MISSOURI PUBLIC SERVICE COMMISSION

RATE DESIGN
AND
CLASS COST-OF-SERVICE
REPORT

KANSAS CITY POWER & LIGHT COMPANY
FILE NO. ER-2010-0355

Jefferson City, Missouri
November 24, 2010

****<u>Denotes Highly Confidential Information</u>****

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I. Executive Summary

Staff's Class Cost-of-Service (CCOS) and Rate Design recommendations in this case are that the Commission order Kansas City Power and Light Company (KCPL or Company) to:

1. Eliminate those frozen General Service All-Electric space heating rate schedules where no customers are currently served, retain all other existing rate schedules and implement any revenue requirement increase/decrease resulting from this case as follows:
   a. Allocate the first $13 million of any Commission ordered increase as an equal percentage increase to the rate schedules for the customer classes shown in Table 1 below (Staff's CCOS study results) to have a positive percent (revenue is less than the cost to serve that class).
   b. Allocate any Commission ordered increase above $13 million to all rate schedules on an equal percentage basis.
   c. Allocate any Commission ordered decrease as an equal percentage decrease to the rate schedules for the customer classes shown in Table 1 below to have a negative percent (revenues exceed cost to serve).
2. Implement, with certain modifications, the new "Residential Other Use" (ROU) tariff provision KCPL has proposed.
3. Implement the "Collection Charge" provision KCPL has proposed.
4. Complete its evaluation of Light Emitting Diode (LED) Street and Area Lighting (SAL) systems and, no later than twelve (12) months of the effective date of the Commission's Report and Order in this case, file proposed LED lighting tariff sheet(s) to offer a LED SAL demand-side program, unless KCPL's analysis shows that a LED SAL demand-side program would not be cost-effective. If a LED SAL demand-side program is not cost-effective, update the Staff as to the finding's rationale and file a proposed tariff sheet(s) that would provide LED SAL services at cost to its customers

Staff's CCOS and Rate Design objectives in this case are:

1. To present an overview of Staff's CCOS study and the study results based upon the test year of January 1, 2009, through December 31, 2009, updated and trued-up through December 31, 2010.
2. Provide the Commission with a rate design recommendation based on each customer class's relative cost of service responsibility.
3. Provide methods to implement in rates any Commission-ordered overall change in customer revenue responsibility.
4. Retain, to the extent possible, existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock.
5. Provide the Commission with a recommendation on the ROU tariff provision KCPL has proposed.
6. Provide the Commission with a recommendation on the "Collection Charge" tariff provision KCPL has proposed.
7. Provide the Commission with a recommendation for a high efficiency street and area lighting tariff provision.

Staff's Class Cost-of-Service and Rate Design Report (Report) is organized into six main sections. They are:

- Executive Summary
- Class Cost-of-Service and Rate Design Overview
- Staff Class Cost-of-Service Study
- Rate Design
- Miscellaneous Tariff Issues
- High Efficiency Street and Area Lighting

The results of Staff's CCOS study for KCPL are summarized in Table 1 below. Table 1 shows the rate revenue shifts necessary for the current rate revenues from each customer class to exactly match with Staff's determination of KCPL's cost of serving that class. Staff developed its analysis of the cost of serving each class using inputs taken from the Staff's

Revenue Requirement Cost of Service Report (COS Report) and the Staff Accounting Schedules filed in this case on November 10, 2010.

Table 1
Summary Results of Staff's CCOS Study – KCPL

Customer Class	Revenue Deficiency	CCOS % Increase
Residential		
Regular	$13,026,349	6.79%
All Electric	$2,952,965	6.98%
Separately Metered	$2,813,915	21.27%
Time of Day	$8,871	15.72%
Small General Service		
Primary & Secondary	($9,621,959)	-22.29%
Unmetered	($105,278)	-13.27%
All Electric	($185,792)	-10.05%
Separately Metered	$86,524	11.99%
Medium General Service		
Primary	($280,808)	-27.39%
Secondary	($4,019,039)	-5.20%
All Electric	$335,748	3.45%
Separately Metered	$281,706	14.96%
Large General Service		
Primary	($3,034,768)	-20.63%
Secondary	($7,537,361)	-9.53%
All Electric	$3,567,970	6.27%
Separately Metered	$511,503	11.36%
Large Power Service		
Primary	$3,471,774	4.76%
Secondary	$2,382,626	9.62%
Substation	$2,914,744	15.02%
Transmission	($239,433)	-4.94%
Lighting		
Lighting	($359,350)	-4.32%
Total	$6,970,906	1.04%

The results of a CCOS study can be presented either in terms of (1) the rate of return realized for providing service to each class or (2) in terms of the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class. Staff prefers to present its results in the latter format, i.e., negative or positive dollar amounts or percentages. The results of Staff's analysis are presented in terms of the shifts in revenue that produce an equal rate of return for KCPL from each customer class.

A negative amount or percentage indicates revenue from the customer class exceeds the cost of providing service to that class; therefore, to equalize revenues and cost of service, rate revenues should be reduced, i.e., the class has overpaid. A positive amount or percentage indicates revenue from the class is less than the cost of providing service to that class; therefore, to equalize revenues and cost of service, rate revenues should be increased, i.e., the class has underpaid.

Staff's customer classes correspond to KCPL's current rate schedules, except that all lighting rate schedules were combined into one customer class. Aside from lighting rate schedules, KCPL has twenty rate schedules: four Residential (RES) rate schedules, four Small General Service (SGS) rate schedules, four Medium General Service (MGS) rate schedules, four Large General Service (LGS) rate schedules, and four Large Power Service (LPS) rate schedules. Staff's customer classes are shown above in Table 1 above.

Staff's revenue shift, increase and decrease recommendations are designed to bring each customer class closer to its cost of service. Based on Staff's CCOS study results, Staff recommends that each customer class with a negative revenue shift percentage (revenue exceeds the cost to serve) receive no rate increase for any Commission ordered increase up to and including $13 million. Furthermore, for any increase above $13 million, Staff recommends that the additional amount above $13 million be allocated to all customer classes on an equal percentage basis. The impact of the $13 million on the customer classes with a positive revenue shift percentage (revenues less than cost to serve) would be an increase in their rates of approximately 1%. If the Commission's ordered increase is $13 million or less, customer classes with a positive revenue shift percentage (revenues exceed cost to serve) should have their rates increased on an equal percentage basis. If the Commission orders a revenue decrease, Staff recommends that the Commission allocate the decrease based on an equal percentage basis to the customer classes where revenues exceed cost to serve.

Staff's recommended customer class revenue adjustments would bring each customer class closer to KCPL's cost to serve that class while still maintaining rate continuity, rate stability, and revenue stability; and minimizes rate shock to any customer class.

II. Class Cost-of-Service and Rate Design Overview

The purpose of a CCOS study is to determine whether each class of customers is providing the utility with a level of revenue reasonably necessary to cover (1) the utility's investments required to provide service to that class of customers and (2) the utility's ongoing expenses to provide electric service to that class of customers. A CCOS study provides a basis for allocating and/or assigning to the customer classes the utility's total jurisdictional cost of providing electric service to all the customer classes in a manner which best reflects cost causation. Since those jurisdictional costs equate to the utility's jurisdictional revenue requirement, the results of a CCOS study determine class revenue requirements based on the cost responsibility of each customer class for its equitable share of the utility's total annual cost of providing electric service within a given jurisdiction - Missouri retail in this case.

Appendix A provides fundamental concepts, terminology, and definitions used in CCOS studies and rate design. It addresses functionalization, classification, and allocation as used in CCOS studies. It lists generation allocation methods outlined in the National

Association of Regulatory Utility Commissioners ELECTRIC UTILITY COST ALLOCATION MANUAL, January 1992 (NARUC Manual) and provides Staff's descriptions of the strengths and weaknesses of some of the more common allocation methods used in CCOS studies.

III. Staff's Class Cost-of-Service Study

The Stipulation and Agreement the Commission approved in Case No. EO-2005-0329 (Regulatory Plan) contemplated up to four rate filings during the construction of Iatan 2, a new coal unit primarily owned by KCPL anticipated to be completed in 2010.[1] This case, File No. ER-2010-0355, is the fourth and final rate filing contemplated in the KCPL Regulatory Plan. The Regulatory Plan required KCPL to perform a CCOS study for the first filing, but the Regulatory Plan did not permit any new or updated CCOS studies by any of the signatories to the Regulatory Plan in the optional second and third rate filings. The Regulatory Plan is silent regarding CCOS studies for this, the last rate filing under the plan. However, in KCPL's last rate case, Case No. ER-2009-0089, KCPL entered into a Non-Unanimous Stipulation and Agreement the Commission approved effective June 23, 2009, in which KCPL committed to file a CCOS study with the Commission by December 31, 2009. Staff anticipated then that KCPL's CCOS study would be based on data associated with KCPL's fourth rate case filing under the Regulatory Plan. However, KCPL did not make its fourth filing under the Regulatory Plan until June 4, 2010, so on December 30, 2009, KCPL filed in Case No. ER-2009-0089 an updated version of the CCOS study it filed in its first Regulatory Plan rate case filing, Case No. ER-2006-0314. KCPL filed a new CCOS study in this case in its direct filing. The results of Staff's CCOS study appear in Table 1 above and are outlined

[1] The first of the four rate filings, Case No. ER-2006-0314, and this rate filing, File No. ER-2010-0355, were mandated by the Regulatory Plan. The second and third filings, Case Nos. ER-2007-0291 and ER-2009-0089, were optional. Iatan 2 met the applicable in-service criteria in August, 2010.

in Schedule MSS-1. Both show the changes to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with KCPL's cost to serve that class. The results are also presented, on a revenue neutral basis, as the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class.

Revenue neutral means that the revenue shifts among classes do not change the utility's total system revenues. Staff finds the revenue neutral format aids in comparing revenue deficiencies between customer classes and makes it easier to discuss revenue neutral shifts between classes, if appropriate. Staff calculated the revenue neutral percent increase to a class's rate revenue by subtracting the overall system average increase of 1.04% from each customer class's required percentage increase to rate revenue to match the revenues KCPL should receive from that class to match KCPL's cost to serve that class.

For example, based on Schedule MSS-1, on a revenue neutral basis, the Residential - Regular customer class is providing 6.79% fewer revenues to KCPL than KCPL's cost to serve that class. Also, the SGS Primary and Secondary customer class is providing 22.29% more revenues to KCPL than KCPL's cost to serve that class. Staff's CCOS study results for all twenty-one of the customer classes Staff used for KCPL are presented in Schedule MSS-1.

Because a CCOS study is not precise it should be used only as a guide for designing rates. In addition, bill impacts need to be considered. While reducing over collection from customer classes with negative revenue shift percentages (revenues greater than cost to serve)—for KCPL customer classes on the SGS, MGS, and LGS rate schedules—to zero is appealing, the bill impact on the customer classes with positive revenue shift percentages must be considered—for KCPL, customer classes on the RES and LPS rate schedules. Based on its study results and judgment, Staff recommends revenue adjustments to all KCPL rate schedules.

Staff's CCOS study used costs and revenues from Staff's accounting information and other sources as outlined below:

A. Data Sources

Staff's CCOS study is a continuation of the Staff's revenue requirement position as filed on November 10, 2010, through Staff's direct revenue requirement cost of service recommendation for KCPL's Missouri jurisdictional retail cost of service. This data includes:

- Adjusted Missouri Jurisdictional Investment and cost data by FERC account;
- Annualized, Normalized Rate Revenues;
- Fuel and Purchase Power costs;
- Other operating and maintenance expenses;
- Depreciation and Amortizations;
- Taxes; and
- Off-System Sales.

In addition, data was also obtained from KCPL witness Paul Normand's Direct Testimony and Workpapers from this case, which include:

- Customer Demand Splits;
- Customer Coincidental Peaks per rate schedule;
- Customer Non-Coincidental Peaks per rate schedule;
- Customer Maximums per rate schedule;
- Annual Energy per rate schedule; and
- Certain other allocation factors for specific customer allocations (CUST4, CUST5, CUST6, CUST10, CUST 18, CUST21). These relate to information on services, meters, meter reading, uncollectible accounts, customer premise installations, and customer deposits.

B. Classes and Rate Schedules

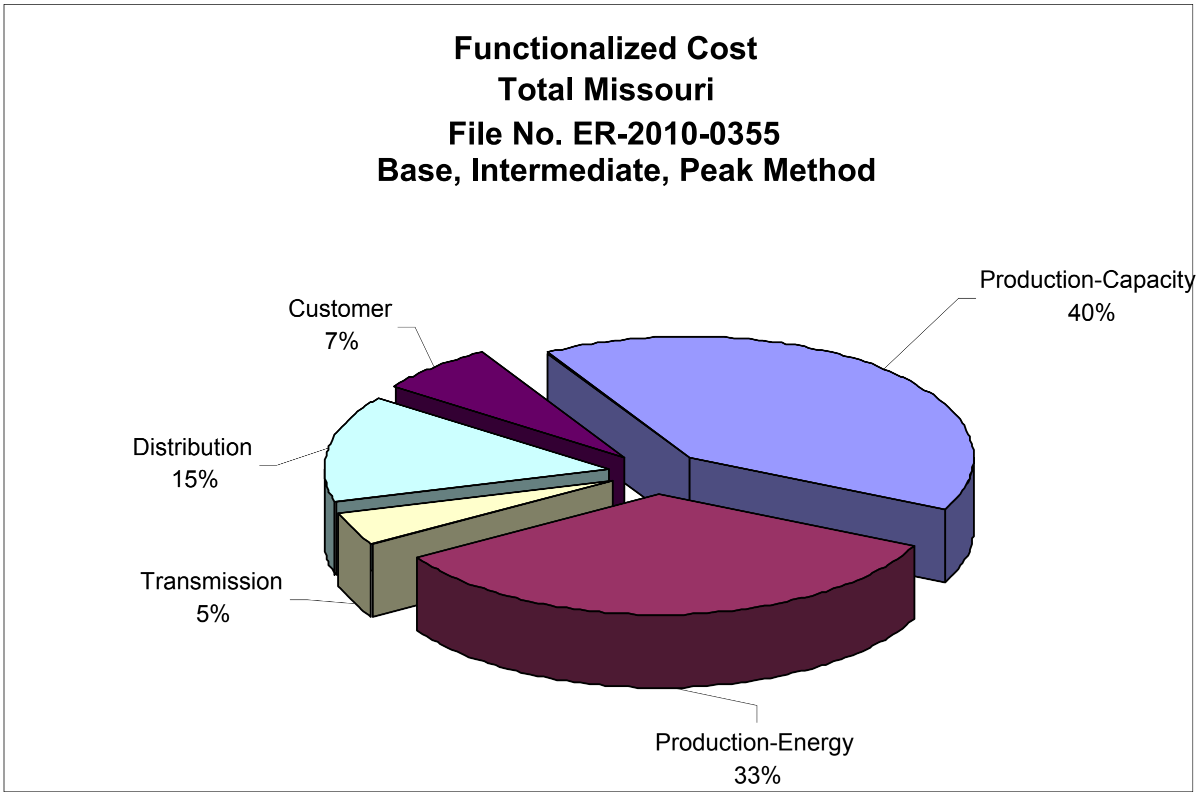
KCPL currently provides service to its customers in a number of rate classifications that are designated for residential or non-residential service and are listed in Table 1 above. The non-residential customer groups are differentiated by voltage level and/or by all electric or separately metered service.

C. Functions

The major functional cost categories Staff used in its CCOS study are Production, Transmission, Distribution, and Customer. Within the Production Function, a distinction was made between "Production-Capacity" and "Production-Energy." Production-Capacity is allocated by designated base plants, intermediate plants, and peaking plants. The designated plants for each group (base, intermediate, and peak) is allocated to each customer class based on plant investment and costs associated with the usage characteristics of the customers in the class.

Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, a portion of production plant maintenance expenses and the energy portion of net interchange power costs. The chart below shows for KCPL the percentage of total costs associated within each major function.

Table 2



The Production Function (combination of Production-Capacity and Production-Energy) is the single largest cost component, and represents 73% of the total cost. The Distribution Function, at 15% of the total cost, is the second largest contributor to total cost, and includes substations, overhead and underground lines, and line transformers, as well as the costs to operate and maintain this equipment. Customer Services at 7% and Transmission at 5% round out the total cost. Schedule MSS-2 provides a detailed description of each external allocation factor Staff used in its CCOS study.

D. Allocation of Production Costs

Allocators are used to distribute the functionalized costs to the classes. The production investment and costs comprise approximately 73% of the functionalized investment and cost. Both the demand and energy characteristics of KCPL's load are important determinants of production investment and costs, since production must produce output to satisfy periods of normal use and intermittent peak use throughout the year. These functionalized costs are 1) Production–Capacity and 2) Production–Energy.

Staff allocated Production–Capacity costs and Production-Energy fuel costs based on a Base-Intermediate-Peak (BIP) method. The BIP method is based on recognition that capacity requirements are an important determinant of production–capacity investment and costs. With the BIP method the utility company's required investments and the ongoing expense of providing service are allocated based on:

1. A base component consisting of the annual energy attributable to a given customer class;
2. An intermediate component consisting of the average 12 Non-Coincident Peaks (NCP)[2] of demand for electricity for a given class minus the base component previously allocated; and
3. A peaking component consisting of the average 4 NCP[3] component of demand for electricity less the base and intermediate components previously allocated.

The BIP method is described in the NARUC Manual. The NARUC Manual describes the BIP method as a time-differentiated method that assigns production plant costs to three rating periods (1) peak hours, (2) secondary peak, or intermediate hours, and (3) base loading hours. In the BIP method, generating units are ranked from lowest to highest based on operating costs. The lowest operating cost units are considered base load units. Generally, base load units have high capital costs, generally take five to ten years to build and have low, constant running costs. Because of this, these units run almost continuously, except for when

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[2] 12 NCP is each month's maximum peak demand of each customer class at any time during the months of January through December.

[3] 4 NCP is each month's maximum peak demand of each customer class during June, July, August, and September

they need maintenance. Because base load units operate regardless of peak requirements, they are appropriately classified as energy-related.[4] Intermediate units, those with capital costs and operating characteristics between those of base load units and peaking units, serve a dual purpose in that they are partially energy-related and partially-demand related.[5] Older coal units sometimes are in this category. Gas–fired combined cycle units are also generally considered intermediate units. Peaking units have low capital costs, are relatively quick to build—typically twelve to eighteen months—but are costly to run. It is most cost effective to only run these units for the few hours of the year when the system load is the highest. The output of peaking units is most effectively used when it is changed to follow the energy requirements of the system on a real-time basis.

KCPL operates and maintains generating units that are required to provide both capacity and energy for its customers throughout the year. Prudency requires that KCPL operate and maintain these units in a manner that minimizes the overall cost for it to produce safe and reliable electricity for its customers through a mix of generating units that best fits the load on KCPL's system, both instantaneously and over time.

In order to recognize the generating units in an equitable manner, for purposes of its CCOS study, Staff reviewed the energy produced at each unit—anticipated energy output for Iatan 2 and Spearville 2, based on the normalized and annualized capacity and energy produced by each generating unit. Staff then classified each generating unit as a base, intermediate, or peak load requirement to satisfy periods of normal use and intermittent peak

[4] **Energy-related**: Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, a portion of production plant maintenance expenses and the energy portion of net interchange power costs.

[5] **Demand-related:** Demand–related costs are rate base investment and related operating and maintenance expenses associated with facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption.

use throughout the year. This review resulted in grouping KCPL's generating units into base, intermediate, and peak categories. The category groupings are summarized below and provided in detail in Schedule MSS-3:

- Base generating units – First generating units available to meet KCPL's base load requirements. The base generating units consist of Wolf Creek nuclear plant, wind plants, and most efficient coal plants.
- Intermediate generating units – Generating plants that would be used to meet additional load requirements after the dispatch of base units. The intermediate generating plants consist of KCPL's older coal plants.
- Peak generating units – generating units that would be used to meet peak load requirements to satisfy capacity loads in any hour. The peak generating plants consist of KCPL's combustion turbine plants.

The BIP method Staff used to allocate Production-Capacity costs is based on a recognition that generation is built to meet both peak demands and energy usage. The basic components of the BIP method are:

1. A portion of the total Production-Capacity costs is allocated to each customer class based upon that class's contribution to annual energy. This portion is classified as the base peak portion;
2. A portion of the total Production-Capacity costs is allocated to each customer class based upon that class's contribution to intermediate peak demand. Because for each class the portion allocated to it includes the base portion allocated to the class, the base portion allocated to the class is subtracted; and
3. A portion of the total costs allocated to each class based upon each class's contribution to the peak demand. Because for each class the portion allocated to it includes both the base portion and the intermediate portion allocated to it, the base and intermediate portions allocated to the class is subtracted.

The first step of the BIP method is to evaluate the system monthly loads of the test period. A listing of monthly peak loads, Table 3 below, helps to define the twelve months in terms of a peak season and a non-peak season. KCPL is a summer peaking utility (see Table 3) with the system four highest monthly coincident peaks occurring in the summer season (June through September).

Table 3

KCPL Coincident System Peak @ Generation (kW)		
Month	kW Peak	% of Annual Peak
Jan-09	1,474,583	74.4%
Feb-09	1,354,825	68.3%
Mar-09	1,216,821	61.4%
Apr-09	1,107,217	55.8%
May-09	1,336,333	67.4%
Jun-09	1,756,557	88.6%
Jul-09	1,978,997	99.8%
Aug-09	1,982,705	100.0%
Sep-09	1,565,830	79.0%
Oct-09	1,095,941	55.3%
Nov-09	1,266,392	63.9%
Dec-09	1,469,600	74.1%

In the BIP method, the base allocator (B portion of BIP method) is calculated on each class's annual kWh usage at generation in the test year. This level of demand formed the basis to allocate the capacity requirements to each customer class for production investment and costs. The intermediate piece (I portion of BIP method) involves using the average of the 12 NCP for the intermediate piece. The NCP demand is defined as the maximum monthly peak demand of each customer class at any time during the study period, and it may or may not fall on the same hour as the system peak for that month. The intermediate portion is determined by the intermediate peak less the base portion already allocated to the various classes. The final step is to determine the peak portion (P portion of BIP method) for allocation to the various classes. The peak portion is allocated to the various classes based on each class's share of the summer peak less the base and intermediate portion already allocated to the various classes. Staff used the four summer months during the test year for calculating the Production–Capacity cost allocator, since the four highest peaks are in excess of the winter load requirements.

The BIP method takes into consideration the differences in the capacity/energy cost trade-off that exists across a company's generation mix. The BIP methodology gives weight to both considerations. It does so by considering energy in the base component through the allocation of base units to all classes and by considering capacity in the allocation of intermediate and peak components. For these reasons, Staff recommends using the BIP method for production investment and for production costs for KCPL. This is the same methodology KCPL used in its direct filing. Staff explains the BIP method further, and addresses other production methods from the NARUC Manual, in attached Appendix A (Appendix A – p. 12). The BIP method is outlined in the NARUC Manual in Part IV C Section 2. Schedule MSS-4 details the BIP method as described in the NARUC Manual.

E. Allocation of Transmission Costs

KCPL's transmission investment and transmission costs comprise approximately 5% of the functionalized investment and costs Staff allocated to the customer classes. KCPL's transmission system consists of highly integrated bulk power supply facilities, high voltage power lines and substations that transport power to other transmission or distribution voltages. Staff allocated Transmission investment and costs to the customer classes on a 12 coincident peak (12 CP) basis. Staff recommends the 12 CP allocation method for this purpose because by including periods of normal use and intermittent peak use throughout all twelve months of the year it takes into account the needs for a transmission system that is designed both to transmit electricity during both peak loads and also to transmit electricity throughout the year.

F. Allocation of Distribution Costs

Voltage level is a factor that Staff considered when allocating distribution costs to customer classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level needs of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, substation, or transmission level voltages. Transmission facilities are utilized by all customers. Therefore, all customer classes are allocated a portion of transmission investment and costs.

Only those customers in customer classes served at substation voltage or below (i.e., all substation, primary and secondary customers) were included in the calculation of the allocation factor for distribution substations. Staff used the annual class peak of these customer classes to allocate substation costs, because it includes the appropriate level of diversity at the distribution substation.

Staff allocated the costs of the primary distribution facilities on the basis of each customer class's annual peak demand measured at primary voltage. All customers, except those served at transmission level, (i.e., primary and secondary customers) were included in the calculation of the primary distribution allocation factor, so that distribution primary costs were allocated only to those customers that used these facilities. Staff used the annual customer class peak to allocate primary costs because it represents the appropriate level of diversity at the distribution primary voltage.

Load diversity is a condition that exists when the peak demands of customers do not occur at the same time. The spread of individual customer peaks over time within a customer class reflects the diversity of the class load, and should be used to allocate facilities that are shared by groups of customers. Load diversity is important in allocating demand-related distribution costs because the greater the amount of diversity among customers within a class or among classes, the smaller the total capacity (and total cost) of the equipment required for the utility company to meet those customers' needs. Therefore, when allocating demand-related distribution costs, it is important to choose a measure of demand that corresponds to the proper level of diversity. The following table summarizes the type of demands Staff used for allocating the demand-related portions of the various distribution function categories.

Table 4
Allocation of Demand Related Distribution Facilities

Functional Category	Demand Measure	Amount of Diversity
N/A	Coincident Peak	High
Substations	Class Peak	Moderate to High
Primary	Class Peak	Moderate to High
OH/UG Conduits/Conductors	Diversified Demand	Low to Moderate
Line Transformers	Diversified Demand	Low to Moderate

Coincident peak demand is defined as the demand of each customer class and each customer at the hour when the overall system peak occurs. Coincident peak demand reflects the maximum amount of diversity, because most customer classes are not at their individual class peaks at the time of the coincident peak. Class peak demand, which is defined as the maximum hourly demand of all customers within a specific class, often does not occur at the same hour as the coincident peak (system peak). Although, not all customers peak at the same time (diversity), a significant percentage of the customers in the class will be at or near their peak in order to achieve the class peak. Therefore, class peak demand will have less diversity than the coincident peak.

Diversified demand is the weighted average of the class's customer maximum demand and its annual maximum class peak demand. As constructed, diversified demand has less diversity than the class peak, but more diversity than the customer maximum demand. Customer maximum demand has no diversity. It is defined as the sum of the annual peak demands of each customer, whenever it occurs. If there is no sharing of equipment, there is no diversity.

Staff recommends allocating the costs of distribution secondary and line transformers on the basis of diversity factors which include each class's annual peak demand and customer maximum demands. Only secondary customers served at the secondary voltage level were included in the calculation of the allocation factor, so that distribution secondary costs were allocated only to those customers that use these facilities.

KCPL conducted special studies to split the cost of poles, towers, fixtures; and overhead (OH) and underground (UG) distribution lines between the portions that are primary and secondary related.

Staff recommends allocating meter costs using KCPL's CUST5 allocator. This allocator is based on a KCPL study that weights the meter investment by class, and by the cost of the meter used to serve that class.

G. Allocation of Customer Service Costs

Customer-related costs are minimum costs necessary to make electric service available to the customer, regardless of the electric service utilized. Examples of such costs include meter reading, billing, postage, customer accounting, and customer service expenses.

Staff recommends using KCPL's allocators CUST6 for allocating meter reading costs, CUST10 for allocating uncollectible accounts, and CUST21 for allocating customer deposits.

These three allocators are derived in KCPL's studies that directly assign the costs of meter reading, uncollectible accounts, and customer deposits to the customer classes. The allocators CUST6, CUST10, and CUST21 are the fraction of total costs of meter reading, uncollectible accounts and customer deposits assigned to each class, respectively. Staff allocated other customer service accounts on unweighted customer counts or according to KCPL's CCOS study.

H. Revenues

Operating revenues consists of two components: the revenue that the utility collects from the sales of electricity to Missouri retail customers (rate revenue); and the revenue the utility receives for providing other services (other revenue). Rate Revenues are also used in developing Staff's rate design proposal and will be used to develop the rate schedules required to implement the Commission's ordered revenue requirement and rate design for KCPL in this case. Rate Revenues in Staff's Cost-of-Service Revenue Requirement Report filed November 10, 2010, were used to obtain KCPL's normalized and annualized rate revenues. The Total Rate Revenues as shown in the Rate Revenue Summary in Staff's Accounting Schedules filed on November 10, 2010 is $669.5 million.

Other Electric Revenues of $101.5 million were also allocated to the rate classes using Staff's Production-Energy and other cost allocators.

Staff Expert: Manisha Lakhanpal and Michael S. Scheperle

IV. Rate Design

Staff's rate design objectives in this case are:

- Provide the Commission with a rate design recommendation based on each customer class's relative cost of service responsibility.

- Provide methods to implement in rates any Commission-ordered overall change in customer revenue responsibility.
- Retain, to the extent possible, existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock.
- Provide the Commission with a recommendation on the ROU tariff provision KCPL has proposed.
- Provide the Commission with a recommendation on the "Collection Charge" tariff provision KCPL has proposed.
- Provide the Commission with a recommendation for a high efficiency street and area lighting tariff provision.

Staff's rate design recommendations in this case are that the Commission order KCPL to:

1. Eliminate those frozen General Service All-Electric space heating rate schedules where no customers are currently served, retain all other existing rate schedules and implement any revenue requirement increase/decrease resulting from this case as follows:
    a. Allocate the first $13 million of any Commission ordered increase as an equal percentage increase to the rate schedules for the customer classes shown in Table 1 (Staff's CCOS study results) to have a positive percent (revenue is less than the cost to serve that class).
    b. Allocate any Commission ordered increase above $13 million to all rate schedules on an equal percentage basis.
    c. Allocate any Commission ordered decrease as an equal percentage decrease to the rate schedules for the customer classes shown in Table 1 to have a negative percent (revenues exceed cost to serve).
2. Implement, with certain modifications, the new ROU tariff provision KCPL has proposed.
3. Implement the "Collection Charge" provision KCPL has proposed.
4. Complete its evaluation of LED SAL systems and, no later than twelve (12) months of the effective date of the Commission's Report and Order in this case, file proposed LED lighting tariff sheet(s) or state to the Commission when it will file them.

Current Rate Schedules

The residential rate schedules consist of the following elements:

- Regular Rate Schedule
- Separate All Electric Rate Schedules (one or two meters)
- Residential Time of Day rate schedule
- Customer Charge $ per month
- Energy Charge $ per kWh by kWh rate block by season

The non-residential, non-lighting rate schedules consist of the following rate groups and rate elements:

- Small General Service (SGS) rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)
- Medium General Service (MGS) rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)
- Large General Service (LGS) rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)
- Large Power Service (LPS) rate schedules (secondary, primary, substation, transmission)
- Two Part – Time of Use rate schedule
- Customer Charge $ per month
- Facilities Charge $ per kW of facilities demand
- Demand Charge $ per kW of billed demand
- Energy Charge $ per kWh by hours use rate block
- Reactive Charge $ per kVar (MGS, LGS, LPS)

The difference between the rate structure of the standard rate schedules and rate structures of the companion All-Electric rate schedules is the treatment of electric space heating. The General Service All-Electric rate schedules are frozen (grandfathered) where the Commission has restricted the availability of the All Electric and Separately Metered Space Heating rate schedules to customers currently served on one of those rate schedules, but only for so long as the customer continuously remains on that rate schedule.

Important Rate Design Features

Within each rate schedule, demand and energy rates should continue to be seasonally differentiated (i.e., summer rates are higher than winter rates). The remaining rates (customer, facilities, reactive) should be constant year-round.

The rate schedules should continue to reflect any cost difference associated with service at different voltage levels (i.e., losses and facilities ownership by customers).

The customers who belong to the residential class and the lighting class are well defined. The remaining customers generally belong to one of four main rate groups based upon their load and cost characteristics. A typical customer in each of the rate groups can be described as follows:

- SGS: very small (under 25 kilowatt kW) commercial or industrial customers with low load factor (average demand divided by peak demand); almost always served at secondary voltage (99.9%).
- MGS: medium size (25 kW – 200 kW) commercial or industrial customer with moderate load factor; customer must have, or be willing to assume, a 25kW minimum demand; 99% are metered at secondary and 1% are metered at primary voltage.
- LGS: large size (200 kW – 1000 kW) commercial or industrial customer with higher load factor; customers must have, or be willing to assume, a 200kW minimum demand; 92% are served at secondary and 8% are served at primary voltage.
- LPS: very large size (above 1000 kW) commercial or industrial customer with very high load factor, customer must have, or be willing to assume, a 1000 kW minimum demand; 37% are served at secondary, 57% at primary, 4% at substation and 2% are served at transmission voltage level.

For its CCOS study Staff broke the above rate groups into the four separate rate schedules within each for the customer classes it used in the study, with the exception of the lighting class which is all customers taking service on any lighting rate schedule. The Staff's CCOS study provided the investment and costs associated for KPCL to provide service to the Lighting class.

Currently KCPL has no customer taking service on the frozen SGS – Primary All-electric rate schedule, and per Commission order, it cannot serve any new customer on that schedule. Therefore, Staff recommends the Commission order KCPL to eliminate this General Service rate schedule.

KCPL has proposed a new rate schedule titled, ROU. Staff recommends the Commission, after certain modifications are made, order KCPL to implement that rate schedule. Schedule ROU applies to residential customers who do not qualify under any other residential rate. A prospective customer who would qualify for this rate schedule generally will be one with well pumps, barns, machine sheds, detached garages or a home workshop, whose meter is not connected to a single or multiple occupancy dwelling unit. KCPL proposes seasonal customer charges and seasonal energy charges. The KCPL proposed ROU is similar to KCP&L Greater Missouri Operations Company's (GMO) rate schedule for similar services. However, Staff proposes that instead of being tied to KCPL's SGS rate component the seasonal customer charge be tied to KCPL's residential customer rate component. The SGS rate component includes a meter with "hours of use" based on demand (kW) meter functionality along with a kWh (energy) meter functionality. The ROU customer will only need a meter with kWh functionality. This will reduce the fixed costs to serve the customer to be approximately the same as the fixed costs to serve residential customers. Therefore, Staff recommends that the customer charge for the ROU rate schedule be the same as the regular residential customer charge.

Staff Expert: Michael S. Scheperle

V. Miscellaneous Tariff Issues

Minor Changes, and Errors identified for P.S.C. MO. No. 7 (Rates)

Staff recommends the following modifications to certain of KCPL's tariff sheets:

1. All Sheets – Footer: "Curtis D. Blanc, Sr. Director" change to "Senior Director" [appears to be Curtis D. Blanc, Sr.]
2. Sheet No. TOC-1 – add "Residential Other Use, Schedule ROU"; delete "Incremental Energy Rider, Schedule IER"
3. Sheet Nos. 14A, 14B – add summer and winter rate headings
4. Sheet Nos. 30 – 37G, header – change "Rate Area No. (1)(3) – Urban Area" to "Missouri Retail Service Area"
5. Suggestion: Sheet No. 33, Private Lighting – insert "1¾%" after the words in next to last paragraph
6. Sheet Nos. 35, 35A – move "Limited to the units in service on April 18, 1992, until removed" from 35A to 35; Sheet No. 35 – change "*" to"(2)" Twin lamps shall ….; Sheet No. 35A – delete "RATE (Optional Equipment): (continued)"
7. Sheet No. 35B - change "*" to"(1)" at end of paragraph 10.0; add footnote "(2) Limited to the units in service on May 4, 2011, until removed" to paragraph10.1
8. Sheet No. 37B – add "This basic … continuously thereafter." and "North Kansas City 23rd and Howell, 23rd and Iron"; ERROR: need period at end of (6) last paragraph
9. Sheet No. 37G – add "(18) <u>Traffic Signal Pole</u>."

Minor Changes for P.S.C. MO. No. 2 (Rules)

Staff recommends the following modifications to certain of KCPL's tariff sheets.

1. Sheet No. 1.17 - header – change "Rate Area No. (1)(3) – Urban Area" to "Missouri Retail Service Area"; under 4.10 Tampering With Company Facilities – add "or

unauthorized use" and "associated" and "including, but … charges, and" – delete "the" and "for".

2. Sheet No. 1.28 – add section heading "8. Billing And Payment (continued)"

Incremental Energy Rider, Schedule IER

Staff supports deleting rate schedule entitled "Incremental Energy Rider, Schedule IER" as proposed by KCPL presently on Sheet Nos. 24, 24A, 24B. KCPL currently has no customers on this rate schedule. KCPL proposes the three tariff sheets become "Reserved For Future Use".

Municipal Street Lighting Service, Schedule 1-ML: RATE (Mercury Vapor) 7.0, 7.1

Staff supports deleting street light entitled "RATE (Mercury Vapor) 7.0, 7.1" as proposed by KCPL presently on Sheet No. 35. KCPL currently has no customers on this lighting schedule.

Collection Charge

Staff supports adding rule 8.08 entitled "Collection Charge" as proposed by KCPL on Sheet No. 1.28. KCPL proposes to implement a fee of $25.00 for customer collection by a field service person making a final collection attempt at the meter location prior to the meter to be disconnected for non-payment. The fee is consistent with collection charges of other regulated electric utilities.

Staff Expert: William (Mack) L. McDuffey

VI. High Efficiency Street and Area Lighting

Staff recommends that the Commission order KCPL to complete their evaluation of LED SAL systems and to file a proposed LED lighting tariff(s) no later than twelve (12) months following its Report and Order approving tariff sheets in this case or an update to the Commission on when it will file a proposed LED lighting tariff(s).

A. Current Street Lighting for KCPL Missouri

Currently, the Missouri jurisdictional operations of KCPL has approximately 89,800 SAL systems for 56 public street and highway lighting customers in its service territory, using a total of about 70,000 MWh according to its 2009 Annual Report. The KCPL currently approved lighting tariffs consist of: (1) private unmetered protective lighting service (Schedule AL), (2) municipal street lighting service (Schedule 1-ML and Schedule 3-ML), and (3) off-peak lighting service (Schedule OLS). The rates in Schedule AL, 1-ML, and 3-ML include the installation and maintenance costs of the lighting, in addition to the energy costs. Most of KCPL's SAL systems are owned by the City of Kansas City, Missouri[6] which takes service under Schedule OLS. Virtually all of the existing installed lighting in the City of Kansas City area are high pressure sodium (HPS) lamps, which were determined the most efficient available technology for the SAL at the time most of these SALs were installed.

B. An Alternative for the SAL System: LED Lighting

The LED lighting system is the most energy efficient SAL fixtures available today. LED advantages over traditional high-intensity discharge (HID) lamps and HPS lamps include improved efficiency and longer lamp life. Other advantages of LED street lights include:

- Improved night visibility due to higher color rendering, higher color temperature and increased luminance uniformity;
- Reduced maintenance costs;
- No mercury, lead or other known disposable hazards; and
- An opportunity to implement programmable controls (e.g. bi-level lighting)[7]

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[6] The City of Kansas City has 82,894 SAL in January, 2010 which is over 92% of SAL in KCPL's service territory.

[7] http://www.pge.com/mybusiness/energysavingsrebates/rebatesincentives/ref/lighting/lightemittingdiodes/streetlightprogram.shtml

C. Studies from Other Utilities and Municipalities

The Pacific Gas and Electric Company (PG&E) offers a LED Street Light Program to non-metered customer-owned street LED lights based on PG&E's LS-2 rate.[8] In PG&E's LED Street Light Program, customers have two types of incentives for replacing traditional (HID and HPS) street lights billed at a fixed LS-2 rate with LED fixtures. First, customers who have installed or replaced existing street light fixtures with LED fixtures are able to switch to a lower billing rate under LS-2 rate schedule. Second, customers who perform such replacements will be eligible for a rebate for every qualified LED fixture purchased and installed.[9]

Southern California Edison (SCE) offers not only a LED street light rate to non-metered customer-owned street lights based on SCE's LS-2 rate[10], but also a 'Midnight' service[11] rate for a programmable lighting system that can turn off or dim at a designated time such as 10 p.m. until 5 a.m., within all of their outdoor lighting tariffs.

The challenge for cities regarding their SAL networks is to increase the quality of lighting service to the community while reducing its operating costs. While citizens consider streetlights a critical safety and public service and complain loudly about lamp failures, they also want city governments to reduce operating budgets. In the last couple of years, hundreds of cities[12] have launched pilot LED SAL programs including some cities in Missouri such as Columbia, Independence, and Springfield.

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[8] See PG&E's LS-2 rate schedule at http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_LS-2.pdf

[9] See PG&E's LED Street Light Rebates at http://www.pge.com/mybusiness/energysavingsrebates/rebatesincentives/ref/lighting/lightemittingdiodes/incentives/index.shtml

[10] See SCE's LS-2 rate schedule at http://www.sce.com/NR/sc3/tm2/pdf/ce37-12.pdf

[11] Robert Wagner from the International Dark-Sky Association mentions as 'Voluntary Part-Night Rates' for outdoor lighting in Case No. ER-2010-0355 and Case No. ER-2010-0356.

[12] http://newstreetlights.com/index_files/New_Streetlights_News_100.htm

D. KCPL and GMO's LED SAL Research13

KCPL and GMO are collaborating with the Electric Power Research Institute (EPRI) to test and evaluate the potential of currently available LED lighting. The issues that need to be addressed are system compatibility, technology performance, validating industry performance claims and efficacy issues. In particular, assuming the lamps perform reliably, the efficacy of the lamps will determine the total energy savings possible.

EPRI's LED SAL collaboration project involves a test site where HID lighting is being replaced with LED lighting. As a project participant, KCPL and GMO are involved in the quarterly project measurement process to take readings of the pre-installation HID lighting and the post-installation LED lighting. In addition to testing the efficacy of the LED lighting, the quarterly observations will provide information about degradation, spectrum shift, and reliability and maintenance issues. A significant part of the operating cost savings from LED lighting comes from the reduced need for maintenance and monitoring. The quarterly monitoring will continue until spring 2012, at which time the project will close and a final report will be produced. This report will address the many concerns surrounding the adoption of LED street lighting.

Through data requests responses from KCPL and GMO, Staff has learned that in addition to the EPRI collaboration, KCPL and GMO are conducting a LED pilot program with five (5) area communities where similar test sites will be evaluated using various lighting manufacturers. KCPL and GMO are also evaluating LED incentives within the tariffs of other utilities and will be using the pilot sites to help determine the potential structure of LED lighting tariffs on their system.

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[13] Based on the Data Request No. 0509 for Case No. ER-2010-0355 and on the Data Request No. 0333 for Case No. ER-2010-0356.

E. Staff Recommendation

Staff recommends that the Commission order KCPL to complete its evaluation of LED SAL systems and to file a proposed LED lighting tariff(s) no later than twelve (12) months following its Report and Order approving tariff sheets in this case or an update to the Commission on when it will file a proposed LED lighting tariff(s). Staff is not recommending that KCPL offer a LED SAL demand-side program unless KCPL's analysis shows that a LED SAL demand-side program would be cost-effective. However, if a LED SAL demand-side program is not cost-effective, the Staff recommends that KCPL update the Staff as to the finding's rationale and file a proposed tariff sheet(s) that would provide LED SAL services at cost to its customers.

Staff Expert: Hojong Kang

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 Continue the Implementation of Its Regulatory Plan	)))))	File No. ER-2010-0355

AFFIDAVIT OF MANISHA LAKHANPAL

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Manisha Lakhanpal, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that she has participated in the preparation of the accompanying Staff Report on pages 1 – 19, and the facts therein are true and correct to the best of her knowledge and belief..

Manisha Lakhanpal
Manisha Lakhanpal

Subscribed and sworn to before me this 24th day of November, 2010.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L Sundermeyer
Notary Public

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 Continue the Implementation of Its Regulatory Plan	)))))	File No. ER-2010-0355

AFFIDAVIT OF MICHAEL S. SCHEPERLE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael S. Scheperle, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Status Report on pages 1 – 24, and the facts therein are true and correct to the best of his knowledge and belief.

Michael S. Scheperle
Michael S. Scheperle

Subscribed and sworn to before me this 23rd day of November, 2010.

Susan L. Sundermeyer
Notary Public

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

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 Continue the Implementation of Its Regulatory Plan	)))))	File No. ER-2010-0355

AFFIDAVIT OF WILLIAM L. McDUFFEY

STATE OF MISSOURI)) ss COUNTY OF COLE)

William L. McDuffey, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Status Report on pages 24 & 25, and the facts therein are true and correct to the best of his knowledge and belief.

William L McDuffey
William L. McDuffey

Subscribed and sworn to before me this 22nd day of November, 2010.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L Sundermeyer
Notary Public

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 Continue the Implementation of Its Regulatory Plan	)))))	File No. ER-2010-0355

AFFIDAVIT OF HOJONG KANG

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Hojong Kang, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Status Report on pages 25 – 29, and the facts therein are true and correct to the best of his knowledge and belief.

Hojong Kang

Hojong Kang

Subscribed and sworn to before me this 23rd day of November, 2010.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer

Notary Public

Missouri Public Service Commission
Case No. ER-2010-0355

Summary Results of Staff's Revenue Neutral CCOS Study

Customer Class	Required % Increase	Less: System Average	Revenue Neutral % Increase
RESIDENTIAL			
Regular	6.79%	-1.04%	5.75%
All Electric	6.98%	-1.04%	5.94%
Separately Metered	21.27%	-1.04%	20.23%
Time of Day	15.72%	-1.04%	14.67%
SMALL GENERAL SERVICE			
Primary & Secondary	-22.29%	-1.04%	-23.33%
Other	-13.27%	-1.04%	-14.32%
All Electric	-10.05%	-1.04%	-11.09%
Separately Metered	11.99%	-1.04%	10.95%
MEDIUM GENERAL SERVICE			
Primary	-27.39%	-1.04%	-28.43%
Secondary	-5.20%	-1.04%	-6.24%
All Electric	3.45%	-1.04%	2.41%
Separately Metered	14.96%	-1.04%	13.92%
LARGE GENERAL SERVICE			
Primary	-20.63%	-1.04%	-21.67%
Secondary	-9.53%	-1.04%	-10.57%
All Electric	6.27%	-1.04%	5.23%
Separately Metered	11.36%	-1.04%	10.31%
LARGE POWER SERVICE			
Primary	4.76%	-1.04%	3.72%
Secondary	9.62%	-1.04%	8.58%
Substation	15.02%	-1.04%	13.98%
Transmission	-4.94%	-1.04%	-5.98%
LIGHTING	-4.32%	-1.04%	-5.36%
TOTAL	1.04%	-1.04%	0.00%

Missouri Public Service Commission
Case No. ER-2010-0355
Summary of Functions and Allocation Methods in CCOS Study

Function	Allocation to Rate Schedules
Production Plant and Reserve	
Base	Annual kWh usage @ generation for each rate schedule
Intermediate	12 NCP Average less Base
Peak	4 NCP remaining less Base and Intermediate
Transmission Plant and Reserve	12 CP Average
Distribution Plant and Reserve	
Substations	NCP
Primary	NCP
Secondary	NCP and customer maximum demands
Line Transformers	NCP and customer maximum demands
Services	KCPL assignment
Meters	KCPL assignment
General and Intangible Plant and Reserve	Functional separation of Production, Transmission and Distribution Plant
Other Rate Base	Revenues, Energy, Labor, Plant, O&M, and company studies
Expenses	
Production	
Fuel	Fuel cost by plant based on Base, Intermediate and Peak Plants
Other	Fixed & Variable - follows NARUC Manual
Maintenance	Fixed & Variable - follows NARUC Manual
Transmission	12 CP Average
Distribution	NCP, customer maximum demands, Distribution Plant, and company studies
Customer Billing, Services and Sales	Number of customers and company studies
Depreciation and Amortization Expenses	
Production	Base, Intermediate, and Peak component based on Production Plant
Transmission	12 CP Average
Distribution	Distribution Plant
General and Intangible	Functional separation of Production, Transmission and Distribution Plant
A&G expenses	Labor, plant, and revenues
Taxes, other than Income Taxes	Plant, Labor
Taxes	Rate Base

Schedule MSS-3

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TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

TABLE 4-18

SUMMARY OF PRODUCTION PLANT
COST ALLOCATIONS USING DIFFERENT COST OF SERVICE METHODS

	1 CP METHOD		12 CP METHOD		3 SUMMER & 3 WINTER PEAK METHOD		ALL PEAK HOURS APPROACH		AVERAGE AND EXCESS METHOD	
	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total
DOM	$ 369,461,692	34.84	$ 340,287,579	32.09	$ 388,925,712	36.67	$ 340,747,311	32.13	$ 386,682,685	36,46
LSMP	394,976,787	37.25	407,533,507	38.43	376,433,254	35.50	384,043,376	36.21	369,289,317	34.82
LP	261,159,089	24.63	283,283,130	26.71	266,582,600	25.14	299,737,319	28.26	254,184,071	23.97
AG&P	34,878,432	3.29	25,700,311	2.42	23,555,089	2.22	28,970,743	2.73	41,218,363	3.89
SL	0	0.00	3,671,473	0.35	4,978,544	0.47	6,977,251	0.66	9,101,564	0.86
Total	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.0

	EQUIVALENT PEAKER COST METHOD		BASE AND PEAK METHOD		1 CP AND AVERAGE DEMAND METHOD		12 CP AND 1/13th AVERAGE DEMAND METHOD		PRODUCTION STACKING METHOD	
Rate Class	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total
DOM	$ 340,657,471	32.12	$ 3350,522,360	33.05	$ 354,381,313	33.42	$ 339,370,900	32.00	$ 334,590,738	31.55
LSMP	362,698,678	34.20	382,505,016	36.07	381,842,722	36.01	403,814,709	38.08	360,965,510	34.04
LP	317,863,510	29.97	293,007,874	27.63	286,764,179	27.04	286,948,099	27.06	324,315,213	30.58
AG&P	32,021,813	3.02	27,868,280	2.63	34,623,156	3.36	26,352,815	2.48	33,089,034	3.12
SL	7,232,529	0.68	6,572,470	0.62	2,864,631	0.27	3,989,478	0.38	7,515,505	0.71
Total	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00

STAFF CLASS COST-OF-SERVICE AND RATE DESIGN REPORT

APPENDIX

Class Cost-of-Service and Rate Design Overview

A Class Cost of Service (CCOS) study is a detailed analysis where the costs incurred to provide utility service to a particular jurisdiction (e.g., Missouri retail) are assigned to customers, or customer classes, based on the manner in which the costs are incurred. An electric utility's power system is designed, constructed, and operated in order to meet the ongoing energy and load requirements of vast numbers of diverse customers. How and when customers utilize energy has a great bearing on the fixed and variable costs of service. Customer classes are groups of customers with similar electrical service characteristics. For proper cost assignment, the composite load of the system must be differentiated by the various customer classes in order to determine the proportional responsibilities of each customer class. In other words, the customers' load contributions to the total demand are a major cost driver. Staff's CCOS study generally follows the procedures described in Chapter 2 of the NARUC Manual. Staff produces an embedded cost study using historical information developed from data collected over the test year updated through the true-up date set in the case.

Definitions and Fundamental Concepts of Electric CCOS and Rate Design

Cost-of-Service: All the costs that a utility prudently incurs to provide utility service to all of its customers in a particular jurisdiction.

Cost-of-Service Study: A study of total company costs, adjusted in accordance with regulatory principles (annualizations and normalizations), allocated to the relevant jurisdiction, and then compared to the revenues the utility is generating from its retail rates, off-system sales and other sources. The results of a cost-of-service study are typically presented in terms of the additional revenue required for the utility to recover its cost-of-service or the amount of revenue over what is required for the utility to recover its cost-of-service.

Class Cost-of-Service (CCOS) Study: A Class Cost-of-Service study is where a utility's revenue requirement is allocated among the various rate classes of that utility. It is a quantitative analysis of the costs the utility incurs to serve each of its various customer classes. When Staff performs a CCOS study it performs each of the following steps: a) categorize or functionalize costs based upon the specific role the cost plays in the operations of the utility's integrated electrical system; b) classify costs by whether they are demand-related, energy-related, or customer-related; and c) allocate the functionalized/classified costs to the utility's customer classes. The sum of all the costs allocated to a customer class is the cost to serve[1] that class.

Relationship between Cost-of-Service and Class Cost-of-Service: The sum of all *class* cost-of-service in a jurisdiction is the cost-of-service of that jurisdiction. The purpose of a Cost-of-Service study is to determine what portion of a utility's costs are attributable to a particular jurisdiction. The purpose of a Class-Cost-of-Service study is to allocate the cost-of-service study costs to the customer classes in that jurisdiction.

Cost allocation: A procedure by which costs incurred to serve multiple customers or customer classes are apportioned among those customers or classes of customers.

Cost Functionalization: The grouping of rate base and expense accounts according to the specific function they play in the operations of an integrated electrical system. The most aggregated functional categories are production, transmission, distribution and customer-

[1] The cost to serve a particular class is sometimes referred to as the cost-of-service for that class.

related costs, but numerous sub-categories within each functional category are commonly used.

Customer Class: A group of customers with similar characteristics (such as usage patterns, conditions of service, usage levels, etc.) that are identified for the purpose of setting rates for electric service.[2]

Rate Design: (1) A process used to determine the rates for an electric utility once cost-of-service and CCOS is known; (2) Characteristics such as rate structure, rate values, and availability that define a rate schedule and provide the instructions necessary to calculate a customer's electric bill. Rates are designed to collect revenue to recover the cost to serve the class.

Rate Design Study: While a CCOS study focuses on customer class revenue responsibility, a rate design study focuses on how service is priced and billed to the individual customers within each class and to sending appropriate price signals to customers. The rate design process attempts to recover costs in each time period (such as summer/winter seasonal pricing, or peak/off-peak time-of-day pricing) from each rate component for each customer in a way that best approximates the cost of providing service and send appropriate price signals, e.g., costs are higher in the summer so rates are higher in the summer..

Rate Schedule: One or more tariff sheets that describes the availability requirements, prices, and terms applicable to a particular type of retail electric service. A customer class is used in a class cost-of-service study may consist of one or more rate schedules.

Rate Structure: Rate structure is the composition of the various charges for the utility's products. These charges include

[2] A customer class used in a class cost-of-service study may consist of one or more rate schedules.

1) customer charge: a fixed dollar amount per month irrespective of the amount of usage;
2) usage (energy) charges: a price per unit charged on the total units of the usage during the month; and
3) peak (demand) usage charge: a price per unit charge on the maximum units of the product taken over a short period of time (for electricity, usually 15 minutes or 30 minutes), which may or may not have occurred within the particular billing month.

More elaborate variations such as seasonal differentials (different charges for different seasons of the year), time-of-day differentials (different charges for different times during the day), declining block rates (lowest per-unit charges for higher usage), hours-use rates (rates which decline as the customer's hours of use – the ratio of monthly usage to maximum hourly usage – increases) are also possible. Different variations are used to send price signals to the customer.

Rate Values (Rates): The per-unit prices the utility charges for each element of its rate structure. Rate values are expressed as dollars per unit of demand (kilowatt), cents per unit of energy (kWh), etc.

Tariff: A document filed by a regulated entity with either a federal or state commission. It describes both the rate values (prices) the regulated entity will charge to provide service to its customers as well as the terms and conditions under which those rate values are applicable.

<u>Class Cost-of-Service Overview on Functionalization, Classification and Allocation</u>

The cost allocation process consists of three major parts: functionalization, classification and allocation.

1. Functionalization

A utility's equipment investment and operations can be organized along the lines of the function (purpose) that each piece of equipment or task provides in delivering electricity to customers. The result of functionalization is the assignment of plant investment and expenses to the principal utility functions, which include:

1. Production
2. Transmission
3. Distribution
4. Customer Accounts
5. Customer Assistance
6. Customer Sales

Appendix A1 is a diagram of a typical vertically integrated electrical system, and illustrates the concept of functionalization. Electric power is produced at the generation station, transmitted some distance through high voltage lines, stepped down to secondary voltage and distributed to secondary voltage customers. Other customers (high voltage and primary voltage) are served from various points along the system.

In practice, each major Federal Energy Regulatory Commission (FERC) account is assigned to the functional area that causes the cost. This assignment process is called functionalization. Some costs cannot be directly attributed to a single functional area, and are shared between functions -- these costs are refunctionalized to more than one functional area, with the distribution of costs between functions based upon some relating factor.[3] As an example, it is reasonable to assume that social security taxes are directly related to payroll costs so that these taxes can be assigned to functions in the same manner as payroll costs. In this case, the ratio of labor costs assigned to the various functional categories becomes the factor for distributing social security taxes between functional groups.

[3] The costs in the FERC account are distributed based on a relationship of the distributed cost to a function rather than all the costs in that account being associated to a particular function.

Yet other costs can be clearly attributed to providing service to a particular class of customers, and these costs can be directly assigned to that customer class. Special studies are undertaken by the utility to determine the assignment of costs to customer classes. An example of a direct assignment is the assignment of the cost of transmission equipment used only by a large customer on a particular rate schedule to the rate class associated with that rate schedule.

Functionalized costs are then subdivided into measurable, cost-defining service components. Measurable means that data is available to appropriately divide costs between service components. Cost-defining means that a cost-causing relationship exists between the service component and the cost to be allocated. Functionalized costs are often divided into customer-related costs and demand-related costs. In addition, some functionalized costs can be classified on the basis of the voltage level at which the customer receives electric service.

2. Classification

Classification is a means to divide the functionalized, cost-defining components into a 1) customer component, 2) demand component, 3) and an energy component for rate design considerations. The January 1992 edition of the NARUC Manual references customer-related, demand-related, and energy-related cost components for all distribution plant and operating expense accounts, other than for substations and street lighting.

Customer-related costs are the costs to connect the customer to the electrical system and to maintain that connection. Examples of such costs include meter reading expense, billing expense, postage expense, customer accounting expense, customer service expense, and various distribution costs (plant, reserve, and operating and maintenance expenses). The customer components of the distribution system are those costs necessary to make service available to a customer.

Demand-related costs are rate base investment and related operating and maintenance expenses associated with the facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption each month. The major portion of demand-related costs consists of generation and transmission plant and the non-customer-related portion of distribution plant. Demand-related costs are based on the maximum rate of use (maximum demand) of electricity by the customer. In addition, some demand-related investment and costs can be classified on the basis of voltage level at which the customer receives electric service.

Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, a portion of production plant maintenance expenses and the energy portion of net interchange power costs.

The purpose of classification is to make the third step, allocation, more accurate. For example, assume a special study shows that overhead lines for distribution can be classified into a demand component directly related to a customer's maximum rate of energy usage, and a customer component that is directly related to the fact that a customer exists and requires service. The demand-related portion of overhead distribution line costs can be allocated on the basis of customer maximum demands and the customer-related portion can be allocated on the basis of the number of customers in each class. Typically, the information allowing classification is obtained through special studies of the distribution system. These studies often include statistical analysis of equipment and labor costs, and line losses.

3. Allocation

After the costs have been functionalized and classified, the next step in a CCOS study is to allocate costs to the customer classes. This process involves applying the allocation factors developed for each class to each component of rate base investment and each of the elements of expense specified in the jurisdictional cost of service study. The allocation factors or allocators determine the results of this process. The aggregation of such cost allocations indicates the total annual revenue requirement associated with serving a particular customer class. Allocation factors are chosen that will reasonably distribute a portion of the functionalized costs to each customer class on the basis of cost causation. Allocation factors are typically ratios that represent the fraction of total units (e.g., total number of customers; total annual energy consumption) that are attributable to a certain customer class. These ratios are then used to calculate the fraction of various cost categories for which a class is responsible.

Calculation of Class Net Income and Rate of Return

The operating revenues of each customer class minus its total operating expenses determined through the functionalization, classification and allocation process provide the resulting net income to the utility of each class. The net operating income divided by the allocated rate base of each class will indicate the percentage rate of return being earned by the utility from a particular customer class.

<u>Generation Allocation Methods Listed in NARUC Manual</u>

Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. It is impossible to determine which customer classes are being served by which facilities. As such, generation facilities are joint costs used by all customers and allocated to customer classes. Utilities experiences periods of high demand during certain times of the year and during various hours of the day (summer hours). All customer classes do not contribute in equal proportions to the varying demands placed on the utility system. Utilities design their mix of generation facilities to minimize the total costs of energy and capacity, while making certain that there is enough available capacity to meet demands for every hour of the year. For example, base load nuclear and coal units require high capital expenditures resulting in large investments per kW, whereas smaller units like gas and oil require less investment per kW but higher variable production costs. It is most cost-effective to build base load units to meet the continuous load of the year and depend on small units to meet the few peak hours of the year. Therefore, production costs vary each hour of the year.

Different parties use different methodologies to allocate generation related plant and expenses. For example, the National Association of Regulatory Commissioners (NARUC) outlined thirteen (13) generation allocation methods in its 1992 Electric Utility Cost Allocation Manual (Manual). The thirteen generation allocation methods are:

1. Single Coincident Peak Method (1-CP)
2. Summer and Winter Peak Method (S/W)
3. Twelve Monthly Coincident Peak (12CP)
4. Multiple Coincident Peak Method
5. All Peak Hours Approach
6. Average and Excess Method (A&E)
7. Equivalent Peaker Methods (EP)
8. Base and Peak Method
9. Peak and Average Demand (P&A)
10. Production Stacking Methods
11. Base-Intermediate-Peak (BIP)
12. Loss of Load Probability (LOLP)
13. Probability of Dispatch Method (POD)

A brief description of some of the cost methodologies used most often along with the assumptions and implications are as follows:

Single Coincident Peak Method (1-CP) – The NARUC Manual describes the objective of the (1-CP) is to allocate production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year, the class coincident peak load. The calculation translates class load at the time of the system peak into a percentage of the company's total system peak, and applies that percentage to the company's production-demand revenue requirements. The basic premise of the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. Strengths of this methodology are that the concepts are easy to understand and the data to conduct the CCOS are relatively simple and easy to obtain. The weaknesses are that the sole criteria is based on load during a single hour of the year; the results of the 1-CP method can be unstable from year to year i.e., if peak occurs on a weekend or holiday, the class contributions to the peak load will be significantly different if the peak occurred during a weekday; Also, when using this methodology there can be free ride allocation. In this context, free ridership is when service rendered completely off-peak is not assigned any responsibility for capacity costs. An example of the free ride allocation may occur for street lighting. Street lights are not on during the day and would be allocated no capacity costs at all if the peak occurred during daylight hours.

The system peak typically occurs on days with extreme weather. Therefore this allocation methodology will allocate more costs to weather sensitive classes and less costs to non-weather sensitive classes than other methodologies.

Summer and Winter Coincident Peak (S/W Peak) – The NARUC Manual describes the objective of S/W Peak method is to reflect the effect of two distinct seasonal peaks on customer cost assignment. This approach may be used if the summer and winter peaks are close in value. The S/W Peak method was developed because some utilities annual peak load occurs in the summer for certain years and in the winter during other years. This method has essentially the same strengths and weaknesses as the 1-CP method except that two hours are used to define the class allocations for generating facilities.

Twelve Monthly Coincident Peak (12-CP) - The NARUC Manual describes this method as an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range for all twelve months. Most electric utilities have distinct seasonal load patterns such as high peaks in the summer months and lower peaks during the winter, spring and autumn months. However, depending on types of heating options available, winter months may be equal or exceed summer month peaks. This method may be appropriate for some electric utilities where the winter heating season is within a narrow band with the summer cooling season.

The 12-CP method assigns class responsibilities based on their respective contributions throughout the year more closely matching the fact that utilities use all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods than the 1-CP and S/W Peak methods. Weakness of this method are that the utility must accurately track load data for all twelve months and customer classes who have major off-peak usage may not receive its fair share of generation facilities. A strength of this method is that a utility can allocate its proportion of cost using twelve months of data information and this method takes into account some class diversity in allocations. The percent allocated to weather sensitive classes is not a great as with the 1-CP and S/W Peak methods.

Average and Excess Method (A&E) – The NARUC Manual describes the A&E method as a method that allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands. All production plant costs are usually classified as demand related. The A&E method consists of two parts. The first component of each class's allocation factor is its proportion of the class' total average demand (based on energy consumption) times the system load factor. The second component of each class's allocation factor is called the "excess" demand factor. This component is multiplied by the remaining proportion of production plant (1 minus system load factor). The first and second components (Average and Excess components) are then added to obtain the total allocator. A weakness of this method is that the allocation favors high load factor customers, e.g., classes with industrial customers, and disfavors customer classes with lower load factor customers, e.g., residential and small commercial classes, because the "excess" portion of the allocator uses non-coincidental peak information. Some of the non-coincidental peaks for classes may not occur in peaking seasons. Strengths are that no class of customers will receive a free-ride under this method, e.g., street lighting, and recognition is given to average consumption as well as to additional costs imposed by certain classes for not maintaining a perfectly constant load.

Equivalent Peaker (EP) – The NARUC Manual describes EP as a method based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load, intermediate load, and peaking load generation resources. The EP method has some appeal because base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used are allocated based on peak demands to those classes contributing to the system peak load. With the EP method, only the combustion turbines and the combustion turbines equivalent capacity cost portion of all other units are treated as demand related. The remainder of the total plant investment is thus treated as energy related. A strength of the EP method is that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units used sparingly and only called upon during peak periods are allocated based on peak demands to those classes contributing to the system peak load. One weakness of this method is that it requires a significant amount of data.

Peak and Average (P&A) – The NARUC Manual describes the impetus for this method as some regulatory commissions recognizing that energy loads are an important determinant of production plant costs, requiring the incorporation of judgmentally-established energy weightings into cost studies. The allocator is effectively the average of adding together each class's contribution to the system peak demand and its average demand. This methodology premise is that a utility's actual generation facilities are placed into service to meet peak load and to serve customers demands throughout the entire year. This method assigns capacity cost partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year or peak period. Strengths of this methodology are an attempt to recognize the capacity/energy allocation in the assignment of fixed capacity costs and that data requirements are minimal. Weaknesses are that the capacity/energy allocation method may have the perception that double-counting occurs in the capacity/energy allocation.

Base-Intermediate-Peak (BIP) – The NARUC Manual describes the BIP method as a time-differentiated method that assigns production plant costs to three rating periods.: (1) peak hours, (2) secondary peak (intermediate hours), and (3) base loading hours. The BIP method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load (base, intermediate, and peak). The BIP method is an accepted allocation method that attempts to recognize the capacity/energy trade-off that exists within a utility's generation asset portfolio. A utility's base load units tend to operate during all periods of the year (less outages or maintenance) to satisfy energy requirements in the most efficient manner possible during minimum periods. Because base load units operate regardless of peak requirements, they are appropriately classified as energy related. Intermediate plants serve a dual purpose in that they are partially energy-related and partially-demand related. Peaking plants operate with high variable cost and are only utilized to help meet peak period demands. As such, peaker generating facilities plants are classified as peak demand-related. The BIP method considers the differences in the capacity/energy trade off that exist across a company's generation mix. Strengths of the BIP method are that there are three different components being allocated to the various rate classes. There is a base component (based on energy), an intermediate component based on demands less base portion, and a peaking component based on demands less the base and intermediate components already allocated to the classes. Another strength is that each generating plant is classified as a base, intermediate, or peak generating facility based on fuel costs, heat rates, and operating hours in its classification. An additional strength is it eliminates free ridership by customer classes with a substantial off-peak usage. A general weakness is that the BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

Time of Use (TOU) – A production allocation method that assigns production costs to each hour of the year that the specific production occurs. The TOU method apportions production plant accounts for both demand and energy characteristics as each much satisfy both periods of normal use throughout the year and intermittent peak use. The TOU is used for analyzing cost of service by time periods. This method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. Previous Staff employee Mike Proctor refined this process with the Commission adopting the TOU methodology in previous cases in Case No. EO-78-161, Case No. EO-85-17, and Case No. ER-85-60. Strengths of the method is that all 8,760 hours are analyzed and assigned to rate groups. Also, each class of customers is assigned their share of costs for the entire test year period. Weaknesses are that a lot of data is needed to analyze and the data needs to be weather normalized for each hour. The Commission rejected this method in a previous case noting that the TOU in unreliable because it considers every hour in the year to be a demand peak.

Basic Components of Electricity Production and Delivery