Exhibit No.:
Issue: Allocations;
Depreciation;
Staff's Updated EMS Run, Etc.
Witness: Don A. Frerking
Type of Exhibit: Rebuttal Testimony
Sponsoring Party: Kansas City Power & Light Company
Case No.: ER-2006-0314
Date Testimony Prepared: September 8, 2006

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2006-0314

REBUTTAL TESTIMONY

OF

DON A. FRERKING

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
September 2006

REBUTTAL TESTIMONY

OF

DON A. FRERKING

Case No. ER-2006-0314

Q. Please state your name and business address.

A. My name is Don A. Frerking. My business address is 1201 Walnut, Kansas City, Missouri 64106.

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

A. I am employed by Kansas City Power & Light Company ("KCPL") as Senior Regulatory Analyst.

Q. Are you the same Don A. Frerking who pre-filed direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut the testimony of Staff witnesses Erin L. Maloney regarding Demand allocation and Rosella L. Schad regarding depreciation. I will also be rebutting the Staff's use of an Energy allocation for off-system sales "margins".

Q. Are there any corrections or clarifications that you would like to make to your direct testimony or other information that you previously provided at this time?

A. Yes. I would like to correct an error in the calculation of the "Unused Energy " allocator, which KCPL is proposing to use as the basis for allocating off-system sales "margins". The "Available Energy" component of the calculation was incorrectly calculated by utilizing the average coincident peak ("CP") loads. The correct megawatts ("MW") for calculation of the "Available Energy" should have been based on the total "Available Capacity" as allocated using the jurisdictional Demand allocation factors. The corrected calculation of the "Unused Energy" allocator is attached to this testimony as Schedule DAF-6. This corrected calculation included in Schedule DAF-6 has also been submitted as a corrected response to MPSC Data Request No. 502.

Q. What was the impact of the corrected calculation on the "Unused Energy" allocator?

A. Based on the load, energy usage, and Demand allocation methodology assumptions in the Company's June Update, the Missouri jurisdictional "Unused Energy" allocation factor would go from 46.97% prior to the correction to 51.55% after the correction. Based on the Company's proposed level of non-firm off-system energy sales "margins" in the Company's June Update, the corrected "Unused Energy" allocator would allocate approximately $3.6 million more "margin" to the Missouri jurisdiction.

Q. Will you be discussing the rationale for using the "Unused Energy" allocation factor for allocating off-system sales "margins" later in your testimony?

A. Yes. Later in my testimony, I will discuss the rationale behind the "Unused Energy" allocator and why it is more appropriate than an Energy allocator for allocating the off-system sales "margins" to the jurisdictions.

I. ALLOCATIONS

4-CP vs. 12-CP Demand Allocation

Q. What methodology did the Staff propose for Demand allocation in this case?

A. Staff Witness Erin L. Maloney recommended that a 4-CP Demand allocation methodology be utilized.

Q. Does the Company agree with Staff's recommendation for the use of a 4-CP methodology for Demand allocation?

A. No. The Company believes that a 12-CP Demand allocation methodology is more appropriate for allocating the plant and other fixed costs associated with production and transmission assets.

Q. What was the basis for Ms. Maloney's recommendation of the 4-CP Demand allocation methodology?

A. The following Q&A from Pages 7 & 8 of Ms. Maloney's direct testimony in this case describes the basis for her recommendation of the 4-CP Demand allocation methodology:

> Q. How was the decision made to recommend using the 4 CP method?
>
> A. The 4 CP methodology is appropriate for a utility, such as KCP&L, where the monthly peak demands during the non-summer months are significantly below the summer monthly peak demands. The lower demand in the non-summer months will have little or no influence on the capacity planning process and it would not be rational to consider all twelve monthly peaks in a jurisdictional allocation methodology when there are such significant statistical variations in the monthly seasonal peaks.
>
> Q. Is there additional support for the position that a 4 CP methodology is appropriate in this case?
>
> A. Yes. In various cases, the Federal Energy Regulatory Commission (FERC) has, among other things, used a number of tests as a guide in its determination of an appropriate demand methodology. These tests are arithmetical calculations whose results I compared to specific ranges determined from prior FERC decisions which suggest which methodology is more appropriate. Attached to this testimony as Schedule 3 is an excerpt (Chapter 5) from a publication entitled "A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers," Third Edition (1994), authored by Michael E. Small. As this excerpt shows, FERC has used these tests to support its adoption of a 4 CP methodology in a number of cases.

Q. Did Ms. Maloney attach to her direct a copy of Chapter 5 of the publication that she appears to have relied upon for her recommendation?

A. Chapter 5 of the publication referenced by Ms. Maloney consists of nine (9) pages starting at Page 103 and continuing through Page 111. Ms. Maloney attached only Pages 103, 105, 107, 109, and 111.

Q. Did Ms. Maloney also prepare direct testimony regarding Demand allocation methodology in a recent Empire District Electric Company rate case?

A. Yes, she did. Ms. Maloney prepared direct testimony dated June 23, 2006 in Case No. ER-2006-0315. I have attached a copy of Ms. Maloney's direct testimony in the Empire District Electric Company case as Schedule DAF-7.

Q. Did Ms. Maloney also utilize Chapter 5 of the previously mentioned 1994 Michael E. Small publication for her analysis in the Empire District Electric Company case?

A. Yes, she did.

Q. Did Ms. Maloney attach Chapter 5 of the publication to her direct testimony in the Empire District Electric Company case?

A. Yes, she did. In fact, she attached <u>all</u> of the pages from Chapter 5 of the publication.

Q. What methodology did Ms. Maloney propose for Demand allocation in the Empire District Electric Company case?

A. She recommended that a 12-CP Demand allocation methodology be utilized. Her recommendation was based at least partly on the results of the tests described in Chapter 5 of the previously mentioned 1994 Michael E. Small publication.

Q. Did Ms. Maloney consider other factors in determining the appropriate allocation methodology in the Empire District Electric Company case?

A. Yes. The following Q&A from Pages 9 & 10 of Ms. Maloney's direct testimony in the Empire District Electric Company case describes the other factors that she considered in determining the appropriate allocation methodology in the Empire District Electric Company case:

> Q. Are there any other factors to consider in determining the appropriate allocation methodology?
>
> A. Yes. These FERC tests are part of a larger set of factors historically utilized by the FERC in its determination of which coincident peak methodology should be used in electric utility cases. In a rate case decision involving Carolina Power and Light Company [*Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶61,107 at 61,230 (Aug. 1978)], for example, the FERC states: "...it is necessary to consider the full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments" (footnote omitted). In the adoption of the 12 CP methodology, FERC has cited these operating realities, all of which affect a utility's effective capacity, as important to its determination.
>
> Q. How do these operational realities apply to Empire?
>
> A. There are periods of time, typically in the spring or fall, when the usage level of the Company's native load customers is reduced. At such times, the Company is able either to perform necessary maintenance on its power plants or to pursue off-system sales, while retaining sufficient capacity to adequately meet its customers' requirements. Furthermore, the Company's capacity planning process takes into account all the hours of the year, not just the peak hour or any seasonal peak. These operational realities, along with the test results and aforementioned analysis, provide ample evidence to support Staff's recommendation to adopt a 12 CP methodology in the current proceeding.

Q. Where did the quote referenced in the answer to the first question above come from?

A. The quote came from Page 106 of the previously mentioned 1994 Michael E. Small publication.

Q. Is Page 106 one of the pages that Ms. Maloney did not attach to her direct testimony in this case?

A. Yes, it is.

Q. Does the information from Page 106 seem relevant to the determination of the appropriate Demand allocation methodology?

A. Yes, it does.

Q. Do any of the operational realities that Ms. Maloney describes for Empire District Electric Company in the answer to the second question above also apply to KCPL?

A. Yes, they all do.

Q. Does KCPL perform necessary maintenance on its power plants during the spring or fall, when the usage level of the Company's native load customers is reduced?

A. Yes, that is when KCPL performs most of the maintenance on its nuclear and coal-fired generating facilities.

Q. Does KCPL pursue off-system sales during the spring or fall, when the usage level of the Company's native load customers is reduced?

A. Yes, KCPL pursues a significant level of off-system sales.

Q. Does KCPL's capacity planning process take into account all the hours of the year and not just the peak hour or any seasonal peak?

A. Yes, KCPL's capacity planning process takes into account all the hours of the year.

Q. Can you think of any reason, other than a strict reliance on the FERC tests described in Chapter 5 of the previously mentioned 1994 Michael E. Small publication, why Ms. Maloney would have recommended a 4-CP Demand allocation methodology for a Company with the operational realities of KCPL?

A. I can think of no reason, other than a strict reliance on the FERC tests, that Ms. Maloney would have recommended a 4-CP Demand allocation methodology. Even at that, much of the information contained on the pages of the publication that she did not attach to her direct testimony in this case would lead one to the conclusion that the 12-CP Demand allocation methodology is appropriate for KCPL.

Q. Have you attempted to quantify what the effect of incorporating off-system sales into the FERC tests would have on the results of those tests?

A. Yes, I have. Since there are no load requirements for off-system sales I have attempted to quantify the effect of the off-system sales on the FERC tests by using total MWH sales, including off-system MWH sales, in the FERC tests.

Q. What were the results of those FERC tests using the total MWH sales?

A. The results of the FERC tests using total MWH sales, including off-system MWH sales, for the 12-month period ending December 31, 2005 are shown below:

Test 1 = 13%

Test 2 = 83%

Test 3 = 71%

These results all fall well within the ranges, as defined by Ms. Maloney, for a 12-CP allocation methodology. The calculation of these percentages is attached as Schedule DAF-8.

Q. What methodology is the Company proposing for Demand allocation?

A. The Company is proposing the use of a 12-CP Demand allocation methodology for allocating the plant and other fixed costs associated with production and transmission assets.

Q. Is the 12-CP Demand allocation methodology consistent with what has been used for the Company in its Kansas jurisdiction?

A. Yes. The 12-CP Demand allocation methodology has historically been utilized in the Company's Kansas jurisdiction. In addition, in the Kansas Regulatory Plan Stipulation & Agreement that precipitated the Company's current Kansas rate case filing, the Company agreed to utilize a 12-CP Demand allocator in its rate case filing.

Q. Is the 12-CP Demand allocation methodology consistent with what has been used for the Company in its FERC jurisdiction?

A. Yes. The 12-CP Demand allocation methodology has historically been utilized in the Company's FERC jurisdiction, and the Company's current FERC jurisdictional rates were established utilizing the 12-CP Demand allocation methodology.

Q. Why is it important that consistent allocation is utilized in all of the Company's jurisdictions?

A. If consistent allocation methodologies are not utilized in the Company's various jurisdictions, the result will be over- or under-recovery of the Company's prudently incurred costs.

<u>Allocation of Non-Firm Off-System Sales Margins</u>

Q. What methodology did the MPSC Staff use to allocate to the jurisdictions the "margin" or "profit" on non-firm off-system sales?

A. The Staff used an Energy allocator to allocate non-firm off-system sales margins to the jurisdictions.

Q. Does the Company agree with Staff's allocation methodology for non-firm off-system sales margins?

A. No. The Company does not believe that there is any rationale for allocating the "margin" on non-firm off-system sales based on an Energy allocation methodology.

Q. If you believe that there is no rationale for allocating non-firm off-system sales margins by using an Energy allocator why do you suppose the Staff used the Energy allocator?

A. I can't say for sure, because Staff did not present testimony supporting the use of the Energy allocation methodology for allocating the margins on non-firm off-system sales. I suspect, however, that Staff used the Energy allocator, because that is historically how "total revenues" on off-system energy sales have been allocated.

Q. Can you please elaborate on the distinction between "margins" and "total revenues" on non-firm off-system energy sales?

A. The "total revenues" on non-firm off-system energy sales can be broken into two components; (1) the "cost" component of the sales and (2) the "margin" or profit component of the sales.

Q. You previously stated that "total revenues" on off-system energy sales have historically been allocated using an Energy allocator. Why have the "cost" and "margin" components of the "total revenues" on non-firm off-system energy sales not historically been allocated separately?

A. KCPL and, I suspect, many other utilities have historically only reported the "total revenues" on non-firm off-system energy sales.

Q. In your opinion was it appropriate, historically, to have been allocating "total revenues" on non-firm off-system energy sales by using an Energy allocator?

A. It has probably never been "completely" appropriate to allocate "total revenues" on non-firm off-system energy sales by using an Energy allocator, but at the time when many of the allocation methodologies were developed it was probably a reasonable approach. At the time when many of the allocation methodologies were developed the market for non-firm off-system energy sales was very different than it is today. Off-system sales volumes were very limited by today's standards and the pricing of non-firm off-system sales was done on a "cost plus a small margin" basis rather than on the "market price" basis of today. As such, historically, the "cost" component comprised a much larger percentage than the "margin" component of the "total revenues" on non-firm off-system energy sales. Thus, because it is appropriate to allocate the "cost" component based on an Energy allocator, it was reasonably appropriate, though not theoretically appropriate, to allocate "total revenues" on non-firm off-system energy sales based on an Energy allocator.

Q. You stated that it is appropriate to allocate the "cost" component of the "total revenues" on non-firm off-system energy sales by using an Energy allocator. First, is that how the Company has allocated the "cost" component, and, second, can you please explain why you believe its is appropriate to allocate the "cost" component based on an Energy allocator?

A. Yes, the Company allocated the "cost" component of "total revenues" on non-firm off-system energy sales based on the Energy allocator. The "cost" component of the "total revenues" on non-firm off-system energy sales covers the incremental costs to produce those sales. Those incremental costs consist of fuel and/or energy purchases. The Company's total fuel and energy purchase costs, including the costs to produce non-firm off-system energy sales, are allocated to the jurisdictions based on the Energy allocator. Thus, it is appropriate to allocate the component of the "total revenues" on non-firm off-system energy sales that covers the incremental fuel and energy purchases to also be allocated based on the Energy allocator. In other words, the jurisdictions are being reimbursed for the costs that have been charged to them on a consistent basis.

Q. Why is not appropriate to also allocate the "margin" component of the "total revenues" on non-firm off-system energy sales?

A. The "margins" on non-firm off-system sales are not unlike margins or profits on sales in any other business. It is a general business principle that margins or profits on sales are allocated or distributed based on the ownership percentage of the fixed assets of the business, not on the allocation of variable expenses. In the case of non-firm off-system energy sales the ownership percentage of the fixed assets, as it applies to the jurisdictions, is defined by the Demand allocation methodology.

Q. Why then is it not appropriate to simply allocate the "margin" component of the "total revenues" on non-firm off-system energy sales by using the Demand allocator?

A. The Demand allocation of the plant and other fixed costs to the jurisdictions essentially defines the "Available Capacity" (the MW capacity of the generating units and purchased power contracts) that the jurisdictions have paid for. It, thus, also defines each jurisdiction's rights to call on a level of MWH output or "Available Energy" that corresponds with the jurisdiction's allocated "Available Capacity". The "Available Energy" is calculated by multiplying the "Available Capacity" by 8760 (the number of hours in a year). The reason why it is not appropriate to simply allocate the "margin" component based on the Demand allocator has to do with how non-firm off-system energy is available for sale in the first place. Non-firm off-system energy is available for sale, because the jurisdictions have not used all of their "Available Energy" as defined above. If the jurisdictions did use all of their "Available Energy" there would be no energy available to sell off-system. Because of this fact the relevant factor is not just the "Available Capacity" that the jurisdictions have paid for through the Demand allocation methodology, but rather the "Available Energy" that the jurisdictions have paid for but not used or, in other words, the "Unused Energy".

Q. Can you please describe the calculation of this "Unused Energy"?

A. The "Unused Energy" is calculated by subtracting a jurisdiction's actual "Energy Used" from its "Available Energy." The "Unused Energy" is essentially a measure of the portion the fixed costs that the jurisdictions have paid for but not used, and is also a measure of the energy available to make off-system energy sales. The calculation of the "Unused Energy" allocator can be found in Schedule DAF-6.

Q. Is the "Unused Energy" that you have described the basis for the Company's proposed allocation of the "margin" component of the "total revenues" on non-firm off-system energy sales?

A. Yes it is.

II. DEPRECIATION

__Depreciation Issues__

Q. Did the MPSC Staff perform a depreciation study in conjunction with its direct filing in this case?

A. Yes it did. Staff Witness Rosella L. Schad submitted direct testimony in support of Staff's depreciation study.

Q. What were the results of Staff's depreciation study?

A. According to the direct testimony of Ms. Schad "[t]he depreciation rates determined in this study will decrease the currently ordered annual depreciation expense from approximately $65 million to $55 million, a difference of approximately $10 million.

Q. **Does the Company agree with the quantification of the result of applying Staff's proposed depreciation rates?**

A. At the time of the Staff's direct filing in this case, the Staff had a number of errors in the Missouri jurisdictional plant balances to which Ms. Schad was applying Staff's proposed depreciation rates, so it is impossible tell if the $10 million Missouri jurisdictional decrease was the actual result of the depreciation study. At the time of this filing, I believe that the Staff reconciliation with the Company would estimate the impact of the difference between current depreciation rates and those proposed by the Staff to be approximately $15 million.

Q. **Does the Company agree with the Staff's proposed depreciation rates and the resulting decrease in depreciation expense?**

A. No, it does not. The Company does not believe that it is appropriate to change depreciation rates at this time. In addition, the Company believes that there are a number of significant flaws in the Staff's depreciation study.

Q. **Did the Company perform a depreciation study in conjunction with its direct filing in this case?**

A. No, it did not. KCPL did, however, submit a depreciation study to the MPSC Staff pursuant to 4 CSR 240-20.030 on March 31, 2005 based on data through December 31, 2004.

Q. The Staff's depreciation study was based on data through December 31, 2005. Would you expect the one-year difference in available data to dramatically impact the results of a depreciation study?

A. As a general rule the more years of data that you can incorporate into a depreciation study the better, but one year of activity for a Company with the lengthy plant history of KCPL should not to make a discernable difference.

Q. Did the results of your last depreciation study, then, result in proposed depreciation rate changes that, if implemented, would have resulted in a significant overall decrease in depreciation expense?

A. No, in fact, the results of KCPL's last depreciation study suggested changes to depreciation rates that, if implemented, would have increased the overall depreciation expense. The magnitude of the overall increase would depend on whether whole-life or remaining-life depreciation rates were applied and/or to which accounts they were applied.

Q. If the Company had filed a depreciation study in conjunction with its direct filing in this case, would you have expected the results and recommendations to be similar to that of your last depreciation study?

A. Yes, had the Company filed a depreciation study with its direct filing in this case, it very likely would have recommended similar depreciation rate changes and a similar resulting overall increase in depreciation expense.

Q. Why, then, did the Company not file testimony supporting an adjustment to depreciation rates in its direct filing in this case?

A. The Company believed that it was the intent of the Regulatory Plan Stipulation & Agreement in Case No. EO-2005-3029 that the depreciation rates listed in Appendix G of the Regulatory Plan Stipulation & Agreement were to be used in this case. As a result, KCPL did not sponsor any testimony relating to depreciation rates in its direct filing.

Q. Does the Company believe the Regulatory Plan Stipulation & Agreement precludes parties to the case from proposing depreciation rate changes?

A. No, it does not. However, while review of depreciation rates is generally part of a rate proceeding, the Company does not believe it is appropriate in this case.

Q. Why does the Company believe it is not appropriate to change depreciation rates in this case?

A. As I stated previously, it is the Company's belief that it was the intent of the Regulatory Plan Stipulation & Agreement to use the Appendix G depreciation rates in this case. In addition, it does not make sense to change depreciation rates, because the credit ratio amortization mechanism established in the Regulatory Plan Stipulation & Agreement provides for additional amortization expense, if necessary, to provide cash to maintain adequate credit metrics during the term of the Regulatory Plan. From a practical standpoint any adjustment to depreciation rates would necessitate an equal and offsetting adjustment to amortization expense to maintain equivalent cash flow. The Regulatory Plan Stipulation & Agreement contemplates that the accumulated amortization can be re-directed to specific plant accounts to be determined at a later time. It appears appropriate that any revision to depreciation rates should occur at the conclusion of the Regulatory Plan when the total accumulated amortization related to the Regulatory Plan is known.

Depreciation Study

Q. Other than the fact that the Company does not believe that is appropriate to adjust depreciation rates at this time, do you have any other concerns about the depreciation study filed by the Staff?

A. Yes, the Company has identified what it considers to be a number of very significant flaws in the Staff's depreciation study. The Company's analysis of the Staff's depreciation study is certainly not complete at this point, but the flaws that have been identified to this point certainly shed doubt an the validity of Staff's study.

Q. Can you briefly describe some of the flaws in the Staff's study?

A. Yes. First, the Staff's study appears to contain some major flaws with regard to the lifespan analysis and the related interim retirements for the generation accounts. Second, the retirement curve matching for a number of the transmission, distribution, and general plant accounts is questionable. And third, the approach the Staff used to calculate net salvage rates is mathematically and analytically incorrect.

Q. Can you describe the lifespan analysis as it relates to generation accounts and further describe the problems with the Staff's lifespan analysis and the related interim retirements for the generation accounts?

A. Yes, lifespan analysis deals with the fact that for certain assets, like power plants, there will come a time when all of the assets at the site will be retired as a whole regardless of age or condition of some of the individual units of property within the plant. In other words, power plants are subject to interim retirements that occur throughout the life of the plant as individual units of property wear out and are replaced, but they are also subject to a final retirement of the plant as whole. Ms. Schad's testimony makes no mention of the Staff's lifespan analysis, and it is not obvious from Ms. Schad's depreciation workpapers what exactly the Staff has done with regard to its lifespan analysis. It appears from the results of the Staff's study that the Staff must have incorporated some lifespan analysis for the generation accounts. If the Staff study did not incorporate lifespan analysis for the generation accounts, Ms. Schad has misapplied the generation retirement data that the Company provided and has not followed standard depreciation principles with regard to generation assets. Again, it appears that the Staff study has incorporated lifespan analysis, but it is not obvious from the testimony or workpapers.

Q. Assuming that Staff utilized lifespan estimates for the generation assets, what do those lifespan estimates appear to be?

A. As I mentioned previously, it appears that the Staff's study has utilized lifespan analysis for the generation accounts. It appears that Staff has utilized a 45-year lifespan for most of the coal generation accounts, a 59.5-year lifespan for the nuclear accounts, and a 35-year lifespan for most of the combustion turbine accounts. In addition, it appears that Staff has utilized a 60-year lifespan for all of the structures and improvements accounts including those accounts for transmission, distribution, and general plant.

Q. Do Staff's apparent lifespan estimates seem reasonable?

A. The Company would argue that the 45-year coal generation lifespan is a little long and that the 60-year structures lifespan is too long, but in general, the lifespan estimates are within a reasonable range.

Q. If Staff's apparent lifespan estimates are within a reasonable range, what is the significant flaw in Staff's analysis to which you previously referred?

A. The significant flaw is that Staff appears to have not incorporated any interim retirements into the life analysis for the generation and structures accounts. This can be most obviously seen by examining the nuclear accounts. Staff's study suggests that the average service life for the nuclear accounts should be 59.5 years. In order to have an average service life of 59.5 years, one would have to assume that there have been no retirements in the past in these nuclear accounts, and that there will be no retirements of existing plant in these nuclear accounts in the future until the final retirement of the whole plant at the end of the assumed extended operating license. The lack of any interim retirements is obviously a major error in the analysis.

Q. What would be the result on the average services lives for the generation and structures accounts of applying a reasonable level of interim retirements?

A. Applying a reasonable level of interim retirements to the generation and structures accounts would likely reduce Staff's average service life estimates for these accounts by roughly 10-15 years.

Q. The second major flaw in Staff's study that you referred to is what you considered to be questionable retirement curve matching for a number of transmission, distribution, and general plant accounts. Can you please describe the problem?

A. In general, the average service lives for transmission, distribution, and general plant accounts are derived by matching the observed life data from the Company's plant history records to a set of empirically derived mortality data known as the Iowa Curves. These curve matches are done on both a mathematical and visual basis. Ms. Schad also described this curve matching process in her testimony. In order to check the reasonableness of Staff's curve matches, I plotted Staff's proposed curve matches against the observed life data in the Company's last depreciation study. The result of that reasonableness check is that it appears that Staff's curve matching is questionable for Accounts 355, 358, 362, 364, 365, 367, 369, 370, 371, 396, & 398. These curve plots are attached to my testimony as Schedule DAF-9. The results of these questionable curve matches are average service lives for many of these accounts that are approximately 10-20 years too long.

Q. The third major flaw in Staff's study that you referred to is what you considered to be a mathematically and analytically incorrect calculation of the net salvage rates. Can you please describe the problem?

A. In Ms. Schad testimony she states that: "Net salvage rates realized by the Company were developed by taking the experienced net salvage for the last ten years, exclusive of the highest and lowest net salvage amounts, and dividing by the original cost of plant retired for the last ten years for each account. Excluding the highest and lowest net salvage amounts in determining a ten year average eliminates outliers that can result from the delayed timing of data entry into the accounting system."

Q. Why is what Ms. Schad described as Staff's calculation of net salvage rate a problem?

A. The approach that Ms. Schad has taken for eliminating outliers does not accomplish her stated intention. In fact, it often creates a situation of greater outliers than occurred prior to the "correction." What Ms. Schad has done is replace the highest and lowest net salvage amounts with zero amounts. Since most of the Company's accounts are in a negative net salvage position for most of the years, what Ms. Shad has done creates a situation where she often replaces the highest and lowest net salvage amounts with two new amounts that are higher than what the previous highest amount was. The result of Ms. Schad's "correction" significantly overstates the net salvage rates that have been proposed by the Staff to be included in the depreciation rate calculations.

Q. Are there any other significant flaws in the Staff depreciation study?

A. The Company has not identified any other significant flaws at this time, but the Company has not completed an exhaustive analysis of the Staff's depreciation study. The Company certainly has not determined for sure that there are no other major flaws in the depreciation analysis.

Q. In your opinion could the Staff's depreciation study be used as a basis for establishing a reasonable level of depreciation expense?

A. In my opinion, Staff's depreciation study is too significantly flawed to be relied upon as the basis for setting a reasonable level of depreciation expense.

<u>Depreciation Reserve Analysis</u>

Q. Ms. Schad's testimony claims that the Company's depreciation reserve is theoretically over-accrued by approximately \$800 million on a total company basis. Does the Company consider that to be a reasonable representation of its depreciation reserve situation?

A. No, it does not. As is noted in Ms. Shad's testimony, the calculation of the theoretical reserve is predicated on the proposed depreciation rates from the depreciation study. The significant flaws that have been identified in the Staff's depreciation study completely invalidate the \$800 million of theoretical over-accrual.

Q. Does the Company believe that there are any individual depreciation reserve accounts that are theoretically over-accrued at this point in time?

A. Yes, it does. The assumed extension of the Wolf Creek operating license from 40 to 60 years created a situation where the nuclear depreciation reserve accounts are theoretically over-accrued. In addition, the insurance and litigation proceeds in the Hawthorn 5 Rebuild depreciation reserve accounts created a situation where those accounts are theoretically over-accrued.

Q. In Ms. Schad's testimony, she states that "[t]he Staff does not propose an adjustment to the depreciation reserve at this time". Has the Company proposed any adjustments to the depreciation reserve?

A. Yes, it has through the deprecation rates that were included in Appendix G of the Regulatory Plan Stipulation & Agreement. The nuclear depreciation rates that were included in Appendix G are remaining-life depreciation rates. The calculation of remaining-life depreciation rates takes into account the current level of the depreciation reserve for the account in question. Remaining-life depreciation rates, thus, correct for any current theoretical over- or under-accruals over the remaining life of the property in the account. Likewise the Hawthorn 5 Rebuild depreciation rates that were included in Appendix G were calculated in such a way that they are essentially remaining life rates and will correct for the theoretical over-accrual in the Hawthorn 5 Rebuild depreciation reserve accounts over time.

III. SUMMARY OF RECOMMENDATIONS

Q. Please summarize the recommendations from your testimony.

A. I recommend the following as detailed previously in my testimony:

- The calculation of the "Unused Energy" allocator should be changed to reflect the corrections as shown in Schedule DAF-6.

- The 12-CP methodology should be used for the Demand allocator.
- The corrected "Unused Energy" allocator should be used for the allocation of the "margin" component of the "total revenues" on non-firm off-system energy sales.
- The depreciation rates listed in Appendix G of the Regulatory Plan Stipulation & Agreement in Case No. EO-2005-0329 should be used as the basis for calculating depreciation expense.

Q. Are there any other issues that you would like to address?

A. Yes. I would like to note that I have attached, as Schedule DAF-10, the Staff's September 5, 2006 EMS Run (accounting schedules). I have also attached, as Schedule DAF-11, the Staff's calculation of the additional amortization associated with the September 5, 2006 EMS Run.

Q. Why have you attached these Staff schedule?

A. I have attached this September 5, 2006 Staff EMS Run, and the associated Staff additional amortization calculation, because this version is the basis for the Company's rebuttal testimony. The EMS Run that the Staff originally filed in conjunction with the their direct filing in this case contained a number of errors and omissions which the Staff has subsequently corrected. The Staff corrections have been incorporated into the attached September 5, 2006 EMS Run. The Company has not addressed in rebuttal testimony any of the errors and omissions in the Staff's originally filed EMS Run that have subsequently been corrected.

Q. Does the Company believe that the September 5, 2006 Staff EMS Run now contains all of the necessary corrections of errors and omissions?

A. The Company is continuing to review and evaluate the Staff EMS Runs as corrections are made. As such the Company cannot confirm at this time that no other corrections are necessary.

Q. Does that conclude your testimony?

A. Yes, it does.

Corrected Unused Energy Allocator

		Missouri	Kansas	FERC	Total
Demand Allocator (D1)					
12-CP Avg Load (MW)		1,427.4	1,201.5	23.2	2,652.2
Demand Allocator	D1	53.82%	45.30%	0.88%	100.00%
Energy w/ Losses Allocator (E1)					
Energy Used (MWH)		8,960,193	6,583,077	144,287	15,687,557
Energy w/ Losses Allocator	E1	57.12%	41.96%	0.92%	100.00%
Unused Energy w/ Losses Allocator (UE1)					
Available Capacity (MW)					4,389.0
Demand Allocator (D1)		53.82%	45.30%	0.88%	100.00%
Max Total Peak Allocated Using D1 Factors (MW)		2,362.2	1,988.4	38.5	4,389.0
x Hours in Year		8760	8760	8760	8760
Available Energy (MWH)		20,692,662	17,418,096	336,882	38,447,640
- Energy Used (MWH)		8,960,193	6,583,077	144,287	15,687,557
Unused Energy (MWH)		11,732,469	10,835,019	192,595	22,760,083
Unused Energy w/ Losses Allocator	UE1	51.55%	47.61%	0.85%	100.00%

Rationale for Allocating Off-System Sales Margins based on Unused Energy Allocator

As can be seen in the calculation above, the Unused Energy Allocator is calculated based on the same underlying data as is used to calculate the Demand and Energy Allocators.

Plant, capacity purchases and other fixed costs are typically allocated to the jurisdictions using the Demand Allocator.

Total fuel cost and energy purchases (including fuel and energy purchases used for off-system sales) are typically allocated to the jurisdictions using the Energy Allocator.

Given how the generation costs, both fixed and variable, are being allocated to the jurisdictions, what is the appropriate way to allocate the credit to the jurisdictions for off-system sales?

First, it is clear that revenues from capacity sales should be allocated to the jurisdictions based on the Demand Allocator, because that is how the costs for plant, capacity purchases, and other fixed costs have been allocated to the jurisdictions. In other words, the jurisdictions are being reimbursed for the costs that have been charged to them.

Second, it is also clear that the portion of the revenues from off-system energy sales that cover the costs to produce those sales (fuel and/or energy purchases) should be allocated to the jurisdictions based on the Energy Allocator, because that is how the costs for the fuel and energy purchases used to produce those off-system sales have been allocated to the jurisdictions. In other words, the jurisdictions are being reimbursed for the costs that have been charged to them.

How then should the "margin" portion of the revenues on off-system energy sales be allocated to the jurisdictions? The allocation of the margins is dependent on and must be consistent with how the total generation costs are being allocated to the jurisdictions (Demand and Energy Allocators). Through the Demand Allocator the jurisdictions have essentially paid for a certain level of "Available Capacity" and, thus, the "rights" to a certain level MWH output or "Available Energy". This "Available Energy" is calculated by multiplying the "Available Capacity" by 8760 (the hours in a year). The "Unused Energy" is calculated by subtracting a jurisdiction's actual "Energy Used" from its "Available Energy". The "Unused Energy" is essentially a measure of the portion the fixed costs that the jurisdictions have paid for but not used, and is also a measure of the energy available to make off-system energy sales.

Unused Energy Allocator Used in KCPL's June Update

		Missouri	Kansas	FERC	Total
Demand Allocator (D1)					
12-CP Avg Load (MW)		1,427.4	1,201.5	23.2	2,652.2
Demand Allocator	D1	53.82%	45.30%	0.88%	100.00%
Energy w/ Losses Allocator (E1)					
Energy Used (MWH)		8,960,193	6,583,077	144,287	15,687,557
Energy w/ Losses Allocator	E1	57.12%	41.96%	0.92%	100.00%
Unused Energy w/ Losses Allocator (UE1)					
12-CP Avg Load (MW)		1,427.4	1,201.5	23.2	2,652.2
x Hours in Year		8760	8760	8760	8760
Available Energy (MWH)		12,504,203	10,525,441	203,572	23,233,216
- Energy Used (MWH)		8,960,193	6,583,077	144,287	15,687,557
Unused Energy (MWH)		3,544,010	3,942,364	59,285	7,545,659
Unused Energy w/ Losses Allocator	UE1	46.97%	52.25%	0.79%	100.00%

Rationale for Allocating Off-System Sales Margins based on Unused Energy Allocator

As can be seen in the calculation above, the Unused Energy Allocator is calculated based on the same underlying data as is used to calculate the Demand and Energy Allocators.

Plant, capacity purchases and other fixed costs are typically allocated to the jurisdictions using the Demand Allocator.

Total fuel cost and energy purchases (including fuel and energy purchases used for off-system sales) are typically allocated to the jurisdictions using the Energy Allocator.

Given how the generation costs, both fixed and variable, are being allocated to the jurisdictions, what is the appropriate way to allocate the credit to the jurisdictions for off-system sales?

First, it is clear that revenues from capacity sales should be allocated to the jurisdictions based on the Demand Allocator, because that is how the costs for plant, capacity purchases, and other fixed costs have been allocated to the jurisdictions. In other words, the jurisdictions are being reimbursed for the costs that have been charged to them.

Second, it is also clear that the portion of the revenues from off-system energy sales that cover the costs to produce those sales (fuel and/or energy purchases) should be allocated to the jurisdictions based on the Energy Allocator, because that is how the costs for the fuel and energy purchases used to produce those off-system sales have been allocated to the jurisdictions. In other words, the jurisdictions are being reimbursed for the costs that have been charged to them.

How then should the "margin" portion of the revenues on off-system energy sales be allocated to the jurisdictions? The allocation of the margins is dependent on and must be consistent with how the total generation costs are being allocated to the jurisdictions (Demand and Energy Allocators). Through the Demand Allocator the jurisdictions have essentially paid for the "rights" to a certain level MWH output. This "Available Energy" is calculated by multiplying the average CP load by 8760 (the hours in a year). The "Unused Energy" is calculated by subtracting a jurisdiction's actual "Energy Used" from its "Available Energy". The "Unused Energy" is essentially a measure of the portion the fixed costs that the jurisdictions have paid for but not used, and is also a measure of the energy available to make off-system energy sales.

Demand Allocator Used in KCPL's June Update

	CoinMOPeak	CoinKSPeak	CoinResale	WNPeak
Jan	1,299.0	1,112.8	24.6	2,436.4
Feb	1,270.4	1,076.6	24.0	2,371.0
Mar	1,142.0	929.9	20.5	2,092.4
Apr	1,077.8	848.4	17.7	1,943.8
May	1,478.3	1,223.6	20.3	2,722.2
Jun	1,804.9	1,524.9	26.4	3,356.3
Jul	1,903.0	1,643.5	28.7	3,575.3
Aug	1,815.3	1,588.6	29.2	3,433.2
Sep	1,539.7	1,317.4	25.5	2,882.7
Oct	1,186.3	936.4	14.6	2,137.2
Nov	1,239.1	1,046.0	22.5	2,307.7
Dec	1,373.2	1,170.3	24.8	2,568.3
MAX	1,903.0	1,643.5	29.2	3,575.3
1-CP Avg	1,903.0	1,643.5	28.7	3,575.3
4-CP Avg	1,765.8	1,518.6	27.5	3,311.9
12-CP Avg	1,427.4	1,201.5	23.2	2,652.2

Demand Allocator
Jurisdictional COS for Revenue (June 2006 Update)
Adjusted for Weather and Growth in Number of Customers

Production and Transmission Demand Allocators (D1, D2)

Jurisdiction	12-CP Avg Loads	D1, D2 Allocator
Missouri	1,427.4	53.8204%
Kansas	1,201.5	45.3034%
SFR	23.2	0.8762%
Total	**2,652.2**	**100.0000%**

Energy Allocators Used in KCPL June Update

ENERGY WITH LOSSES (E1)

	MWH	E1 Allocator
MISSOURI	8,960,193	57.1166%
KANSAS	6,583,077	41.9637%
SALES FOR RESALE	144,287	0.9198%
TOTAL	15,687,557	100.0000%

ENERGY WITHOUT LOSSES (E2)

	MWH	E2 Allocator
MISSOURI	8,505,252	57.2379%
KANSAS	6,216,341	41.8342%
SALES FOR RESALE	137,889	0.9280%
TOTAL	14,859,482	100.0000%

Exhibit No.:
Issues: System Energy Losses

Witness: Erin L. Maloney
Sponsoring Party: MO PSC Staff
Type of Exhibit: Direct Testimony
Case No.: ER-2006-0315
Date Testimony Prepared: June 23, 2006

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

DIRECT TESTIMONY

OF

ERIN L. MALONEY

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2006-0315

Jefferson City, Missouri
June 2006

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Company of Joplin, Missouri for authority to file tariffs increasing rates for electric service provided to customers in Missouri service area of the Company.	))))	Case No. ER-2006-0315

AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Direct Testimony in question and answer form, consisting of 12 pages to be presented in the above case; that the answers in the foregoing Direct Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of her knowledge and belief.

Erin L. Maloney
Erin L. Maloney

Subscribed and sworn to before me this 22nd day of June 2006.

Dawn L. Hake

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

DAWN L. HAKE
My Commission Expires
March 16, 2009
Cole County
Commission #05407643

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

ERIN L. MALONEY

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2006-0315

DIRECT TESTIMONY

OF

ERIN L. MALONEY

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2006-0315

Q. Please state your name and business address?

A. Erin L. Maloney, P.O. Box 360, Jefferson City, Missouri, 65102.

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

A. I am employed by the Missouri Public Service Commission (Commission) as a Utility Engineering Specialist II in the Energy Department of the Utility Operations Division.

Q. Please describe your educational and work background.

A. I graduated from the University of Nevada - Las Vegas with a Bachelor of Science degree in Mechanical Engineering in June 1992. From August 1995 through November 2002, I was employed by Electronic Data Systems of Kansas City, Missouri, as a System Engineer. In January 2005, I joined the Commission Staff (Staff) as a Utility Engineering Specialist I.

Q. Have you previously filed testimony before the Commission?

A. Yes. I filed testimony on reliability in Case No. ER-2005-0436.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to recommend that the Commission adopt the system energy loss factor and the jurisdictional allocation factors for demand and energy that were calculated as shown on Schedules 1, 2, and 3 respectively, attached to this direct testimony. This testimony also describes how these factors were determined.

EXECUTIVE SUMMARY

Q. Please briefly summarize your testimony.

A. The system energy loss factor was calculated to be 6.98%.

The jurisdictional allocation factors for demand and energy have been calculated using a Twelve Coincident Peak (12 CP) methodology as follows:

	Missouri Retail	Non-Missouri Retail	Wholesale
Demand	0.8221	0.1149	0.0630
Energy	0.8256	0.1093	0.0651

SYSTEM ENERGY LOSS FACTOR

Q. What is the result of your system energy loss factor calculation?

A. As shown on Schedule 1, attached to this Direct Testimony, the calculated system energy loss factor is 0.0698.

Q. What are system energy losses?

A. System energy losses largely consist of the energy losses that occur in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) in Empire's system between the generating sources and the customers' meters. In addition, small, fractional amounts of energy either stolen (diversion) or not metered are included as system energy losses.

Q. How are system energy losses determined?

A. The basis for this calculation is that Net System Input (NSI) equals the sum of "Total Sales," "Company Use," and "System Energy Losses." This can be expressed mathematically as:

NSI = Total Sales + Company Use + System Energy Losses

NSI, Company Use and Total Sales are known; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI – Total Sales – Company Use

The system energy loss factor is the ratio of system energy losses to NSI:

System Energy Loss Factor = System Energy Losses ÷ NSI

Q. How is NSI determined?

A. In addition to the equation above, NSI is also equal to the sum of Empire's net generation, net interchange, and any inadvertent flows. Net interchange is the difference between interchange purchases and off-system sales. Net generation is the total energy output of each generating station minus the energy consumed internally to enable its production. The output of each generating station is monitored continuously, as is the net of off-system purchases and sales. This information was obtained from data supplied by Empire in response to Staff Data Request Nos. 119, 125, and 210. The difference between scheduled and actual flows on a system is termed inadvertent interchange. This information was provided on a monthly basis in Empire's response to Staff Data Request 210.

Q. What are Total Sales and Company Use and how are these values determined?

A. Total Sales includes all of Empire's retail and wholesale sales of energy. Company Use is the electricity consumed at Empire's non-generation facilities, such as its corporate office building at 620 Joplin Street, Joplin, Missouri. Total Sales data was provided by Empire in response to Staff Data Request No. 206. Company Use data was provided by Empire in response to Staff Data Request Nos. 206 and 207.

Q. Which Staff witness used your calculated system energy loss factor?

A. The system energy loss factor was used by Staff witness Shawn E. Lange.

JURISDICTIONAL ALLOCATIONS

Q. Please define the phrase "jurisdictional allocation".

A. For purposes of this testimony, jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. In this case, demand-related and energy-related costs are divided among three jurisdictions: Missouri retail operations, non-Missouri retail operations and wholesale operations. The particular allocation factor applied is dependent upon the types of costs being allocated.

DEMAND ALLOCATION FACTOR

Q. What are the demand allocation factors that you are recommending be used in this case?

A. As shown on Schedule 2 attached to this direct testimony, the calculated demand allocation factors for the test year are as follows:

Missouri Retail	0.8221
Non-Missouri Retail	0.1149
Wholesale	0.0630

Q. What is the definition of demand?

A. Demand refers to the rate at which electric energy is delivered to or by a system, generally expressed in kilowatts (kW) or megawatts (MW), either at an instant in time or averaged over any designated interval of time. In this analysis, hourly demands were used.

Q. What types of costs are allocated on the basis of demand?

A. Capital costs associated with generation and transmission plant and certain operational and maintenance expenses are allocated on this basis. This is appropriate for these expenditures because generation and transmission are planned, designed and constructed to meet anticipated demand.

Q. What methodology was used to determine the demand allocators?

A. A methodology known as the Twelve Coincident Peak (12 CP) methodology was used.

Q. What is meant by the twelve coincident peak methodology?

A. The term coincident peak refers to the load of each jurisdiction that coincides with the hour of Empire's overall system peak. A 12 CP methodology refers to utilizing the recorded peaks in each of the twelve (12) months of the selected test year.

Q. Why use peak demand as the basis for allocations?

A. Peak demand is the largest electric load requirement occurring on a utility's system within a specified period of time (e.g., day, month, season, year). Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands plus required reserves, the contribution of each individual jurisdiction to these peak demands is the appropriate basis on which to allocate the costs of these facilities.

Q. Please describe the procedure for calculating the jurisdictional demand allocation factors using the 12 CP methodology.

A. The allocation factor for each jurisdiction was determined using the following process:

1. Empire's peak hourly monthly loads in calendar year 2005 were identified and summed.

2. Each jurisdiction's loads during Empire's monthly peak hours, identified in #1 above, were summed.

3. The sum for each jurisdiction calculated in #2 above was divided by the sum of Empire's 12 monthly peak loads (result of #1 above).

This resulted in the allocation factor for each jurisdiction. The sum of the demand allocation factors across all jurisdictions equals one.

Q. How was the decision made to recommend using the 12 CP method?

A. The 12 CP method is appropriate for a utility, such as Empire, that experiences relatively small variations in monthly and/or seasonal (e.g., summer and winter) peaks during a particular year. Schedule 4, attached to this Direct Testimony, presents a table of Empire's maximum hourly peak in each month for calendar years 2001 through 2005. This information was taken from the Federal Energy Regulatory Commission (FERC) Form 1, and data provided by the Company in response to Staff Data Request No. 130 in this case, and Staff Data Request No. 2921 in Case No. ER-2002-424. As shown, Empire experiences its system peak during the summer months (July, August, and September); however, the monthly peak hours occurring during the winter months (December and January) are relatively high due to the Company's high saturation of electric heat customers.

The line graph on Schedule 6 attached to this Direct Testimony presents, for each of the years 2001 through 2005, a plot of each month's peak hour as a percentage of:

a) The peak hour for the corresponding year; and

b) The average of the monthly peak hours for the corresponding year.

The graph, which was derived from the data shown in Schedule 4, indicates consistent peaks in both the summer and the winter across the time period.

Q. Is there additional support for the position that a 12 CP methodology is appropriate in this case?

A. Yes. In various cases, the FERC has, among other things, used a number of tests as a guide in its determination of an appropriate allocation methodology. These tests are arithmetical calculations whose results are compared to specific ranges determined from prior FERC decisions which suggest which methodology is more appropriate. Attached to this testimony as Schedule 5 is an excerpt (Chapter 5) from a publication entitled "A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers," Third Edition (1994), authored by Michael E. Small. As this excerpt shows, FERC has used these tests to support its adoption of a 12 CP methodology in a number of cases. On occasion, however, these tests have suggested that an alternative coincident peak methodology (such as a 4 CP) might be more appropriate.

Q. Please describe the tests you used in your selection of a CP methodology.

A. The following tests included in the aforementioned guidelines (attached as Schedule 5) were used:

Test 1 - Computes the difference between the following two percentages:

a) The average of the monthly system peaks during the reported peak period as a percentage of the annual peak, and

b) The average of the system peaks during the remainder of the test period as a percentage of the annual peak.

For calculated differences that fell between 18% and 19%, the FERC typically adopted a 12 CP methodology. For differences that fell between 26% and 31%, the FERC typically adopted a 4 CP methodology.

Test 2 - The average of the twelve monthly peaks in the reporting period as a percentage of the annual peak.

When the resulting percentage fell between 81% and 88%, the FERC typically adopted a 12 CP methodology. When the resulting percentage fell between 78% and 81%, the FERC typically adopted a 4 CP methodology.

Test 3 - The lowest monthly peak as a percentage of the annual peak.

When the resulting percentage fell between 66% and 81%, the FERC typically adopted a 12 CP methodology. When the resulting percentage fell between 55% and 60%, the FERC typically adopted a 4 CP methodology.

Q. Did you apply these FERC tests to Empire's data?

A. Yes. As illustrated on Schedule 7, the following percentages using the demands recorded for the twelve-month period ending December 31, 2005 were calculated:

Test 1 -	18.63%
Test 2 -	83.28%
Test 3 -	57.22%

Q. Please discuss the significance of these results.

A. The result of the first test (18.63%) falls within the above-indicated 18%-19% range of results that led to FERC decisions adopting a 12 CP methodology. Likewise, the result of the second test (83.28%) is within the 81%-88% range of results in FERC decisions adopting a 12 CP methodology. The result of the third test (57.22%) falls within the 55%-60% range for which the FERC issued decisions adopting a 4 CP methodology. Overall, these tests lend support for usage of the 12 CP methodology.

Q. Are there any other factors to consider in determining the appropriate allocation methodology?

A. Yes. These FERC tests are part of a larger set of factors historically utilized by the FERC in its determination of which coincident peak methodology should be used in electric utility cases. In a rate case decision involving Carolina Power and Light Company[1], for example, the FERC states: "...it is necessary to consider the full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments" (footnote omitted). In the adoption of the 12 CP methodology, FERC has cited these operating realities, all of which affect a utility's effective capacity, as important to its determination.

Q. How do these operational realities apply to Empire?

[1] *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶61,107 at 61,230 (Aug. 1978).

A. There are periods of time, typically in the spring or fall, when the usage level of the Company's native load customers is reduced. At such times, the Company is able either to perform necessary maintenance on its power plants or to pursue off-system sales, while retaining sufficient capacity to adequately meet its customers' requirements. Furthermore, the Company's capacity planning process takes into account all the hours of the year, not just the peak hour or any seasonal peak. These operational realities, along with the test results and aforementioned analysis, provide ample evidence to support Staff's recommendation to adopt a 12 CP methodology in the current proceeding.

Q. Did the Company incorporate the 12 CP methodology in its filing of this rate case?

A. Yes.

Q. Which Staff witness used your jurisdictional demand allocation factors?

A. I provided these jurisdictional demand allocation factors to Staff witness Dana E. Eaves.

ENERGY ALLOCATION FACTOR

Q. What energy allocation factors are you recommending be used in this case?

A. The factors are shown in Schedule 3 and repeated here.

Missouri Retail	0.8256
Non-Missouri Retail	0.1093
Wholesale	0.0651

Q. What types of costs were allocated on the basis of energy?

A. Variable expenses, such as fuel and certain operational and maintenance (O&M) costs, are allocated to the jurisdictions based on energy consumption.

Q. How did you calculate the energy allocation factor?

A. The energy allocation factor for an individual jurisdiction is the ratio of the normalized annual kilowatt-hour (kWh) usage in the particular jurisdiction to the total normalized Empire kWh usage. The sum of the energy allocation factors across jurisdictions equals one. The actual jurisdictional kWh usage totals were provided in the Company response to Staff Data Request No. 206.

Q. What adjustments were made to these recorded kWhs?

A. The Staff made the following adjustments to be consistent with the net system hourly loads used in determining normalized fuel costs:

a. Normalization Adjustment

b. Annualization Adjustment

c. Customer Growth Adjustment

d. Wholesale Weather Adjustment

Q. Did you calculate these adjustments?

A. No. Staff witness Shawn E. Lange supplied adjustments a., b., and d. Please refer to Mr. Lange's testimony for a summary of these adjustments. Staff witness Dana E. Eaves provided me with the customer growth adjustment. Please see Mr. Eaves's testimony for a further explanation of this adjustment.

Q. Which Staff witness used your jurisdictional energy allocation factors?

A. I provided these jurisdictional energy allocation factors to Staff witness Dana E. Eaves.

Q. Does this conclude your prepared Direct Testimony?

A. Yes, it does.

SYSTEM ENERGY LOSS PERCENTAGE

	Net Generation	Net Interchange	Inadvertant Flows	Net System Input	Retail Sales	Wholesale Sales	Company Use	Losses
Jan-05	359,432,000	105,872,000	(98,000)	465,206,000	405,500,151	26,648,420	1,037,012	32,020,417
Feb-05	278,342,000	109,559,000	239,000	388,140,000	336,988,002	23,256,760	877,762	27,017,476
Mar-05	288,439,000	118,832,000	(166,000)	407,105,000	352,501,296	25,414,260	849,487	28,339,957
Apr-05	245,128,000	102,738,000	6,000	347,872,000	299,568,077	23,273,720	720,648	24,309,555
May-05	274,438,000	116,001,000	(56,000)	390,383,000	336,579,672	25,725,760	772,383	27,305,185
Jun-05	377,077,000	96,711,000	(126,000)	473,662,000	409,239,536	30,378,300	851,798	33,192,366
Jul-05	432,826,000	91,543,000	171,000	524,540,000	454,675,874	32,229,500	831,267	36,803,359
Aug-05	460,055,000	86,612,000	(244,000)	546,423,000	473,283,050	33,959,380	895,157	38,285,413
Sep-05	355,965,000	106,694,000	445,000	463,104,000	400,252,282	29,601,960	887,215	32,362,543
Oct-05	274,833,000	117,786,000	(274,000)	392,345,000	338,347,423	25,762,040	812,931	27,422,606
Nov-05	275,285,000	124,429,000	40,000	399,754,000	346,440,259	24,606,480	752,649	27,954,612
Dec-05	340,430,000	154,143,000	(63,000)	494,510,000	431,044,071	27,946,280	974,978	34,544,671
Totals	3,962,250,000	1,330,920,000	(126,000)	5,293,044,000	4,584,419,693	328,802,860	10,263,287	369,558,160

System Energy Loss Percentage = (Losses / Net System Input) X 100% = 6.98%

DEMAND ALLOCATION FACTOR

Month	Missouri Retail	Non-Missouri Retail	Wholesale	Total System
Jan-05	747.7	99.8	52.5	900
Feb-05	680.5	90.4	49.1	820
Mar-05	679.9	88.5	49.6	818
Apr-05	508.9	70	43.1	622
May-05	666.8	98.4	54.8	820
Jun-05	844.2	120.3	68.5	1033
Jul-05	890.7	127.9	68.4	1087
Aug-05	850.2	129.3	70.5	1050
Sep-05	808.9	117	65.1	991
Oct-05	689	106.6	58.4	854
Nov-05	695.3	93	48.7	837
Dec-05	868.9	106.4	55.7	1031
Twelve Month Avg	8931	1247.6	684.4	10863
Allocation Factor	**0.8221**	**0.1149**	**0.0630**	**1.0000**

Scedule 2

ENERGY ALLOCATION FACTOR

Month	Missouri Retail	Non-Missouri Retail	Wholesale	Total System
Jan-05	369,748,480	48,881,895	26,648,420	445,278,795
Feb-05	330,464,071	42,282,384	23,256,760	396,003,215
Mar-05	301,063,765	38,939,497	25,414,260	365,417,522
Apr-05	297,497,572	40,388,179	23,273,720	361,159,471
May-05	276,137,730	37,648,373	25,725,760	339,511,863
Jun-05	322,496,512	45,132,952	30,378,300	398,007,764
Jul-05	380,571,229	53,070,231	32,229,500	465,870,960
Aug-05	404,240,551	55,222,724	33,959,380	493,422,655
Sep-05	409,802,040	56,243,727	29,601,960	495,647,727
Oct-05	325,125,397	45,643,433	25,762,040	396,530,870
Nov-05	287,954,047	38,168,556	24,606,480	350,729,083
Dec-05	359,886,332	43,846,299	27,946,280	431,678,911
12 Month Totals	4,064,987,726	545,468,250	328,802,860	4,939,258,836
Normalization Adjustment	(17,993,790)	(5,246,325)		(23,240,115)
Annualization Adjustment	(7,576,451)	(1,542,899)		(9,119,350)
Customer Growth Adjustment	76,232,504	6,230,469		82,462,973
Wholesale Weather Adjustment			(4,075,784)	(4,075,784)
Adjusted 12 Month Totals	4,115,649,989	544,909,495	324,727,076	4,985,286,560
Allocation Factor	**0.8256**	**0.1093**	**0.0651**	**1.0000**

Monthly System Peaks (MW)

	2005	2004	2003	2002	2001
January	900	937	987	891	919
February	820	895	865	872	841
March	818	691	806	870	701
April	622	635	697	655	642
May	820	803	736	738	791
June	1033	911	927	897	859.3
July	1087	1010	1019	984	999
August	1050	1014	1041	987	1001
September	991	873	813	950	878
October	854	633	613	804	618
November	837	756	754	748	769
December	1031	913	849	820	764

Schedule 4 - Monthly Demands

Chapter Five—Functionalization, Classification, and Allocation

In allocating costs to a particular class of customers, there are three major steps (if all cost of service issues have been resolved): (1) functionalization, (2) classification, and (3) allocation. FERC has indicated that a guiding principle for this step is that the allocation must reflect cost causation. *See, e.g., Kentucky Utilities Co.*, Opinion No. 116-A, 15 FERC ¶61,222, p. 61,504 (1983), *Utah Power & Light Co.*, Opinion No. 113, 14 FERC ¶61,162, p. 61,298 (1981).[133]

A. Functionalization

Generally, plant or expense items are first functionalized into five major categories:

(1) Production;

(2) Transmission;

(3) Distribution;

(4) General and Intangible; and

(5) Common and Other.

See 18 C.F.R. §35.13(h)(4)(iii) (plant); 18 C.F.R. §35.13(h)(8)(i) (O&M expenses). Each plant or expense item will be segregated into the category with which it is most closely related.

While functionalization for most items is relatively straightforward, and not usually litigated, problems do arise with respect to the functionalization of administrative and general expenses (A&G)[134] and general plant expenses.[135] FERC stated that:

> The Commission normally requires that A&G and General Plant expenses be allocated on the basis of total company labor ratios. Under such allocation method, A&G and General Plant expense items are 'functionalized,' or segregated into...

133 Where a company has significant non-jurisdictional business, the above cost incurrence principle is important in keeping FERC within its jurisdictional constraints. *See Panhandle Eastern Pipe Line Co. v. FPC*, 324 U.S. 635, 641-42 (1945) ("the Commission must make a separation of the regulated and unregulated business.. Otherwise the profits or losses.. of the unregulated business would be assigned to the regulated business and the Commission would transgress the jurisdictional lines which Congress wrote into the Act").

134 A&G expenses include salaries of officers, executives, and office employees, employee benefits, insurance, etc.

135 General plant includes office furniture and equipment, transportation vehicles, lockers, tools, lab equipment, etc.

Schedule 4-1

> production, transmission, distribution, customer accounts, customer service, information, and sales. This "functionalization" is in proportion to the ratio of the labor cost in each major function to total labor costs less A&G and General Plant labor. Each functionalized component is allocated to customer groups.

Utah Power & Light Co., Opinion No. 308, 44 FERC ¶61,166, p. 61,549 (1988). *See also Minnesota Power & Light Co.*, Opinion No. 20, 4 FERC ¶61,116, p. 61,268 (1978) (general plant will be functionalized by labor ratios unless it is shown that the use of labor ratios produces unreasonable results). In many cases, FERC has allowed labor ratios to be used to functionalize general plant. *See, e.g., Utah Power & Light Co.*, Opinion No. 308, 44 FERC at 61,549; *Kansas City Power & Light Co.*, 21 FERC ¶63,003, p. 65,034 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Delmarva Power & Light Co.*, 17 FERC ¶63,044, p. 65,204 (1981), *aff'd*, Opinion No. 185, 24 FERC ¶61,199 (1983); *Philadelphia Electric Co.*, 10 FERC ¶63,034, pp. 65,355-56, *aff'd*, 13 FERC ¶61,057 (1980). Similarly, FERC has required that most A&G expenses be functionalized on the basis of labor ratios. *Missouri Power & Light Co.*, Opinion No. 31, 5 FERC ¶61,086, pp. 61,137-38 (1978); *Kansas City Power & Light Co.*, 21 FERC at 65,035; *Delmarva Power & Light Co.*, 17 FERC at 65,204. An exception to this has been established for property insurance which has been functionalized on plant ratios. *Pacific Gas & Electric Co.*, 16 FERC ¶63,004, pp. 65,015-16 (1981), *aff'd*, Opinion No. 147, 20 FERC ¶61,340 (1982); *Kansas-Nebraska Natural Gas Co.*, Opinion No. 731, 53 FPC 1691, 1722 (1975).

Common plant and intangible plant also have been analogized to general plant and functionalized on the basis of labor ratios. *Kansas City Power & Light*, 21 FERC at 65,035; *Delmarva Power & Light Co.*, 17 FERC at 65,204; *Philadelphia Electric*, 10 FERC at 65,355-56.

Another issue that has arisen is the calculation of the labor ratios. Usually, the labor ratio consists of total labor costs in the denominator with the labor costs associated with a particular category in the numerator. In a number of proceedings, companies have attempted to change the ratio by only including production, transmission, and distribution-related labor costs in the denominator, thereby excluding customer service related labor costs. FERC rejected this in at least one case. *Kansas City Power & Light*, 21 FERC at 65,033-34.

B. Classification

After functionalizing, the next step is to classify those expenses or costs into one of three categories (1) demand, (2) energy, or (3) other. *See* 18 C.F.R. §35.13(h)(8)(ii)(A).

FERC's Staff for a number of years has used the predominance method for classifying production O&M accounts. Under this method if an account is *predominantly* (51-100%) energy-related, it will be classified as energy. The same also is true with respect to demand related costs. FERC has accepted this method in a number of cases. *See, e.g., Arizona Public Service Co.*, 4 FERC ¶61,101, pp. 61,209-10 (1978); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,255-56 (1980), *aff'd*, 15 FERC ¶61,050, p. 61,093 (1981); *Kansas City Power & Light*

Co., 21 FERC ¶63,003, p. 65,037 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Minnesota Power & Light Co.*, Opinion No. 86, 11 FERC ¶61,312, pp. 61,648-49 (1980).[136]

In addition to FERC's adoption of Staff's predominance method, FERC also has adopted Staff's classification index of production O&M accounts. *Arizona Public Service Co.*, 4 FERC at 61,209-10; *Kansas City Power & Light*, 21 FERC at 65,037; *Minnesota Power & Light Co.*, 11 FERC at 61,648-49. In *Montaup Electric Co.*, Opinion No. 267, 38 FERC at 61,864, FERC rejected a proposed rate tilt, finding that the "proposal is inconsistent with the classification table of predominant characteristics for operation and maintenance accounts used by Staff, which has been approved by the Commission." In *Southern Company Services*, Opinion No. 377, 61 FERC ¶61,075, p. 61,311 (1992), *reh. denied*, 64 FERC ¶61,033 (1993), FERC, however, stated that the Staff index is not mandatory. FERC accepted a departure from the Staff's index, though it held that a party proposing a departure has the burden of justifying that departure.

C. Allocation

After classifying costs to demand, energy, and customer categories, the next step is to allocate these costs to the various classes to determine their respective cost responsibilities. In the past, the most hotly litigated allocation issue involved demand cost allocation. Typically, FERC has allocated demand costs on a coincident peak (CP) method. *Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) ("Maine Public has cited a legion of Commission decisions affirming the use of a coincident peak demand allocator.... And, it denies knowledge of '*any* decision, involving an electric utility since the FERC came into existence in 1977, where FERC did not follow a coincident peak method of allocating demand costs' "). In *Lockhart Power Co.*, 4 FERC ¶61,337, p. 61,807 (1978), FERC stated that its "general policy is to allocate demand costs on the basis of peak responsibility as is demonstrated by the overwhelming majority of decided cases." *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092. Under a CP method, the demands used in the allocation are the demands of a particular customer or class occurring at the time of the system peak for a particular time period. The basic assumption behind this method is that capacity costs are incurred to serve the peak needs of customers.

1. Coincident Peak Allocation

In most cases, FERC has accepted one of four CP methods—1 CP, 3 CP, 4 CP, and 12 CP, with the largest number of companies using a 12 CP allocation. Under a 1 CP method, the allocator for a particular wholesale class will be developed by dividing the wholesale class's CP for the peak month by the total company system peak. Similarly, for 3, 4, and 12

136 If a company is able to justify a percentage split, such as 70-30, in an account, then FERC may accept that split. However, in light of FERC precedent on this subject, any party proposing a deviation from the predominance method likely will have the burden of justifying its proposed split.

CP companies the numerator would consist of the average of the wholesale class's coincident peaks for each of the peak months, while the denominator would consist of the average of the total system peaks for each of the peak months. FERC has held that interruptible loads should not be reflected in this demand allocation.[137] *See Delmarva Power & Light Co.*, Opinion No. 185, 25 FERC at 61,121; *Delmarva Power & Light Co.*, Opinion No. 185, 24 FERC ¶61,199, p. 61,462 (1983).

While FERC has not established a hard and fast rule for determining which allocation method is appropriate, it has stated that the following factors should be considered:

> [T]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments. (footnote omitted).

Carolina Power & Light Co., Opinion No. 19, 4 FERC ¶61,107, p. 61,230 (1978); *Commonwealth Edison Co.*, 15 FERC ¶63,048, p. 65,196 (1981), *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,247–48 (1980), *aff'd*, 15 FERC ¶61,050 (1981). *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092 (applying FERC's various tests in finding that a 12 CP was appropriate).

a. System Demand Tests

If a utility's system demand curve is relatively flat, then that supports the use of a 12 CP method under FERC precedent. If a utility experiences a pronounced peak during one, three, or four consecutive months, then under FERC precedent the use of another CP method would be supported.

In determining whether a utility experiences a pronounced peak during a particular time period, FERC considers a number of tests. First, FERC has compared the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak. FERC has held that large differences between these two figures lends support to using something other than a 12 CP method, while a smaller difference supports 12 CP, as shown below:[138]

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(31% difference—4 CP);

---

[137] FERC ordered that the revenues from the interruptible loads be credited to the cost of service. *Delmarva Power & Light Co.*, 28 FERC ¶61,279, p. 61,510 (1984).

[138] *See also Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) (the ALJ stated that "using established Commission tests that compare average monthly peaks with the annual peak, lowest monthly peak to the annual peak, average monthly demand peaks of the peak season to the monthly demand peaks of the off-peak service" Maine Public is a 12 CP company).

(2) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(26% difference—4 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(18% difference—12 CP);

(4) *Illinois Power Co.*,
11 FERC at 65,248,
(19% difference—12 CP);

(5) *Commonwealth Edison Co.*,
15 FERC at 65,196
(16.4-24.9% differences—4 CP);

(6) *Southwestern Public Service Co.*,
18 FERC at 65,034
(average difference of 22.9%, high of 28.3%—3 CP).

FERC also has used a second test involving the lowest monthly peak as a percentage of the annual peak. The higher the percentage, the greater the support for 12 CP. This test has been used in the following cases:

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(50%—5 CP);

(2) *Idaho Power Co.*,
Opinion No. 13,
3 FERC ¶61,108 (1978)
(58%—3 CP);

(3) *Southwestern Electric Power Co.*,
Opinion No. 28,
4 FERC ¶61,330 (1978)
(55.8%—4 CP);

(4) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(73%—12 CP);

(5) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(79%—12 CP);

(6) *Alabama Power Co.*,
Opinion No. 54,
8 FERC ¶61,083 (1979)
(75%—12 CP);

(7) *Illinois Power Co.*,
11 FERC at 65,248
(66%—12 CP);

(8) *Commonwealth Edison Co.*,
15 FERC at 65,198
(64.6-67.8%—4 CP);

(9) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(61.9%—4 CP);

(10) *El Paso Electric Co.*,
Opinion No. 109,
14 FERC ¶61,082 (1981)
(71%—12 CP);

(11) *Carolina Power & Light Co.*,
Opinion No. 19,
4 FERC ¶61,107 (1978)
(72%—12 CP);

(12) *New England Power Co.*,
Opinion No. 803,
58 FPC 2322 (1977)
(80%—12 CP);

(13) *Southwestern Public Service Co.*,
18 FERC at 65,034
(on average, almost 67 percent—3 CP); and

Schedule DAF-7

(14) *Delmarva Power & Light Co.*,
17 FERC at 65,201
(71.4%—12 CP)

Another test that has been utilized by FERC is the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. In *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,230, FERC adopted a 12 CP approach where the monthly peaks in three nonpeak months exceeded the peaks in two of the alleged peak months. In *Commonwealth Edison Co.*, 15 FERC at 65,198, FERC adopted a 4 CP method where over a four year period, a peak in one of the 4 peak months was exceeded only once by a peak from a non-peak month. *See also Southwestern Public Service Co.*, 18 FERC at 65,034 (monthly peak in any non-peaking month exceeded the monthly peak in peak month only once and 3 CP adopted).

A last test involves the average of the twelve monthly peaks as a percentage of the highest monthly peak and has been used in the following cases:

(1) *Illinois Power Co.*,
11 FERC at 65,248-49
(81%—12 CP);

(2) *El Paso Electric Co.*
Opinion No. 109,
14 FERC ¶61,082 (1981)
(84%—12 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(84%—12 CP);

(4) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(87.8%—12 CP);

(5) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(61.2%—4 CP);

(6) *Commonwealth Edison Co.*,
15 FERC at 65,198
(79.4-79.5%—4 CP).

Schedule 4-7

(7) *Southwestern Public Service Co.*,
18 FERC at 65,035
(80.1%—3 CP); and

(8) *Delmarva Power & Light Co.*,
17 FERC at 65,202
(83.3%—12 CP).

b. Tests Relating to Reserves/Maintenance

To the extent a utility uses the off-peak months to perform its scheduled maintenance, FERC has found that supportive of the use of a 12 CP method. *Alabama Power Co.*, Opinion No. 54, 8 FERC ¶61,083, p. 61,327 (1979); *Illinois Power Co.*, 11 FERC at 65,249; *New England Power Co.*, Opinion No. 803, 58 FPC 2322, 2338 (1977); *Delmarva Power & Light Co.*, 17 FERC at 65,202. *But see Commonwealth Edison*, 15 FERC at 65,199.[139]

However, the scheduled maintenance must be considered together with the reserves available after the maintenance. To the extent the reserve margins are fairly stable after maintenance, then a 12 CP method is supported. If the reserve margins drop substantially to marginal levels during certain months, then a method other than 12 CP may be supported. *See, e.g., Illinois Power Co.*, 11 FERC at 65,249 (46 percent reserves after maintenance non-summer months and 34.5 percent for summer months—12 CP); *Commonwealth Edison Co.*, 15 FERC at 65,200 (for 1979 36.63 percent reserves after maintenance for 8 non-summer months and 22.15 percent for 4 summer months—4 CP).

c. Projection of CP and Total System Demands

In a number of cases, parties and the FERC Staff have challenged the filing company's estimated coincident peak or total system demand estimates.[140] While FERC appears to have established few hard and fast rules, the following cases provide some guidance. First, parties have challenged projections on the basis that the historical periods used were not representative. In some cases, FERC has held that multiple years of historical data should be

---

139 In *Southwestern Public Service Co.*, Opinion No. 337, 49 FERC ¶61,296, p. 62,132 (1989), FERC declined to depart from the 3 CP method based on "monthly load patterns and reserve margins as affected by scheduled maintenance" which "show that Southwestern's capacity requirements are largely determined by the peak demands imposed on the system during a three-month summer period."

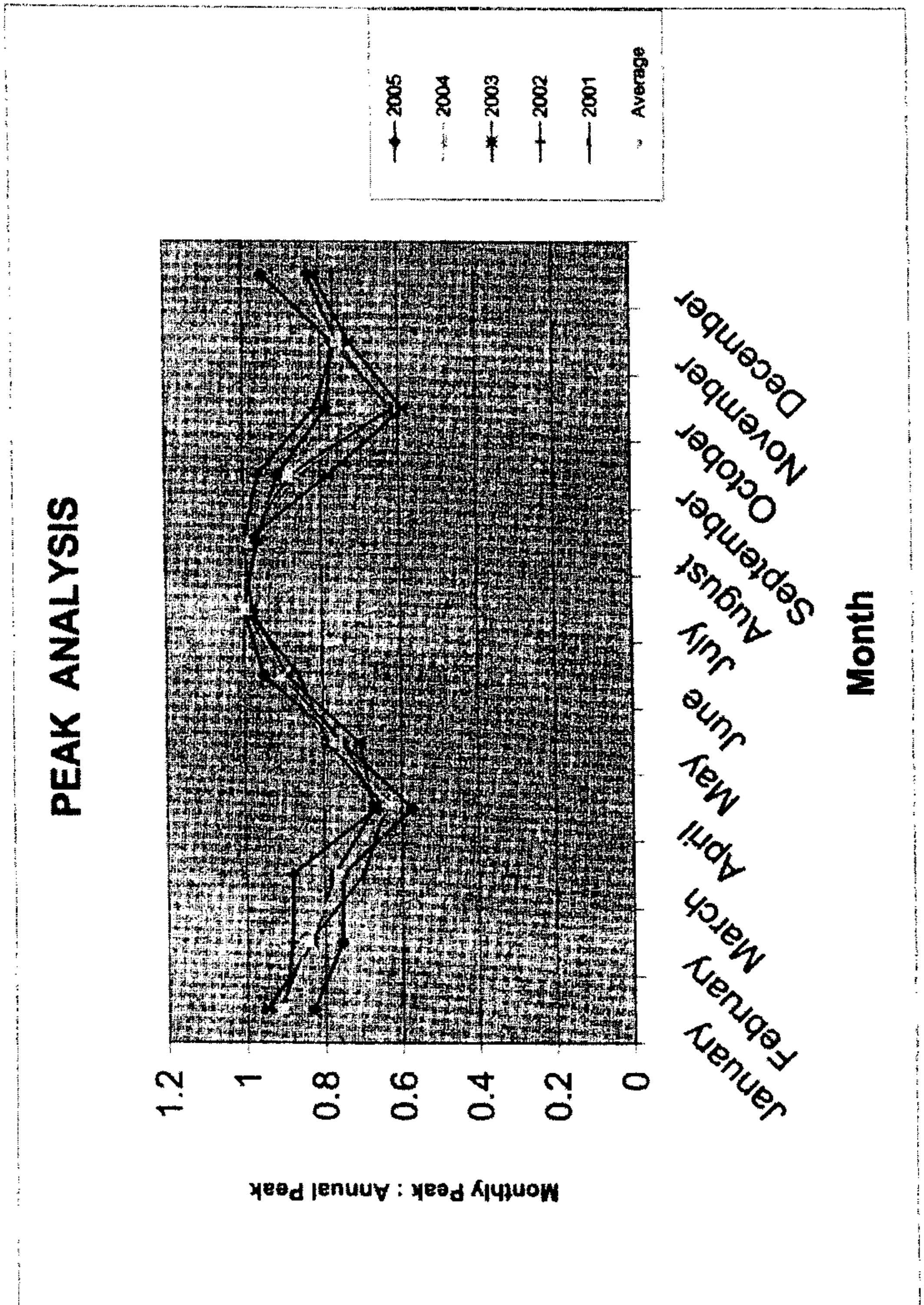
140 In *Blue Ridge Power Agency v. Appalachian Power Co.*, Opinion No. 363, 55 FERC ¶61,509, p. 62,788 (1991), FERC accepted the Staff's method for deriving a coincident peak estimate. The Staff asserted that the noncoincident peak estimate must be divided by the diversity factor to convert each noncoincident peak demand into a comparable coincident peak demand. 55 FERC at 62,788-89. The "diversity factor is the noncoincident peak demand divided by the coincident peak demand." 55 FERC at 62,788 n. 87. FERC, however, stated that "[n]ormally, we would calculate the coincident peak demand for the sales for resale group by looking at its consumption at the time of Appalachian's peak. In this case, however, we have the forecasted monthly noncoincident peak demands for the customer group" and that "[u]sing the historical diversity factor for the group, we can derive the calculated coincident peak." *Id.*

used in developing the estimate and not just one year. *See, e.g., Otter Tail Power Co.*, Opinion No. 93, 12 FERC ¶61,169, p. 61,429 (1980). *Commonwealth Edison Co.*, 15 FERC at 65,190, *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983) (3 year average adopted); *Southern California Edison Co.*, Opinion No. 359-A, 54 FERC at 62,020 (accepted system peak demand and energy sales forecasts based on 1967-1981 data and 1981 coincidence factors). In other cases, FERC, however, has adopted CP projections based on the use of one year's data. *See, e.g., Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,229-30.

Second, FERC has expressed concern that the numerator and the denominator be developed on similar bases. In *Otter Tail Power Co.*, Opinion No. 93, 12 FERC at 61,429, FERC modified a demand allocator to provide for the use of the same number of years data in the derivation of both the numerator and the denominator.

Finally, FERC has held that billing demands should be consistent with the demands used in the demand allocator. *See El Paso Electric Co.*, Opinion No. 109, 14 FERC ¶61,082, p. 61,147 (1981).

Schedule 4-9


PEAK ANALYSIS
Monthly Peak : Annual Peak
1.2
1
0.8
0.6
0.4
0.2
0
January
February
March
April
May
June
July
August
September
October
November
December
Month
2005
2004
2003
2002
2001
Average

Schedule 6

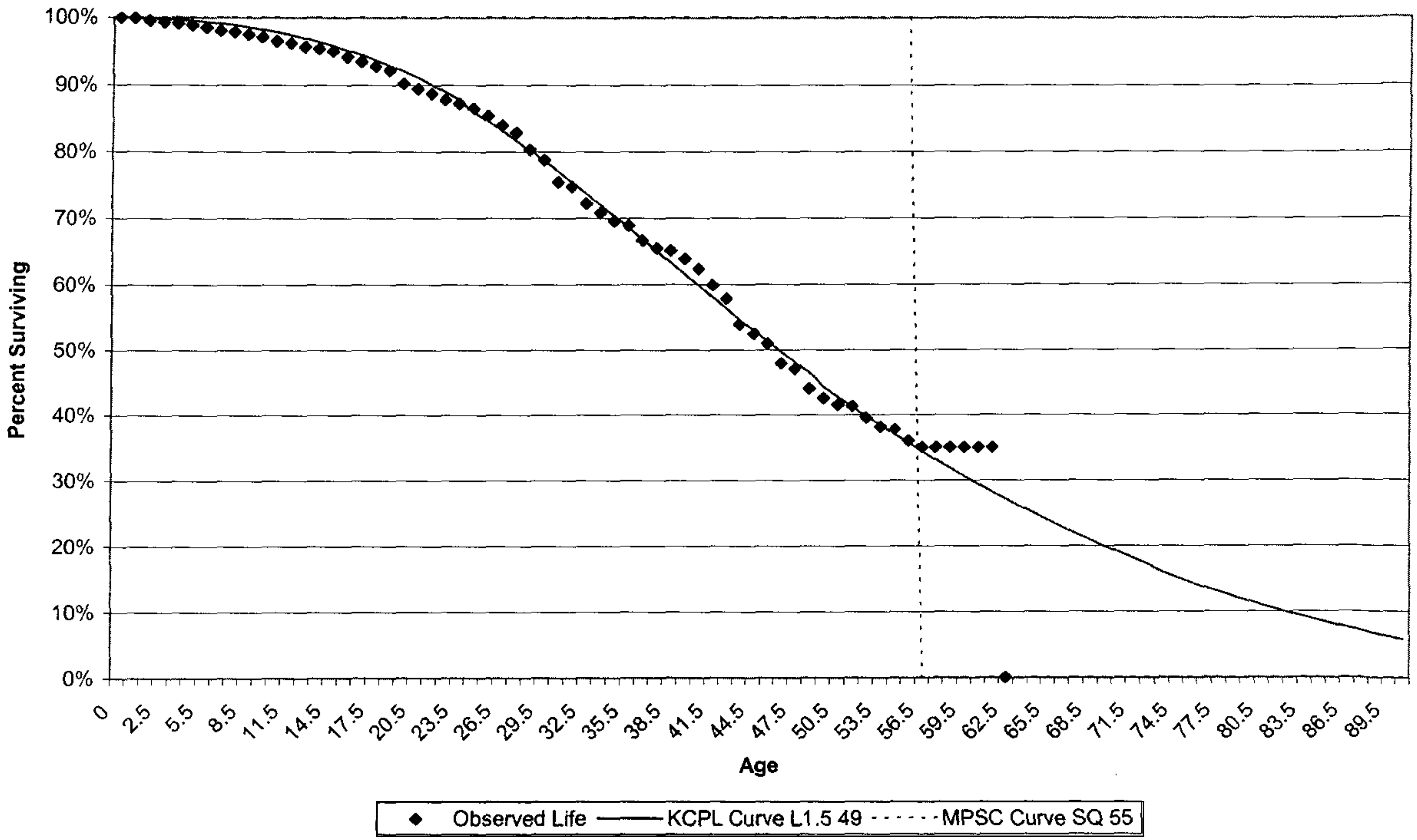
FERC Test Calculations

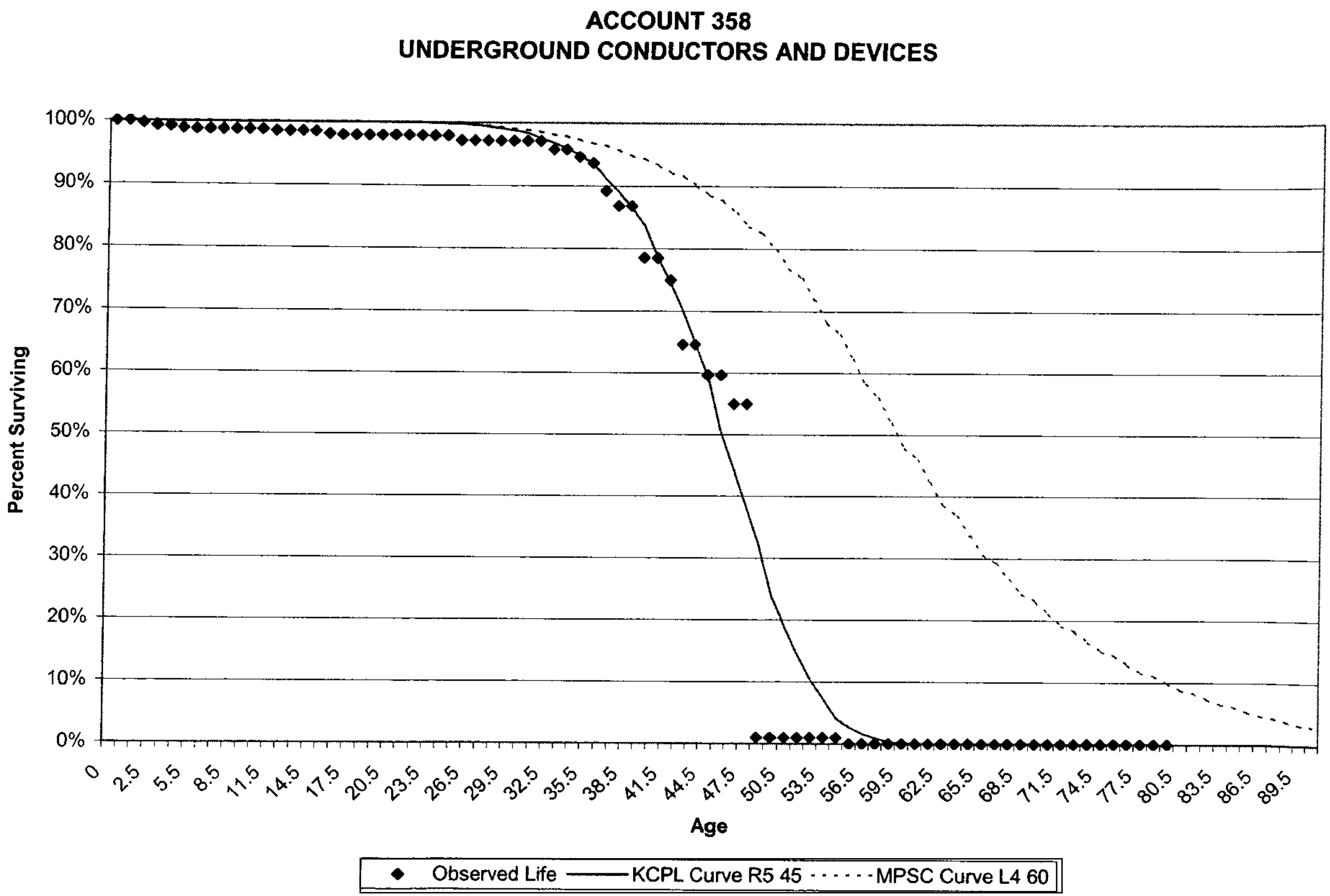
			Empire Monthly Peaks (MWs)		
January			900		
February			820		
March			818		
April			622		
May			820		
June			1033		
July			1087		
August			1050		
September			991		
October			854		
November			837		
December			1031		
Minimum Peak	=		622		
Maximum Peak	=		1087		
Summer Month Avg	=		1040.25		
Other Months Avg	=		837.75		
12 Month Avg	=		905.25		
Ratio 1a = (Summer_Avg) / Max	=		0.95699172		
Ratio 1b = (8-Month_Avg) / Max	=		0.770699172		
FERC Test 1	=	Ratio 1a - Ratio 1b	0.186292548	=	18.63%
FERC Test 2	=	(12 Month Avg) / Max Peak	0.832796688	=	83.28%
FERC Test 3	=	Min Peak / Max Peak	0.572217111	=	57.22%

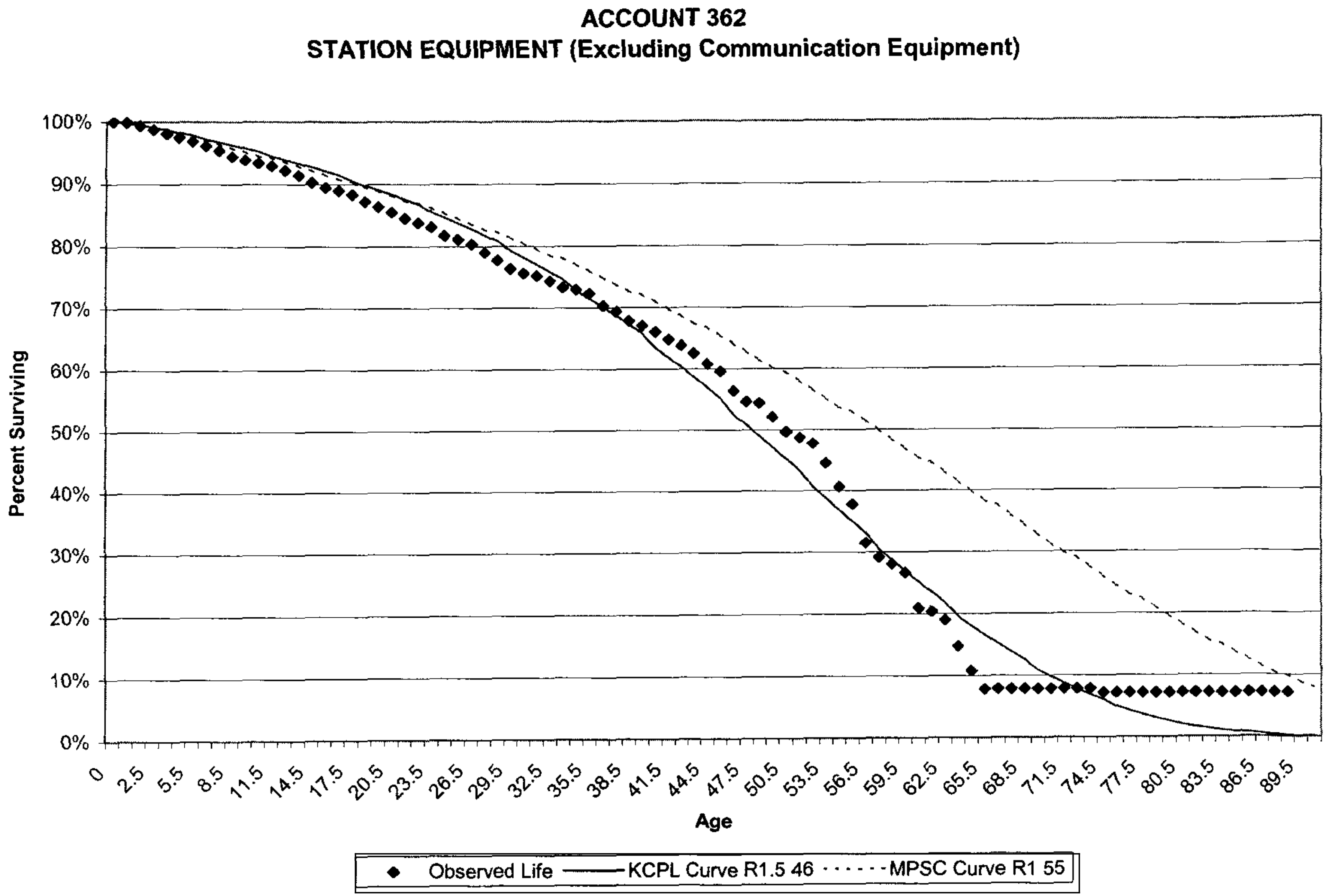
FERC Test Calculations Using Total kWh Sales Including Off-System Sales
Reflects Test Year 2005 KCPL kWh Sales

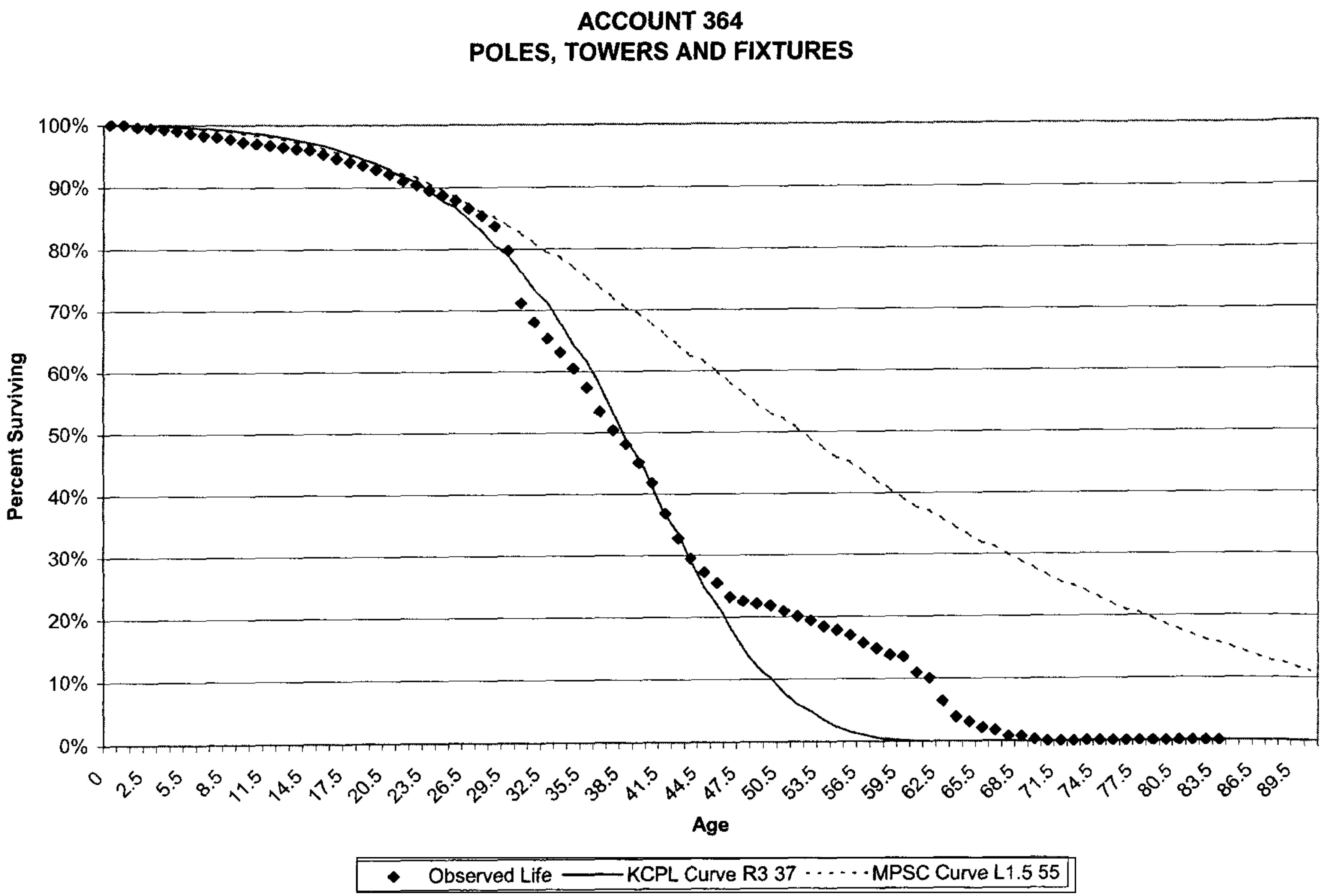
			Total Monthly kWh Sales KCPL		
January			1,756,120,024		
February			1,425,608,325		
March			1,417,115,134		
April			1,386,792,333		
May			1,460,037,982		
June			1,764,338,664		
July			1,961,984,580		
August			1,901,106,514		
September			1,562,421,764		
October			1,700,801,361		
November			1,575,778,785		
December			1,617,653,437		
Minimum Peak	=		1,386,792,333		
Maximum Peak	=		1,961,984,580		
Summer Month Avg	=		1,797,462,881		
Other Months Avg	=		1,542,488,423		
12 Months Avg	=		1,627,479,909		
Ratio 1a = (Summer Avg) / Max	=		0.91614526		
Ratio 1b = (8-month Avg) / Max	=		0.78618784		
FERC Test 1	=	Ratio 1a - Ratio 1b	0.12995742	=	13%
FERC Test 2	=	(12 Months Avg) / Max Peak	0.82950698	=	83%
FERC Test 3	=	Min Peak / Max Peak	0.70683141	=	71%

ACCOUNT 355
POLES AND FIXTURES

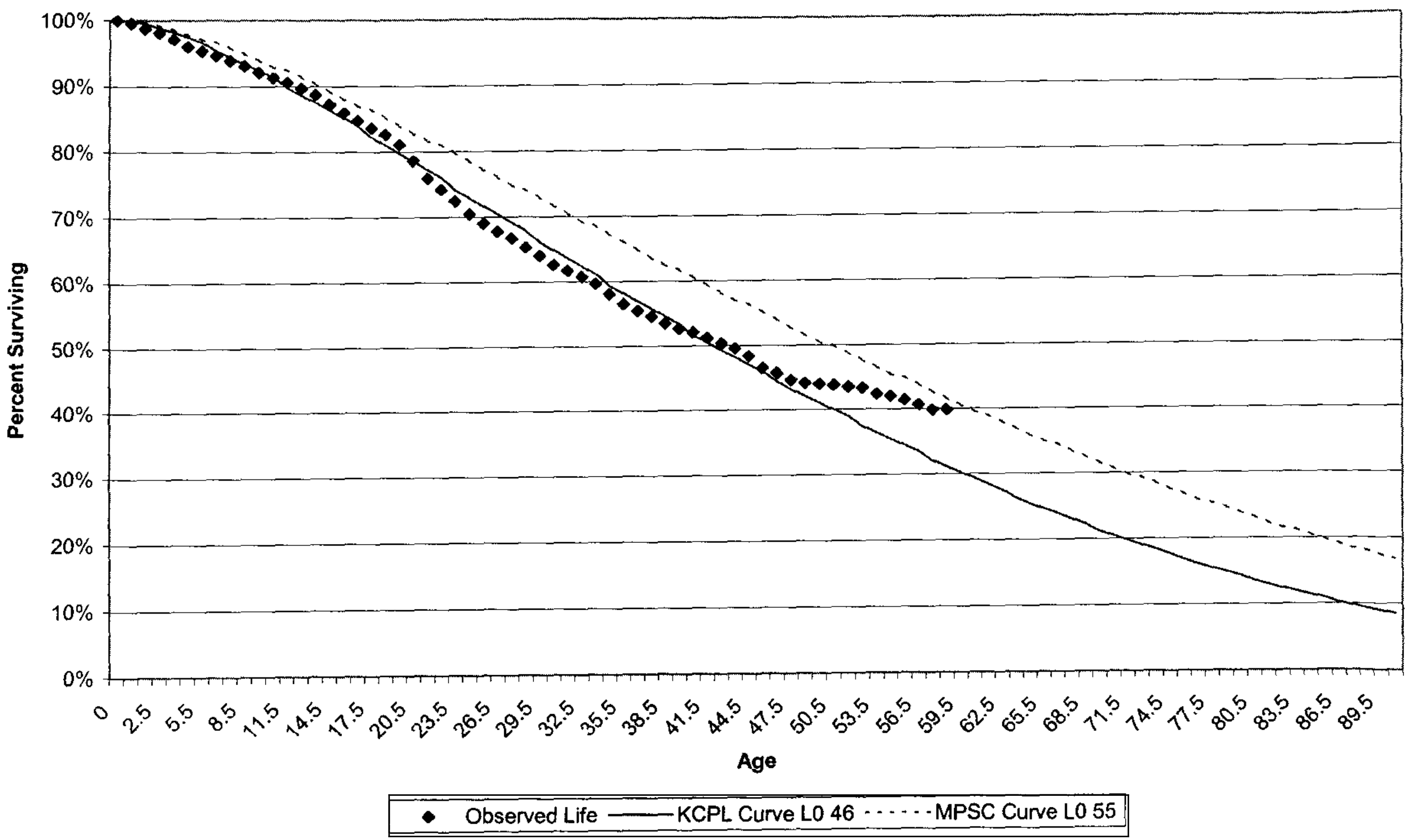



ACCOUNT 358
UNDERGROUND CONDUCTORS AND DEVICES
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent Surviving
0
2.5
5.5
8.5
11.5
14.5
17.5
20.5
23.5
26.5
29.5
32.5
35.5
38.5
41.5
44.5
47.5
50.5
53.5
56.5
59.5
62.5
65.5
68.5
71.5
74.5
77.5
80.5
83.5
86.5
89.5
Age
Observed Life
KCPL Curve R5 45
MPSC Curve L4 60

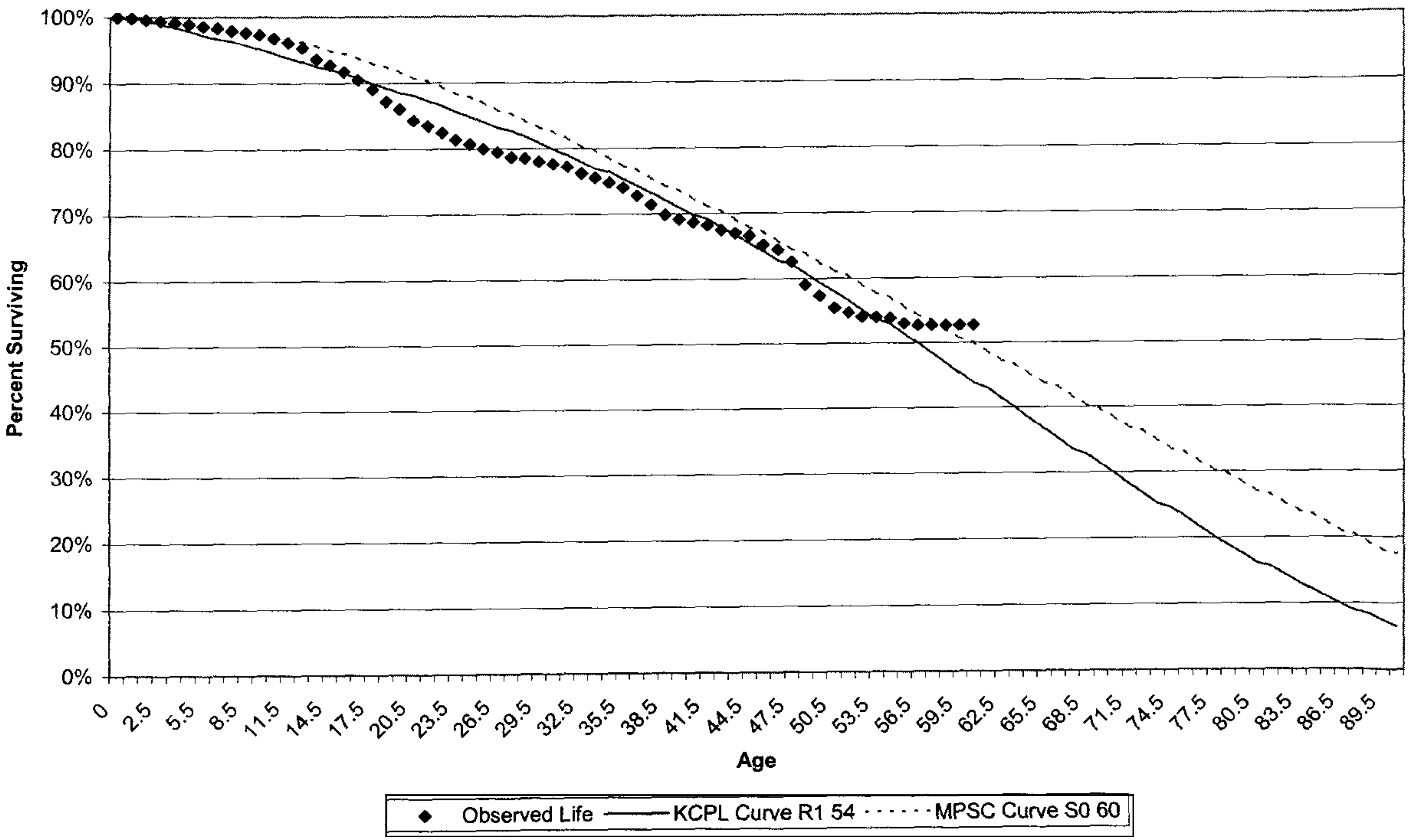

ACCOUNT 362
STATION EQUIPMENT (Excluding Communication Equipment)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent Surviving
0
2.5
5.5
8.5
11.5
14.5
17.5
20.5
23.5
26.5
29.5
32.5
35.5
38.5
41.5
44.5
47.5
50.5
53.5
56.5
59.5
62.5
65.5
68.5
71.5
74.5
77.5
80.5
83.5
86.5
89.5
Age
Observed Life
KCPL Curve R1.5 46
MPSC Curve R1 55


ACCOUNT 364
POLES, TOWERS AND FIXTURES
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent Surviving
0
2.5
5.5
8.5
11.5
14.5
17.5
20.5
23.5
26.5
29.5
32.5
35.5
38.5
41.5
44.5
47.5
50.5
53.5
56.5
59.5
62.5
65.5
68.5
71.5
74.5
77.5
80.5
83.5
86.5
89.5
Age
Observed Life
KCPL Curve R3 37
MPSC Curve L1.5 55

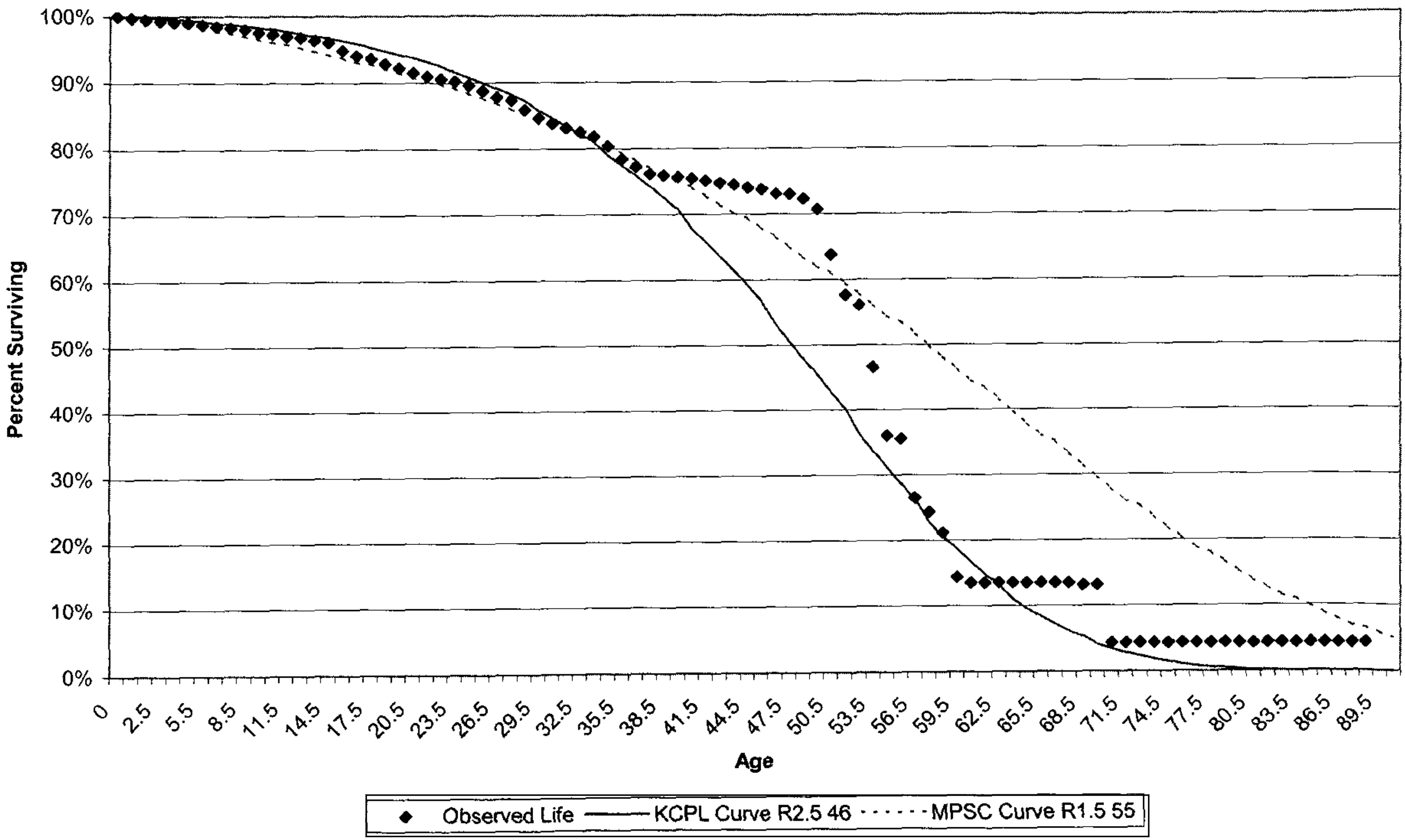
ACCOUNT 365
OVERHEAD CONDUCTORS AND DEVICES

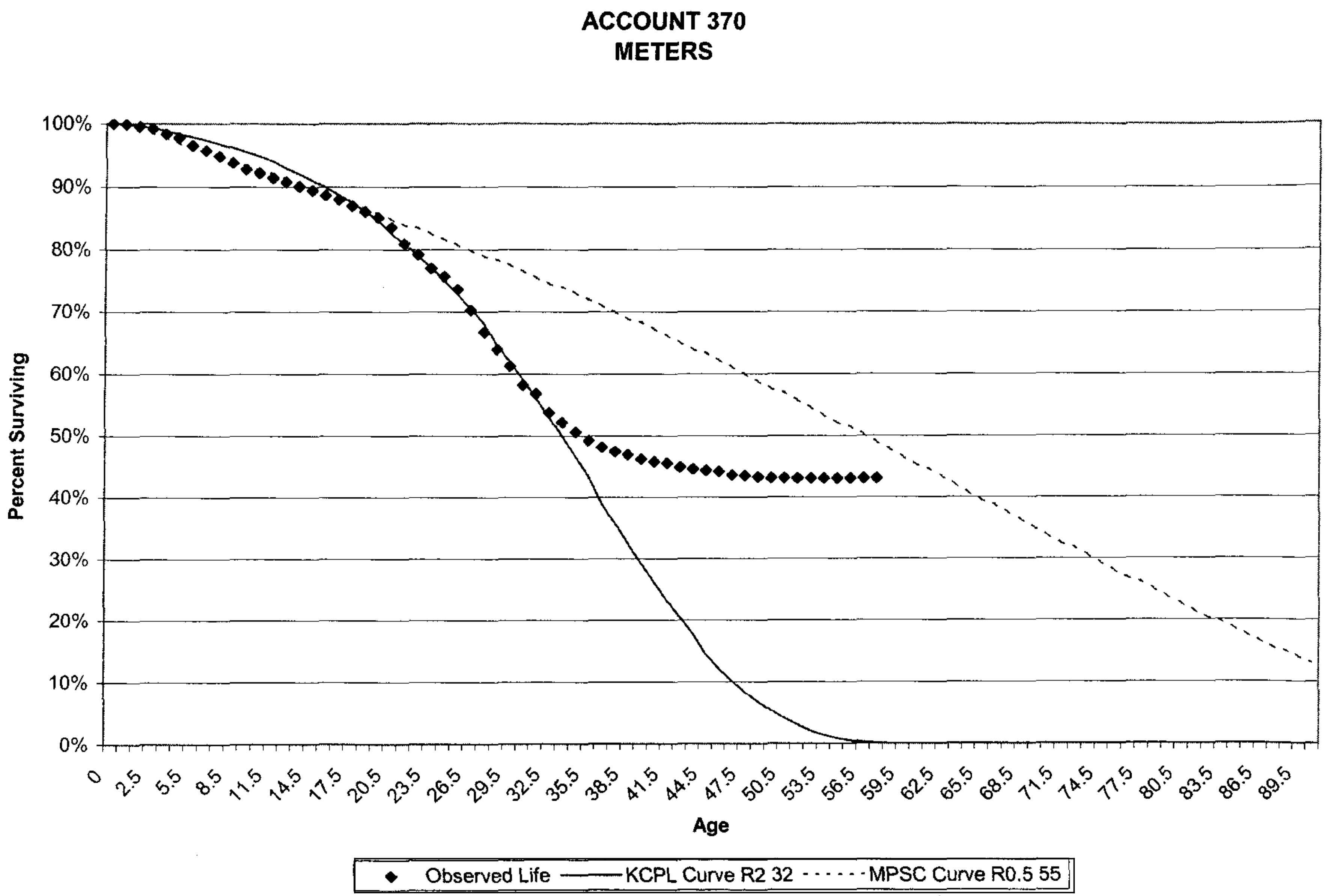


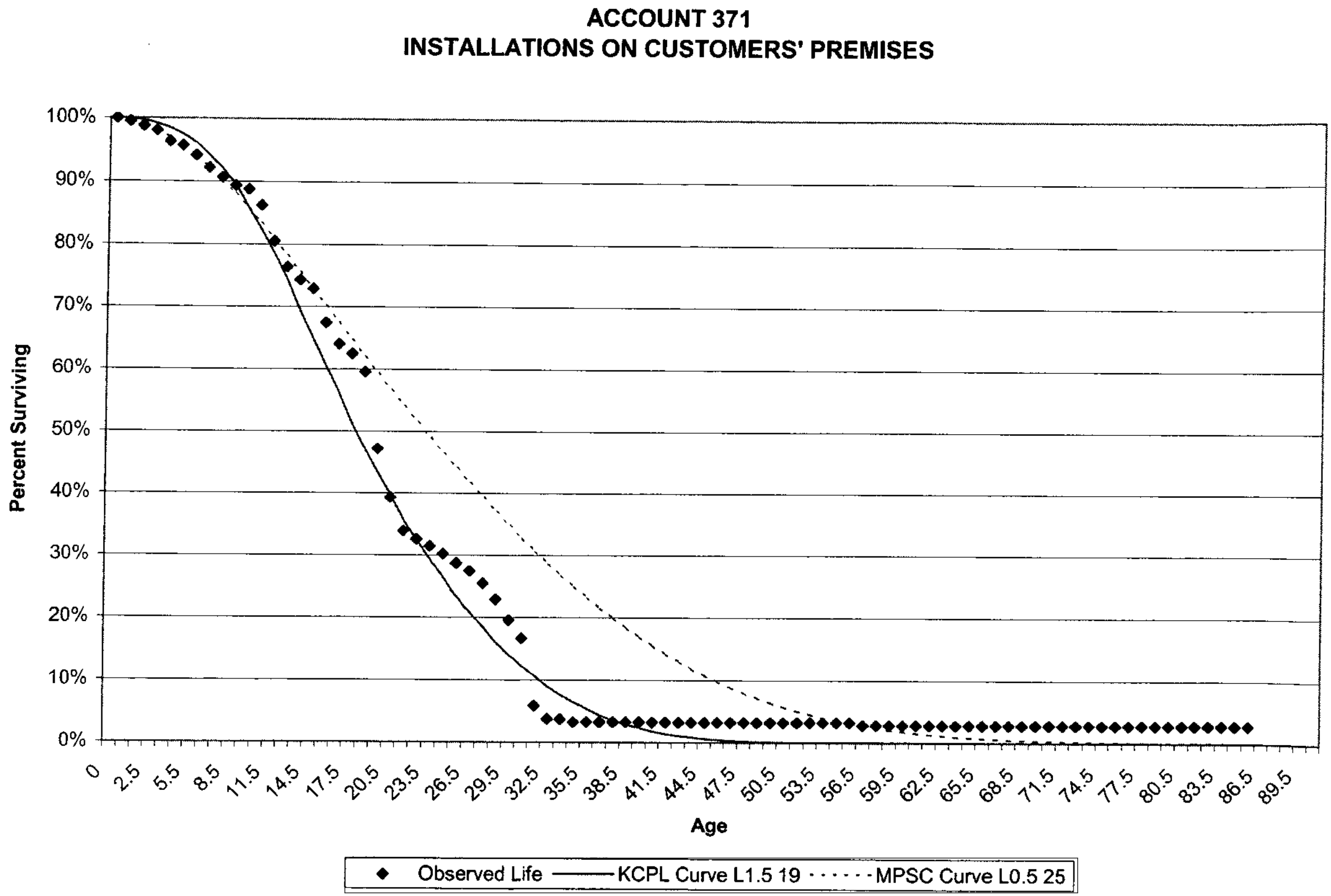
ACCOUNT 367
UNDERGROUND CONDUCTORS AND DEVICES

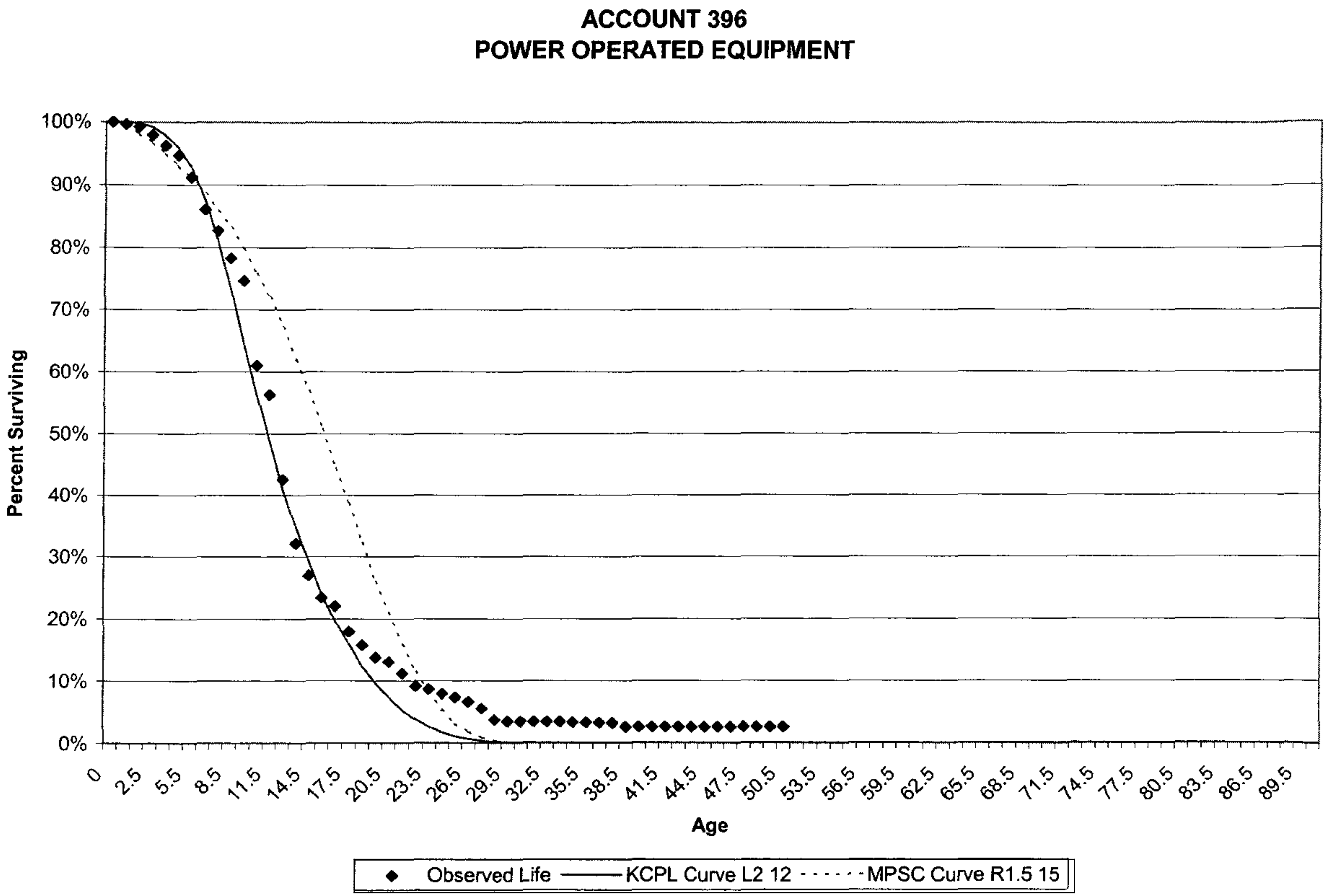


ACCOUNT 369
SERVICES

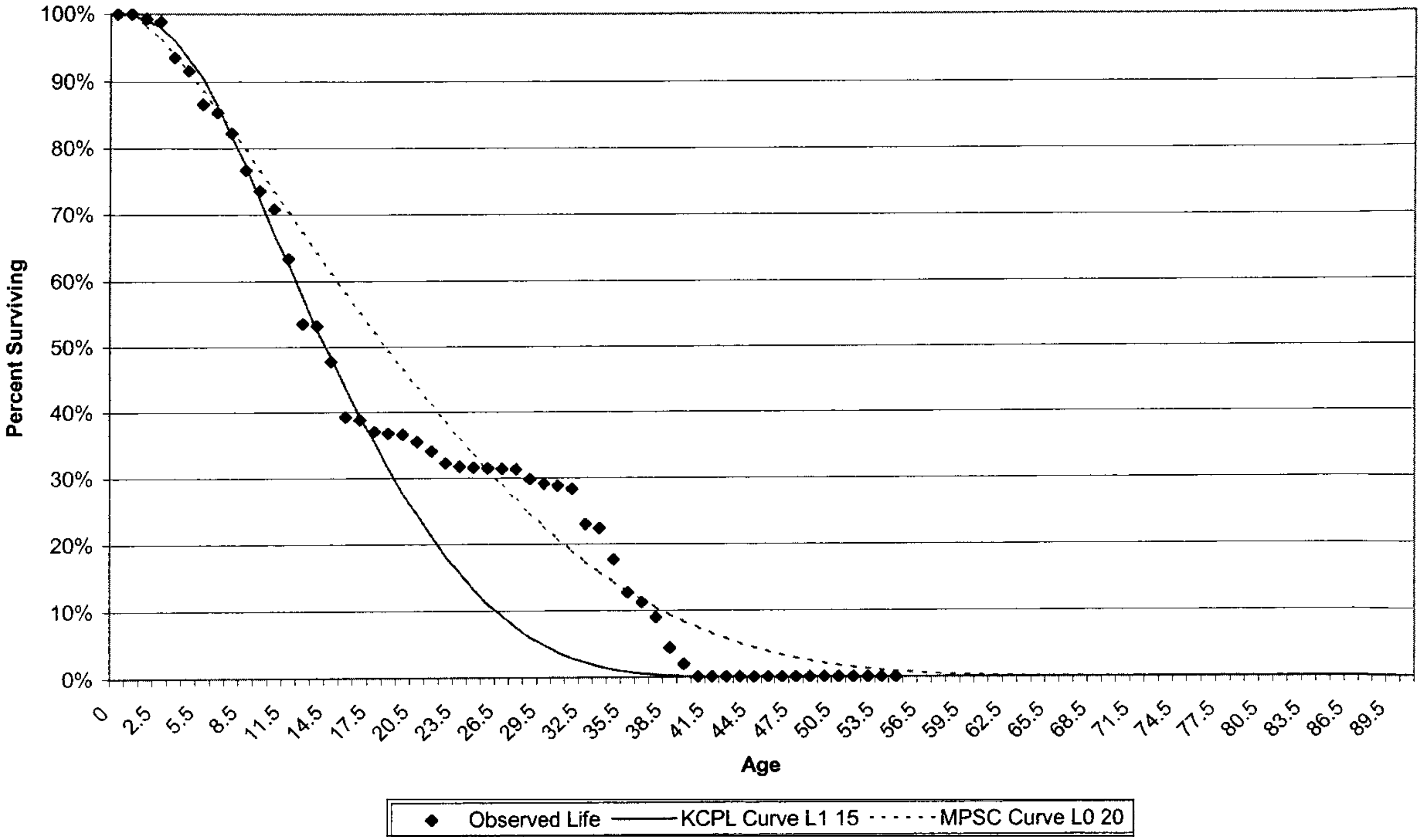



ACCOUNT 370
METERS
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent Surviving
0
2.5
5.5
8.5
11.5
14.5
17.5
20.5
23.5
26.5
29.5
32.5
35.5
38.5
41.5
44.5
47.5
50.5
53.5
56.5
59.5
62.5
65.5
68.5
71.5
74.5
77.5
80.5
83.5
86.5
89.5
Age
Observed Life
KCPL Curve R2 32
MPSC Curve R0.5 55


ACCOUNT 371
INSTALLATIONS ON CUSTOMERS' PREMISES
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent Surviving
0
2.5
5.5
8.5
11.5
14.5
17.5
20.5
23.5
26.5
29.5
32.5
35.5
38.5
41.5
44.5
47.5
50.5
53.5
56.5
59.5
62.5
65.5
68.5
71.5
74.5
77.5
80.5
83.5
86.5
89.5
Age
Observed Life
KCPL Curve L1.5 19
MPSC Curve L0.5 25


ACCOUNT 396
POWER OPERATED EQUIPMENT
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent Surviving
0
2.5
5.5
8.5
11.5
14.5
17.5
20.5
23.5
26.5
29.5
32.5
35.5
38.5
41.5
44.5
47.5
50.5
53.5
56.5
59.5
62.5
65.5
68.5
71.5
74.5
77.5
80.5
83.5
86.5
89.5
Age
Observed Life
KCPL Curve L2 12
MPSC Curve R1.5 15

ACCOUNT 398
MISCELLANEOUS EQUIPMENT



Accounting Schedule: 1
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Revenue Requirement

Line		7.78% Return	7.81% Return	7.83% Return
	(A)	(B)	(C)	(D)
1	Net Orig Cost Rate Base (Sch 2)	$1,169,625,282	$1,169,625,282	$1,169,625,282
2	Rate of Return	7.78%	7.81%	7.83%
3	Net Operating Income Requirement	$ 90,996,847	$ 91,347,735	$ 91,581,660
4	Net Income Available (Sch 9)	$ 114,094,414	$ 114,094,414	$ 114,094,414
5	Additional NOIBT Needed	$ (23,097,567)	$ (22,746,679)	$ (22,512,754)
6	Income Tax Requirement (Sch 11)			
7	Required Current Income Tax	$ 32,502,613	$ 32,724,788	$ 32,872,903
8	Test Year Current Income Tax	$ 47,127,483	$ 47,127,483	$ 47,127,483
9	Additional Current Tax Required	$ (14,624,870)	$ (14,402,695)	$ (14,254,580)
10	Required Deferred ITC	$ 0	$ 0	$ 0
11	Test Year Deferred ITC	$ 0	$ 0	$ 0
12	Additional Deferred ITC Required	$ 0	$ 0	$ 0
13	Total Additional Tax Required	$ (14,624,870)	$ (14,402,695)	$ (14,254,580)
14	Gross Revenue Requirement	$ (37,722,437)	$ (37,149,374)	$ (36,767,334)

Accounting Schedule: 1-1

Accounting Schedule: 2
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Rate Base

Line	Description	Amount
	(A)	(B)
1	Total Plant in Service (Sch 3)	$2,694,683,608
	Subtract from Total Plant	
2	Depreciation Reserve (Sch 6)	$1,258,035,828
3	Net Plant in Service	$1,436,647,780
	Add to Net Plant in Service	
4	Cash Working Capital (Sch 8)	$ (28,692,365)
5	Materials and Supplies-Exempt	30,400,565
6	Prepayments	5,869,318
7	Prepaid Pension Asset EO-2005-0329	19,963,915
8	Reg Asset Excess Act FAS 87 vs Rate	13,024,460
9	Reg Asset Demand Side Management	1,264,594
10	Fuel Inventory - Coal	15,157,697
11	Fuel Inventory - Oil	3,230,100
12	Fuel Inventory Lime/Limestone	76,831
13	Nuclear Fuel	15,385,641
	Subtract from Net Plant	
14	Federal Tax Offset 4.2250 %	$ 1,167,815
15	State Tax Offset 11.0880 %	481,609
16	City Tax Offset 0.0000 %	0
17	Interest Expense Offset 17.9380 %	5,769,703
18	Customer Deposits	5,506,507
19	Contribution in Aid of Construction	225,372
20	Deferred Income Taxes-Depreciation	295,897,313
21	Amort Depr EO-94-199 in Reserve	0
22	Reg Liab Emission Allowance Sales	33,654,935
23	Total Rate Base	$1,169,625,282

Accounting Schedule: 2-1

Accounting Schedule: 3
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Total Plant in Service

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment		Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)		(F)
		Intangible Plant						
1	301.000	Organization	$ 72,186	$ 0	53.9790	$ 0		$ 38,965
2	302.000	Franchises & Consents	22,937	0	100.0000	0		22,937
3	303.000	Miscellaneous Intangible Plant	794,963	0	53.9790	0		429,113
4	303.200	Miscl Intangible Plt - 5yr Software	36,704,828	0	53.9790	0		19,812,899
5	3030.300	Miscl Intangible Plt-10yr Software	49,520,894	0	53.9790	0		26,730,883
6	303.050	Miscl Intang Plt-WC 5yr Software	8,448,479	0	53.9790	0		4,560,404
7		Total	$ 95,564,287	$ 0		$ 0		$ 51,595,201
		Production-Stm-Hawthorn Unit 5						
8	310.000	Land & Land Rights	$ 807,281	$ 0	53.4600	$ 0		$ 431,572
9	311.000	Structures & Improvements	22,652,417	0	53.4600	0	P-1	12,109,982
10	311.020	Structures - H 5 Rebuild	8,923,285	(405,160)	53.4600	0	P-2	4,553,790
11	312.000	Boiler Plant Equipment	41,321,702	0	53.4600	0	P-3	22,090,582
12	312.020	Boiler AQC Equip - Electric	170,530	0	53.4600	0	P-4	91,165
13	312.030	Boiler Plant - H5 Rebuild	235,695,777	(10,701,728)	53.4600	0	P-5	120,281,819
14	314.000	Turbogenerator Units	72,908,021	0	53.4600	0	P-6	38,976,628
15	315.000	Accessory Electric Equipment	4,151,943	0	53.4600	0	P-7	2,219,629
16	315.010	Accessory Equip - H5 Rebuild	39,588,666	(1,797,517)	53.4600	0	P-8	20,203,148
17	316.000	Miscellaneous Power Plant Equipment	7,766,205	0	53.4600	0	P-9	4,151,813
18	316.010	Miscellaneous Equip - H5 Rebuild	2,305,286	(104,671)	53.4600	0	P-10	1,176,449
19		Total	$ 436,291,113	$ (13,009,076)		$ 0		$ 226,286,577
		Production-Stm-Iatan I						
20	310.000	Land	$ 3,713,446	$ 0	53.4600	$ 0		$ 1,985,208
21	311.000	Structures & Improvements	20,965,153	0	53.4600	0		11,207,971
22	312.000	Boiler Plant Equip - Electric	159,867,033	0	53.4600	0		85,464,916
23	314.000	Turbogenerators - Electric	42,957,886	0	53.4600	0		22,965,286
24	315.000	Accessory Equipment - Electric	27,556,225	0	53.4600	0		14,731,558
25	316.000	Miscl Plant Equipment - Electric	4,273,445	0	53.4600	0		2,284,584
26		Total	$ 259,333,188	$ 0		$ 0		$ 138,639,523

Accounting Schedule: 3
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Total Plant in Service

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Production-Stm-Lacygne 1 & 2					
27	310.000	Land	$ 2,687,422	$ 0	53.4600	$ 0	$ 1,436,696
28	311.000	Structures & Improvements	22,321,556	0	53.4600	0	11,933,104
29	312.000	Boiler Plant Equipment - Electric	183,894,856	0	53.4600	0	98,310,190
30	312.010	Boiler Plt - Unit Train Electric	129,045	0	53.4600	0	68,987
31	312.002	Boiler Plant AQC Equipment - Elect	33,435,198	0	53.4600	0	17,874,457
32	314.000	Turbogenerator Plant - Electric	55,162,044	0	53.4600	0	29,489,629
33	315.000	Accessory Equipment - Electric	26,566,590	0	53.4600	0	14,202,499
34	315.200	Accessory Equipment - Electric	14,320	0	53.4600	0	7,655
35	316.000	Miscle Plat Equipment - Electric	4,680,667	0	53.4600	0	2,502,285
36		Total	$ 328,891,698	$ 0		$ 0	$ 175,825,502
		Production Stm-Montrose 1, 2 & 3					
37	310.000	Land	$ 1,406,842	$ 0	53.4600	$ 0	$ 752,098
38	311.000	Structures - Electric	14,599,474	0	53.4600	0	7,804,879
39	312.000	Boiler Plant Equipment - Electric	108,369,823	0	53.4600	0	57,934,507
40	314.000	Turbogenerators - Electric	38,116,999	0	53.4600	0	20,377,348
41	315.000	Accessory Equipment - Electric	16,557,651	0	53.4600	0	8,851,720
42	316.000	Miscl Plant Equipment - Electric	3,744,468	0	53.4600	0	2,001,793
43		Total	$ 182,795,257	$ 0		$ 0	$ 97,722,345
		Production-Hawthorn 6 Combined Cycl					
44	311.000	Structures - H6	$ 2,967	$ 0	53.4600	$ 0	$ 1,586
45	315.000	Accessory Equip - H6	216,179	0	53.4600	0	115,569
46	341.000	Other Prod - Structures H6	154,046	0	53.4600	0	82,353
47	342.000	Pther Prod - Fuel Holders	1,068,454	0	53.4600	0	571,196
48	344.000	Other Production - Generators H6	40,951,064	0	53.4600	0	21,892,439
49	345.000	Other Prod - Accessory Equip - H6	1,371,550	0	53.4600	0	733,231
50		Total	$ 43,764,260	$ 0		$ 0	$ 23,396,374

Accounting Schedule: 3
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Total Plant in Service

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Production-Hawthorn 9 Combined Cycl					
51	311.000	Structures & Improv - H9	$ 3,266,915	$ 0	53.4600	$ 0	$ 1,746,493
52	312.000	Boile Plant Equip - H9	41,350,116	0	53.4600	0	22,105,772
53	314.000	Turbogenerators - H9	15,864,067	0	53.4600	0	8,480,930
54	315.000	Accessory Equipment - H9	12,588,646	0	53.4600	0	6,729,890
55	316.000	Miscl Pwr Plt Equip - H9	225,288	0	53.4600	0	120,439
56		Total	$ 73,295,032	$ 0		$ 0	$ 39,183,524
		Production-Northeast Station					
57	315.000	Accessory Equip - NE	$ 111,815	$ 0	53.4600	$ 0	$ 59,776
58	316.000	Miscl Plant Equip - NE	16,955	0	53.4600	0	9,064
59	340.000	Other Production - Land NE	136,550	0	53.4600	0	73,000
60	342.000	Other Prod - Fuel Holders NE	1,283,424	0	53.4600	0	686,118
61	344.000	Other Prod - Generators NE	38,657,670	0	53.4600	0	20,666,390
62	345.000	Other Prod - Accessory Equip - NE	5,137,094	0	53.4600	0	2,746,290
63		Total	$ 45,343,508	$ 0		$ 0	$ 24,240,638
		Other Prod Hawthorn Units 7 & 8					
64	311.000	Structures - H7&8	$ 13,234	$ 0	53.4600	$ 0	$ 7,075
65	341.000	Other Prod - Structures - H7&8	763,408	0	53.4600	0	408,118
66	342.000	Other Prod - Fuel Holders H7&8	3,435,764	0	53.4600	0	1,836,759
67	344.000	Other Prod - Generators - H7&8	46,063,662	0	53.4600	0	24,625,634
68	345.000	Other Prod - Access Equip - H7&8	2,094,772	0	53.4600	0	1,119,865
69		Total	$ 52,370,840	$ 0		$ 0	$ 27,997,451
		Prod Other-West Gardner 1, 2, 3 & 4					
70	316.000	Miscl Plant Equip - Electric	$ 3,642	$ 0	53.4600	$ 0	$ 1,947
71	340.000	Other Prod - Land	177,836	0	53.4600	0	95,071
72	341.000	Other Prod - Structures WG	2,072,122	0	53.4600	0	1,107,756
73	342.000	Other Prod - Fuel Holders WG	2,986,583	0	53.4600	0	1,596,627
74	344.000	Other Prod - Generators WG	109,347,040	0	53.4600	0	58,456,928
75	345.000	Other Prod - Access Equip - WG	4,226,773	0	53.4600	0	2,259,633
76		Total	$ 118,813,996	$ 0		$ 0	$ 63,517,962

Accounting Schedule: 3
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Total Plant in Service

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Prod Other-Miami/Osawatomie 1					
77	340.000	Other Prod - Land M/Os	$ 694,545	$ 0	53.4600	$ 0	$ 371,304
78	341.000	Other Prod - Structures M/Os	1,496,067	0	53.4600	0	799,797
79	342.000	Other Prod - Fuel Holders M/Os	1,992,551	0	53.4600	0	1,065,218
80	344.000	Other Prod - Generators M/Os	26,192,196	0	53.4600	0	14,002,348
81	345.000	Other Prod - Accessory Equip - M/Os	1,112,901	0	53.4600	0	594,957
82		Total	$ 31,488,260	$ 0		$ 0	$ 16,833,624
		Prod Plt-Nuclear-Wolf Creek					
83	320.000	Land & Land Rights	$ 3,411,585	$ 0	53.4600	$ 0	$ 1,823,833
84	321.000	Structures & Improvements	398,996,877	0	53.4600	0	213,303,730
85	321.010	Structures MO Gr Up AFC Ele	19,168,175	0	100.0000	0	19,168,175
86	322.000	Reactor Plant Equipment	635,266,768	0	53.4600	0	339,613,614
87	322.010	Reactor - MO Gr Up AFDC	49,326,298	0	100.0000	0	49,326,298
88	323.000	Turbogenerator Units	165,896,036	0	53.4600	0	88,688,021
89	323.010	Turbogenerator Mo GR Up AFDC	5,851,539	0	100.0000	0	5,851,539
90	324.000	Accessory Electric Equipment	132,569,388	0	53.4600	0	70,871,595
91	324.010	Accessory Equip - MO Gr Up AFDC	6,544,224	0	100.0000	0	6,544,224
92	325.000	Miscellaneous Power Plant Equipment	69,184,197	0	53.4600	0	36,985,872
93	325.010	Miscl Plt Equip - MO Gr Up AFDC	1,164,439	0	100.0000	0	1,164,439
94	328.000	Disallow - Mo Gr Up AFDC	(8,478,301)	0	100.0000	0	(8,478,301)
95	328.010	MPSC Disallow - 100%	(136,514,958)	0	53.4600	0	(72,980,897)
96		Total	$1,342,386,267	$ 0		$ 0	$ 751,882,142
		Production Plant - Wind Generation					
97	341.000	Structures & Improvements	$ 0	$ 0	53.4600	$ 0	$ 0
98	344.000	Generator Equipment	0	0	53.4600	0	0
99	345.000	Accessory Electric Equipment	0	0	53.4600	0	0
100		Total	$ 0	$ 0		$ 0	$ 0

Accounting Schedule: 3-4

Accounting Schedule: 3
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Total Plant in Service

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Production Non-Unit Facilities					
101	310.000	Land and Land Rights	$ 148,900	$ 0	53.4600	$ 0	$ 79,602
102	311.000	Structures & Improvements	1,070,200	0	53.4600	0	572,129
103	311.010	Structures & Improvements	245,144	0	53.4600	0	131,054
104	312.000	Boiler Plant Equipment	647,003	0	53.4600	0	345,888
105	315.000	Turbogenerator Units	24,948	0	53.4600	0	13,337
106	316.000	Miscellaneous Equipment	3,725,904	0	53.4600	0	1,991,868
107		Total	$ 5,862,099	$ 0		$ 0	$ 3,133,878
		Transmission Plant					
108	350.000	Land	$ 1,521,900	$ 0	53.4600	$ 0	$ 813,608
109	350.010	Land Rights	22,908,109	0	53.4600	0	12,246,675
110	350.020	Land Rights - Wolf Creek	355	0	53.4600	0	190
111	352.000	Structures & Improvements	4,148,817	0	53.4600	0	2,217,958
112	352.010	Structures & Improv - Wolf Creek	250,476	0	53.4600	0	133,904
113	352.020	Strct & Imprv-WlfCrk-Mo Gr Up	15,694	0	100.0000	0	15,694
114	353.000	Station Equipment	115,135,016	0	53.4600	0	61,551,180
115	353.010	Station Equip - Wolf Creek	9,717,857	0	53.4600	0	5,195,166
116	353.020	Stat Equip-Wlf Crk Mo Gr Up	558,231	0	100.0000	0	558,231
117	353.030	Station Equip - Communications	6,154,502	0	53.4600	0	3,290,197
118	354.000	Towers & Fixtures	4,029,692	0	53.4600	0	2,154,273
119	355.000	Poles & Fixtures	96,595,354	0	53.4600	0	51,639,876
120	355.010	Poles & Fixtures - Wolf Creek	58,255	0	53.4600	0	31,143
121	355.020	Poles & Fix - Wlf Crk Mo Gr Up	3,506	0	100.0000	0	3,506
122	356.000	Overhead Conductors & Devices	77,931,838	0	53.4600	0	41,662,361
123	356.010	Ovrhd Cond & Dev - Wolf Creek	39,418	0	53.4600	0	21,073
124	356.020	Ovrhd Cond-Dev-Wlf Crk-Mo Gr Up	2,552	0	100.0000	0	2,552
125	357.000	Underground Conduit	3,080,287	0	53.4600	0	1,646,721
126	358.000	Underground Conductors & Devices	2,822,718	0	53.4600	0	1,509,025
127		Total	$ 344,974,577	$ 0		$ 0	$ 184,693,333

Accounting Schedule: 3-5

Accounting Schedule: 3
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Total Plant in Service

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Distribution Plant					
128	360.000	Land	$ 7,941,883	$ 0	45.4074	$ 0	$ 3,606,203
129	360.010	Land Rights	15,219,128	0	59.2017	0	9,009,983
130	361.000	Structures & Improvements	10,142,752	0	50.8621	0	5,158,817
131	362.000	Station Equipment	140,966,485	0	57.3875	0	80,897,142
132	362.030	Station Equip - Communications	3,446,289	0	52.5651	0	1,811,545
133	364.000	Poles, Towers & Fixtures	214,749,475	0	54.0095	0	115,985,118
134	365.000	Overhead Conductors & Devices	176,132,351	0	55.6200	0	97,964,814
135	366.000	Underground Conduit	139,593,054	0	53.1195	0	74,151,132
136	367.000	Underground Conductors & Devices	306,730,908	0	50.4985	0	154,894,508
137	368.000	Line Transformers	206,335,660	0	58.1300	0	119,942,919
138	369.000	Services	78,294,864	0	51.5242	0	40,340,802
139	370.000	Meters	84,783,673	0	54.8400	0	46,495,366
140	371.000	Installation On Customers' Premises	9,400,985	0	73.7253	0	6,930,904
141	373.000	Street Lighting & Signal Systems	34,409,229	0	21.0904	0	7,257,044
142		Total	$1,428,146,736	$ 0		$ 0	$ 764,446,297

Accounting Schedule: 3-6

Accounting Schedule: 3
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Total Plant in Service

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		General Plant					
143	389.000	Land & Land Rights	$ 2,252,136	$ 0	53.9790	$ 0	$ 1,215,680
144	390.000	Structures & Improvements	51,252,896	0	53.9790	0	27,665,801
145	390.010	Struct & Imprv Leasehold (Bonfil)	88,945	0	53.9790	0	48,012
146	390.020	Struct & Imprv-Leasehold (1201 Wal)	1,666,354	0	53.9790	0	899,481
147	390.030	Struct & Imprv-Leasehold (801 Char)	1,668,623	0	53.9790	0	900,706
148	390.040	Struct & Imprv-Leasehold (Marshal)	123,334	0	53.9790	0	66,574
149	391.000	Office Furniture & Equipment	10,203,323	0	53.9790	0	5,507,652
150	391.010	Off Furniture & Equip - Wolf Creek	2,563,588	0	53.9790	0	1,383,799
151	391.020	Off Furniture & Equip - Computer	103,259	0	53.9790	0	55,738
152	392.000	Transportation Equipment	731,815	0	53.9790	0	395,026
153	392.010	Trans Equip - Light Trucks	13,007,188	0	53.9790	0	7,021,150
154	392.000	Trans Equip - Heavy Trucks	13,360,548	0	53.9790	0	7,211,890
155	392.030	Trans Equip - Tractors	545,050	0	53.9790	0	294,213
156	392.040	Trans Equip - Trailers	1,125,524	0	53.9790	0	607,547
157	393.000	Stores Equipment	666,859	0	53.9790	0	359,964
158	394.000	Tools, Shop, & Garage Equipment	3,196,940	0	53.9790	0	1,725,676
159	395.000	Laboratory Equipment	4,731,962	0	53.9790	0	2,554,266
160	396.000	Power Operated Equipment	11,018,967	0	53.9790	0	5,947,928
161	397.000	Communication Equipment	76,389,678	0	53.9790	0	41,234,384
162	397.010	Communications Equip - Wolf Creek	143,390	0	53.9790	0	77,400
163	397.020	Comm Equip-Wlf Crk Mo Grs Up	9,280	0	53.9790	0	5,009
164	398.000	Miscellaneous Equipment	206,267	0	53.9790	0	111,341
165		Total	$ 195,055,926	$ 0		$ 0	$ 105,289,237
166		Total Plant In Service	$4,984,377,044	$ (13,009,076)		$ 0	$2,694,683,608

Accounting Schedule: 3-7

Accounting Schedule: 4
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Total Plant

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Structures - H 5 Rebuild	P-2	$ (405,160)	
1.	To adjust the plant-in-service balances to refelect Staff's recalculation of the AFUDC associated with the rebuild of Hawthorn 5. (Williams)		$ (405,160)	
	Boiler Plant - H5 Rebuild	P-5	$ (10,701,728)	
1.	To adjust the plant-in-service balances to refelect Staff's recalculation of the AFUDC associated with the rebuild of Hawthorn 5. (Williams)		$ (10,701,728)	
	Accessory Equip - H5 Rebuild	P-8	$ (1,797,517)	
1.	To adjust the plant-in-service balances to refelect Staff's recalculation of the AFUDC associated with the rebuild of Hawthorn 5. (Williams)		$ (1,797,517)	
	Miscellaneous Equip - H5 Rebuild	P-10	$ (104,671)	
1.	To adjust the plant-in-service balances to refelect Staff's recalculation of the AFUDC associated with the rebuild of Hawthorn 5. (Williams)		$ (104,671)	

Accounting Schedule: 5
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Expense

Line No	Acct	Description (A)	Adjusted Jurisdictional (B)	Depreciation Rate (C)	Depreciation Expense (D)
		Intangible Plant			
1	301.000	Organization	$ 38,965	0.0000	$ 0
2	302.000	Franchises & Consents	22,937	0.0000	0
3	303.000	Miscellaneous Intangible Plant	429,113	0.0000	0
4	303.200	Miscl Intangible Plt - 5yr Software	19,812,899	0.0000	0
5	3030.300	Miscl Intangible Plt-10yr Software	26,730,883	0.0000	0
6	303.050	Miscl Intang Plt-WC 5yr Software	4,560,404	0.0000	0
7		Total	$ 51,595,201		$ 0
		Production-Stm-Hawthorn Unit 5			
8	310.000	Land & Land Rights	$ 431,572	0.0000	$ 0
9	311.000	Structures & Improvements	12,109,982	1.8700	226,457
10	311.020	Structures - H 5 Rebuild	4,553,790	1.8700	85,156
11	312.000	Boiler Plant Equipment	22,090,582	2.3500	519,129
12	312.020	Boiler AQC Equip - Electric	91,165	2.3500	2,142
13	312.030	Boiler Plant - H5 Rebuild	120,281,819	2.3500	2,826,623
14	314.000	Turbogenerator Units	38,976,628	2.3800	927,644
15	315.000	Accessory Electric Equipment	2,219,629	2.2600	50,164
16	315.010	Accessory Equip - H5 Rebuild	20,203,148	2.2600	456,591
17	316.000	Miscellaneous Power Plant Equipment	4,151,813	2.8000	116,251
18	316.010	Miscellaneous Equip - H5 Rebuild	1,176,449	2.8000	32,941
19		Total	$ 226,286,577		$ 5,243,098
		Production-Stm-Iatan I			
20	310.000	Land	$ 1,985,208	0.0000	$ 0
21	311.000	Structures & Improvements	11,207,971	1.8700	209,589
22	312.000	Boiler Plant Equip - Electric	85,464,916	2.3500	2,008,426
23	314.000	Turbogenerators - Electric	22,965,286	2.3800	546,574
24	315.000	Accessory Equipment - Electric	14,731,558	2.2600	332,933
25	316.000	Miscl Plant Equipment - Electric	2,284,584	2.8000	63,968
26		Total	$ 138,639,523		$ 3,161,490

Accounting Schedule: 5
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Expense

Line No	Acct	Description	Adjusted Jurisdictional	Depreciation Rate	Depreciation Expense
		(A)	(B)	(C)	(D)
		Production-Stm-Lacygne 1 & 2			
27	310.000	Land	$ 1,436,696	0.0000	$ 0
28	311.000	Structures & Improvements	11,933,104	1.8700	223,149
29	312.000	Boiler Plant Equipment - Electric	98,310,190	2.3500	2,310,289
30	312.010	Boiler Plt - Unit Train Electric	68,987	2.3500	1,621
31	312.002	Boiler Plant AQC Equipment - Elect	17,874,457	2.3500	420,050
32	314.000	Turbogenerator Plant - Electric	29,489,629	2.3800	701,853
33	315.000	Accessory Equipment - Electric	14,202,499	2.2600	320,976
34	315.200	Accessory Equipment - Electric	7,655	2.2600	173
35	316.000	Miscle Plat Equipment - Electric	2,502,285	2.8000	70,064
36		Total	$ 175,825,502		$ 4,048,175
		Production Stm-Montrose 1, 2 & 3			
37	310.000	Land	$ 752,098	0.0000	$ 0
38	311.000	Structures - Electric	7,804,879	1.8700	145,951
39	312.000	Boiler Plant Equipment - Electric	57,934,507	2.3500	1,361,461
40	314.000	Turbogenerators - Electric	20,377,348	2.3800	484,981
41	315.000	Accessory Equipment - Electric	8,851,720	2.2600	200,049
42	316.000	Miscl Plant Equipment - Electric	2,001,793	2.8000	56,050
43		Total	$ 97,722,345		$ 2,248,492
		Production-Hawthorn 6 Combined Cycl			
44	311.000	Structures - H6	$ 1,586	1.8700	$ 30
45	315.000	Accessory Equip - H6	115,569	2.2600	2,612
46	341.000	Other Prod - Structures H6	82,353	1.7400	1,433
47	342.000	Pther Prod - Fuel Holders	571,196	2.8600	16,336
48	344.000	Other Production - Generators H6	21,892,439	2.9400	643,638
49	345.000	Other Prod - Accessory Equip - H6	733,231	2.8600	20,970
50		Total	$ 23,396,374		$ 685,019

Accounting Schedule: 5-2

Accounting Schedule: 5
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Expense

Line No	Acct	Description	Adjusted Jurisdictional	Depreciation Rate	Depreciation Expense
		(A)	(B)	(C)	(D)
		Production-Hawthorn 9 Combined Cycl			
51	311.000	Structures & Improv - H9	$ 1,746,493	1.8700	$ 32,659
52	312.000	Boile Plant Equip - H9	22,105,772	2.3500	519,486
53	314.000	Turbogenerators - H9	8,480,930	2.3800	201,846
54	315.000	Accessory Equipment - H9	6,729,890	2.2600	152,096
55	316.000	Miscl Pwr Plt Equip - H9	120,439	2.8000	3,372
56		Total	$ 39,183,524		$ 909,459
		Production-Northeast Station			
57	315.000	Accessory Equip - NE	$ 59,776	2.2600	$ 1,351
58	316.000	Miscl Plant Equip - NE	9,064	2.8000	254
59	340.000	Other Production - Land NE	73,000	0.0000	0
60	342.000	Other Prod - Fuel Holders NE	686,118	2.8600	19,623
61	344.000	Other Prod - Generators NE	20,666,390	2.9400	607,592
62	345.000	Other Prod - Accessory Equip - NE	2,746,290	2.8600	78,544
63		Total	$ 24,240,638		$ 707,364
		Other Prod Hawthorn Units 7 & 8			
64	311.000	Structures - H7&8	$ 7,075	1.8700	$ 132
65	341.000	Other Prod - Structures - H7&8	408,118	1.7400	7,101
66	342.000	Other Prod - Fuel Holders H7&8	1,836,759	2.8600	52,531
67	344.000	Other Prod - Generators - H7&8	24,625,634	2.9400	723,994
68	345.000	Other Prod - Access Equip - H7&8	1,119,865	2.8600	32,028
69		Total	$ 27,997,451		$ 815,786
		Prod Other-West Gardner 1, 2, 3 & 4			
70	316.000	Miscl Plant Equip - Electric	$ 1,947	2.8000	$ 55
71	340.000	Other Prod - Land	95,071	0.0000	0
72	341.000	Other Prod - Structures WG	1,107,756	1.7400	19,275
73	342.000	Other Prod - Fuel Holders WG	1,596,627	2.8600	45,664
74	344.000	Other Prod - Generators WG	58,456,928	2.9400	1,718,634
75	345.000	Other Prod - Access Equip - WG	2,259,633	2.8600	64,626
76		Total	$ 63,517,962		$ 1,848,254

Accounting Schedule: 5
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Expense

Line No	Acct	Description	Adjusted Jurisdictional	Depreciation Rate	Depreciation Expense
		(A)	(B)	(C)	(D)
		Prod Other-Miami/Osawatomie 1			
77	340.000	Other Prod - Land M/Os	$ 371,304	0.0000	$ 0
78	341.000	Other Prod - Structures M/Os	799,797	1.7400	13,916
79	342.000	Other Prod - Fuel Holders M/Os	1,065,218	2.8600	30,465
80	344.000	Other Prod - Generators M/Os	14,002,348	2.9400	411,669
81	345.000	Other Prod - Accessory Equip - M/Os	594,957	2.8600	17,016
82		Total	$ 16,833,624		$ 473,066
		Prod Plt-Nuclear-Wolf Creek			
83	320.000	Land & Land Rights	$ 1,823,833	0.0000	$ 0
84	321.000	Structures & Improvements	213,303,730	1.7500	3,732,815
85	321.010	Structures MO Gr Up AFC Ele	19,168,175	1.7500	335,443
86	322.000	Reactor Plant Equipment	339,613,614	1.7600	5,977,200
87	322.010	Reactor - MO Gr Up AFDC	49,326,298	1.7600	868,143
88	323.000	Turbogenerator Units	88,688,021	1.7000	1,507,696
89	323.010	Turbogenerator Mo GR Up AFDC	5,851,539	1.7000	99,476
90	324.000	Accessory Electric Equipment	70,871,595	1.6800	1,190,643
91	324.010	Accessory Equip - MO Gr Up AFDC	6,544,224	1.6800	109,943
92	325.000	Miscellaneous Power Plant Equipment	36,985,872	1.6500	610,267
93	325.010	Miscl Plt Equip - MO Gr Up AFDC	1,164,439	1.6500	19,213
94	328.000	Disallow - Mo Gr Up AFDC	(8,478,301)	1.6800	(142,435)
95	328.010	MPSC Disallow - 100%	(72,980,897)	1.6800	(1,226,079)
96		Total	$ 751,882,142		$ 13,082,325
		Production Plant - Wind Generation			
97	341.000	Structures & Improvements	$ 0	5.0000	$ 0
98	344.000	Generator Equipment	0	5.0000	0
99	345.000	Accessory Electric Equipment	0	5.0000	0
100		Total	$ 0		$ 0

Accounting Schedule: 5
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Expense

Line No	Acct	Description	Adjusted Jurisdictional	Depreciation Rate	Depreciation Expense
		(A)	(B)	(C)	(D)
		Production Non-Unit Facilities			
101	310.000	Land and Land Rights	$ 79,602	0.0000	$ 0
102	311.000	Structures & Improvements	572,129	1.8700	10,699
103	311.010	Structures & Improvements	131,054	1.8700	2,451
104	312.000	Boiler Plant Equipment	345,888	2.3500	8,128
105	315.000	Turbogenerator Units	13,337	2.2600	301
106	316.000	Miscellaneous Equipment	1,991,868	2.8000	55,772
107		Total	$ 3,133,878		$ 77,351
		Transmission Plant			
108	350.000	Land	$ 813,608	0.0000	$ 0
109	350.010	Land Rights	12,246,675	0.0000	0
110	350.020	Land Rights - Wolf Creek	190	0.0000	0
111	352.000	Structures & Improvements	2,217,958	1.6900	37,483
112	352.010	Structures & Improv - Wolf Creek	133,904	1.6900	2,263
113	352.020	Strct & Imprv-WlfCrk-Mo Gr Up	15,694	1.6900	265
114	353.000	Station Equipment	61,551,180	1.9700	1,212,558
115	353.010	Station Equip - Wolf Creek	5,195,166	1.9700	102,345
116	353.020	Stat Equip-Wlf Crk Mo Gr Up	558,231	1.9700	10,997
117	353.030	Station Equip - Communications	3,290,197	1.9700	64,817
118	354.000	Towers & Fixtures	2,154,273	1.8200	39,208
119	355.000	Poles & Fixtures	51,639,876	2.2900	1,182,553
120	355.010	Poles & Fixtures - Wolf Creek	31,143	2.2900	713
121	355.020	Poles & Fix - Wlf Crk Mo Gr Up	3,506	2.2900	80
122	356.000	Overhead Conductors & Devices	41,662,361	0.8200	341,631
123	356.010	Ovrhd Cond & Dev - Wolf Creek	21,073	0.8200	173
124	356.020	Ovrhd Cond-Dev-Wlf Crk-Mo Gr Up	2,552	0.8200	21
125	357.000	Underground Conduit	1,646,721	1.6700	27,500
126	358.000	Underground Conductors & Devices	1,509,025	1.6700	25,201
127		Total	$ 184,693,333		$ 3,047,808

Accounting Schedule: 5-5

Accounting Schedule: 5
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Expense

Line No	Acct	Description	Adjusted Jurisdictional	Depreciation Rate	Depreciation Expense
		(A)	(B)	(C)	(D)
		Distribution Plant			
128	360.000	Land	$ 3,606,203	0.0000	$ 0
129	360.010	Land Rights	9,009,983	0.0000	0
130	361.000	Structures & Improvements	5,158,817	1.7000	87,700
131	362.000	Station Equipment	80,897,142	1.9100	1,545,135
132	362.030	Station Equip - Communications	1,811,545	1.9100	34,601
133	364.000	Poles, Towers & Fixtures	115,985,118	2.1800	2,528,476
134	365.000	Overhead Conductors & Devices	97,964,814	1.7800	1,743,774
135	366.000	Underground Conduit	74,151,132	1.9500	1,445,947
136	367.000	Underground Conductors & Devices	154,894,508	1.6000	2,478,312
137	368.000	Line Transformers	119,942,919	3.0000	3,598,288
138	369.000	Services	40,340,802	3.9300	1,585,394
139	370.000	Meters	46,495,366	1.7700	822,968
140	371.000	Installation On Customers' Premises	6,930,904	4.2800	296,643
141	373.000	Street Lighting & Signal Systems	7,257,044	5.0000	362,852
142		Total	$ 764,446,297		$ 16,530,090

Accounting Schedule: 5-6

Accounting Schedule: 5
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Expense

Line No	Acct	Description	Adjusted Jurisdictional	Depreciation Rate	Depreciation Expense
		(A)	(B)	(C)	(D)
	General	Plant			
143	389.000	Land & Land Rights	$ 1,215,680	0.0000	$ 0
144	390.000	Structures & Improvements	27,665,801	1.7000	470,319
145	390.010	Struct & Imprv Leasehold (Bonfil)	48,012	1.7000	816
146	390.020	Struct & Imprv-Leasehold (1201 Wal)	899,481	1.7000	15,291
147	390.030	Struct & Imprv-Leasehold (801 Char)	900,706	1.7000	15,312
148	390.040	Struct & Imprv-Leasehold (Marshal)	66,574	1.7000	1,132
149	391.000	Office Furniture & Equipment	5,507,652	3.4500	190,014
150	391.010	Off Furniture & Equip - Wolf Creek	1,383,799	3.4500	47,741
151	391.020	Off Furniture & Equip - Computer	55,738	3.4500	1,923
152	392.000	Transportation Equipment	395,026	7.7500	30,615
153	392.010	Trans Equip - Light Trucks	7,021,150	7.7500	544,139
154	392.000	Trans Equip - Heavy Trucks	7,211,890	7.7500	558,921
155	392.030	Trans Equip - Tractors	294,213	7.7500	22,802
156	392.040	Trans Equip - Trailers	607,547	7.7500	47,085
157	393.000	Stores Equipment	359,964	3.3300	11,987
158	394.000	Tools, Shop, & Garage Equipment	1,725,676	2.4500	42,279
159	395.000	Laboratory Equipment	2,554,266	3.2600	83,269
160	396.000	Power Operated Equipment	5,947,928	6.0300	358,660
161	397.000	Communication Equipment	41,234,384	3.3300	1,373,105
162	397.010	Communications Equip - Wolf Creek	77,400	3.3300	2,577
163	397.020	Comm Equip-Wlf Crk Mo Grs Up	5,009	3.3300	167
164	398.000	Miscellaneous Equipment	111,341	4.5000	5,010
165		Total	$ 105,289,237		$ 3,823,164
166		Total Depreciation Expense	$2,694,683,608		$ 56,700,941

Accounting Schedule: 6
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Reserve

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment		Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)		(F)
		Intangible Plant						
1	303.010	Miscl Intang Plt - Like 353	$ 119,654	$ 0	53.9790	$ 0		$ 64,588
2	303.020	Miscl Intang Plt - 5 yr Software	28,122,799	0	53.9790	0		15,180,406
3	303.030	Miscl Intang Plt - 10 yr Software	36,288,741	0	53.9790	0		19,588,300
4	303.050	Miscl Int Plt-Wlf Crk 5 yr Software	7,875,958	0	53.9790	0		4,251,363
5		Total	$ 72,407,152	$ 0		$ 0		$ 39,084,657
		Prod Steam - Hawthorn 5						
6	311.000	Structures & Improvements	$ 7,396,089	$ 0	53.4600	$ 0		$ 3,953,949
7	311.020	Pr-Struct-Hawthorn 5 Rebuild	7,203,506	(25,270)	53.4600	0	R-1	3,837,485
8	312.000	Boiler Plant Equipment	(17,432,235)	0	53.4600	0		(9,319,273)
9	312.020	Stm Pr-Boiler AQC Equip	10,789	0	53.4600	0		5,768
10	312.030	Boiler Hawthorn 5 Rebuild	182,142,233	(675,416)	53.4600	0	R-2	97,012,160
11	314.000	Turbogenerator Units	19,654,612	0	53.4600	0		10,507,356
12	315.000	Accessory Electric Equipment	(4,684,471)	0	53.4600	0		(2,504,318)
13	315.010	Access Hawthorn 5 Rebuild	30,356,135	(111,795)	53.4600	0	R-3	16,168,624
14	316.000	Miscellaneous Power Plant Equipment	3,285,604	0	53.4600	0		1,756,484
15	316.010	Miscl Eqp Hawth 5 Rebuild	1,778,515	(6,581)	53.4600	0	R-4	947,276
16		Total	$ 229,710,777	$ (819,062)		$ 0		$ 122,365,511
		Prod Steam - Iatan I						
17	311.000	Structures & Imprvements	$ 13,013,845	$ 0	53.4600	$ 0		$ 6,957,202
18	312.000	Boiler Plt Equip - Electric	129,164,652	0	53.4600	0		69,051,423
19	314.000	Turbogenerators - Electric	29,817,942	0	53.4600	0		15,940,672
20	315.000	Accessory Equip - Electric	10,639,612	0	53.4600	0		5,687,937
21	316.000	Miscl Pwr Plt Equipment - Electric	2,386,192	0	53.4600	0		1,275,658
22		Total	$ 185,022,243	$ 0		$ 0		$ 98,912,892

Accounting Schedule: 6
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Reserve

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Prod Stm - LaCygne 1 & 2					
23	311.000	Structures & Improvements	$ 12,553,745	$ 0	53.4600	$ 0	$ 6,711,232
24	312.000	Boiler Plt Equipment - Electric	130,688,123	0	53.4600	0	69,865,871
25	312.010	Boiler Plt - Unit Train - Electric	129,045	0	53.4600	0	68,987
26	312.020	Boiler Plt - AQC Equip - Electric	40,796,646	0	53.4600	0	21,809,887
27	314.000	Turbogenerator - Electric	28,010,668	0	53.4600	0	14,974,503
28	315.000	Accessory Equip - Electric	12,278,468	0	53.4600	0	6,564,069
29	315.020	Accessory Equipment - Electric	1,116	0	53.4600	0	597
30	316.000	Miscl Pwr Plt Equip - Electric	2,262,793	0	53.4600	0	1,209,689
31		Total	$ 226,720,604	$ 0		$ 0	$ 121,204,835
		Prod Steam - Montrose 1, 2 & 3					
32	311.000	Structures & Improvements	$ 6,727,016	$ 0	53.4600	$ 0	$ 3,596,263
33	312.000	Boiler Plt Equipment - Electric	62,340,827	0	53.4600	0	33,327,406
34	314.000	Turbogenerator - Electric	18,612,741	0	53.4600	0	9,950,371
35	315.000	Accessory Equipment - Electric	6,376,121	0	53.4600	0	3,408,674
36	316.000	Miscl Pwr Plnt Equip - Electric	1,584,771	0	53.4600	0	847,219
37		Total	$ 95,641,476	$ 0		$ 0	$ 51,129,933
		Prod Stm/Other-Hawthorn 6 Comb Cycl					
38	311.000	Structures & Improvements	$ 353	$ 0	53.4600	$ 0	$ 189
39	315.000	Accessory Equipment - Electric	14,162	0	53.4600	0	7,571
40	341.000	Other Structures & Improvement	28,061	0	53.4600	0	15,001
41	342.000	Other - Fuel Holders - Electric	214,444	0	53.4600	0	114,642
42	344.000	Other - Generation - Electric	7,110,856	0	53.4600	0	3,801,464
43	345.000	Other Accessory Equipment - Electri	335,034	0	53.4600	0	179,109
44		Total	$ 7,702,910	$ 0		$ 0	$ 4,117,976
		Prod Stm/Other-Hawthorn 9 Comb Cycl					
45	311.000	Stm - Structures & IMprovements	$ 481,083	$ 0	53.4600	$ 0	$ 257,187
46	312.000	Stm Boiler Equipment - Electric	10,614,233	0	53.4600	0	5,674,369
47	314.000	Stm - Turbogenerator - Electric	3,241,213	0	53.4600	0	1,732,752
48	315.000	Stm Accessory Equip - Elect	2,228,641	0	53.4600	0	1,191,431
49	316.000	Miscl Pwr Plt Equip - Electric	32,687	0	53.4600	0	17,474
50		Total	$ 16,597,857	$ 0		$ 0	$ 8,873,213

Accounting Schedule: 6-2

Accounting Schedule: 6
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Reserve

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Prrod Other - Northeast Station					
51	315.000	Accessory Equipment - Electric	$ 2,082	$ 0	53.4600	$ 0	$ 1,113
52	316.000	Miscl Pwr Plnt Equipment	2,205	0	53.4600	0	1,179
53	342.000	Other - Fuel Holders	1,015,728	0	53.4600	0	543,008
54	344.000	Other - Generators - Electric	35,656,565	0	53.4600	0	19,062,000
55	345.000	Other - Accessory Equipment - Elect	5,377,642	0	53.4600	0	2,874,887
56		Total	$ 42,054,222	$ 0		$ 0	$ 22,482,187
		Prod Other - Hawthorn 7 & 8					
57	311.000	Stm - Structures & Improvements	$ 2,096	$ 0	53.4600	$ 0	$ 1,121
58	341.000	Other Structures & Improvements	162,313	0	53.4600	0	86,773
59	342.000	Other - Fuel Holders - Electric	811,498	0	53.4600	0	433,827
60	344.000	Other - Generators	12,550,005	0	53.4600	0	6,709,233
61	345.000	Other - Accessory Equipment	638,110	0	53.4600	0	341,134
62		Total	$ 14,164,022	$ 0		$ 0	$ 7,572,088
		Prod Other - West Gardner 1,2,3&4					
63	316.000	Stm - Miscl Pwr Plnt Equipment	$ 19	$ 0	53.4600	$ 0	$ 10
64	341.000	Other - Structures & Improvements	46,177	0	53.4600	0	24,686
65	342.000	Other - Fuel Holders	66,406	0	53.4600	0	35,501
66	344.000	Other - Generators	6,089,327	0	53.4600	0	3,255,354
67	345.000	Other - Accessory Equipment	88,747	0	53.4600	0	47,444
68		Total	$ 6,290,676	$ 0		$ 0	$ 3,362,995
		Prod Other - Miami/Osawatomie 1					
69	341.000	Other - Structures & Improvements	$ 33,193	$ 0	53.4600	$ 0	$ 17,745
70	342.000	Other - Fuel Holders	44,304	0	53.4600	0	23,685
71	344.000	Other - Generators	1,526,351	0	53.4600	0	815,987
72	345.000	Other - Accessory Equipment	24,695	0	53.4600	0	13,202
73		Total	$ 1,628,543	$ 0		$ 0	$ 870,619

Accounting Schedule: 6
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Reserve

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Prod Nuclear - Wolf Creek					
74	321.000	Structures & Improvements	$ 209,591,676	$ 0	53.4600	$ 0	$ 112,047,710
75	321.010	Strct&Imprv Mo Grs UP AQC	9,706,923	0	100.0000	0	9,706,923
76	322.000	Reactor Plant Equipment	320,875,517	0	53.4600	0	171,540,051
77	322.005	Rctor Plt Equip-60/40 Depr MO	0	0	100.0000	0	0
78	322.010	Reactor - Mo Grs UP AFDC	25,790,202	0	100.0000	0	25,790,202
79	322.020	Nuclear Prd - Mo Jurisdictional	9,476,983	0	100.0000	0	9,476,983
80	323.000	Turbogenerator Units	99,356,319	0	53.4600	0	53,115,888
81	323.010	Turbo/Gen - Mo Grs Up AFDC	4,762,845	0	100.0000	0	4,762,845
82	324.000	Accessory Equipment	60,813,054	0	53.4600	0	32,510,659
83	324.010	Access Equip - Mo Grs Up AFDC	3,074,724	0	100.0000	0	3,074,724
84	325.000	Miscl Pwr Plant Equipment	15,104,637	0	53.4600	0	8,074,939
85	325.010	Miscl Pwr Equip - Mo Grs Up AFDC	456,640	0	100.0000	0	456,640
86	328.000	Disallowance - MO Grs Up AFDC	(4,470,283)	0	100.0000	0	(4,470,283)
87	328.010	MPSC Disallowance - 100%	(62,070,960)	0	54.0920	0	(33,575,424)
88	328.020	Mo Disallowance - Not Mo Juris	0	0	0.0000	0	0
89	328.030	KCC Disallowance - 100%	0	0	0.0000	0	0
90	328.040	KCC Disallowance - Not Ks Juris	0	0	0.0000	0	0
91	328.050	Not State Specific 1988 Reserve	(10,086,006)	0	53.4600	0	(5,391,979)
92		Est Salvage & Rmoval Not Classified	11,753	0	54.0920	0	6,357
93		Total	$ 682,394,024	$ 0		$ 0	$ 387,126,235
		Prod Other - Wind Generation					
94	341.000	Structures & Improvements	$ 0	$ 0	53.4600	$ 0	$ 0
95	344.000	Generator Equipment	0	0	53.4600	0	0
96	345.000	Accessory Equipment	0	0	53.4600	0	0
97		Total	$ 0	$ 0		$ 0	$ 0
		Production Non-Unit Facilities					
98	311.000	Structures & Improvements	$ 444,313	$ 0	53.4600	$ 0	$ 237,530
99	311.010	Structures & Improvements	115,557	0	53.4600	0	61,777
100	312.000	Boiler Plant Equipment	441,616	0	53.4600	0	236,088
101	314.000	Turbogenerators - Electric	124	0	53.4600	0	66
102	315.000	Accessory Equipment	12,202	0	53.4600	0	6,523
103	316.000	Miscl. Plant Equipment	673,460	0	53.4600	0	360,032
104		ESt. Salvage & Removal Not Classed	(3,287,428)	0	53.4600	0	(1,757,459)
105		Total	$ (1,600,156)	$ 0		$ 0	$ (855,443)

Accounting Schedule: 6-4

Schedule DAF-10

Accounting Schedule: 6
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Reserve

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		Transmission Plant					
106	350.010	Land & Land Rights	$ 5,951,409	$ 0	53.4600	$ 0	$ 3,181,623
107	350.020	Land Rights - Wolf Creek	81	0	53.4600	0	43
108	352.000	Structures & Improvements	1,143,879	0	53.4600	0	611,518
109	352.010	Struct & Imprv - Wolf Creek	51,121	0	53.4600	0	27,329
110	352.020	Struct & Imprv - Wlf Crk Mo Grs Up	3,064	0	100.0000	0	3,064
111	353.000	Station Equipment	39,578,441	0	53.4600	0	21,158,635
112	353.010	Station Equip - Wolf Creek	4,615,766	0	53.4600	0	2,467,589
113	353.020	Station Equip - Wlf Crk MO Grs Up	279,130	0	100.0000	0	279,130
114	353.030	Station Equip - Communications	158,800	0	53.4600	0	84,894
115	354.000	Towers & Fixtures	3,196,496	0	53.4600	0	1,708,847
116	355.000	Poles & Fixtures	42,450,602	0	53.4600	0	22,694,092
117	355.010	Poles & Fixtures - Wolf Creek	36,357	0	53.4600	0	19,436
118	355.020	Oles & Fixt - Wlf Crk Mo Grs Up	2,528	0	100.0000	0	2,528
119	356.000	Overhead Conductors & Devices	36,618,091	0	53.4600	0	19,576,031
120	356.010	Ovrhd Conduct & Devices - Wlf Crk	16,711	0	53.4600	0	8,934
121	356.020	Ovrhd Condct&Dev-Wlf Crk Mo Grs Up	975	0	100.0000	0	975
122	357.000	Underground Conduit	1,648,720	0	53.4600	0	881,406
123	358.000	Uunderground Conductors & Devices	2,077,365	0	53.4600	0	1,110,559
124		Est Salvage & Removal Not Classifie	102,139	0	53.4600	0	54,604
125		Total	$ 137,931,675	$ 0		$ 0	$ 73,871,237
		Distribution Plant					
126	360.000	Land & Land Rights	$ 4,854,234	$ 0	54.4716	$ 0	$ 2,644,179
127	361.000	Structures & Improvements	4,447,402	0	50.8621	0	2,262,042
128	362.000	Station Equipment	47,354,496	0	57.3875	0	27,175,561
129	362.030	Station Equip - Communications	972,743	0	52.5651	0	511,323
130	364.000	Poles, Towers & Fixtures	109,118,346	0	54.0095	0	58,934,273
131	365.000	Overhead Conductors & Devices	47,949,782	0	55.6200	0	26,669,669
132	366.000	Underground Conduit	23,658,275	0	53.1195	0	12,567,157
133	367.000	Underground Conductors & Devices	56,687,642	0	50.4985	0	28,626,409
134	368.000	Line Transformers	83,527,097	0	58.1300	0	48,554,301
135	369.000	Services	36,128,611	0	51.5242	0	18,614,978
136	370.000	Meters	47,647,529	0	54.8400	0	26,129,905
137	371.000	Installation On Customers' Premises	8,484,015	0	73.7253	0	6,254,866
138	373.000	Street Lighting & Signal Systems	7,306,840	0	21.0904	0	1,541,042
139		Est Slavage & Removal not Classifie	(2,158,993)	0	53.7699	0	(1,160,888)
140		Total	$ 475,978,019	$ 0		$ 0	$ 259,324,817

Accounting Schedule: 6-5

Schedule DAF-10

Accounting Schedule: 6
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Depreciation Reserve

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment	Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)	(F)
		General Plant					
141	390.000	Structures & Improvements	$ 16,238,257	$ 0	53.9790	$ 0	$ 8,765,249
142	390.010	Struct & Improv-Leasehold (Bonfil)	82,498	0	53.9790	0	44,532
143	390.020	Struct & Imprv Leasehold (1201 Wal)	1,434,975	0	53.9790	0	774,585
144	390.030	Struct & Imprv-Leasehold (801 Char)	1,057,480	0	53.9790	0	570,817
145	390.040	Struct & Imprv-Leasehold (Marshall)	123,334	0	53.9790	0	66,574
146	391.000	Office Furniture & Equipment	5,561,229	0	53.9790	0	3,001,896
147	391.010	Off Furniture & Equip - Wlf Crk	756,394	0	53.9790	0	408,294
148	391.020	Off Furn & Equip - Computer	7,089	0	53.9790	0	3,827
149	392.000	Transportation Equipment	291,080	0	53.9790	0	157,122
150	392.010	Trans Equip - Light truck	388,681	0	53.9790	0	209,806
151	392.020	Trans Equip - Heavy Truck	1,385,480	0	53.9790	0	747,868
152	392.030	Trans Equip - Tractors	7,171	0	53.9790	0	3,871
153	392.040	Trans Equip - Trailers	398,215	0	53.9790	0	214,952
154	393.000	Stores Equipment	490,507	0	53.9790	0	264,771
155	394.000	Tools, Shop, & Garage Equipment	1,711,662	0	53.9790	0	923,938
156	395.000	Laboratory Equipment	2,186,404	0	53.9790	0	1,180,199
157	396.000	Power Operated Equipment	1,087,895	0	53.9790	0	587,235
158	397.000	Communication Equipment	9,203,293	0	53.9790	0	4,967,846
159	397.010	Communications Equip - Wolf Creek	56,965	0	53.9790	0	30,749
160	397.020	Commun Equip - Wlf Crk Mo Grs Up	1,488	0	53.9790	0	803
161	398.000	Miscellaneous Equipment	59,788	0	53.9790	0	32,273
162	399.000	Tng Prty-Accum Amort EO-94-199	34,924,731	0	100.0000	0	34,924,731
163		Est Salvage & Removal Not Classifie	1,315,582	0	53.9790	0	710,138
164		Total	$ 78,770,198	$ 0		$ 0	$ 58,592,076
165		Total Depreciation Reserve	$2,271,414,242	$ (819,062)		$ 0	$1,258,035,828

Accounting Schedule: 7
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Depreciation Reserve

Adj No	Description			Total Co Adjustment	Mo Juris Adjustment
	Pr-Struct-Hawthorn 5 Rebuild	R-1	$	(25,270)	
	1. To adjust the reserve to eliminate the accumulated depreciation on the AFUDC Disallowance. (Williams)		$	(25,270)	
	Boiler Hawthorn 5 Rebuild	R-2	$	(675,416)	
	1. To adjust the reserve to eliminate the accumulated depreciation on the AFUDC Disallowance. (Williams)		$	(675,416)	
	Access Hawthorn 5 Rebuild	R-3	$	(111,795)	
	1. To adjust the reserve to eliminate the accumulated depreciation on the AFUDC Disallowance. (Williams)		$	(111,795)	
	Miscl Eqp Hawth 5 Rebuild	R-4	$	(6,581)	
	1. To adjust the reserve to eliminate the accumulated depreciation on the AFUDC Disallowance. (Williams)		$	(6,581)	

Accounting Schedule: 8
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Cash Working Capital

Line No	Acct Description	Test Year Expenses	Revenue Lag	Expense Lag	Net Lag (C) - (D)	Factor (Col E/365)	CWC Req (B) x (F)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Operation and Maintenance Expense						
1	Cash Vouchers	$ 89,369,368	23.7300	30.0000	(6.2700)	(0.017178)	$ (1,535,187)
2	Payroll Expense	42,326,819	23.7300	13.8540	9.8760	0.027058	1,145,279
3	Payroll Taxes Withheld	22,715,314	23.7300	13.6300	10.1000	0.027671	628,555
4	FICA Taxes Withheld	5,801,987	23.7300	13.7700	9.9600	0.027288	158,325
5	Wolf Creek Operating Exp	19,611,505	23.7300	13.8100	9.9200	0.027178	533,001
6	Wolf Creek Fuel Outage Accrual	8,270,291	23.7300	215.0700	(191.3400)	(0.524219)	(4,335,444)
7	Accrued Vacation	5,710,782	23.7300	344.8300	(321.1000)	(0.879726)	(5,023,923)
8	Fuel - Coal	72,931,977	23.7300	20.8793	2.8507	0.007810	569,599
9	Fuel - Purchased Gas	20,509,051	23.7300	28.6200	(4.8900)	(0.013397)	(274,760)
10	Fuel - Purchased Oil	2,863,066	23.7300	8.5000	15.2300	0.041726	119,464
11	Purchased Power	38,055,033	23.7300	30.7200	(6.9900)	(0.019151)	(728,792)
12	Injuries and Damages	4,872,357	23.7300	185.0000	(161.2700)	(0.441836)	(2,152,783)
13	Pensions	16,767,573	23.7300	51.7400	(28.0100)	(0.076740)	(1,286,744)
14	OPEB's	2,156,829	23.7300	178.4400	(154.7100)	(0.423863)	(914,200)
15	Total Operation and Maintenance Expense	$ 351,961,952					$ (13,097,610)
	Taxes						
16	Employers FICA Taxes	$ 5,801,987	23.7300	13.7700	9.9600	0.027288	$ 158,325
17	Federal Unemployment Taxes	58,789	23.7300	75.0000	(51.2700)	(0.140466)	(8,258)
18	State Unemployment Taxes	10,191	23.7300	71.0000	(47.2700)	(0.129507)	(1,320)
19	Property Taxes	30,097,256	23.7300	208.8400	(185.1100)	(0.507151)	(15,263,853)
20	Gross Receipts Taxes	39,012,075	6.5200	20.5300	(14.0100)	(0.038384)	(1,497,439)
21	Sales & Use Taxes	17,273,838	6.5200	22.0000	(15.4800)	(0.042411)	(732,601)
22	Corporate Franchise Taxes	6,342,616	23.7300	(77.0000)	100.7300	0.275973	1,750,391
23	Total Taxes	$ 98,596,752					$ (15,594,755)
24	Total Cash Working Capital Req						$ (28,692,365)

Accounting Schedule: 8-1

Accounting Schedule: 9
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Income Statement

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment		Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)		(F)
		Operating Revenues						
1	440.444	Retail Sales	$ 526,074,301	$ 0	100.0000	$ (42,685,585)	S-1	$ 483,388,716
2	447.000	Firm Bulk Power Capac Fixed	12,643,444	793,501	53.4600	0	S-2	7,183,391
3	447.000	Firm Bulk Sales - Energy	31,735,056	14,705,183	56.6800	0	S-7	26,322,327
4	447.000	Non Firm Interchange Sales	143,589,216	0	56.6800	0	S-93	81,386,368
5	447.000	FERC Wholesale Firm Power	4,389,711	0	1.1461	0		50,310
6	450.000	Other Oper Rev - Forfeited Discount	2,179,387	0	59.6760	0	S-3	1,300,571
7	451.000	Other Oper Rev-Miscl Serv Rev	1,474,225	0	61.1865	0	S-4	902,027
8	454.000	Other Revenue Rents	2,343,535	0	54.8595	0	S-5	1,285,652
9	456.000	Revenue Transmission for Others	8,325,116	0	54.1324	0	S-6	4,506,585
10		Total	$ 732,753,991	$ 15,498,684		$ (42,685,585)		$ 606,325,947
		Operation & Maintenance Expense						
11	500.000	Prod Stm Oper - Suprv & Engineering	$ 6,499,360	$ (953,998)	53.4600	$ 0	S-8	$ 2,964,551
12	501.000	Fuel Expense	150,584,982	(1,677,210)	56.6800	0	S-9	84,400,925
13	502.000	Steam Operations Expense	12,683,639	(70,078)	53.4600	0	S-10	6,743,210
14	505.000	Prod Operating Expense	6,776,556	(54,724)	53.4600	0	S-11	3,593,491
15	506.000	Miscl Stm Pwr Operations	8,883,627	(44,878)	53.4600	0	S-12	4,725,195
16	507.000	Stm Pwr Operations - Rent Exp	377,605	0	53.4600	0	S-13	201,868
17	510.000	Prod Maint - Suprv & Engineering	2,566,021	70,572	53.4600	0	S-14	1,409,523
18	511.000	Prod Maint - Maint of Structures	3,472,585	(300,054)	53.4600	0	S-15	1,696,035
19	512.000	Prod Maint - Maint of Boiler Plnt	24,658,731	632,110	53.4600	0	S-16	13,520,484
20	513.514	Mint of Electric & Miscl Plant	7,394,463	512,727	53.4600	0	S-17	4,227,184
21	517.000	Prod Nuclear Oper-Superv & Engineer	5,358,029	(32,642)	53.4600	0	S-18	2,846,952
22	518.000	Prod Nuclear - Nuclear Fuel Exp	18,066,445	(271,860)	56.6800	0	S-19	10,085,971
23	519.000	Prod Nuclear Oper - Coolants	2,090,168	(7,252)	53.4600	0	S-20	1,113,527
24	520.000	Prod Nuclear Gen-Reactor Operation	9,480,259	(42,094)	53.4600	0	S-21	5,045,643
25	523.000	Prod Nuclear Gen- Electric Expense	762,235	(5,915)	53.4600	0	S-22	404,329
26	524.000	Prod Nuclear Oper-Miscl Nuclear Exp	20,506,296	(40,434)	53.4600	0	S-23	10,941,050
27	524.000	Security	659,218	0	100.0000	0		659,218
28	528.000	Prod Nuclear Maint-Suprv & Engineer	5,009,730	168,386	53.4600	0	S-24	2,768,221
29	529.000	Prod Nucl Maint-Maint of Structures	1,845,417	480	53.4600	0	S-25	986,817
30	530.000	Prod Nucl Maint-Maint Reactor Plnt	6,428,151	270,029	53.4600	0	S-26	3,580,847
31	531.000	Prod Nucl Maint-Maint	3,714,972	143,317	53.4600	0	S-27	2,062,641
32	532.000	Prod Nucl Maint-Maint of Miscl Plnt	2,016,949	57,117	53.4600	0	S-28	1,108,796
33	546.000	Prod Trubine Oper Suprv & Engineer	1,534,619	(6,385)	53.4600	0	S-29	816,994
34	547.000	Other Pwr Oper - Fuel Expense	39,223,450	(591,136)	56.6800	0	S-30	21,896,796
35	548.000	Oth Pwr Oper - Generation Expense	420,763	(3,242)	53.4600	0	S-31	223,207
36	549.000	Oth Pwr Oper-Miscl Oth Pwr Geneatio	124,016	(949)	53.4600	0	S-32	65,792

Accounting Schedule: 9-1

Accounting Schedule: 9
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Income Statement

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment		Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)		(F)
37	551.000	Oth Pwr Maint - Suprv & Engineering	15,727	87	53.4600	0	S-33	8,454
38	552.554	Oth Maint-Struct, Gen & Miscl Plnt	486,476	630,062	53.4600	0	S-34	596,901
39	555.000	Purchase Power - Energy	50,295,309	10,766,162	56.6800	0	S-35	34,609,642
40	555.000	Purchased Power - Demand	10,967,451	(4,522,650)	53.4600	0	S-36	3,445,391
41	556.000	Oth Pwr Supp - Load Dispatching	2,939,301	(23,275)	53.4600	0	S-37	1,558,907
42	557.000	Oth Pwr Supp - Other Expense	5,166,163	(38,494)	53.4600	0	S-38	2,741,252
43	560.000	Transmission Oper -Suprv & Engineer	5,932,177	(263,912)	52.3247	0	S-39	2,965,903
44	561.000	Trans Oper - Load Dispatching	642,572	(6,104)	52.3247	0	S-40	333,030
45	562.000	Transmiss Oper - Station Expense	195,166	(970)	54.0986	0	S-41	105,057
46	563.564	Transmiss Oper - Overhead Line Exp	248,662	(337)	53.6041	0	S-42	133,112
47	565.000	Trans Oper-Transmit Elctricity Oth	2,386,931	0	53.6041	0	S-43	1,279,493
48	566.000	Transmiss Oper - Miscellaneous Exp	1,617,443	(9,267)	52.3247	0	S-44	841,473
49	567.000	Transmission Oper - Rents	2,808,238	0	53.6041	0	S-45	1,505,331
50	568.570	Trans Maint-Structures & Station Eq	752,702	(3,824)	53.9316	0	S-46	403,882
51	571.572	Tran Maint-Ovrhd & Undgrnd Line Exp	1,189,406	(463)	53.5950	0	S-47	637,214
52	580.000	Distrb Oper - Suprv & Engineering	2,231,745	(39,032)	53.9527	0	S-48	1,183,028
53	581.000	Distrb Oper - Load Dispatching	1,193,725	(7,856)	53.3398	0	S-49	632,540
54	582.000	Distrb Oper - Station Expense	31,244	(283)	56.8114	0	S-50	17,589
55	583.584	Distrb - Ovrhd & Undrgrnd Line Exp	5,797,773	(27,371)	55.2123	0	S-51	3,185,972
56	585.000	Distrb Oper - Street Light & Signal	125,736	(1,028)	20.1356	0	S-52	25,111
57	586.000	Distrb Operation - Meter Expense	1,244,583	(10,267)	54.8016	0	S-53	676,425
58	587.000	Distrb Oper - Customer Install Exp	636,176	(4,289)	73.0037	0	S-54	461,301
59	588.000	Distrb Oper - Miscl Distrb Expense	13,470,388	(899,395)	53.9527	126,459	S-55	6,908,849
60	589.000	Distrb Oper - Distribution Rents	932,100	0	53.3399	0	S-56	497,181
61	590.000	Distrb Maint - Suprv & Engineering	302,272	(15,047)	53.4210	0	S-57	153,438
62	591.592	Distrb Maint - Struct & Station Equ	1,656,610	(277,902)	50.3776	0	S-58	694,560
63	593.000	Distrb Maint - Maint Ovrhd Lines	20,912,286	(968,202)	55.2123	0	S-59	11,011,587
64	594.000	Distrb Maint - Maint Undrgrnd Lines	1,865,924	(193,149)	50.4767	0	S-60	844,362
65	595.000	Distrb Maint-Maint Line Transformer	1,225,118	(117,314)	58.1899	0	S-61	644,630
66	596.000	Distrb Miant-Maint St Lights&Signal	1,427,762	(290,701)	20.1359	0	S-62	228,957
67	597.000	Distrb Maint - Maint of Meters	553,751	5,715	54.8032	0	S-63	306,605
68	598.000	Distrb Maint-Maint Miscl Distrb Pln	267,003	(85,384)	53.4210	0	S-64	97,023
69	901.000	Customer Accts-Suprv & Engineering	739,668	(72,380)	53.5650	0	S-65	357,433
70	902.000	Cust Accts - Meter Reading Exp	6,615,418	(8,576)	53.5650	0	S-66	3,538,955
71	903.905	Cust Accts-Rec & Collect & Miscl Ex	11,057,077	4,196,775	53.5650	495,586	S-67	8,666,312
72	904.000	Cust Accts-Uncollectible Accts Exp	1,408,673	1,321,817	100.0000	0	S-68	2,730,490
73	907.910	Cust Accts- Customer Assistance Exp	1,462,770	(88,954)	53.5650	0	S-69	735,885
74	912.000	Sales Expense - Supervision	532,394	(13,002)	53.5650	0	S-70	278,212
75	913.916	Sales Exp - Miscl Sales Exp	479,113	(2,463)	53.5662	0	S-71	255,323
76	920.000	Admin & Gen-Administrative Salaries	36,258,926	(7,571,192)	53.8993	0	S-72	15,462,488
77	921.000	Admin & Gen - Office Supply Expense	2,290,014	(251,188)	57.0974	0	S-73	1,164,117

Accounting Schedule: 9-2

Accounting Schedule: 9
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Income Statement

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment		Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)		(F)
78	921.000	Security	978,239	0	100.0000	0		978,239
79	922.000	Admin & Gen - Admin Exp Transferred	(2,721,743)	0	57.0974	0	S-74	(1,554,044)
80	923.000	Admin & Gen - Outside Services Exp	11,684,386	(4,085,555)	57.0974	0	S-75	4,338,735
81	924.000	Admin & Gen-Property Insurance Exp	2,507,375	0	54.1175	0	S-76	1,356,929
82	925.000	Admin & Gen-Injuries & Damages Exp	9,025,832	(1,092,438)	53.8993	0	S-77	4,276,044
83	926.000	Admin & Gen-Empl Pension & Benefits	39,543,929	20,306,023	53.8993	0	S-78	32,258,705
84	928.000	Admin & Gen-Regulate Commission Exp	3,484,383	(278,759)	42.4925	(301,041)	S-79	1,061,109
85	930.100	Admin & Gen-General Advertising Exp	1,728,009	(1,380,766)	53.5662	0	S-80	186,005
86	930.200	Admin & Gen - Miscl General Exp	7,144,698	(1,171,475)	57.0974	0	S-81	3,410,555
87	931.000	Admin & Gen - Admin Rent Expense	7,287,856	0	57.0974	0	S-82	4,161,176
88	933.000	Admin & Gen - Transportation Exp	239,185	(32,603)	53.1401	0	S-83	109,778
89	935.000	Admin & Gen Maint - Maint Gen Plant	2,555,353	(4,060)	53.5430	0	S-84	1,366,039
90		Total	$ 624,957,761	$ 11,118,601		$ 321,004		$ 351,961,952
		Depreciation Expense						
91	703.000	Depreciation Expense	$ 138,044,832	$ 0	53.9800	$ (17,815,659)	S-85	$ 56,700,941
92	730.100	Other Depreciation	0	(6,647,127)	53.9800	0	S-92	(3,588,119)
93		Total	$ 138,044,832	$ (6,647,127)		$ (17,815,659)		$ 53,112,822
		Other Operating Expenses						
94	704.707	Amortization of Plant Exp	$ 8,503,148	$ 0	54.2792	$ (2,094,918)	S-86	$ 2,520,523
95	708.000	Taxes Other Than Income Taxes	65,768,093	1,534,433	53.6908	0	S-87	36,135,265
96	708.000	Gross Receipts Taxes	39,012,075	(39,012,075)	100.0000	0	S-95	0
97		Total	$ 113,283,316	$ (37,477,642)		$ (2,094,918)		$ 38,655,788
98		Total Operating Expenses	$ 876,285,909	$ (33,006,168)		$ (19,589,573)		$ 443,730,562
99		Net Income Before Taxes	$ (143,531,918)	$ 48,504,852		$ (23,096,012)		$ 162,595,385
		Current Income Taxes						
100	709.000	Current Income Taxes	$ 94,652,951	$ 0	47.3250	$ 2,332,974	S-88	$ 47,127,483
101		Total	$ 94,652,951	$ 0		$ 2,332,974		$ 47,127,483

Accounting Schedule: 9-3

Accounting Schedule: 9
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Income Statement

Line No	Acct	Description	Total Company	Total Co Adjustment	Alloc Factor	Jurisdictional Adjustment		Adjusted Jurisdictional
		(A)	(B)	(C)	(D)	(E)		(F)
		Deferred Income Taxes						
102	710.000	Deferred Income Taxes	$ 0	$ 0	100.0000	$ 7,388,367	S-89	$ 7,388,367
103	711.100	Amort of Excess Deferred Inc. Taxes	0	0	100.0000	(993,300)	S-90	(993,300)
104	711.410	Inv Tax Credit - Amortization	0	0	100.0000	(1,444,946)	S-91	(1,444,946)
105	711.100	Amort of Prior Deferred Taxes	0	0	100.0000	(3,576,633)	S-94	(3,576,633)
106		Total	$ 0	$ 0		$ 1,373,488		$ 1,373,488
107		Total Income Taxes	$ 94,652,951	$ 0		$ 3,706,462		$ 48,500,971
108		Net Operating Income	$ (238,184,869)	$ 48,504,852		$ (26,802,474)		$ 114,094,414

Accounting Schedule: 9-4

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Retail Sales	S-1		$ (42,685,585)
1.	To remove the Gross Receipts Taxes. (Bolin)			$ (39,213,356)
2.	To adjust the test year revenues to reflect Staff's annualization of customer growth. (Bolin)			$ 1,579,214
3.	To adjust test year revenues to reflect Staff's annualization of large power customers. (Bolin)			$ 917,462
4.	To adjust revenues for weather normalization. (Wells)			$ (6,438,339)
5.	To adjust for Large Power manual billings, PLCC credits, and Revenue Adjustments (RVADMR & RVADMC). (Wells)			$ 469,434
	Firm Bulk Power Capac Fixed	S-2	$ 793,501	
1.	To annualize demand revenue for firm capacity bulk power customers. (Traxler)		$ 793,501	
	Firm Bulk Sales - Energy	S-7	$ 14,705,183	
1.	To annualize energy revenue for firm capacity bulk power customers. (Traxler)		$ 14,705,183	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Prod Stm Oper - Suprv & Engineering	S-8	$ (953,998)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (50,565)	
2.	To remove Short-Term Incentive Compensation Beneficial to Shareholders but not to the Ratepayers. (Harris)		$ (903,433)	
	Fuel Expense	S-9	$ (1,677,210)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (50,067)	
2.	To amortize over 5 years costs incurred for the Union Pacific Complaint Case before the Surface Transportation Board. (Hyneman)		$ 282,828	
3.	To annualize the fuel costs. (Hyneman)		$ (2,265,971)	
4.	To annualize the nuclear replacement power outage accrual. (Hyneman)		$ 356,000	
	Steam Operations Expense	S-10	$ (70,078)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (70,078)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Prod Operating Expense	S-11	$ (54,724)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (54,724)	
	Miscl Stm Pwr Operations	S-12	$ (44,878)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (44,878)	
	Prod Maint - Suprv & Engineering	S-14	$ 70,572	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (21,905)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ 92,477	
3.	To remove the Grand Avenue maintenance expense from the test year. (Harris)			
	Prod Maint - Maint of Structures	S-15	$ (300,054)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (10,624)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ (289,430)	
3.	To remove the Grand Avenue maintenance expense from the test year. (Harris)			
	Prod Maint - Maint of Boiler Plnt	S-16	$ 632,110	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (81,504)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ 713,614	
3.	To remove the Grand Avenue maintenance expense from the test year. (Harris)			
4.	To adjust the 6-year historical average maintenance expense to reflect Hawthorn 5 outage. (Harris)			
	Mint of Electric & Miscl Plant	S-17	$ 512,727	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (21,095)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ (740,129)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
3.	To remove the Grand Avenue maintenance expense from the test year. (Harris)			
4.	To reflect Hawthorn 5 turbine overhaul not included in the 6-year average maintenance expense. (Harris)		$ 750,000	
5.	To reflect the LaCygne 2 turbine overhal not included in the 6-year average maintenance expense. (Harris)		$ 523,951	
	Prod Nuclear Oper-Superv & Engineer	S-18	$ (32,642)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (46,431)	
2.	To adjust for Wolf Creek refueling outage accrual operations. (Harris)		$ 13,789	
	Prod Nuclear - Nuclear Fuel Exp	S-19	$ (271,860)	
1.	To annualize the fuel costs. (Hyneman)		$ (271,860)	
	Prod Nuclear Oper - Coolants	S-20	$ (7,252)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (12,631)	

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
2.	To adjust for Wolf Creek refueling outage accrual operations. (Harris)		$ 5,379	
	Prod Nuclear Gen-Reactor Operation	S-21	$ (42,094)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (66,492)	
2.	To adjust for Wolf Creek refueling outage accrual operations. (Harris)		$ 24,398	
	Prod Nuclear Gen- Electric Expense	S-22	$ (5,915)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (7,877)	
2.	To adjust for Wolf Creek refueling outage accrual operations. (Harris)		$ 1,962	
	Prod Nuclear Oper-Miscl Nuclear Exp	S-23	$ (40,434)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (94,905)	
2.	To adjust for Wolf Creek refueling outage accrual operations. (Harris)		$ 54,471	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Prod Nuclear Maint-Suprv & Engineer	S-24	$ 168,386	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (25,003)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ 193,389	
	Prod Nucl Maint-Maint of Structures	S-25	$ 480	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (16,503)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ 16,983	
	Prod Nucl Maint-Maint Reactor Plnt	S-26	$ 270,029	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (17,078)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ 287,107	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Prod Nucl Maint-Maint	S-27	$ 143,317	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (16,092)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ 159,409	
	Prod Nucl Maint-Maint of Miscl Plnt	S-28	$ 57,117	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (9,994)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ 67,111	
	Prod Trubine Oper Suprv & Engineer	S-29	$ (6,385)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (6,385)	
	Other Pwr Oper - Fuel Expense	S-30	$ (591,136)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (910)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description			Total Co Adjustment	Mo Juris Adjustment
2.	To annualize the fuel costs. (Hyneman)		$	(590,226)	
	Oth Pwr Oper - Generation Expense	S-31	$	(3,242)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$	(3,242)	
	Oth Pwr Oper-Miscl Oth Pwr Geneatio	S-32	$	(949)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$	(949)	
	Oth Pwr Maint - Suprv & Engineering	S-33	$	87	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$	(155)	
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$	242	
	Oth Maint-Struct, Gen & Miscl Plnt	S-34	$	630,062	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$	(1,742)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
2.	To annualize non-labor production maintenance expense (per DR 403). (Harris)		$ 246,804	
3.	To reflect maintenance expense related to newly owned CT's that had previously been leased. (Harris)		$ 385,000	
	Purchase Power - Energy	S-35	$ 10,766,162	
1.	To annualize the purchased power energy charges. (Hyneman)		$ 10,766,162	
	Purchased Power - Demand	S-36	$ (4,522,650)	
1.	To annualize the purchased power demand charges. (Hyneman)		$ (4,522,650)	
	Oth Pwr Supp - Load Dispatching	S-37	$ (23,275)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (23,275)	
	Oth Pwr Supp - Other Expense	S-38	$ (38,494)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (36,557)	
2.	To adjust test year expense to reflect the disallowance of charitable contributions. (Williams)		$ (600)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description	Total Co Adjustment	Mo Juris Adjustment
3.	To adjust test year expense to eliminate lobbying charged to cost of service. (Williams)	$ (679)	
4.	To remove costs associated with the director/officer Sea Island George Retreat. (Hyneman)	$ (658)	
	Transmission Oper -Suprv & Engineer S-39	**$ (263,912)**	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)	$ (19,924)	
2.	To adjust test year expense to eliminate lobbying charged to cost of service. (Williams)	$ (2,741)	
3.	To remove Short-Term Incentive Compensation Beneficial to Shareholders but not to the Ratepayers. (Harris)	$ (241,247)	
	Trans Oper - Load Dispatching S-40	**$ (6,104)**	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)	$ (6,104)	
	Transmiss Oper - Station Expense S-41	**$ (970)**	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)	$ (970)	

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Transmiss Oper - Overhead Line Exp	S-42	$ (337)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (337)	
	Transmiss Oper - Miscellaneous Exp	S-44	$ (9,267)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (9,267)	
	Trans Maint-Structures & Station Eq	S-46	$ (3,824)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (3,824)	
2.	To annualize non-labor transmission maintenance expense (DR 403). (Harris)			
	Tran Maint-Ovrhd & Undgrnd Line Exp	S-47	$ (463)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (463)	
2.	To annualize non-labor transmission maintenance expense (DR 403). (Harris)			

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Distrb Oper - Suprv & Engineering	S-48	$ (39,032)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (18,025)	
2.	To remove Short-Term Incentive Compensation Beneficial to Shareholders but not to the Ratepayers. (Harris)		$ (8,833)	
3.	To remove 50% of entertainment business meals charged to expense. (Hyneman)		$ (12,174)	
	Distrb Oper - Load Dispatching	S-49	$ (7,856)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (7,856)	
	Distrb Oper - Station Expense	S-50	$ (283)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (283)	
	Distrb - Ovrhd & Undrgrnd Line Exp	S-51	$ (27,371)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (27,371)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Distrb Oper - Street Light & Signal	S-52	$ (1,028)	
	1. To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (1,028)	
	Distrb Operation - Meter Expense	S-53	$ (10,267)	
	1. To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (10,267)	
	Distrb Oper - Customer Install Exp	S-54	$ (4,289)	
	1. To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (4,289)	
	Distrb Oper - Miscl Distrb Expense	S-55	$ (899,395)	$ 126,459
	1. To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (85,388)	
	2. To remove Short-Term Incentive Compensation Beneficial to Shareholders but not to the Ratepayers. (Harris)		$ (813,724)	
	3. To remove costs associated with the director/officer Sea Island George Retreat. (Hyneman)		$ (283)	

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
4.	To reflect the amortization of Demand Response, Efficiency and Affordability Programs agreed to in Case No. EO-2005-0329. (Featherstone)			$ 126,459
	Distrb Maint - Suprv & Engineering	S-57	$ (15,047)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (2,435)	
2.	To annualize non-labor distribution maintenance expense (DR 403). (Harris)		$ (12,612)	
	Distrb Maint - Struct & Station Equ	S-58	$ (277,902)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (5,959)	
2.	To annualize non-labor distribution maintenance expense (DR 403). (Harris)		$ (271,943)	
	Distrb Maint - Maint Ovrhd Lines	S-59	$ (968,202)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (28,824)	
2.	To annualize non-labor distribution maintenance expense (DR 403). (Harris)		$ (939,378)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Distrb Maint - Maint Undrgrnd Lines	S-60	$ (193,149)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (10,069)	
2.	To annualize non-labor distribution maintenance expense (DR 403). (Harris)		$ (183,080)	
	Distrb Maint-Maint Line Transformer	S-61	$ (117,314)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (8,422)	
2.	To annualize non-labor distribution maintenance expense (DR 403). (Harris)		$ (108,892)	
	Distrb Miant-Maint St Lights&Signal	S-62	$ (290,701)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (2,677)	
2.	To annualize non-labor distribution maintenance expense (DR 403). (Harris)		$ (288,024)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Distrb Maint - Maint of Meters	S-63	$ 5,715	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (4,471)	
2.	To annualize non-labor distribution maintenance expense (DR 403). (Harris)		$ 10,186	
	Distrb Maint-Maint Miscl Distrb Pln	S-64	$ (85,384)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (1,343)	
2.	To annualize non-labor distribution maintenance expense (DR 403). (Harris)		$ (84,041)	
	Customer Accts-Suprv & Engineering	S-65	$ (72,380)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (3,926)	
2.	To remove Short-Term Incentive Compensation Beneficial to Shareholders but not to the Ratepayers. (Harris)		$ (68,454)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Cust Accts - Meter Reading Exp	S-66	$ (8,576)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (8,576)	
	Cust Accts-Rec & Collect & Miscl Ex	S-67	$ 4,196,775	$ 495,586
1.	To adjust test year expesne to reflect Staff's annulaistion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (63,773)	
2.	To adjust test year expense to reflect the disallowance of charitable contributions. (Williams)		$ (122,059)	
3.	To adjust test year expense to reflect the inclusion of Banking Fees associated with the accounts receivable sales. (Williams)		$ 3,882,607	
4.	To include in cost of service interest on annualized customer deposits. (Williams)			$ 495,586
5.	To include in rates expenses for costs associated with accepting credit card payments. (Williams)		$ 500,000	
	Cust Accts-Uncollectible Accts Exp	S-68	$ 1,321,817	
1.	To normalize bad debt expense. (Bolin)		$ 1,321,817	
2.	To normalize bad debt expense.			

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Cust Accts- Customer Assistance Exp	S-69	$ (88,954)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (11,667)	
2.	To remove Short-Term Incentive Compensation Beneficial to Shareholders but not to the Ratepayers. (Harris)		$ (77,287)	
	Sales Expense - Supervision	S-70	$ (13,002)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (1,557)	
2.	To remove 50% of entertainment business meals charged to expense. (Hyneman)		$ (11,445)	
	Sales Exp - Miscl Sales Exp	S-71	$ (2,463)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (2,463)	
	Admin & Gen-Administrative Salaries	S-72	$ (7,571,192)	
1.	To adjust test year expense to remove severance costs. (Hyneman)		$ (2,383,662)	

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description	Total Co Adjustment	Mo Juris Adjustment
2.	To adjust test year expense to annualize Admin & Gen payroll charged to Acct. 920 based upon the test year capitalization ratio. (Bolin)	$ 5,185,777	
3.	To adjust test year expense to correct the test year capitalization ratio for Admin & Gen payroll charged to Acct. 920. (Bolin)	$ (7,014,443)	
4.	To adjust test year expense to eliminate lobbying charged to cost of service. (Williams)	$ (147,373)	
5.	To remove Short-Term Incentive Compensation Beneficial to Shareholders but not to the Ratepayers. (Harris)	$ (1,467,733)	
6.	To adjust test year expense to remove the Equity based Long-Term Executive Compensation. (Harris)	$ (1,668,100)	
7.	To remove discretionary bonuses paid to executives based upon criteria unrelated to providing electric service to ratepayers. (Harris)	$ (43,470)	
8.	To remove 50% of entertainment business meals charged to expense. (Hyneman)	$ (32,188)	
	Admin & Gen - Office Supply Expense S-73	$ (251,188)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)	$ (293)	

Accounting Schedule: 10
Williams
16:19 03/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description	Total Co Adjustment	Mo Juris Adjustment
2.	To adjust test year expense to reflect the disallowance of charitable contributions. (Williams)	$ (500)	
3.	To adjust test year expense to eliminate lobbying charged to cost of service. (Williams)	$ (992)	
4.	To remove 50% of entertainment business meals charged to expense. (Hyneman)	$ (126,626)	
5.	To remove costs associated with the director/officer Sea Island George Retreat. (Hyneman)	$ (3,251)	
6.	To reflect amortizing over 5 years costs charged to Project "CORDP-KCPL". (Vesely)	$ (18,915)	
7.	To reflect amortizing over 5 years costs charged to Project "LED-LDI". (Vesely)	$ (100,611)	
	Admin & Gen - Outside Services Exp S-75	**$ (4,085,555)**	
1.	To remove costs that should be capitalized to the Iatan II Project but were expensed to Project MSC0140. (Vesely)	$ (1,688,267)	
2.	To reflect amortizing over 5 years costs charged to Project "CORDP-KCPL". (Vesely)	$ (1,210,554)	
3.	To reflect amortizing over 5 years costs charged to Project "LED-LDI". (Vesely)	$ (1,186,734)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Admin & Gen-Injuries & Damages Exp	S-77	$ (1,092,438)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (1,800)	
2.	To adjust test year expense to reflect the disallowance of charitable contributions. (Williams)		$ (5,000)	
3.	To adjust test year expense to reflect Staff's annualization of Injuries and Damages. (Vesely)		$ (1,085,638)	
	Admin & Gen-Empl Pension & Benefits	S-78	$ 20,306,023	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ 531	
2.	To adjust test year expense to eliminate lobbying charged to cost of service. (Williams)		$ (154,253)	
3.	To adjust test year expense to reflect the amortization of the FAS 87 Regulatory Asset over 5 years. (Traxler)		$ 3,798,166	
4.	To adjust test year expense to reflect the 2006 FAS 87 Pension Cost. (Traxler)		$ 14,977,783	
5.	To adjust test year expense to reflect a 3-year average of the SERP payments. (Harris)		$ 585,555	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description	Total Co Adjustment	Mo Juris Adjustment
6.	To annualize the 401K costs. (Bolin)	$ 145,013	
7.	To annualize the FAS 106 costs. (Traxler)	$ 456,143	
8.	To normalize the LTD, Life & AD&D insurance costs. (Bolin)	$ (10,918)	
9.	To normalize the cost of dental benefits. (Bolin)	$ 37,672	
10.	To normalize the vision insurance costs. (Bolin)	$ 3,349	
11.	To normalize test year medical costs. (Bolin)	$ 270,430	
12.	To normalize the test year costs for Wolf Creek employees benefit costs. (Bolin)	$ 196,552	
	Admin & Gen-Regulate Commission Exp S-79	$ (278,759)	$ (301,041)
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)	$ (3,925)	
2.	To reflect the 2007 PSC assessment effective July 1, 2006. (Harris)		$ 72,427
3.	To adjust test year expense to amortize the rate case expense over 3 years. (Harris)		$ (373,468)
4.	To remove costs that should be capitalized to the Iatan II Project but were expensed to Project MSC0140. (Vesely)	$ (274,834)	

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Admin & Gen-General Advertising Exp	S-80	$ (1,380,766)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (2,230)	
2.	To adjust test year expense to reflect the disallowance of charitable contributions. (Williams)		$ (291,528)	
3.	To adjust test year expense to reflect advertising capitalized to Iatan. (Vesely)		$ (113,681)	
4.	To adjust test year expense to reflect the elimination of general advertising costs without documentation. (Vesely)		$ (76,036)	
5.	To adjust test year expense to reflect the elimination of institutional advertising. (Vesely)		$ (461,018)	
6.	To adjust test year expense to reflect the elimination of advertising expense described as other. (Vesely)		$ (104,191)	
7.	To adjust test year expense to reflect the elimination of non-advertising costs charged to acct. 930.1. (Vesely)		$ (332,082)	
	Admin & Gen - Miscl General Exp	S-81	$ (1,171,475)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (7,888)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description	Total Co Adjustment	Mo Juris Adjustment
2.	To adjust test year expense to reflect the disallowance of charitable contributions. (Williams)	$ (5,210)	
3.	To adjust test year expense to eliminate lobbying charged to cost of service. (Williams)	$ (122)	
4.	To adjust test year expense to reflect the elimination of dues paide to EEI which supports lobbying. (Williams)	$ (223,269)	
5.	To adjust test year expense to reflect the elimination of industry dues & memberships. (Williams)	$ (381,549)	
6.	To remove 50% of entertainment business meals charged to expense. (Hyneman)	$ (3,469)	
7.	To remove costs associated with the director/officer Sea Island George Retreat. (Hyneman)	$ (49,968)	
8.	To include a disallowance for costs that have been booked incorrectly, related to to lobbying activities, and are related to expense account charges that should not have be charged to KCPL. (Hyneman)	$ (500,000)	
	Admin & Gen - Transportation Exp S-83	$ (32,603)	
1.	To adjust test year expene to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)	$ (32,481)	
2.	To adjust test year expense to eliminate lobbying charged to cost of service. (Williams)	$ (122)	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Admin & Gen Maint - Maint Gen Plant	S-84	$ (4,060)	
1.	To adjust test year expesne to reflect Staff's annulaiztion of payroll based upon employees and wage rates at 6-30-06. (Bolin)		$ (4,060)	
	Amortization of Plant Exp	S-86		$ (2,094,918)
1.	To adjust test year amortization expense to reflect the elimination of the expense associated with the amortization of AFUDC for Iatan, Case No. ER-81-42. (Williams)			$ (194,085)
2.	To adjust test year expense to reflect the annualization of the amortization of the 2002 incremental ice storm costs, which ends in January 2007. (Williams)			$ (1,900,833)
3.	To reflect the Regulatory Plan Amortization. (Traxler)			
	Taxes Other Than Income Taxes	S-87	$ 1,534,433	
1.	To adjust test year expense to reflect Staff's annualization of the payroll taxes. (Bolin)		$ (152,117)	
2.	To adjust property tax expense to reflect Staff's annualized property tax level. (Williams)		$ 1,684,275	
3.	To adjust property tax expense to reflect Staff's annualized property taxes for vehicles cleared to expense. (Williams)		$ 2,275	

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Amort of Excess Deferred Inc. Taxes	S-90		$ (993,300)
	1. To reflect the annualization of Excess Deferred Income Taxes. (Traxler)			$ (993,300)
	Inv Tax Credit - Amortization	S-91		$ (1,444,946)
	1. To annualize the Investment Tax Credit - Amortization. (Traxler)			$ (1,444,946)
	Other Depreciation	S-92	$ (6,647,127)	
	1. To remove the test year transportation depreciation cleared to expense. (Williams)		$ (947,410)	
	2. To remove from expense annualized depriation on transportation equipment that would be cleared to capital accounts. (Williams)		$ (392,363)	
	3. To adjust depreciation expense associated with the booking of the Hawthorn 5 insurance and lawsuit subrogation proceeds charged to salvage. (Williams)		$ (5,307,354)	
	Amort of Prior Deferred Taxes	S-94		$ (3,576,633)
	1. To annualize the Amortization of Prior Deferred Taxes. (Traxler)			$ (3,576,633)

Accounting Schedule: 10
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Adjustments to Income Statement

Adj No	Description		Total Co Adjustment	Mo Juris Adjustment
	Gross Receipts Taxes	S-95	$ (39,012,075)	
1.	To remove Gross Receipts Taxes. (Bolin)		$ (39,012,075)	

Accounting Schedule: 11
Williams
16:19 09/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Income Tax

Line	(A)	Test Year (B)	7.78% Return (C)	7.81% Return (D)	7.83% Return (E)
1	Net Income Before Taxes (Sch 9)	$ 162,595,385	$ 124,872,948	$ 125,446,011	$ 125,828,051
	Add to Net Income Before Taxes				
2	Book Depreciation Expense	$ 53,112,822	$ 53,112,822	$ 53,112,822	$ 53,112,822
3	50% Meals & Intertainment	252,377	252,377	252,377	252,377
4	Book Nuclear Fuel Amortization	7,249,344	7,249,344	7,249,344	7,249,344
5	Book Amortization Expense	2,520,523	2,520,523	2,520,523	2,520,523
6	Total	$ 63,135,066	$ 63,135,066	$ 63,135,066	$ 63,135,066
	Subtr from Net Income Before Taxes				
7	Interest Expense 2.7500 %	$ 32,164,695	$ 32,164,695	$ 32,164,695	$ 32,164,695
8	Straight Line Tax Depreciation	41,620,873	41,620,873	41,620,873	41,620,873
9	Tax Deprec over Straight-Line Tax	19,144,954	19,144,954	19,144,954	19,144,954
10	Production Income Deduction	1,371,905	1,371,905	1,371,905	1,371,905
11	IRS Nuclear Fuel Amortization	9,242,234	9,242,234	9,242,234	9,242,234
12	IRS Amortization Deduction	628,231	628,231	628,231	628,231
13	Wind Production Tax Credit	0	0	0	0
14	Total	$ 104,172,892	$ 104,172,892	$ 104,172,892	$ 104,172,892
15	Net Taxable Income	$ 121,557,559	$ 83,835,122	$ 84,408,185	$ 84,790,225
	Provision for Federal Income Tax				
16	Net Taxable Income	$ 121,557,559	$ 83,835,122	$ 84,408,185	$ 84,790,225
17	Deduct Missouri Income Tax 100.0 %	$ 6,297,930	$ 4,343,520	$ 4,373,211	$ 4,393,004
18	Deduct City Income Tax	751,819	518,510	522,055	524,417
19	Federal Taxable Income	114,507,810	78,973,092	79,512,919	79,872,804
20	Total Federal Tax	$ 40,077,734	$ 27,640,583	$ 27,829,522	$ 27,955,482

Accounting Schedule: 11-1

Accounting Schedule: 11
Williams
16:19 05/05/2006

Kansas City Power & Light Co.
Case: ER-06-314C
12-Months Ended Deember 31, 2005

Income Tax

Line		Test Year	7.78% Return	7.81% Return	7.83% Return
	(A)	(B)	(C)	(D)	(E)
	Provision for Missouri Income Tax				
21	Net Taxable Income	$ 121,557,559	$ 83,835,122	$ 84,408,185	$ 84,790,225
22	Deduct Federal Income Tax 50.0 %	$ 20,038,867	$ 13,820,292	$ 13,914,761	$ 13,977,741
23	Deduct City Income Tax	751,819	518,510	522,055	524,417
24	Missouri Taxable Income	100,766,873	69,496,321	69,971,369	70,288,067
25	Total Missouri Tax	$ 6,297,930	$ 4,343,520	$ 4,373,211	$ 4,393,004
	Provision for City Income Tax				
26	Net Taxable Income	$ 121,557,559	$ 83,835,122	$ 84,408,185	$ 84,790,225
27	Deduct Federal Income Tax	$ 40,077,734	$ 27,640,583	$ 27,829,522	$ 27,955,482
28	Deduct Missouri Income Tax	6,297,930	4,343,520	4,373,211	4,393,004
29	City Taxable Income	75,181,895	51,851,019	52,205,452	52,441,739
30	Total City Tax	$ 751,819	$ 518,510	$ 522,055	$ 524,417
	Summary of Provision for Income Tax				
31	Federal Income Tax	$ 40,077,734	$ 27,640,583	$ 27,829,522	$ 27,955,482
32	Missouri Income Tax	6,297,930	4,343,520	4,373,211	4,393,004
33	City Income Tax	751,819	518,510	522,055	524,417
34	Total	$ 47,127,483	$ 32,502,613	$ 32,724,788	$ 32,872,903
	Deferred Income Taxes				
35	Deferred Investment Tax Credit	$ 0	$ 0	$ 0	$ 0
36	Deferred Repair Allowance	0	0	0	0
37	Deferred Tax Depreciation	7,388,367	7,388,367	7,388,367	7,388,367
38	Amort of Deferred Tax Depreciation	0	0	0	0
39	Amort of Repair Allowance	0	0	0	0
40	Amort of Deferred ITC	0	0	0	0
41	Deferred Unbilled	0	0	0	0
42	Total	$ 7,388,367	$ 7,388,367	$ 7,388,367	$ 7,388,367
43	Total Income Tax	$ 54,515,850	$ 39,890,980	$ 40,113,155	$ 40,261,270

Accounting Schedule: 11-2

Attachment 1 to Appendix F - 9/5,2006 - Revised

Line			Total Company		Jurisdictional Allocation	Jurisdictional Adjustments	Jurisdictional Proforma
1	Additional net Assets on KCPL's balance sheet				30,830,731		
2	Rate Base		NA		1,169,625,282		
3	Net Assets supported by LTD & Equity				1,200,456,013		
4	Jusrisdictional Allocator for Capital	Jurisdictional Rate Base / Total Company Rate Base			54.20%		
5							
6	Total Capital	Barnes Schedule 9	2,530,901,000		1,200,456,013	-	1,200,456,013
7	Equity	Barnes Schedule 9	1,347,348,000	53.24%	639,073,598	-	639,073,598
8	Preferred	Barnes Schedule 9	39,000,000	1.54%	18,498,465		18,498,465
9	Long-term Debt	Barnes Schedule 9	1,144,553,000	45.22%	542,883,950		542,883,950
10	Cost of Debt	Barnes Schedule 10	6.08%		6.08%		6.08%
11	Interest Expense	Line 13 * Line 14	69,588,822		33,007,344	-	33,007,344
12							
13	Retail Sales Revenue	Staff Accounting Schedule 9-1 plus Revenue Requirement	0		483,388,716	54,768,299	538,157,015
14	Other Revenue	Staff Accounting Schedule 9-1	0		85,787,857		85,787,857
15	Operating Revenue	Staff Accounting Schedule 9-1	0		569,176,573	54,768,299	623,944,872
16							
17	Operating & Maintenance Expenses	Staff Accounting Schedule 9-3 - Less Customer Deposit Interest			351,961,952		351,961,952
18	Depreciation	Staff Accounting Schedule 9-3			53,112,822		53,112,822
19	Amortization	Staff Accounting Schedule 9-3			2,520,523	54,768,299	57,288,822
20	Interest on Customer Deposits						0
21	Taxes other than income taxes	Staff Accounting Schedule 9-3			36,135,265		36,135,265
22	Federal and State income taxes	Staff Accounting Schedule 9-4			34,098,276		34,098,276
23	Gains on disposition of plant				0		0
24	Total Electric Operating Expenses	Sum of Lines 21 to 27	0		477,828,838	54,768,299	532,597,137
25							
26	Operating Income	Staff Accounting Schedule 1-1 Line 3	0		91,347,735	0	91,347,735
27	less Interest Expense	- Line 15	-		(33,007,344)	-	(33,007,344)
28	Depreciation	Staff Accounting Schedule 9-3			53,112,822	-	53,112,822
29	Amortization	Staff Accounting Schedule 9-3			2,520,523	54,768,299	57,288,822
30	Deferred Taxes	Staff Accounting Schedule 9-4			1,373,488		1,373,488
31	Funds from Operations (FFO)	Sum of Lines 30 to 34	-		115,347,224	54,768,299	170,115,523
32							
33	Net Income	Line 30 + Line 31	-		58,340,391	-	58,340,391
34	Return on Equity	Line 37 / Line 11	0.0%		9.1%	0.0%	9.1%
35	Unadjusted Equity Ratio	Line 11 / Line 10	53.2%		53.2%	0.0%	53.2%

Additional financial information needed for the calculation of ratios

Line			Total Company	Jurisdictional Allocation	Jurisdictional Adjustments	Jurisdictional Proforma
36	Capitalized Lease Obligations	KCPL Trial Balance accts 227100 & 243100	2,314,096	1,254,334		1,254,334
37	Short-term Debt Balance	KCPL Trial Balance accts 231xxx	82,400,000	44,664,151		44,664,151
38	Short-term Debt Interest	KCPL T.B. accts 831014, 831015, 831016	5,681,983	3,079,866		3,079,866

Adjustments made by Rating Agencies for Off-Balance Sheet Obligations

Line			Total Company	Jurisdictional Allocation	Jurisdictional Adjustments	Jurisdictional Proforma
39	Debt Adjustments for Off-Balance Sheet Obligations					
40	Operating Lease Debt Equivalent	Present Value of Operating Lease Obligations discounted @ 6.1%	86,657,361	46,971,814		46,971,814
41	Purchase Power Debt Equivalent	Present Value of Purchase Power Obligations discounted @ 6.1%	12,443,708	6,744,996		6,744,996
42	Accounts Receivable Sale	KCPL Trial Balance account 142011	70,000,000	37,942,847		37,942,847
43	Total OBS Debt Adjustment	Sum of Lines 50 to 52	169,101,069	91,659,656	-	91,659,656
44						
45	Interest Adjustments for Off-Balance Sheet Obligations					
46	Present Value of Operating Leases	Line 50 * 6.10%	5,286,099	2,865,281	-	2,865,281
47	Purchase Power Debt Equivalent	Line 51 * 6.10%	759,066	411,445	-	411,445
48	Accounts Receivable Sale	Line 52 * 5%	3,500,000	2,314,514	-	2,314,514
49	Total OBS Interest Adjustment	Sum of Lines 56 to 58	9,545,165	5,591,239	-	5,591,239

Ratio Calculations

Line			Total Company	Jurisdictional Allocation	Jurisdictional Adjustments	Jurisdictional Proforma
50	Adjusted Interest Expense	Line 15 + Line 45 + Line 59	84,815,971	41,678,449	-	41,678,449
51	Adjusted Total Debt	Line13 + Line 43 + Line 44 + Line 53	1,398,368,165	680,462,091	-	680,462,091
52	Adjusted Total Capital	Line 10 + Line 43 + Line 44 + Line 53	2,784,716,165	1,338,034,154	-	1,338,034,154
53						
54	FFO Interest Coverage	(Line 35 + Line 63) / Line 63	1.00	3.77	1.31	5.08
55	FFO as a % of Average Total Debt	Line 35 / Line 64	0.0%	17.0%	8.0%	25.0%
56	Total Debt to Total Capital	Line 64 / Line 65	50.2%	50.9%	0.0%	50.9%

Changes required to meet ratio targets

Line			Total Company	Jurisdictional Allocation	Jurisdictional Adjustments	Jurisdictional Proforma
57	FFO Interest Coverage Target		3.80	3.80	0.00	3.80
58	FFO adjustment to meet target	(Line 73 - Line 67) * Line 63	237,484,718	1,352,433	(54,768,299)	(53,415,865)
59	Interest adjustment to meet target	Line 35 * (1 / (Line 73 - 1) - 1 / (Line 67 - 1))	#DIV/0!	(483,012)	19,560,107	19,077,095
60						
61	FFO as a % of Average Total Debt Target		25%	25%	0%	25%
62	FFO adjustment to meet target	(Line 77 - Line 68) * Line 64	349,592,041	54,768,299	(54,768,299)	-
63	Debt adjustment to meet target	Line 35 * (1 / Line 77 - 1 / Line 68)	#DIV/0!	(219,073,196)	219,073,196	-
64						
65	Total Debt to Total Capital Target		51%	51%	0%	51%
66	Debt adjustment to meet target	(Line 81 - Line 69) * Line 65	21,837,079	1,935,328	-	1,935,328
67	Total Capital adjustment to meet target	Line 64 / Line 81 - Line 65	(42,817,802)	(3,794,760)	-	(3,794,760)

Amortization and Revenue needed to meet targeted ratios

Line			Total Company	Jurisdictional Allocation	Jurisdictional Adjustments	Jurisdictional Proforma
68	FFO adjustment needed to meet target ratios	Maximum of Line 74 , Line 78 , or Zero	349,592,041	54,768,299	(54,768,299)	-
69	Effective income tax rate	Accounting Schedule 11	38.77%	38.77%	38.77%	38.77%
70	Deferred income taxes *	- Line 87 * Line 88 / (1 - Line 88)	(221,356,907)	(34,678,539)	34,678,539	-
71	Total amortization required for the FFO adjustment	Line 87 - Line 89	570,948,949	89,446,838	(89,446,838)	-
72						
73	Retail Sales Revenue Adjustment	Adjustment =Sum(Line 21 to Line 25)+Line 27-Line 18-Line 31+(Line 11*Line 38)/(1-Line 88)		483,388,716	54,768,299	538,157,015
74	Percent increase in retail sales revenue	Line 92 Jurisdictional Adjustments / Line 92 Jurisdictional			11.3%	

* Adjusted for known and measurable changes including changes related to new plant in-service

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City	)	
Power & Light Company to Modify Its Tariff to	)	Case No. ER-2006-0314
Begin the Implementation of Its Regulatory Plan	)	

AFFIDAVIT OF DON A. FRERKING

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

Don A. Frerking, being first duly sworn on his oath, states:

1. My name is Don A. Frerking. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Senior Regulatory Analyst.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Kansas City Power & Light Company consisting of twenty-three (23) pages and Schedules DAF-6 through DAF-11, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Don A. Frerking

Subscribed and sworn before me this 8th day of September 2006.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4, 2007

NICOLE A. WEHRY
Notary Public - Notary Seal
STATE OF MISSOURI
Jackson County
My Commission Expires: Feb. 4, 2007