Exhibit No.: 122
Issues: System Energy Losses
Demand and Energy
Jurisdictional Allocation
Witness: Erin L. Maloney
Sponsoring Party: MO PSC Staff
Type of Exhibit: Direct Testimony
Case No.: ER-2006-0314
Date Testimony Prepared: August 8, 2006

# MISSOURI PUBLIC SERVICE COMMISSION

## UTILITY OPERATIONS DIVISION

## DIRECT TESTIMONY

FILED
NOV 13 2006

## OF

## ERIN L. MALONEY

Missouri Public Service Commission

## KANSAS CITY POWER & LIGHT COMPANY

## CASE NO. ER-2006-0314

**Jefferson City, Missouri**
**August 2006**

Staff Exhibit No. 122
Case No(s). ER-2006-0314
Date 10-16-06 Rptr KF

# BEFORE THE PUBLIC SERVICE COMMISSION

# OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan | ) ) ) ) ) | Case No. ER-2006-0314 |

**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 following Direct Testimony in question and answer form, consisting of 11 pages of Direct Testimony to be presented in the above case, that the answers in the following Direct Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

E. L. Maloney
Erin L. Maloney

Subscribed and sworn to before me this 7th day of August, 2006.

ROSEMARIE RIEDL
MY COMMISSION EXPIRES
June 1, 2009
NOTARY SEAL
#05509538
COLE COUNTY
NOTARY PUBLIC, STATE OF MISSOURI

Rosemarie Riedl
Notary Public

My commission expires June 1, 2009

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OF

ERIN L. MALONEY

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2006-0314

# DIRECT TESTIMONY

# OF

# ERIN L. MALONEY

# KANSAS CITY POWER AND LIGHT COMPANY

# CASE NO. ER-2006-0314

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 and I filed testimony on system losses and jurisdictional allocation in Case No. ER-2006-0315.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to present information and make recommendations on the following three issues:

(1) System Energy Losses

(2) Jurisdictional Demand Allocation

(3) Jurisdictional Energy Allocation

## EXECUTIVE SUMMARY

Q. Please summarize your analysis, results, and recommendations.

A. **(1) System Energy Losses**

I calculated the total company system energy losses to be 5.32% of the total electrical system inputs (i.e., Net System Input or NSI) for the test year using the methods described in this testimony. I then compared my results to the overall system loss calculated in Kansas City Power and Light Company's (KCP&L or Company) most recent loss study (5.34%). I reviewed and verified the Company's loss study and I recommend that Staff adopt the system and class load losses determined in that study.

**(2) & (3) Demand and Energy Jurisdictional Allocation**

I calculated the jurisdictional allocation factors for demand using a Four Coincident Peak (4 CP) methodology. The calculated demand factors are as shown in the Table 1. Table 1 also shows the jurisdictional allocation factors for energy. The energy allocation factors were calculated after applying adjustments for large customer annualization, weather normalization, and customer growth.

**Table 1 Demand and Energy Jurisdictional Allocation Factors**

| | Missouri Retail | Kansas Retail | Wholesale |
|---|---|---|---|
| **Demand** | .5346 | .4573 | .0082 |
| **Energy** | .5668 | .4243 | .0089 |

## 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 overall system energy loss factor is 0.0532 while the loss factor resulting from KCP&L's loss study was 0.0534. Staff is recommending that the Company's loss study results including the class load loss factors be adopted.

Q. What is the 'System Energy Loss Factor'?

A. The system energy loss factor is the ratio of system energy losses to Net System Input (NSI):

System Energy Loss Factor = System Energy Losses ÷ NSI

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 the utility'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. Why is it important to determine system energy losses?

A. The utility must know how much energy is being lost in the system in order to plan enough generation to meet forecasted peak load demands while compensating for losses.

Q. How are system losses determined?

A. The overall system losses are the difference between the metered inputs to the electrical system and the metered outputs to the electrical system. The inputs to the electrical system are the net generation, net interchange of energy, and any inadvertent flow and can be expressed mathematically as:

NSI = Net Generation + Net Interchange + Inadvertent Flows

The outputs of the system, also known as NSI, are the energy sold, energy used by the company, and the system energy losses. This can be expressed mathematically as:

NSI = Total Sales + Company Use + System Energy Losses

Q. How are 'Total Sales' and 'Company Use' output values determined?

A. Total Sales includes all of the Company's retail and wholesale sales of energy. Company Use is the electricity consumed at the Company's non-generation facilities, such as its corporate office building in Kansas City, Missouri. Total Sales data was provided by KCP&L in response to Staff Data Request No. 182. Company Use data was provided by KCP&L in response to Staff Data Request No. 183.

Q. How are the inputs to the electrical system determined?

A. As noted earlier, the inputs to the Company's electrical system are the sum of KCP&L'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. The information I used was obtained from data supplied by KCP&L in response to Staff Data Request Nos. 184 and 74. The difference between scheduled and actual flows on a system is termed inadvertent interchange. This information was provided on a monthly basis in KCP&L's response to Staff Data Request No. 189.

Q. Why are you recommending that the system and class load losses determined in the Company's loss study be used?

A. The study uses the same method to calculate the overall system losses as I did. The study then goes on to determine losses at the transmission, substation, distribution primary, and distribution secondary service levels using engineering methods and estimates. I was able to verify the KCP&L control area as well as the electrical equipment which makes up the KCP&L system used in the study. Next, I verified the soundness of the engineering methods used to determine loss factors at the various service levels. These various service levels ultimately define the various classes.

Q. Are there additional advantages to using the class load loss factors resulting from the Company's study?

A. Yes. Using class load losses is a more accurate depiction of the actual energy losses occurring at the various voltage levels at the transmission, substation, and distribution primary and secondary service levels (classes).

## JURISDICTIONAL ALLOCATION

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, Kansas retail operations and Wholesale operations. The particular allocation factor applied is dependent upon the types of costs being allocated.

## DEMAND ALLOCATION FACTORS

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** | **.5346** |
| **Kansas Retail** | **.4573** |
| **Wholesale** | **.0082** |

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 a designated interval of time that is typically one hour or less.

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 did the Staff use to determine the demand allocation?

A. A methodology known as the four coincident peak (4 CP) methodology was used.

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

A. The term coincident peak refers to the load of each jurisdiction that coincides with the hour of the Company's overall system peak. A 4 CP methodology refers to utilizing the recorded peaks in each of the four (4) peak summer 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, or 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 4 CP methodology.

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

a) The peak hourly loads in the summer months of June, July, August, and September of calendar year 2005 for each jurisdiction were identified and summed.

b) The total peak hourly loads for the summer months of June, July, August, and September of calendar year 2005 were summed for all jurisdictions.

c) The sum for the summer months calculated in (a) was divided by the total sum calculated in (b) for each jurisdiction. 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 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. Please describe the FERC tests you used in your selection of a CP methodology.

A. The following tests included in the aforementioned guidelines (attached as Schedule 3) were used.

<u>Test 1</u> - 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 the KCP&L data?

A. Yes. As illustrated on Schedule 4, the following percentages using the demands recorded for the twelve-month period ending December 31, 2005 were calculated:

**Test 1 -** **28%**

**Test 2 -** **76%**

**Test 3 -** **57%**

Q. Please discuss the significance of these results.

A. The result of the first test (28%) falls within the above-indicated 26%-31% range of results that led to FERC decisions adopting a 4 CP methodology. The result of the second test (76%) is well below the range suggesting a 12 CP methodology (81%-88%) and just slightly below the 78%-81% range of results in FERC decisions adopting a 4 CP methodology. The result of the third test (57%) falls within the 55%-60% range for which the FERC issued decisions adopting a 4 CP methodology. These tests support the usage of the 4 CP method.

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

A. I provided these jurisdictional demand allocation factors to Staff witness Phil Williams.

## ENERGY ALLOCATION FACTORS

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

A. The factors are shown in Schedule 5 and repeated here.

| | |
|---|---|
| **Missouri Retail** | **0.5668** |
| **Kansas Retail** | **0.4243** |
| **Wholesale** | **0.0089** |

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 factors?

A. The energy allocation factor for an individual jurisdiction is the ratio of the adjusted annual kilowatt-hour (kWh) usage in the particular jurisdiction to the total adjusted kWh usage in all jurisdictions. The sum of the energy allocation factors across jurisdictions equals one.

Q. What adjustments were made to these 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 Kim Bolin provided the customer growth adjustment. Please see Ms. Bolin's testimony for a further explanation of this adjustment. These were the same adjustments used in calculating current revenues and the hourly loads input into the fuel and purchased power production cost run.

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

A. I provided these jurisdictional energy allocation factors to Staff witness Phil Williams.

Q. Does this conclude your prepared Direct Testimony?

A. Yes, it does.

# Schedule 1

## Calculation of System Losses in MWh

NSI = Total Sales + Company Use + System Losses
NSI = Net Generation + Net Interchange + Inadvertent Flows
Total Sales + Company Use + System Losses = Net Generation + Net Interchange + Inadvertent Flows

Solving for System Losses:
System Losses = Net Generation + Net Interchange + Inadvertent Flows - Total Sales - Company Use

| | Net Generation | Net Interchange (Off System Purchases - Off System Sales) | Inadvertent Flows | Total Sales to Ultimate Consumers | Company Use | Calculated System Losses | System Loss Factor = System Losses/NSI* |
|---|---|---|---|---|---|---|---|
| Source: | DR # 184 | Ferc Form 1 and Reported 3190 Data | DR # 189 | DR # 182 | DR # 183 | | |
| | 19,613,154.00 | -3,683,286.00 | 251.19 | 15,061,052.00 | 23,611.00 | 845,456.19 | 5.322% |

* NSI data source is DR # 30

| KCP&L 2005 | | Jurisdictional Demand Allocation Factors |
|---|---|---|
| 4CP Totals | | |
| MO Retail | 7100.9 | 0.5346 |
| KS Retail | 6073.9 | 0.4573 |
| Wholesale | 108.3 | 0.0082 |
| LOAD | 13283.1 | |

# A Guide To FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers

*Third Edition*

**Michael E. Small**

*Edison Electric Institute*
WASHINGTON, DC

SCHEDULE 3-1

# 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 confines. *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 3-2

*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 filt, 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.

SCHEDULE 3-3

(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)
(56%—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);

(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)
(81.2%—4 CP);

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

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).

# FERC Tests to Determine Appropriate Allocation Methodology

| | | | | | |
|---|---|---|---|---|---|
| [redacted] | | | | | |
| | This test calculates the difference in the following two averages: Average of monthly system peaks during peak period (June - August) as percentage of annual peak and, | 3320.8 | 0.945497 | 28.05% | [redacted] |
| | Average of system peaks during the remainder of the test period as a percentage of the annual peak | 2335.6 | 0.664993 | | |
| FERC Test # 2 | | | | | |
| | Average of the twelve monthly peaks in the reporting period as a percentage of the annual peak. | 2663.983 | | 75.85% | Results suggest 4CP methodology** |
| [redacted] | | | | | |
| | This test looks at the lowest monthly peak as a percentage of the annual peak: | 0.570355 | | 57.04% | [redacted] |

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

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

***When the percentage falls between 66% and 81%, the FERC typically adopts a 12 CP mehtodology. When the percentage falls between 55% and 60%, the FERC typically adopts a 4CP methodology.

# KANSAS CITY POWER & LIGHT
# COMPONENTS OF ANNUAL NET SYSTEM INPUT
# ER-2006-0314

| | Energy (kwh) w/losses | Large Customer Annualizations | Normalization for Weather | Additional kWh from Cust Growth | Total KCP&L Normalized kWh | Energy Allocation Factors |
|---|---|---|---|---|---|---|
| Mo Retail | 9,048,186,068 | 35,091,217 | -106,330,915 | 28,648,206 | 9,005,594,576 | 0.5668 |
| Non-Mo Retail | 6,741,261,990 | 4,187,176 | -108,604,842 | 105,733,693 | 6,742,578,016 | 0.4243 |
| Wholesale | 143,054,274 | - | -1,534,262 | - | 141,520,012 | 0.0089 |
| Company Use | 24,871,625 | - | - | - | 24,871,625 | |
| NSI | 15,957,373,958 | 39,278,393 | -216,470,019 | 134,381,898 | 15,914,564,230 | 1 |