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
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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

<u>**Depreciation Issues**</u>

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?

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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

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

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ERIN L. MALONEY

EMPIRE DISTRICT ELECTRIC COMPANY

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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...

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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. 189, 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);

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[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. 65,093 (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%—4 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);

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(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

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(14) *Delmarva Power & Light Co.*,
17 FERC at 65,301
(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)
(81.2%—4 CP);

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

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(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

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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 resales 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.*

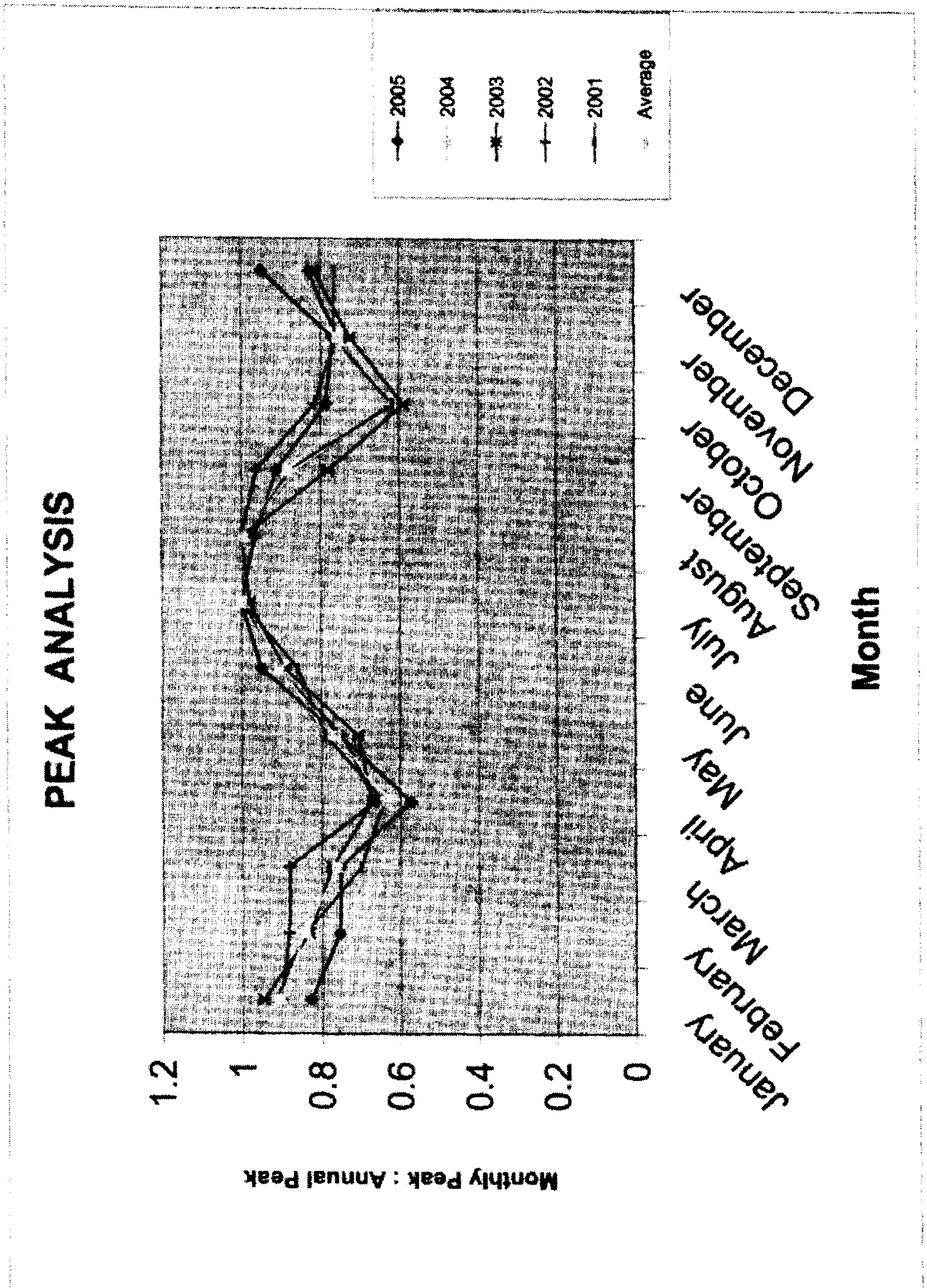
used in developing the estimate and not just one year. *See, e.g., Otter Tail Power Co.*, Opinion No. 93, 12 FERC ¶61,169, p. 61,429 (1980); *Commonwealth Edison Co.*, 15 FERC at 65,190, *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983) (3 year average adopted); *Southern California Edison Co.*, Opinion 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

Schedule 6


PEAK ANALYSIS
2005
2004
2003
2002
2001
Average
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

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%

Schedule 7