation of the recently expired federal interest rate relief beyond 2006, we do not expect future contributions to be required to maintain minimum funding levels for Ameren's pension plans until 2011, at which time we would expect a required contribution of $100 million to $150 million. If federal interest rate relief is not continued in its most recent form, $200 million to $300 million may be needed in 2009 to 2010 based on other recent federal legislative proposals. In the meantime, we may continue our practice of making voluntary contributions to maintain more prudent funded levels than minimally required. These

U.S. Steam Production Heat Rates



U.S. Steam Production Heat Rates

(a Plant with a 20,000 heat rate burns twice as much fuel (measured in Btu's)
per kWh of output as a Plant with a 10,000 heat rate)

Year	Heat Rate, Btu per kWh
1902	92,500
1932	20,700
1941	18,600
1949	15,033
1955	11,699
1960	10,760
1970	10,494
1980	10,338
1990	10,402
2000	10,201
2005	10,241

Table 6. Approximate Heat Rates for Electricity, 1949-2005. http://www.eia.doe.gov/Aer/Txt/stb1306.xls and Appendix A, History of the U.S. ElectricPower Industry, 1882-1991 http://www.eia.doe.gov/cneaf/electricity/page/electric_kid/append_a.html visited on 11/16/2006

Non-Proprietary

Addition to the Pro Forma Depreciation Reserve
For the Accruals in the Period 7/2006 to 12/2006
That Result from the Depreciation Accruals on the "Existing" Plant.
("Existing" Plant is the Plant Investment That Existed as of June 30, 2006)

1. Annual Depreciation Expense At the Current Depreciation Rates On the Investment as of June 30, 2006.[1]	$	319,192,698
2. Divide by 2, to Determine Six Month's Value		2
3. Six Months Annual Depreciation Expense on the Existing Investment.	$	159,596,349
4. Allocation to the Missouri Jurisdiction[2]		0.9905
5. 7/2006 to 12/2006 Annual Depreciation Expense on the Existing Investment-Mo. Jurisdictional	**$**	**158,081,873**

1. Source: AmerenUE Depreciation "Rate Adjustment"
Workpaper, Provide in Response to MPSC 1(c)
("rate adjustment" is non-confidential per 12/13/06 E-mail from Jim Lowery(AmerenUE))
This does not include amortizations, or Coal Cars , Transportation equipment (Acct 392) or
Power Operated Equipment (Acct.396), because they receive special treatments
that may not result in them adding to the depreciation reserve.

2. Source

Missouri Jurisdiction from Company Schedule GSW- E-21-2:	$	4,495,359,000
Total from Company Schedule GSW- E-21-2:	$	4,538,426,000
Ratio -Mo Jurisdictional Divide by Total		0.9905

$1,000 Investment installed in 1962

Account 364 - Distribution Poles and Fixtures
Average Life in Years:[1] 43

A Year	B U.S. CPI-U Index[2]	$C=B/B_{Prior\ Yr}-1$ One Year Inflation	D Investment Amount, Original Cost	$E = E_{Prior\ Yr.}*B/B_{Prior\ Yr})$ Net Salvage[3]	F = E/D Net Salvage Percent
1962	30.20		$1,000 In 1962 $	-$209 in 1962 $	-21%
1963	30.60	1.3%	$1,000 In 1962 $	-$212 in 1963 4	-21%
1964	31.00	1.3%	$1,000 In 1962 $	-$214 in 1964$	-21%
1965	31.50	1.6%	$1,000 In 1962 $	-$218 In 1965 $	-22%
1966	32.40	2.9%	$1,000 In 1962 $	-$224 In 1966 $	-22%
1967	33.40	3.1%	$1,000 In 1962 $	-$231 In 1967 $	-23%
1968	34.80	4.2%	$1,000 In 1962 $	-$241 In 1968 $	-24%
1969	36.70	5.5%	$1,000 In 1962 $	-$254 In 1969 $	-25%
1970	38.80	5.7%	$1,000 In 1962 $	-$268 In 1970 $	-27%
1971	40.50	4.4%	$1,000 In 1962 $	-$280 In 1971 $	-28%
1972	41.80	3.2%	$1,000 In 1962 $	-$289 In 1972 $	-29%
1973	44.40	6.2%	$1,000 In 1962 $	-$307 In 1973 $	-31%
1974	49.30	11.0%	$1,000 In 1962 $	-$341 In 1974 $	-34%
1975	53.80	9.1%	$1,000 In 1962 $	-$372 In 1975 $	-37%
1976	56.90	5.8%	$1,000 In 1962 $	-$393 In 1976 $	-39%
1977	60.60	6.5%	$1,000 In 1962 $	-$419 In 1977 $	-42%
1978	65.20	7.6%	$1,000 In 1962 $	-$451 In 1978 $	-45%
1979	72.60	11.3%	$1,000 In 1962 $	-$502 In 1979 $	-50%
1980	82.40	13.5%	$1,000 In 1962 $	-$570 In 1980 $	-57%
1981	90.90	10.3%	$1,000 In 1962 $	-$628 In 1981 $	-63%
1982	96.50	6.2%	$1,000 In 1962 $	-$667 In 1982 $	-67%
1983	99.60	3.2%	$1,000 In 1962 $	-$688 In 1983 $	-69%
1984	103.90	4.3%	$1,000 In 1962 $	-$718 In 1984 $	-72%
1985	107.60	3.6%	$1,000 In 1962 $	-$744 In 1985 $	-74%
1986	109.60	1.9%	$1,000 In 1962 $	-$758 In 1986 $	-76%
1987	113.60	3.6%	$1,000 In 1962 $	-$785 In 1987 $	-79%
1988	118.30	4.1%	$1,000 In 1962 $	-$818 In 1988 $	-82%
1989	124.00	4.8%	$1,000 In 1962 $	-$857 In 1989 $	-86%
1990	130.70	5.4%	$1,000 In 1962 $	-$903 In 1990 $	-90%
1991	136.20	4.2%	$1,000 In 1962 $	-$941 In 1991 $	-94%
1992	140.30	3.0%	$1,000 In 1962 $	-$970 In 1992 $	-97%
1993	144.50	3.0%	$1,000 In 1962 $	-$999 In 1993 $	-100%
1994	148.20	2.6%	$1,000 In 1962 $	-$1,024 In 1994 $	-102%
1995	152.40	2.8%	$1,000 In 1962 $	-$1,053 In 1995 $	-105%
1996	156.90	3.0%	$1,000 In 1962 $	-$1,085 In 1996 $	-108%
1997	160.50	2.3%	$1,000 In 1962 $	-$1,109 In 1997 $	-111%
1998	163.00	1.6%	$1,000 In 1962 $	-$1,127 In 1998 $	-113%
1999	166.60	2.2%	$1,000 In 1962 $	-$1,152 In 1999 $	-115%
2000	172.20	3.4%	$1,000 In 1962 $	-$1,190 In 2000 $	-119%
2001	177.10	2.8%	$1,000 In 1962 $	-$1,224 In 2001 $	-122%
2002	179.88	1.6%	$1,000 In 1962 $	-$1,243 In 2002 $	-124%
2003	183.96	2.3%	$1,000 In 1962 $	-$1,272 In 2003 $	-127%
2004	188.90	2.7%	$1,000 In 1962 $	-$1,306 In 2004 $	-131%
2005	195.30	3.4%	$1,000 In 1962 $	-$1,350 In 2005 $	-135%

1 AmerenUE Depreciation Study, Schedule JFW-E1, page C-95.

2 The Consumer Price Index-Urban Index (CPI-U) shown was obtained from: http://inflationdata.com/Inflation/Consumer_Price_Index/HistoricalCPI.aspx, visited 11/30/06. The CPI-U is compiled by the Federal Bureau of Labor Statistics.

3 Net Salvage = Gross Salvage - Cost of Removal. For Poles, the Gross Salvage is generally small, and the Net Salvage is primarily the result of the Cost of Removal.

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

Requested From: Bill Dunkel

Data Request No. OPC 5006

Referring to page B-82 of the 2005 Gannett Fleming depreciation study pertaining to the electric utility (Schedule JFW-E1) on the year ¿2005¿ line:
(a) Is it correct that the figure in the ¿cost of removal percent¿ column is the cost of removal in 2005, divided by the original cost for the retired investment, with that original cost as recorded back when the investment went into service? If this is not a correct statement, provide the corrected statement.
(b) Is it a correct statement that, everything else being equal, the greater the inflation between the time the investment went into service, and the time it was retired, the higher the cost of removal percent would be? If this is not a correct statement, provide the corrected statement.
(c) If the Future Net Salvage percent is set equal to the historic net salvage percent as determined from the historic data shown on pages B-81,B-82, and B-83, does that effectively assume that future inflation will be the same as past inflation? If not, explain why not.

Response:

a) Correct. It is the accepted accounting convention to state Property, Plant and Equipment at its original cost when acquired.

b) Yes, that is correct.

c) Yes, that is the assumption when viewed over a long term period of 30 to 40 years.

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

Requested From: Bill Dunkel

Data Request No. OPC 5005

Referring to page B-82 of the 2005 Gannett Fleming depreciation study pertaining to the electric utility (Schedule JFW-E1) on the year ¿2005¿ line:
(a) Is it correct the dollar amount in the ¿regular retirement¿ column is the original cost of the retired plant? If this is not a correct statement, provide the corrected statement.
(b) On the year ¿2005¿ line, if the ¿regular retirement¿ column included the retirement of an investment that went into service in the year 1965, is it correct the dollar amount included in the ¿regular retirement¿ column for that investment would be the original cost as recorded in the year 1965? If this is not a correct statement, provide the corrected statement.
(c) On the year ¿2005¿ line, if the ¿regular retirement¿ column included the retirement of an investment that went into service in the year 1965, is it correct the dollar amount included in the ¿regular retirement¿ column for that investment would be in 1965 dollars? In other words, is it correct you have not made any adjustment for inflation or for the change in the values of a dollar over time to that ¿original cost' amount that was recorded in 1965 dollars? If this is not a correct statement, provide the corrected statement.
(d) On the year ¿2005¿ line, is it correct that the amount in the ¿cost of removal amount¿ column is the cost paid in the year 2005? If this is not a correct statement, provide the corrected statement.
(e) On the year ¿2005¿ line, is it correct that the amount in the ¿cost of removal amount¿ column is the amount in year 2005 dollars? If this is not a correct statement, provide the corrected statement.

Response:

a) Correct. The retirement amounts listed are the original cost of retired plant recorded in that accounting year.

b) Correct. The retirement amount listed for 2005 includes the original cost amount for poles installed in numerous years. The retirement amounts listed are stated at original cost.

c) Correct.

d) Correct.

e) Correct.

Prepared By: John Wiedmayer

Title: Project Manager, Depreciation Studies

Date: December 7, 2006

	CPI-U Index	Annual Inflation
1913	9.90	
1914	10.00	1.0%
1915	10.10	1.0%
1916	10.90	7.9%
1917	12.80	17.4%
1918	15.10	18.0%
1919	17.30	14.6%
1920	20.00	15.6%
1921	17.90	-10.5%
1922	16.80	-6.1%
1923	17.10	1.8%
1924	17.10	0.0%
1925	17.50	2.3%
1926	17.70	1.1%
1927	17.40	-1.7%
1928	17.10	-1.7%
1929	17.10	0.0%
1930	16.70	-2.3%
1931	15.20	-9.0%
1932	13.70	-9.9%
1933	13.00	-5.1%
1934	13.40	3.1%
1935	13.70	2.2%
1936	13.90	1.5%
1937	14.40	3.6%
1938	14.10	-2.1%
1939	13.90	-1.4%
1940	14.00	0.7%
1941	14.70	5.0%
1942	16.30	10.9%
1943	17.30	6.1%
1944	17.60	1.7%
1945	18.00	2.3%
1946	19.50	8.3%
1947	22.30	14.4%
1948	24.10	8.1%
1949	23.80	-1.2%
1950	24.10	1.3%
1951	26.00	7.9%
1952	26.50	1.9%
1953	26.70	0.8%
1954	26.90	0.7%
1955	26.80	-0.4%
1956	27.20	1.5%
1957	28.10	3.3%
1958	28.90	2.8%
1959	29.10	0.7%
1960	29.60	1.7%
1961	29.90	1.0%

U.S. Consumer Price Index-Urban (CPI-U)

	CPI-U Index	Annual Inflation	
1962	30.20	1.0%	
1963	30.60	1.3%	
1964	31.00	1.3%	
1965	31.50	1.6%	
1966	32.40	2.9%	
1967	33.40	3.1%	
1968	34.80	4.2%	
1969	36.70	5.5%	
1970	38.80	5.7%	
1971	40.50	4.4%	
1972	41.80	3.2%	
1973	44.40	6.2%	
1974	49.30	11.0%	
1975	53.80	9.1%	
1976	56.90	5.8%	
1977	60.60	6.5%	
1978	65.20	7.6%	
1979	72.60	11.3%	
1980	82.40	13.5%	
1981	90.90	10.3%	
1982	96.50	6.2%	
1983	99.60	3.2%	
1984	103.90	4.3%	
1985	107.60	3.6%	
1986	109.60	1.9%	
1987	113.60	3.6%	
1988	118.30	4.1%	
1989	124.00	4.8%	
1990	130.70	5.4%	
1991	136.20	4.2%	
1992	140.30	3.0%	
1993	144.50	3.0%	
1994	148.20	2.6%	
1995	152.40	2.8%	
1996	156.90	3.0%	
1997	160.50	2.3%	
1998	163.00	1.6%	
1999	166.60	2.2%	
2000	172.20	3.4%	
2001	177.10	2.8%	
2002	179.88	1.6%	
2003	183.96	2.3%	
2004	188.90	2.7%	
2005	195.30	3.4%	
2006	202.90	3.9%	Value in June, 2006

1982 to 1984=100

Source: http://inflationdata.com/Inflation/Consumer_Price_Index/HistoricalCPI.aspx

Visited on November 30, 2006

Company:	AmerenUE	Non-Proprietary
Account Number:	364	
Account Name:	Poles and Fixtures-Distribution	
Avg Life:	43	

Adjusting Net Salvage Percent
For Future Annual Inflation Rate of 2.50%

		Original Cost Of Investment Retired	Net Salvage	Net Salvage Percent
(1)	Average in Last 10 Years[1]	$1,880,364	-$2,960,447	-157%
(2)	Average Annual Historic Inflation Rate Over the Average Life For Investments That Retired In the Last 10 Years[2]		4.31%	
(3)	Remove Historic Inflation[3]	$1,880,364	-$481,629	-26%
(4)	Adjust Net Salvage for Future Inflation At:[4] 2.50%	$1,880,364	-$1,392,638	**-74%**

Source Notes:

1. Page 2 of This Document
2. Page 3 of This Document
3. -$2,960,447 / (+1+ 0.0431)^ Pol = -$481,629
4. -$481,629 *(+1+ 2.50%)^ Pol = -$1,392,638

Company:	AmerenUE
Account Number:	364
Account Name:	Poles and Fixtures-Distribution
Avg Life:	43

Non-Proprietary

Historic Net Salvage Data-Retirements Last Ten Years

	Regular Retirements (Original Cost)	Net Salvage	
1996	$2,502,125	-$3,006,896	
1997	$2,307,518	-$3,228,311	
1998	$1,253,244	-$3,052,025	
1999	$2,183,536	-$3,149,686	
2000	$1,232,534	-$2,776,018	
2001	$2,039,883	-$2,717,941	
2002	$2,515,869	-$2,129,234	
2003	$1,563,294	-$2,988,607	
2004	$1,544,166	-$2,940,686	
2005	$1,661,473	-$3,615,069	
Total-10 Years	$18,803,642	-$29,604,473	
Average in Last 10 Years	$1,880,364	-$2,960,447	-157%
Per Million of Original Cost at Historic Inflation	$1,000,000	-$1,574,401	-157%

Source: This Account on Pages B-81 to B-141,
AmerenUE Depreciation study, Schedule JFW-E1.

Company: AmerenUE
Account Number: 364
Account Name: Poles and Fixtures-Distribution
Avg Life: 43

Non-Proprietary

Calculation of the Average Annual Inflation Rate
Between Plant in Service and Retirement
For Average Life Investment Retired in the Last Ten Years

Retire In Year	Average Life	Average Installed In	CPI-U Install Year	CPI-U Removal Year	Historic Inflation Ratio, Install to Removal Period	Average Annual Inflation Factor	Average Annual Inflation Over Average Life
(A)	(B)	(C)=(A)-(B)	(D)	(E)	(F)=(E)/(D)	(G)= (F)^(1/(B))	(H)= ((G)-1)*100%
1996	43	1953	26.70	156.90	5.88	1.042045	4.20%
1997	43	1954	26.90	160.50	5.97	1.042414	4.24%
1998	43	1955	26.80	163.00	6.08	1.042879	4.29%
1999	43	1956	27.20	166.60	6.13	1.043049	4.30%
2000	43	1957	28.10	172.20	6.13	1.043062	4.31%
2001	43	1958	28.90	177.10	6.13	1.043061	4.31%
2002	43	1959	29.10	179.88	6.18	1.043272	4.33%
2003	43	1960	29.60	183.96	6.21	1.043403	4.34%
2004	43	1961	29.90	188.90	6.32	1.043801	4.38%
2005	43	1962	30.20	195.30	6.47	1.044368	4.44%
Average Last Ten Year					6.15		4.31%

Impact of Utilizing 2.5% Annual Future Inflation In Determining Future Net Salvage in the Electric "Mass" Accounts (Transmission and Distribution)

Account Number[1]	Account Name	Investment 12/31/2005[2]	AmerenUE Proposed Annual Accrual Prior to Application of Salvage Percent[3]	AmerenUE Proposed Net Salvage Percent	AmerenUE Proposed Net Salvage Annual $[4]	Net Salvage Percent At 2.5% Future Annual Inflation	Net Salvage Annual $ At 2.5% Future Annual Inflation	Difference In Annual Accruals
	Transmission:							
354	Towers and Fixtures	$ 68,198,477	$ 1,050,257	-10%	$ 105,026	-5%	$ 48,682	$ (56,344)
355	Poles and Fixtures-Transmission	$ 103,511,061	$ 1,987,389	-90%	$ 1,788,650	6%	$ (112,080)	$ (1,900,730)
356	Overhead Conductors and Devices-Transmission	$ 112,346,062	$ 2,041,020	-25%	$ 510,255	-4%	$ 81,685	$ (428,570)
	Distribution:							
364	Poles and Fixtures	$ 653,216,782	$ 15,218,126	-135%	$ 20,544,469	-74%	$ 11,270,874	$ (9,273,596)
365	Overhead Conductors and Devices	$ 712,573,522	$ 15,177,816	-50%	$ 7,588,908	-30%	$ 4,623,860	$ (2,965,048)
366	Underground Conduit[5]	$ 164,964,341	$ 2,540,451	-50%	$ 1,270,225	0%	$ -	$ (1,270,225)
367	Underground Conductors and Devices	$ 447,520,715	$ 8,458,142	-25%	$ 2,114,535	-28%	$ 2,365,710	$ 251,175
369.01	Overhead Services	$ 123,917,172	$ 3,340,489	-200%	$ 6,680,978	-95%	$ 3,185,940	$ (3,495,038)
369.02	Underground Services	$ 118,053,966	$ 2,618,125	-80%	$ 2,094,500	-64%	$ 1,663,694	$ (430,806)
373	Street Lighting and Signal Systems	$ 100,172,902	$ 3,035,239	-45%	$ 1,365,858	-22%	$ 682,006	$ (683,851)
	Total				$ 44,063,405		$ 23,810,370	$ (20,253,034)
	Allocate to the Missouri Jurisdiction[6]							0.9905
	Difference at 2.5% Future Annual Inflation Rate							($20,060,630)

Notes:

(1) Transmission and Distribution accounts with significant net salvage $.

(2) From Pages III-4 to III-7, AmerenUE Depreciation Study, Schedule JFW-E1

(3) From Pages C-1 to C-142 for the listed account, AmerenUE Depreciation Study, Schedule JFW-E1
This does not imply endorsement of the AmerenUE proposed annual accruals.
Everything else is kept constant to isolate the impact of the difference in future inflation rates.

(4) From Pages C-1 to C-142 for the listed account, AmerenUE Depreciation Study, Schedule JFW-E1

(5) The Net Salvage for Underground Conduit is highly positive for the Last 10 years, and is positive overall.
This positive net salvage is primarily as the result of a very large gross salvage in 2004.
To be conservative I will use zero net salvage instead of the large positive net salvage indicated by the data.

(6) Ratio from AmerenUE Schedule GSW-E-21-2