MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NO. ER-2011-0004

Jefferson City, Missouri
March 16, 2011

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STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

I. Executive Summary

Staff's Class Cost-of-Service (CCOS) and Rate Design recommendations in this case are that the Commission order The Empire District Electric Company (Empire) to implement revenue neutral rate element adjustments to certain classes as detailed in this Report to reduce the summer/non-summer variation in rate elements and to implement the following rate design after revenue neutral adjustments are implemented:

1. The following Empire customer classes receive the system average increase, as the revenue responsibilities of the customer classes are close to Empire's cost to serve them:
    - Commercial Building
    - Commercial Small Heating
    - Total Electric Building
2. The following Empire customer classes receive the system average percent increase plus an approximate additional 0.4% increase, because the current revenue responsibilities of the customer classes are less than Empire's cost to serve them:
    - Residential Service,
    - Special Transmission Service Contract: Praxair
    - Large Power Service
3. The following Empire customer classes receive no increase for the first $4 million, because their current revenue responsibilities exceed Empire's cost of serving them. For any Commission ordered increase above $4 million, the additional amount above $4 million should be allocated on an equal percentage basis to the following Empire customer classes:
    - General Power Service
    - Feed Mill and Grain Elevator Service
4. The Empire Lighting class, consisting of the Street, Private, Special, and Miscellaneous schedules, receives no increase as their current revenue responsibilities exceed Empire's cost of serving them by over 20%.
5. Allocate any Commission ordered decrease as an equal percentage decrease to the rate schedules for the customer classes shown in Table 1 with a negative percent indicating those classes' revenues exceed the cost to serve those classes.

6. Increase the residential customer charge to $13.00.
7. Decrease the differential between the summer and non-summer rate components in rate classes that have a large summer/non-summer differential.

In addition, this report includes recommendations that the Commission:

1. Address miscellaneous tariff issues:
2. Approve Fuel Adjustment Clause (FAC) tariff sheets that correspond to the exemplar tariff sheets attached to this report: and
3. Require Empire to no later than twelve months following the approval of tariff sheets in this case complete its evaluation of Light Emitting Diode (LED), and Street and Area Lighting (SAL) systems and either file proposed LED lighting rate schedules or file to state when it will file proposed LED lighting tariffs sheets.

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 a test year of the twelve months ending June 30, 2009, updated through November 30, 2010.
2. To provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility.
3. To provide methods to implement in rates any Commission-ordered overall change in customer revenue responsibility.
4. To retain, to the extent possible, existing rate schedules, rate structures, and important features of the current rate design, and mitigate the potential for rate shock.
5. To provide exemplar FAC tariff sheets that incorporate Staff's recommended changes to Empire's FAC and clarify the FAC.
6. To provide various wording and clarifying changes to Empire's tariff.
5. To 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 the following main sections. They are:

- Executive Summary
- Class Cost-of-Service and Rate Design Overview
- Staff Class Cost-of-Service Study
- Rate Design

- Miscellaneous Tariff Recommendations
- Fuel Adjustment Clause Recommendation
- Street and Area Lighting Recommendation

The results of Staff's CCOS study for Empire 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 Staff's determination of Empire's cost of serving that class. Staff developed its analysis of the cost of serving each class using inputs taken from Staff's Revenue Requirement Cost of Service Report (COS Report) and Staff Accounting Schedules filed in this case on February 23, 2011. Staff's revenue requirement is based on a test year of the twelve months ending June 30, 2009, updated through November 30, 2010.

Table 1

Summary Results of Staff's CCOS Study

	Revenue	CCOS %
Customer Class	**Deficiency**	**Increase**
Residential (RG)	$7,725,865	4.17%
Commercial Building (CB)	($1,058,424)	-2.86%
Commercial Small Heating (SH)	($223,663)	-2.29%
General Power (GP)	($5,643,087)	-7.32%
Special Transmission Service Contract: Praxair (SC-P)	$394,691	12.83%
Total Electric Building (TEB)	($1,676,905)	-4.75%
Feed Mill and Grain Elevator (PFM)	($5,485)	-8.57%
Large Power (LP)	$2,956,299	6.39%
Lights (Street, Private, Special, Miscellaneous)	($1,889,348)	-26.35%
Total	$579,943	0.14%

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, which lists the negative or positive dollar amounts or percentages necessary to equalize revenues with cost of service. The results of Staff's analysis are presented as the shifts in revenue that produce an equal rate of return from each customer class.

A negative amount and percentage indicates revenue from the customer class exceeds the cost of providing service to that class. Such classes are overpaying, and to equalize revenues and cost-of-service, rate revenues should be reduced. A positive amount and percentage indicates revenue from the class is less than the cost of providing service to that class. Such classes are underpaying and to equalize revenues and cost-of-service, rate revenues should be increased.

Staff's customer classes used in its study correspond to Empire's current rate schedules, except Staff has combined all lighting rate schedules into one customer class for its study. Aside from lighting rate schedules, Empire has nine rate schedules: Residential Service (RG), Commercial Building Service (CB), Commercial Small Heating Service (SH), General Power Service (GP), Special Transmission Service Contract: Praxair (SC-P), Total Electric Building Service (TEB), Feed Mill and Grain Elevator Service (PFM), and Large Power Service (LP). Also, Empire has a Special Transmission Service (ST) although no customers are currently served under that rate schedule. Staff's customer classes are shown in Table 1 above.

Staff's recommended customer class revenue adjustments would bring the RG, GP, SC-P, PFM, LP, and the Lighting classes closer to Empire's actual cost to serve each class. Staff recommends that the CB, SH and TEB classes receive the system average increase as these classes revenue responsibility are close to Empire's cost to serve them. These adjustments bring each class closer to cost of serving them, while still maintaining rate continuity, rate stability, revenue stability; and minimizing rate shock to any one 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 the utility's total jurisdictional cost of providing service to all the customer classes in a manner which best reflects cost causation.

Thus 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 which is 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 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

Empire filed a new CCOS study in this case based on the financial data upon which it based its direct filing in this case, which was based upon a test year of the twelve months ending June 30, 2009, as updated through November 30, 2010. Staff's CCOS study results are given in Table 1 above, and are outlined 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 Empire's cost to serve that class.

CCOS results can also be 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.[1] Staff calculated the revenue neutral percent change to a class's rate revenue by subtracting the overall system average increase of 0.14% (Staff midpoint range) from each class's required percentage change to rate revenue. The resulting percentage is the increase needed to match the revenues Empire would receive from that class to match Empire's cost to serve that class.

For example on a revenue neutral basis, the RG customer class is providing 4.03% less revenue (the 4.17% shown in Table 1 minus the average increase of 0.14%) than Empire's cost to serve that class. Also, the CB customer class is providing 3.00% more revenue to Empire than its cost to serve that class. Staff's CCOS study results for all of the customer classes Staff used for Empire are presented in Schedule MSS-1.

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[1] 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.

Because a CCOS study is not precise it should be used only as a guide for designing rates. In addition, impact on customer bills need to be considered when recommending a revenue neutral adjustment. While eliminating over-collection from customer classes with revenues greater than cost to serve is appealing, the bill impact on the customer classes with positive revenue shift percentages must be considered. Based on its study results and judgment, at the mid-point of Staff's rate of return, Staff recommends revenue increases to all Empire rate schedules except the Lighting class, as the Lighting class revenues exceed the class revenue responsibility by over 20%.

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

<u>A. Data Sources</u>

Staff's CCOS study utilized Staff's calculation of Empire's jurisdictional retail cost of service, as filed in Staff's COS Report on February 23, 2011. This data includes:

- Adjusted Missouri Jurisdictional Investment and cost data by Federal Energy Regulatory Commission (FERC) account;
- Annualized, Normalized Rate Revenues;
- Fuel and Purchase Power costs;
- Other operating and maintenance expenses;
- Depreciation and Amortizations; and
- Taxes.

In addition, data was also obtained from Empire witness H. Edwin Overcast's Direct Testimony and work papers from this case, including:

- Customer Demand Splits;
- Customer Coincidental Peaks per rate schedule;
- Customer Non-Coincidental Peaks per rate schedule;
- Annual Energy per rate schedule;
- Staff's fuel and purchased power model monthly fuel and purchased power expense; and
- Certain other allocation factors for specific customer allocations. These relate to information on services, meters, meter reading, uncollectible accounts, customer premise installations, and customer deposits.

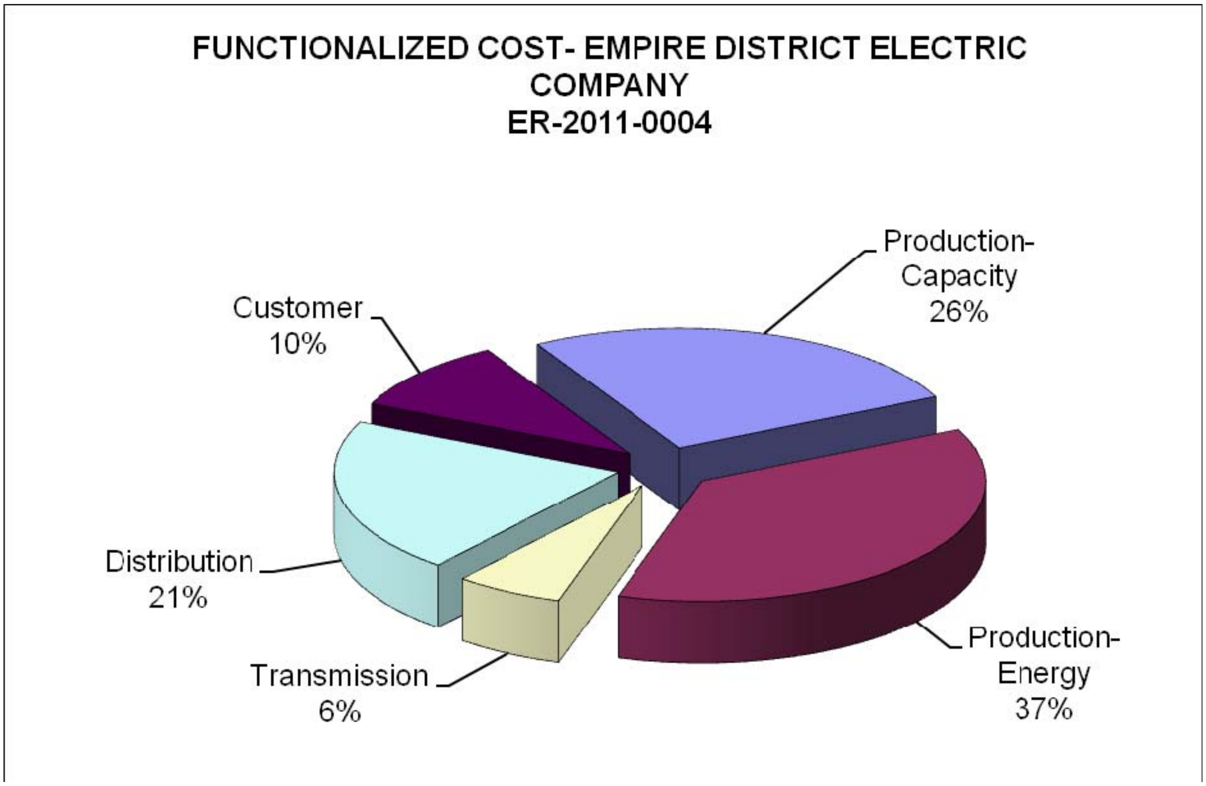
B. Classes and Rate Schedules

Empire provides service to its customers pursuant to rate classifications that are designated for residential or non-residential service. These classifications are listed in Table 1 above. The non-residential customer groups are differentiated by type of service, voltage level, and/or by kW demands.

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 usage and peak usage. The designated usage for each group (base and peak) is allocated to each customer class based on 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, and the energy portion of net interchange power costs. The chart below shows the percentage of total costs associated within each major function for all of Empire's classes, as consolidated.

TABLE 2



The Production Function (consisting of both Production-Capacity and Production-Energy) is the single largest cost component, and represents 63% of total cost of service. The Distribution Function, at 21% of total cost, includes substations, overhead and underground lines, and line transformers, as well as the costs to operate and maintain this equipment. Customer Services at 10%, and Transmission at 6% 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. Both the demand and energy characteristics of Empire's load are important determinants of production investment and costs, since production must produce output to satisfy periods of normal use as well as intermittent peak use throughout the year.

Empire meets 76% of its generation needs with its ownership in generating plants and the remaining 24% of its generation needs with purchases. Purchases come from two main sources which are purchases of wind from Elk River and Meridian Way and spot purchases. Wind purchases account for approximately 64% of all purchases.

Staff allocated Production-Energy fuel costs on annualized kWh usage by class at the point of generation. Staff allocated Production–Capacity costs using 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 generating plants or purchases that would be used to meet additional requirements after the dispatch of base units. Staff after reviewing fuel cost data and generating units owned by Empire determined that generating units or purchases are either used as base or peaking.
3. A peaking component determined by subtracting the base component from the average 6CP[2] component of demand for electricity.

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. Generally, base load units have high capital costs, generally take five to ten years to build, and have low, relatively constant running costs. Because of this, these units run almost continuously, except during periods of maintenance. Because base load units operate regardless of peak requirements, they are appropriately classified as energy-related.[3] 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.[4] Peaking units have low capital costs, are relatively quick to build—typically twelve to eighteen months—but are costly to run. It is typically most cost effective to only run these units for the few hours of the year when the system load is highest.

[2] 6 CP is each month's class demand at the time of the system peak. Staff used CP peaks for the months of January, February, June, July, August and December because they were within 85% of the annual peak.
[3] **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, and the energy portion of net interchange power costs.
[4] **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.

The output of peaking units is used to fulfill the energy requirements of the system on a real-time basis.

Empire operates and maintains generating units that are required to provide both capacity and energy for its customers throughout the year. Prudency requires that Empire 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 Empire's system, both instantaneously and over time.

The first step of the BIP method is to evaluate the system monthly loads of the test period. A listing of monthly peak loads, given in Table 3 below, helps to define the twelve months in terms of a peak season versus non-peak season. Empire is a dual-peaking utility with significant peaks in both winter and summer as compared to its shoulder months. Empire's highest monthly coincident peaks occurred in the summer season for 2008 and 2009 and in the winter season in 2010.

Table 3

Coincident System Peak @ Generation kW Total Company			
Month	2008	2009	2010
January	1,043,000	1,082,000	1,199,000
February	988,000	993,000	1,013,000
March	891,000	933,000	880,000
April	778,000	788,000	628,000
May	815,000	733,000	868,000
June	979,000	1,085,000	1,093,000
July	1,083,000	1,005,000	1,085,000
August	1,152,000	1,028,000	1,156,000
September	897,000	813,000	973,000
October	769,700	636,000	666,000
November	875,000	743,000	
December	1,100,000	1,060,000	

In the BIP method, the base allocator (the “B” portion in BIP) 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 (the “I” in BIP) is allocated using some combination of coincidental peak (CP) or non-coincidental peak (NCP) information. The CP demand is defined as the monthly demand of each customer class at the time of the system peak during the study period. Staff reviewed Empire’s generation and purchases and determined that generating plants or purchases by Empire are either used to meet peak load requirements or peaking capacity. The peak portion (the “P” in BIP) is allocated to the various classes based on each class’s share of the six CP peaks (January, February, June, July, August, and December) less the base portion already allocated to the various classes. Staff used the six monthly peaks since Empire’s system peak has occurred in a summer month in 2008 and 2009 and a winter month in 2010. The six months used for the peaking component are within approximately 85% of system peak.

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 usage 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 Empire. Staff explains the BIP method further, and addresses other production methods from the NARUC Manual, in attached Appendix A-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

Empire’s transmission investment and transmission costs comprise approximately 6% of the functionalized investment and costs Staff allocated to the customer classes. Empire’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 twelve coincident peak (12 CP) basis. Staff recommends the 12 CP allocation method for this purpose because by including both periods of normal use and intermittent peak use it takes into account the needs for a transmission system that is designed to transmit electricity during times of both peak loads and normal loads.

F. Allocation of Distribution Costs

Staff considered voltage level 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. 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.

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	Class Peak	Moderate to High
Line Transformers	Class peak	Moderate to High

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 typically 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 (due to intra-class 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. 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.

Empire 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 Empire's allocator. This allocator is based on an Empire 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 Empire's allocators for allocating meter reading costs, uncollectible accounts, and for allocating customer deposits. These three allocators are derived in Empire's studies that directly assign the costs of meter reading, uncollectible accounts, and customer deposits to the customer classes. The allocators 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 Empire's CCOS study.

H. Revenues

Operating revenues consist of (1) the revenue that the utility collects from the sales of electricity to Missouri retail customers (rate revenue); and (2) the revenue the utility receives for providing other services (other revenue). Rate Revenues are also used in developing Staff's rate design proposal and are used to develop the rate schedules required to implement the Commission's ordered revenue requirement and rate design for Empire in this case. Rate Revenues in Staff's COS Report filed February 23, 2011, were used to obtain Empire's normalized and annualized rate revenues. The Total Rate Revenues as shown in the Rate Revenue Summary in Staff's Accounting Schedules filed on February 23, 2011, is $400.8 million.

Other Electric Revenues of $6.1 million were also allocated to the rate classes using Staff's production-energy and other cost allocators.

Staff Expert/Witness: Michael S. Scheperle

IV. Rate Design

Staff's rate design objectives in this case are to:

- Provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility.
- Provide methods to include 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 in order to reduce the number of customers that will switch rates looking for the lowest bill, and mitigate the potential for rate shock.

The demand for power on an electric system varies over time. For any given utility, variations in demand occur in a fairly predictable pattern during seasons of the year. Most time differentiation of rates stems from the recognition that costs vary by time. For Empire, winter and summer peaks are very close in terms of load. For example, in 2008 the system annual peak occurred in August at 1,152 MW, in 2009 the system peak occurred in June at 1,085 MW, and in 2010 the system annual peak occurred in January 2010 at 1,199 MW. In each of these years, there had been three winter months and three summer months within approximately 85% of the system peak (See Table 3).

Empire's rate structure for residential and non-residential (except lighting and miscellaneous) has a summer season consisting of four months (June through September) and a non-summer season consisting of eight months (October through May) with the tail block of summer rates being considerably higher than non-summer rates for some rate classes. For example, the residential rate per kWh over 600 kWh per month is 48% higher than the non-summer rate ($0.1074 per kWh in summer versus $.0728 per kWh in non-summer). A seasonal differential is appropriate where costs differ significantly by seasons of the year.

Historically, the cost to serve Empire's customers was higher in the four summer months than it was the other eight months of the year. This was true in Empire's last rate case where the net base fuel cost were $0.03182 per kWh for the summer months and $0.02857 for the other months – about a $0.00325 per kWh difference. However, since the last case, Empire has set a new record peak which was set in a winter period. Not surprisingly, Staff's fuel run model results show that the non-summer fuel and purchased costs per kWh were slightly higher than the summer fuel and purchased power costs. In reviewing system peaks for the year ending June 30, 2010 and Empire's FAC net base fuel cost for the summer season and non-summer season, the fuel and purchased costs per kWh are very close in both seasons. Specifically, the annual base fuel costs being filed in this case is $0.02731, the amount calculated for summer is $0.02664, and $0.02767 per kWh for non-summer periods.

Fuel and purchased power costs make up the majority of the variable costs. If the variable costs are similar across the summer and non-summer months, there is little justification for keeping the summer and non-summer differential in the rates. In fact, based on the most recent data, this differential actually results in relative summer and non-summer fuel charges which is counter to the previous costs incurred by Empire for providing service in the summer and non-summer.

However, Staff is recommending continuation of the summer and non-summer rate differential at this time for two reasons: 1) uncertainty and 2) to prevent rate shock. First, while Staff has observed the growth of Empire's non-summer load, this is the first time that Staff has seen an average non-summer fuel kWh cost higher than the summer costs, and it is unclear whether this trend will continue. Staff believes it would needlessly confuse customers to remove the rate differential now, only to reinstate it in a future case if the winter peak did not continue. Second, Staff recommends preserving some summer/non-summer differential, while reducing its magnitude, in order to avoid rate shock. If the non-summer rate components were brought in line with the summer components, those customers with electric heating could experience substantial increase in their heating costs. For these reason Staff is recommending that the summer/non-summer rate differentials be reduced instead of being eliminated entirely.

Staff recommends that before an increase in rates is recommended for any class, that certain revenue neutral adjustments occur to specific rate schedules to reduce the variations in rate elements between the summer and non-summer season as follows:

- For the residential class (rate schedule RG), the current rates and Staff's revenue neutral proposed rates are listed in Schedule MSS-5. As listed, the only variation between the current charges by season is the second energy block where the summer rate ($0.1074 per kwh) is 48% higher than the non-summer rate ($0.0728 per kWh). To minimize the cost variation of the summer/non-summer period, Staff increased the second energy step (over 600 kWh) in the non-summer by $0.01 to reduce the summer and non-summer variation and spread the revenue neutral adjustment to all other energy blocks. This would reduce the summer/non-summer variation (over 600 kWh) from 48% to 23%. The revenue neutral adjustment to the RG class is zero. Schedule MSS-5 details the adjustment by individual customer usage per month and per year.

- For the commercial building class (rate schedule CB), the current rates and Staff's revenue neutral proposed rates are listed in Schedule MSS-6. As listed, the only variation between the current charges by season is the second energy block where the summer rate ($0.1194 per kWh) is 32% higher than the non-summer rate ($0.0906 per kWh). Staff increased the second energy step (over 700 kWh) in the non-summer by $0.01 to reduce the summer and non-summer variation and spread the revenue neutral adjustment to all other energy blocks. This would reduce the summer/non-summer variation (over 700kWh) from 32% to 11%. The revenue neutral adjustment to the CB class is zero. Schedule MSS-6 details the adjustment by individual customer usage per month and per year.
- For the commercial small heating class (rate schedule SH), the current rates and Staff's revenue neutral proposed rates are listed in Schedule MSS-7. As listed, the only variation between the current charges by season is the second energy block where the summer rate ($0.1189 per kWh) is 69% higher than the non-summer rate ($0.0704 per kWh). Staff increased the second energy step (over 700 kWh) in the non-summer by $.01 to reduce the summer and non-summer variation and spread the revenue neutral adjustment to all other energy blocks. This would reduce the summer/non-summer variation (over 700 kWh) from 69% to 34%. The revenue neutral adjustment to the SH class is zero. Schedule MSS-7 details the adjustment by individual customer usage per month and per year.

- For the general power class (rate schedule GP), the current rates and Staff's revenue proposed rates are listed in Schedule MSS-8. As listed, the variations between the current charges by season are demand charges and the three energy charge blocks based on hours use. Staff increased the first energy step (First 150 hours use of Metered Demand per kWh) in the non-summer by $0.01 to reduce the summer and non-summer variation and spread the revenue neutral adjustment to the first energy step (First 150 hours use of Metered Demand per kWh) in the summer. This would reduce the summer/non-summer variation from 67% to 16 %. The revenue neutral adjustment to the GP class is zero. Schedule MSS-8 details the adjustment by individual customer usage per month.
- For the total electric building class (rate schedule TEB), the current rates and Staff's revenue proposed rates are listed in Schedule MSS-9. As listed, the variations between the current charges by season are demand charges and the three energy charge blocks. Staff increased the first energy step (First 150 hours use of Metered Demand, per kWh) in the non-summer by $0.01 to reduce the summer and non-summer variation and spread the revenue neutral adjustment to the first energy step (First 150 hours use of Metered Demand, per kWh) in the summer. This would reduce the summer/non-summer variation from 87% to 31%. The revenue neutral adjustment to the TEB class is zero. Schedule MSS-9 details the adjustment by individual customer usage per month.

Staff's rate design recommendations in this case after revenue neutral adjustments discussed above are:

1. The following Empire customer classes receive the system average increase, as the revenue responsibilities of these customer classes are close to Empire's cost to serve them:
    - Commercial Building
    - Commercial Small Heating

- Total Electric Building

2. The following Empire customer classes receive the system average percent increase plus an approximate additional 0.4% increase, because the current revenue responsibilities of the customer classes are less than Empire's cost to serve them.
    - Residential
    - Special Transmission Service Contract: Praxair
    - Large Power
3. The following Empire customer classes receive no increase for the first $4 million, because their current revenue responsibilities exceed Empire's cost of serving them. For any Commission ordered increase above $4 million, that the additional amount above $4 million be allocated on an equal percentage basis to the following Empire customer classes.
    - General Power
    - Feed Mill and Grain Elevator
4. The Empire Lighting class (Street, Private, Special, Miscellaneous) receive no increase as Staff's CCOS study indicates the Lighting class revenues exceed the revenue responsibility of the class by over 20%.
5. Allocation of any Commission ordered decrease as an equal percentage decrease to the rate schedules for the customer classes shown to have a negative percent (revenues exceed cost to serve) in Table 1.
6. The Residential customer charge be increased from $12.52 to $13.00 per month.
7. That the energy charges for the residential class be increased uniformly, after making the adjustments described in 2 and 6 above.
8. That the customer charges and energy charges for the CB class be increased uniformly, after making the adjustments described in 1 above.
9. That the customer charges and energy charges for SH be increased uniformly, after making the adjustments described in 1 above.
10. That the customer charges, demand charges, facilities charges, and energy charges be increased uniformly for the TEB class after making adjustments described in 1 above.

11. That the customer charges, demand charges, facilities charges, and energy charges for the GP class be increased uniformly after making the adjustments described in 3 above.
12. That the customer charges, demand charges, facilities charges, and energy charges for the LP class be increased uniformly after making the adjustments described in 2 above.
13. That the customer and energy charges for the PFM class be increased uniformly after making the adjustments described in 3 above.
14. That the customer charges, demand charges, facilities charges, and energy charges for the SC-P class be increased uniformly after making the adjustments described in 2 above.

Schedule MSS-3 shows that Empire's residential customer charge is the highest of the five electric utility tariffs in the state. Currently, it costs Empire $17.43 to provide all customer-related functions, this is 1.38 times the $12.52 existing customer charge. Staff recommends increasing Empire's residential customer charge by $0.48, from $12.52 to $13.00. Staff's recommendation considers and takes into account the: (1) potential for rate shock of raising the customer charge to $17.34 at one time; and (2) Staff's revenue neutral rate increase recommendation for the residential class.

A. Current Rate Schedules

The residential rate schedule RG consists of the following elements:

- Customer Charge – per month
- First Block Energy Charge – per kWh per season
- Second Block Energy Charge – per kWh rate is same as the first energy block rate for the summer months, lower in the other months
- Fuel Adjustment Clause – per kWh

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

Commercial Service Schedule CB consists of the following elements:

- Customer Charge – per month
- First Block Energy Charge – per kWh per season

- Second Block Energy Charge – per kWh per season. Rate is the same as the first energy block rate for the summer months, lower in the other months
- Fuel Adjustment Clause – per kWh

Small Heating Service Schedule SH consists of the following elements:

- Customer Charge – per month
- First Block Energy Charge – per kWh per season
- Second Block Energy Charge – per kWh per season. Rate is same as the first energy block rate for the summer months, lower in the other months
- Fuel Adjustment Clause – per kWh

General Power Service Schedule GP consists of the following elements:

- Customer Charge – per month
- Demand Charge – per kW of Billing demand per season
- Facilities Charge – per kW of Facilities Demand per season
- Energy Charge – Hours of use of Metered Demand - per kWh per season
- Fuel Adjustment Clause – per kWh

Large Power Service Schedule LP consists of the following elements:

- Customer Charge – per month
- Demand Charge – per kW of Billing demand per season
- Facilities Charge – per kW of Facilities Demand per season
- Energy Charge – Hours of use of Metered Demand - per kWh per season
- Fuel Adjustment Clause – per kWh

Feed Mill and Grain Elevator Service schedule PFM consists of the following elements:

- Customer Charge – per month
- First Block Energy Charge – per kWh per Season

- Second Block Energy Charge – per kWh per Season. The rate is the same as the first energy block rate for the summer months, lower in the other months.
- Fuel Adjustment Clause – per kWh

Total Electric Building Service Schedule TEB consists of the following elements:

- Customer Charge – per month
- Demand Charge – per kW of Billing demand per season
- Facilities Charge – per kW of Facilities Demand per season
- Energy Charge – Hours of use of Metered Demand - per kWh per season
- Fuel Adjustment Clause – per kWh

Special Transmission Service Contract: Schedule SC-P only applies to one customer – Praxair and consists of the following elements:

- Customer Charge – per month
- On-Peak Demand Charge – per kW of Billing demand per season
- Substation Facilities Charge – per kW of Facilities Demand per season
- Energy Charge – On-Peak Period - per kWh per season
- Energy Charge – Shoulder Period – per kWh per summer season only
- Energy Charge – Off-peak Period – per kWh per season
- Fuel Adjustment Clause – per kWh

Empire witness Jayne Long filed supplemental direct testimony in this case that included a revised tariff sheet for Schedule SC-P. As a result of the expiration of a prior contract, Praxair and the Company have negotiated a new contract that incorporates the current rates as filed with the Commission. Some terms and conditions changed as follows:

- Maximum number of hours of interruption per year be reduced from 400 hours to 100 hours.
- Modified the tariff to permit the Maximum Firm Demand and Customer Peak Demand to automatically adjust two times during each year.

- Places an overall limit of thirteen days on the number of days of curtailment per contract year.
- Tariff places a limit on the number of hours of curtailment in any single day to no more than 8 hours per day.

The terms and condition changes seem appropriate as negotiated by the two parties based on historical past practices.

Special Transmission Service Schedule ST consists of the following elements:

- Customer Charge – per month
- On-Peak Demand Charge – per kW of Billing demand per Season
- Substation Facilities Charge – per kW of Facilities Demand per season
- Energy Charge – On-Peak Period - per kWh per season
- Energy Charge – Shoulder Period – per kWh per Summer Season
- Energy Charge – Off-peak Period – per kWh per Season
- Fuel Adjustment Clause – per kWh

B. Lighting

- Municipal Street Lighting Service Schedule SPL
- Private Lighting Service Schedule PL
- Special Lighting Service Schedule LS
- Miscellaneous Service Schedule MS
- Unmetered service
- Metered service
- Fuel Adjustment Clause

C. Important Rate Design Features

Empire's charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. Staff recommends that the Commission order Empire to implement revenue neutral rate element adjustments as detailed in this report to reduce the summer/non-summer variation in certain energy rate elements. 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 eight main rate groups based upon their load and cost characteristics. A typical customer in each of the other rate groups can be described as follows:

- Commercial Service Schedule CB: Electric load is not in excess of 40 kW.
- Small Heating Service: Average load is not in excess of 40 kW during the summer season and regularly uses electric space-heating equipment for all internal space-heating requirements.
- General Power Service Schedule GP: Available for electric service to any general service customer except those who are conveying electric service received to other whose utilization is purely for residential purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 40 kW, whichever is greater.
- Large Power Service Schedule LP: Available for electric service to any general service customer except those who are conveying electric service received to others whose utilization is purely for residential purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 1000 kW, whichever is greater.
- Feed Mill and Grain Elevator Service Schedule PFM: Available for electric service to any custom feed mill or grain elevator.
- Total Electric Building Service Schedule TEB: Available to any general services customers on the lines of Empire for total electric service except those customers who are conveying electric service to others whose utilization of the same is for residential purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 40 kW, whichever is greater.
- Special Transmission Service Contract: Praxair Schedule SC-P: Schedule is available for electric service to Praxair, Inc. In no event shall the Peak demand be lesser of 6000 kW or customer’s MFD for

- Customers that have contracted interruptible capacity as specified in the contract or any future amendments thereto.
- Special Transmission Service Schedule ST: Schedule is available for electric service to any general service customer who has signed a service contract with the Empire District Electric Company.

For its CCOS study, Staff broke the above rate groups into separate rate classes. Staff's CCOS study provided the investment and costs associated for Empire to provide service to the Lighting class (Municipal, Private, Special, Miscellaneous).

Staff Expert/Witness: Michael S. Scheperle and Curt Wells

IV. Miscellaneous Tariff Revisions

Staff recommends the Commission order Empire to file its revised tariff to reflect the following modifications:

A. Additional Tariff Sheets

A. Inclusion of an additional tariff sheet, Section 2, Sheet No. 9a (Designated 6th, Canceling 5th, Issued 12/28/06) as requested in the supplemental direct testimony of Empire witness Jayna Long.

B. Addition to the tariff of sample contracts for the services described on Tariff Sheets Section 3, Sheet Nos. 2 and 2a, Private Lighting Service, Schedule PL. Empire's current tariff does not include sample contracts or agreements related to Private Lighting. Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company currently include sample lighting contracts in their tariffs. Also, Staff has requested sample contracts be placed in Ameren Missouri tariff in its pending rate case. Tariff Sheet Section 3, Sheet No. 2b is a reasonable location to place the draft contract.

B. Typographical Issues

Correction of the following typographical issues Staff has identified in Empire's filing docketed as File No. YE-2011-0154.

1. Empire's Tariff Sheet Section A, Sheet No. 1, Table of Contents.
   - Add "for Rates and Riders" to the end of header of the Table of Contents
   - Under Section B, Description of Territory

- The sheet number for Territory Maps should read “1-15” and “20-23”
- The sheet number of the Description of Missouri Service Territory should read “16-19”

2. Section 4, Sheet No. 8a.1
   - Add “C. Missouri Commercial and Industrial Facility Rebate Program (Continued)” as a location header for the text just above first line of text, left margin
   - Under Evaluation - change “third year of implementation” to “2012”
   - Under Program Funding – change “fifth year of the program” to “2014”
3. Section 4, Sheet No. 8f
   - Add “G. High Efficiency Residential Central Air Conditioning Rebate Program (Continued)” as a location header for the text just above first line of text, left margin
   - Under Program Funding - change “the fifth year of the program” to “2014”
4. Section 4, Sheet No. 8g
   - Under Evaluation - change “third year of implementation” to “2012”
   - Under Program Funding – change “fifth year of the program” to “2014”
5. Section 4, Sheet No. 8h
   - Under Evaluation - change “the first two program years” to “2010 and 2011”
   - Under Evaluation - change “third program year” to “2012”
   - Under Program Funding – change “fifth year of the program” and “the fifth year of the ESNH Program” to “2014”
6. Section 4, Sheet No. 8j
   - Add “J. Home Performance with Energy Star (Continued)” as a location header for the text just above first line of text, left margin
   - Under Evaluation - change “the first two program years” to “2010 and 2011”

- Under Evaluation - change “third program year” to “2012”
- Under Program Funding – change “fifth year of the program” and “the fifth year of the HPwES Program” to “2014”

7. Section 4, Sheet Nos. 9, 10, 11
    - Delete “Experimental Low-Income Program (ELI”)” from headers
8. No change to text was found by Staff to Section 5, Sheet Nos. A, 5, 28, 30, 31, 32, 33, 34, 36, 38, 40, 41 therefore Staff recommends not filing compliance tariff sheets for the listed tariff sheets above.
9. Section 5, Sheet No. 10
    - Move “F. Type of Service And Rate Schedule” one space to the right for vertical alignment.
10. Section 5, Sheet No.17a, A. General
    - Add “3. Customer Cost on Extension: Empire will furnish customer copy of charges prior to construction.”
11. Section 5, Sheet No.17a, B.1.a.
    - In the last few lines Empire proposed changing “s/he” to “he.”\ Staff suggests not making the change and leaving as “s/he.”
12. Section 5, Sheet No. 17b and 17c
    - Add “B. Electric Distribution Policy, 1. Overhead (Continued)” as a location header for the text just above first line of text, left margin
13. Section 5, Sheet No. 17d, 17e and 17f
    - Add “B. Electric Distribution Policy, 2. Underground and Overhead (Continued)” as a location header for the text just above first line of text, left margin
14. Section 5, Sheet No. 17f
    - Suggest adding as a paragraph on relocation as section h.
15. Section 5, Sheet Nos. 19 and 20 – Problem with subject numbering.
    - Either delete “3.” but keep the sentence on Sheet No. 19 or renumber Sheet No. 20 starting with “4.”
16. Section 5, Sheet No. 21, E.1. second line
    - change “aerials” to “antennas”

Review of Energy-Efficiency Program Tariff Sheets

Staff recommends Empire review of the term of the following tariff sheets applicable to energy-efficiency programs. It is Staff's understanding that these programs are ongoing.

1. Section 4, Sheet No. 8b – D. Residential CFL Program
2. Section 4, Sheet No. 8c.1 – E.1. Weatherization Program

Staff Expert: William (Mack) L. McDuffey

IV. Fuel and Purchased Power Adjustment Clause

Staff recommends the Commission order Empire to file FAC tariffs that reflect the Staff recommendations provided in the COS Report. Staff also recommends modification of Empire's FAC tariff to reflect a single base cost per kWh for all twelve months of the year, eliminating the seasonal distinction present in Empire's current tariff.

In the COS Report, Staff recommended that the Commission modify Empire's FAC concerning the following:

1. Change the sharing mechanism in Empire's FAC from 95%/5% to 85%/15%;
2. Modify the language concerning the Base Cost factors in Empire's FAC.
3. Continue to provide the information as part of its monthly reports as Empire agreed to do in the *Non-Unanimous Stipulation and Agreement* filed May 12, 2010 in File No. ER-2010-0130.

Based on Staff's fuel run, Staff recommends the Commission order changes to Empire's FAC tariff sheets to reflect a change in base cost per kWh from $0.03182 for the summer period and $0.02857 for the non-summer period to a single rate of $0.02731 for all 12 months.

Historically, the cost to serve Empire's customers has been higher in the four summer months than it was the other eight months of the year. This was true in Empire's last rate case, File No. ER-2010-0130 where the net base fuel cost was $0.03182 per kWh for the summer months and $0.02857 for the other eight months – about a $0.00325 per kWh difference. Between this case and the last case, Empire set a new record peak. However, instead of occurring in one of the summer months, the peak was set in December 2010. For the purposes of calculating revenues, Staff weather normalized and annualized customer usage, and therefore net system input in this case, through June 2010. Even after the weather normalization and the annualizations, Staff's normalized loads show that Empire's annual peak for the July 2009 through June 2010 time period occurred in December. Not surprisingly, Staff's fuel run model results show that the non-summer fuel and purchased costs per kWh were slightly higher than the summer fuel and purchased power costs.

As stated in the Rate Design section of this Report, Staff finds that these fuel and purchased power costs support possible elimination of Empire's seasonal differentials. However, for reasons discussed in its Rate Design recommendation, Staff is not recommending complete elimination of the differential in the permanent rates at this time. Staff does recommend elimination of this differential for purposes of setting the base cost per kWh for Empire's FAC.

Staff notes that off-system sales revenues are not included in Staff's revenue requirement and therefore they are not included in the FAC base rate calculation.

Staff has prepared exemplar tariff sheets to effect these recommendations, and Staff recommends Empire be ordered to file tariffs in conformance with the exemplar tariff sheets in Schedule MJB-1. Schedule MJB-1 specifies that the provisions of the current FAC tariff sheets be applicable for determining the Base Fuel Costs for service provided prior to the effective date of the new FAC tariff sheets approved in this case and that the provisions of the new FAC tariff sheets to be applicable to service provided on and after the effective date of the new FAC tariff sheets.

Staff Expert: Matthew J. Barnes

VII. High Efficiency Street and Area Lighting

Staff recommends that the Commission's Report and Order in this case order Empire to complete its evaluation of Light Emitting Diode (LED) Street and Area Lighting (SAL) systems and file either a proposed LED lighting tariff(s) or an update to the Commission on when it will file a proposed LED lighting tariff(s) no later than twelve (12) months following the Report and Order.

A. Current Street Lighting for Empire District Electric Company

During 2010, Empire had approximately 37,900 SAL systems in its Missouri service territory, using a total of about 32,700 MWh based on the Company's response to Data Request No. 0220. Empire's currently approved lighting tariffs consist of: 1) municipal street lighting service (Schedule SPL), 2) private lighting service (Schedule PL), and 3) special lighting service (Schedule LS). Under Schedule SPL, the Company has a separate rate for the municipal-owned lights and the company-owned lights. For the company-owned lights, the Company installs, owns, operates and maintains the street lights and the customer pays a monthly Facilities Usage Charge in the amount of 0.75% of an investment amount in street lights agreed to by Empire and the municipal customers.

Most of the existing lighting in the Company's Missouri service area is high pressure sodium (HPS) lamps or mercury vapor (MV) lamps[5], which were determined the most efficient available technology for the SAL systems at the time the Company installed most of the SALs.

B. An Alternative for the SAL System: Light Emitting Diode (LED) Lighting

The LED lighting system is the most energy efficient SAL fixture available today. Some advantages of LED lighting over traditional high-intensity discharge (HID) lamps and HPS lamps include:

- Improved efficiency;
- Longer lamp life;
- 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)[6]

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 Schedule LS-2 included as Schedule HK-1. As part of 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 the LS-2 rate schedule. Second, customers who perform such replacements will be eligible for a rebate for every

[5] HPS and MV lamps are about 52% and 43% of the total lamps, respectively.

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

qualified LED fixture purchased and installed. Schedule HK 2 shows PG&E LED Street Light Rebates information.

Southern California Edison (SCE) offers not only a LED street light rate to non-metered customer-owned street lights based on SCE's Schedule LS-2 included as Schedule HK 3, but also a 'Midnight' service rate within all of their outdoor lighting tariffs for a programmable lighting system that can turn off or dim at a designated time, such as 10 p.m. until 5 a.m.

Kansas City Power & Light (KCPL) and KCP&L Greater Missouri Operations (GMO) are collaborating with the Electric Power Research Institute (EPRI) to test and evaluate the potential of currently available LED lighting. 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.

Through data requests[7] 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. And KCPL, GMO and the Staff stipulated to the following language in Case Nos. ER-2010-0355 and ER-2010-0356 for filing LED tariffs:

> Both KCPL and GMo agree that they shall file by the end of calendar year 2012 that either a LED lighting tariff, or when the Companies anticipate filing such LED lighting tariff. Also by the end of calendar year 2012, both KCPL and GMO shall file the results of its LED study, which shall include a review of potential LED lighting health issues.

[7] 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.

Ameren Missouri[8] is also collaborating with the EPRI and other utilities to test and evaluate the potential of currently available LED lighting through EPRI's National Demonstration Project, which includes nine national sites with twelve LED lights normally installed per site. However, Ameren Missouri installed eleven LED lights in Ballwin, Missouri. This project started in summer of 2009 and will end sometime in fourth quarter of 2011. As a project participant, Ameren Missouri is interfacing with EPRI for data collection in metering and photometric measurement of the LED lighting. EPRI will provide a final report at the end of project.

The challenge for cities regarding their SAL networks is to increase the quality of lighting service to the community while reducing its operating costs. The Staff understands that while some citizens may 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[9] have launched pilot LED SAL programs, including the Missouri cities of Columbia, Ballwin, Independence, Kansas City, and Springfield.

D. Empire's LED SAL Research[10]

Empire is currently in the early stages of designing a pilot program for LED lighting with a vendor and with one municipality in its service territory, the City of Branson, Missouri. Empire recently had a meeting with the municipality to propose the Company's pilot program. The Staff will continue its evaluation of Empire's LED research and program as new information becomes available.

E. Staff Recommendation

Staff recommends that the Commission's Report and Order in this case order Empire to complete its evaluation of LED SAL systems and file either a proposed LED lighting tariff(s) or an update to the Commission on when it will file a proposed LED lighting tariff(s) with or without completion of its own independent pilot program of LED SAL systems[11] no later than twelve months following the Commission's Report and Order. Staff is not

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[8] Based on the Data Request No. 0353 for Case No. ER-2011-0028.
[9] http://newstreetlights.com/index_files/New_Streetlights_News_100.htm
[10] Based on the Data Request No. 0220 for Case No. ER-2011-0004.
[11] Currently, there is some accessible information from other municipalities or utilities. Also, one can access information from various the Department of Energy (DOE) websites at http://www1.eere.energy.gov/buildings/ssl/resources.html

recommending that Empire offer the LED SAL program as a demand-side program unless Empire'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 Empire update the Staff as to the finding's rationale and file a proposed tariff sheet(s) within the same twelve month time frame recommended above that would provide LED SAL demand-side program services at cost to its customers.

Staff Expert/Witness: Hojong Kang

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	File No. ER-2011-0004

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 Staff Report on pages 1 – 25, 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 15th day of March, 2011.

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 Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	File No. ER-2011-0004

AFFIDAVIT OF CURT WELLS

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

Curt Wells, 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 Staff Report on pages 15 - 25, and the facts therein are true and correct to the best of his knowledge and belief.

Curt Wells
Curt Wells

Subscribed and sworn to before me this 16th day of March, 2011.

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 Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))	File No. ER-2011-0004

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 Staff Report on pages 25 - 28, 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 15th day of March, 2011.

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 Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	File No. ER-2011-0004

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Matthew J. Barnes, 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 Staff Report on pages 28 - 29, and the facts therein are true and correct to the best of his knowledge and belief.

Matthew J. Barnes

Matthew J. Barnes

Subscribed and sworn to before me this 16th day of March, 2011.

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 Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	File No. ER-2011-0004

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 Staff Report on pages 29 – 33, 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 16th day of March, 2011.

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

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.

Generation Allocation Methods Listed in NARUC Manual

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 <u>Electric Utility Cost Allocation Manual (Manual)</u>. 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.

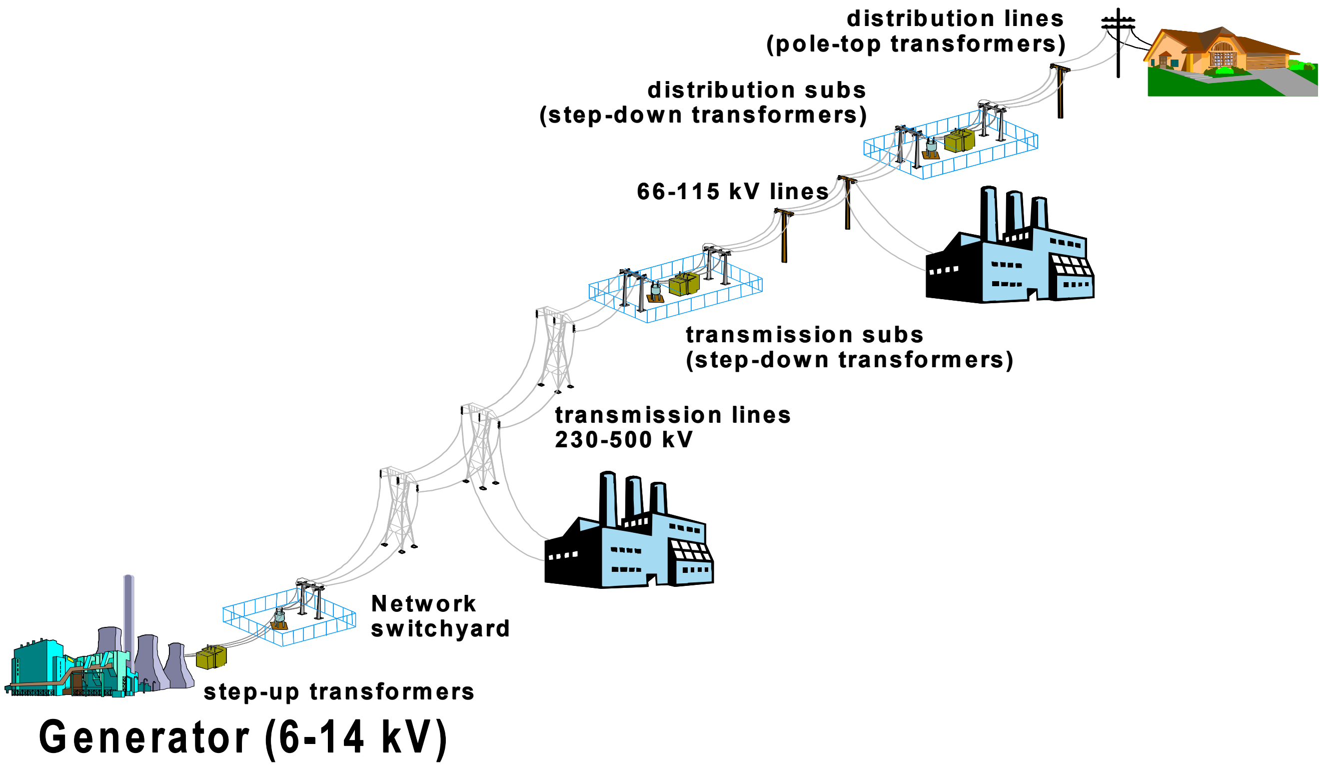
Equivalent Peaker (EP) – The NARUC Manual describes EP as a method based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. The EP 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. The BIP method is one of several methods that allow for a complete recognition of the dual nature of generating resources and provides a structured and precise way to model the costs and develop appropriate class allocators for production plant. Another strength is that each generating may be classified as a base, intermediate, or peak generating facility based on fuel costs, heat rates, and operating hours in its classification or the method may allocate investment in production plant and facilities as a whole and does not require an analysis of individual generating units. 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



Missouri Public Service Commission
Case No. ER-2011-0004
Summary Results of Staff's CCOS Study

Summary Results of Staff's CCOS Study

Customer Class	CCOS % Increase	Less: System Average	Revenue Neutral % Increase
Residentia (RG)	4.17%	-0.14%	4.03%
Commercial Building (CB)	-2.86%	-0.14%	-3.00%
Commercial Small Heating (SH)	-2.29%	-0.14%	-2.44%
General Power (GP)	-7.32%	-0.14%	-7.46%
Special Transmission Service Contract: (SC-P)	12.83%	-0.14%	12.68%
Total Electric Building (TEB)	-4.75%	-0.14%	-4.89%
Feed Mill and Grain Elevator (PFM)	-8.57%	-0.14%	-8.71%
Large Power (LP)	6.39%	-0.14%	6.25%
Lights (Street, Private, Special, Miscellaneous)	-26.35%	-0.14%	-26.50%
Total	0.14%	-0.14%	0.00%

Missouri Public Service Commission
Case No. ER-2011-0004
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 class
Intermediate	Not applicable
Peak	6 CP remaining less Base and Intermediate

Transmission Plant and Reserve	12 CP Average

Distribution Plant and Reserve	
Substations	NCP
Primary	NCP
Secondary	NCP
Line Transformers	NCP
Services	Empire Allocation
Meters	Empire Allocation
General and Intangible Plant and Reserv	Functional separation of Production, Transmission and Distribution Plant
Other Rate Base	Revenues, Energy, Labor, Plant, O&M, and company studies

Expenses	
Production	
Fuel	Annual kWh usage @ generation for each rate class
Other	Fixed & Variable - Based on Staff Accounting Schedules
Maintenance	Fixed & Variable - Based on Staff Accounting Schedules
Transmission	12 CP Average
Distribution	NCP, 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

Missouri Public Service Commission
Case No. ER-2011-0028
Customer Charges for Residential Class

Company	Current Residential Customer Charge
Ameren Missouri (1)	$8.00
Empire District Electric Company (2)	$12.52
Kansas City Power & Light Company (3)	$8.67
KCP&L Greater Missouri Operations Company - L&P (4)	$7.90
KCP&L Greater Missouri Operations Company - MPS (5)	$9.73

(1) Mo. P.S.C. Schedule No. 5 , Sheet No. 28 (Excludes Low-Income Pilot Program)
(2) P.S.C. Mo. No. 5, Section 1, Sheet No. 1
(3) P.S.C. Mo. No. 7, Sheet No. 5A
(4) P.S.C. Mo. No. 1, Sheet No. 18
(5) P.S.C. Mo. No. 1, Sheet No. 51

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. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	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. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	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

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	Current		**Adjusted**	
Residential (RG)	**Summer**	**Winter**	**Summer**	**Winter**
Rates				
Customer Charge	$12.52	$12.52	$12.52	$12.52
The first 600-kWh, per kWh	$0.1074	$0.1074	$0.1017	$0.1017
Additional kWh, per kWh	$0.1074	$0.0728	$0.1017	$0.0828

kWh Usage	Current Summer Rates	Current Winter Rates	Adjusted Summer Rates	Adjusted Winter Rates	Current Annual	Adjusted Annual	Adjusted Less Current
100	$23.26	$23.26	$22.69	$22.69	$279.12	$272.28	($6.84)
200	$34.00	$34.00	$32.86	$32.86	$408.00	$394.32	($13.68)
300	$44.74	$44.74	$43.03	$43.03	$536.88	$516.36	($20.52)
400	$55.48	$55.48	$53.20	$53.20	$665.76	$638.40	($27.36)
500	$66.22	$66.22	$63.37	$63.37	$794.64	$760.44	($34.20)
600	$76.96	$76.96	$73.54	$73.54	$923.52	$882.48	($41.04)
700	$87.70	$84.24	$83.71	$81.82	$1,024.72	$989.40	($35.32)
800	$98.44	$91.52	$93.88	$90.10	$1,125.92	$1,096.32	($29.60)
900	$109.18	$98.80	$104.05	$98.38	$1,227.12	$1,203.24	($23.88)
1000	$119.92	$106.08	$114.22	$106.66	$1,328.32	$1,310.16	($18.16)
1100	$130.66	$113.36	$124.39	$114.94	$1,429.52	$1,417.08	($12.44)
1162	$137.32	$117.87	$130.70	$120.07	$1,492.26	$1,483.37	($8.89)
1300	$152.14	$127.92	$144.73	$131.50	$1,631.92	$1,630.92	($1.00)
1400	$162.88	$135.20	$154.90	$139.78	$1,733.12	$1,737.84	$4.72
1500	$173.62	$142.48	$165.07	$148.06	$1,834.32	$1,844.76	$10.44
1600	$184.36	$149.76	$175.24	$156.34	$1,935.52	$1,951.68	$16.16
1700	$195.10	$157.04	$185.41	$164.62	$2,036.72	$2,058.60	$21.88
1800	$205.84	$164.32	$195.58	$172.90	$2,137.92	$2,165.52	$27.60
1900	$216.58	$171.60	$205.75	$181.18	$2,239.12	$2,272.44	$33.32
2000	$227.32	$178.88	$215.92	$189.46	$2,340.32	$2,379.36	$39.04
2300	$259.54	$200.72	$246.43	$214.30	$2,643.92	$2,700.12	$56.20
2500	$281.02	$215.28	$266.77	$230.86	$2,846.32	$2,913.96	$67.64
2700	$302.50	$229.84	$287.11	$247.42	$3,048.72	$3,127.80	$79.08
3000	$334.72	$251.68	$317.62	$272.26	$3,352.32	$3,448.56	$96.24

The average Residential customer uses 1,162 kWh per month.

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	Current		**Adjusted**	
Commercial Building (CB)	**Summer**	**Winter**	**Summer**	**Winter**
Rates				
Customer Charge	$17.67	$17.67	$17.67	$17.67
The first 700-kWh, per kWh	$0.1194	$0.1194	$0.1118	$0.1118
Additional kWh, per kWh	$0.1194	$0.0906	$0.1118	$0.1006

kWh Usage	Current Summer Rates	Current Winter Rates	Adjusted Summer Rates	Adjusted Winter Rates	Current Annual	Adjusted Annual	Adjusted Less Current
100	$29.61	$29.61	$28.85	$28.85	$355.32	$346.20	($9.12)
200	$41.55	$41.55	$40.03	$40.03	$498.60	$480.36	($18.24)
300	$53.49	$53.49	$51.21	$51.21	$641.88	$614.52	($27.36)
400	$65.43	$65.43	$62.39	$62.39	$785.16	$748.68	($36.48)
500	$77.37	$77.37	$73.57	$73.57	$928.44	$882.84	($45.60)
600	$89.31	$89.31	$84.75	$84.75	$1,071.72	$1,017.00	($54.72)
700	$101.25	$101.25	$95.93	$95.93	$1,215.00	$1,151.16	($63.84)
800	$113.19	$110.31	$107.11	$105.99	$1,335.24	$1,276.36	($58.88)
900	$125.13	$119.37	$118.29	$116.05	$1,455.48	$1,401.56	($53.92)
1000	$137.07	$128.43	$129.47	$126.11	$1,575.72	$1,526.76	($48.96)
1100	$149.01	$137.49	$140.65	$136.17	$1,695.96	$1,651.96	($44.00)
1200	$160.95	$146.55	$151.83	$146.23	$1,816.20	$1,777.16	($39.04)
1300	$172.89	$155.61	$163.01	$156.29	$1,936.44	$1,902.36	($34.08)
1400	$184.83	$164.67	$174.19	$166.35	$2,056.68	$2,027.56	($29.12)
1474	$193.67	$171.37	$182.46	$173.79	$2,145.66	$2,120.21	($25.45)
1600	$208.71	$182.79	$196.55	$186.47	$2,297.16	$2,277.96	($19.20)
1700	$220.65	$191.85	$207.73	$196.53	$2,417.40	$2,403.16	($14.24)
1800	$232.59	$200.91	$218.91	$206.59	$2,537.64	$2,528.36	($9.28)
1900	$244.53	$209.97	$230.09	$216.65	$2,657.88	$2,653.56	($4.32)
2000	$256.47	$219.03	$241.27	$226.71	$2,778.12	$2,778.76	$0.64
2300	$292.29	$246.21	$274.81	$256.89	$3,138.84	$3,154.36	$15.52
2500	$316.17	$264.33	$297.17	$277.01	$3,379.32	$3,404.76	$25.44
2700	$340.05	$282.45	$319.53	$297.13	$3,619.80	$3,655.16	$35.36
3000	$375.87	$309.63	$353.07	$327.31	$3,980.52	$4,030.76	$50.24
4000	$495.27	$400.23	$464.87	$427.91	$5,182.92	$5,282.76	$99.84
5000	$614.67	$490.83	$576.67	$528.51	$6,385.32	$6,534.76	$149.44
8000	$972.87	$762.63	$912.07	$830.31	$9,992.52	$10,290.76	$298.24
10000	$1,211.67	$943.83	$1,135.67	$1,031.51	$12,397.32	$12,794.76	$397.44

The average Commercial Building customer uses 1,474 kWh per month.

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	Current		**Adjusted**	
Commercial Small Heating (SH)	**Summer**	**Winter**	**Summer**	**Winter**
Rates				
Customer Charge	$17.67	$17.67	$17.67	$17.67
The first 700-kWh, per kWh	$0.1189	$0.1189	$0.1076	$0.1076
Additional kWh, per kWh	$0.1189	$0.0704	$0.1076	$0.0804

kWh Usage	Current Summer Rates	Current Winter Rates	Adjusted Summer Rates	Adjusted Winter Rates	Current Annual	Adjusted Annual	Adjusted Less Current
100	$29.56	$29.56	$28.43	$28.43	$354.72	$341.16	($13.56)
200	$41.45	$41.45	$39.19	$39.19	$497.40	$470.28	($27.12)
300	$53.34	$53.34	$49.95	$49.95	$640.08	$599.40	($40.68)
400	$65.23	$65.23	$60.71	$60.71	$782.76	$728.52	($54.24)
500	$77.12	$77.12	$71.47	$71.47	$925.44	$857.64	($67.80)
600	$89.01	$89.01	$82.23	$82.23	$1,068.12	$986.76	($81.36)
700	$100.90	$100.90	$92.99	$92.99	$1,210.80	$1,115.88	($94.92)
800	$112.79	$107.94	$103.75	$101.03	$1,314.68	$1,223.24	($91.44)
900	$124.68	$114.98	$114.51	$109.07	$1,418.56	$1,330.60	($87.96)
1000	$136.57	$122.02	$125.27	$117.11	$1,522.44	$1,437.96	($84.48)
1100	$148.46	$129.06	$136.03	$125.15	$1,626.32	$1,545.32	($81.00)
1200	$160.35	$136.10	$146.79	$133.19	$1,730.20	$1,652.68	($77.52)
1300	$172.24	$143.14	$157.55	$141.23	$1,834.08	$1,760.04	($74.04)
1400	$184.13	$150.18	$168.31	$149.27	$1,937.96	$1,867.40	($70.56)
1500	$196.02	$157.22	$179.07	$157.31	$2,041.84	$1,974.76	($67.08)
1600	$207.91	$164.26	$189.83	$165.35	$2,145.72	$2,082.12	($63.60)
1700	$219.80	$171.30	$200.59	$173.39	$2,249.60	$2,189.48	($60.12)
1800	$231.69	$178.34	$211.35	$181.43	$2,353.48	$2,296.84	($56.64)
1900	$243.58	$185.38	$222.11	$189.47	$2,457.36	$2,404.20	($53.16)
2000	$255.47	$192.42	$232.87	$197.51	$2,561.24	$2,511.56	($49.68)
2300	$291.14	$213.54	$265.15	$221.63	$2,872.88	$2,833.64	($39.24)
2500	$314.92	$227.62	$286.67	$237.71	$3,080.64	$3,048.36	($32.28)
2599	$326.69	$234.59	$297.32	$245.67	$3,183.48	$3,154.65	($28.83)
3000	$374.37	$262.82	$340.47	$277.91	$3,600.04	$3,585.16	($14.88)
4000	$493.27	$333.22	$448.07	$358.31	$4,638.84	$4,658.76	$19.92
5000	$612.17	$403.62	$555.67	$438.71	$5,677.64	$5,732.36	$54.72
8000	$968.87	$614.82	$878.47	$679.91	$8,794.04	$8,953.16	$159.12
10000	$1,206.67	$755.62	$1,093.67	$840.71	$10,871.64	$11,100.36	$228.72
15000	$1,801.17	$1,107.62	$1,631.67	$1,242.71	$16,065.64	$16,468.36	$402.72

The average Commercial Small Heating customer uses 2,599 kWh per month.

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General Power Service	Current		Adjusted	
	Summer	Winter	Summer	Winter
Customer Charge	$60.02	$60.02	$60.02	$60.02
Demand Charge	$6.34	$4.94	$6.34	$4.94
Facilities Charge	$1.789	$1.789	$1.789	$1.789
The first 150 hours use of metered demand	$0.0955	$0.0573	$0.0780	$0.0673
Next 200 hours use of metered demand	$0.0612	$0.0555	$0.0612	$0.0555
All additional kWh	$0.0553	$0.0550	$0.0553	$0.0550

	Current		Adjusted		Current Annual	Adjusted Annual	Adjusted Less Current	Percent
	Summer	Winter	Summer	Winter				
50 kW with 25% Load Factor	$1,274.52	$909.47	$1,143.27	$984.47	$12,373.84	$12,448.84	$75.00	0.61%
50 kW with 50% Load Factor	$1,822.37	$1,408.72	$1,691.12	$1,483.72	$18,559.24	$18,634.24	$75.00	0.40%
50 kW with 75% Load Factor	$2,320.07	$1,903.72	$2,188.82	$1,978.72	$24,510.04	$24,585.04	$75.00	0.31%
100 kW with 25% Load Factor	$2,489.02	$1,758.92	$2,226.52	$1,908.92	$24,027.44	$24,177.44	$150.00	0.62%
100 kW with 50% Load Factor	$3,584.72	$2,757.42	$3,322.22	$2,907.42	$36,398.24	$36,548.24	$150.00	0.41%
100 kW with 75% Load Factor	$4,580.12	$3,747.42	$4,317.62	$3,897.42	$48,299.84	$48,449.84	$150.00	0.31%
200 kW with 25% Load Factor	$4,918.02	$3,457.82	$4,393.02	$3,757.82	$47,334.64	$47,634.64	$300.00	0.63%
200 kW with 50% Load Factor	$7,109.42	$5,454.82	$6,584.42	$5,754.82	$72,076.24	$72,376.24	$300.00	0.42%
200 kW with 75% Load Factor	$9,100.22	$7,434.82	$8,575.22	$7,734.82	$95,879.44	$96,179.44	$300.00	0.31%
300 kW with 25% Load Factor	$7,347.02	$5,156.72	$6,559.52	$5,606.72	$70,641.84	$71,091.84	$450.00	0.64%
300 kW with 50% Load Factor	$10,634.12	$8,152.22	$9,846.62	$8,602.22	$107,754.24	$108,204.24	$450.00	0.42%
300 kW with 75% Load Factor	$13,620.32	$11,122.22	$12,832.82	$11,572.22	$143,459.04	$143,909.04	$450.00	0.31%
400 kW with 25% Load Factor	$9,776.02	$6,855.62	$8,726.02	$7,455.62	$93,949.04	$94,549.04	$600.00	0.64%
400 kW with 50% Load Factor	$14,158.82	$10,849.62	$13,108.82	$11,449.62	$143,432.24	$144,032.24	$600.00	0.42%
400 kW with 75% Load Factor	$18,140.42	$14,809.62	$17,090.42	$15,409.62	$191,038.64	$191,638.64	$600.00	0.31%
500 kW with 25% Load Factor	$12,205.02	$8,554.52	$10,892.52	$9,304.52	$117,256.24	$118,006.24	$750.00	0.64%
500 kW with 50% Load Factor	$17,683.52	$13,547.02	$16,371.02	$14,297.02	$179,110.24	$179,860.24	$750.00	0.42%
500 kW with 75% Load Factor	$22,660.52	$18,497.02	$21,348.02	$19,247.02	$238,618.24	$239,368.24	$750.00	0.31%
600 kW with 25% Load Factor	$14,634.02	$10,253.42	$13,059.02	$11,153.42	$140,563.44	$141,463.44	$900.00	0.64%
600 kW with 50% Load Factor	$21,208.22	$16,244.42	$19,633.22	$17,144.42	$214,788.24	$215,688.24	$900.00	0.42%
600 kW with 75% Load Factor	$27,180.62	$22,184.42	$25,605.62	$23,084.42	$286,197.84	$287,097.84	$900.00	0.31%
700 kW with 25% Load Factor	$17,063.02	$11,952.32	$15,225.52	$13,002.32	$163,870.64	$164,920.64	$1,050.00	0.64%
700 kW with 50% Load Factor	$24,732.92	$18,941.82	$22,895.42	$19,991.82	$250,466.24	$251,516.24	$1,050.00	0.42%
700 kW with 75% Load Factor	$31,700.72	$25,871.82	$29,863.22	$26,921.82	$333,777.44	$334,827.44	$1,050.00	0.31%
800 kW with 25% Load Factor	$19,492.02	$13,651.22	$17,392.02	$14,851.22	$187,177.84	$188,377.84	$1,200.00	0.64%
800 kW with 50% Load Factor	$28,257.62	$21,639.22	$26,157.62	$22,839.22	$286,144.24	$287,344.24	$1,200.00	0.42%
800 kW with 75% Load Factor	$36,220.82	$29,559.22	$34,120.82	$30,759.22	$381,357.04	$382,557.04	$1,200.00	0.31%
900 kW with 25% Load Factor	$21,921.02	$15,350.12	$19,558.52	$16,700.12	$210,485.04	$211,835.04	$1,350.00	0.64%
900 kW with 50% Load Factor	$31,782.32	$24,336.62	$29,419.82	$25,686.62	$321,822.24	$323,172.24	$1,350.00	0.42%
900 kW with 75% Load Factor	$40,740.92	$33,246.62	$38,378.42	$34,596.62	$428,936.64	$430,286.64	$1,350.00	0.31%

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Total Electric Building Service	Current		Adjusted	
	Summer	Winter	Summer	Winter
Customer Charge	$60.02	$60.02	$60.02	$60.02
Demand Charge	$2.96	$2.43	$2.96	$2.43
Facilities Charge	$1.789	$1.789	$1.789	$1.789
The first 150 hours use of metered demand	$0.1114	$0.0596	$0.0910	$0.0696
Next 200 hours use of metered demand	$0.0714	$0.0564	0.0714	0.0564
All additional kWh	$0.0646	$0.0555	0.0646	0.0555

	Current		Adjusted		Current Annual	Adjusted Annual	Adjusted Less Current	Percent
	Summer	Winter	Summer	Winter				
50 kW with 25% Load Factor	$1,240.07	$802.57	$1,087.07	$877.57	$11,380.84	$11,368.84	($12.00)	-0.11%
50 kW with 50% Load Factor	$1,879.27	$1,309.72	$1,726.27	$1,384.72	$17,994.84	$17,982.84	($12.00)	-0.07%
50 kW with 75% Load Factor	$2,460.67	$1,809.22	$2,307.67	$1,884.22	$24,316.44	$24,304.44	($12.00)	-0.05%
100 kW with 25% Load Factor	$2,420.12	$1,545.12	$2,114.12	$1,695.12	$22,041.44	$22,017.44	($24.00)	-0.11%
100 kW with 50% Load Factor	$3,698.52	$2,559.42	$3,392.52	$2,709.42	$35,269.44	$35,245.44	($24.00)	-0.07%
100 kW with 75% Load Factor	$4,861.32	$3,558.42	$4,555.32	$3,708.42	$47,912.64	$47,888.64	($24.00)	-0.05%
200 kW with 25% Load Factor	$4,780.22	$3,030.22	$4,168.22	$3,330.22	$43,362.64	$43,314.64	($48.00)	-0.11%
200 kW with 50% Load Factor	$7,337.02	$5,058.82	$6,725.02	$5,358.82	$69,818.64	$69,770.64	($48.00)	-0.07%
200 kW with 75% Load Factor	$9,662.62	$7,056.82	$9,050.62	$7,356.82	$95,105.04	$95,057.04	($48.00)	-0.05%
300 kW with 25% Load Factor	$7,140.32	$4,515.32	$6,222.32	$4,965.32	$64,683.84	$64,611.84	($72.00)	-0.11%
300 kW with 50% Load Factor	$10,975.52	$7,558.22	$10,057.52	$8,008.22	$104,367.84	$104,295.84	($72.00)	-0.07%
300 kW with 75% Load Factor	$14,463.92	$10,555.22	$13,545.92	$11,005.22	$142,297.44	$142,225.44	($72.00)	-0.05%
400 kW with 25% Load Factor	$9,500.42	$6,000.42	$8,276.42	$6,600.42	$86,005.04	$85,909.04	($96.00)	-0.11%
400 kW with 50% Load Factor	$14,614.02	$10,057.62	$13,390.02	$10,657.62	$138,917.04	$138,821.04	($96.00)	-0.07%
400 kW with 75% Load Factor	$19,265.22	$14,053.62	$18,041.22	$14,653.62	$189,489.84	$189,393.84	($96.00)	-0.05%
500 kW with 25% Load Factor	$11,860.52	$7,485.52	$10,330.52	$8,235.52	$107,326.24	$107,206.24	($120.00)	-0.11%
500 kW with 50% Load Factor	$18,252.52	$12,557.02	$16,722.52	$13,307.02	$173,466.24	$173,346.24	($120.00)	-0.07%
500 kW with 75% Load Factor	$24,066.52	$17,552.02	$22,536.52	$18,302.02	$236,682.24	$236,562.24	($120.00)	-0.05%
600 kW with 25% Load Factor	$14,220.62	$8,970.62	$12,384.62	$9,870.62	$128,647.44	$128,503.44	($144.00)	-0.11%
600 kW with 50% Load Factor	$21,891.02	$15,056.42	$20,055.02	$15,956.42	$208,015.44	$207,871.44	($144.00)	-0.07%
600 kW with 75% Load Factor	$28,867.82	$21,050.42	$27,031.82	$21,950.42	$283,874.64	$283,730.64	($144.00)	-0.05%
700 kW with 25% Load Factor	$16,580.72	$10,455.72	$14,438.72	$11,505.72	$149,968.64	$149,800.64	($168.00)	-0.11%
700 kW with 50% Load Factor	$25,529.52	$17,555.82	$23,387.52	$18,605.82	$242,564.64	$242,396.64	($168.00)	-0.07%
700 kW with 75% Load Factor	$33,669.12	$24,548.82	$31,527.12	$25,598.82	$331,067.04	$330,899.04	($168.00)	-0.05%
800 kW with 25% Load Factor	$18,940.82	$11,940.82	$16,492.82	$13,140.82	$171,289.84	$171,097.84	($192.00)	-0.11%
800 kW with 50% Load Factor	$29,168.02	$20,055.22	$26,720.02	$21,255.22	$277,113.84	$276,921.84	($192.00)	-0.07%
800 kW with 75% Load Factor	$38,470.42	$28,047.22	$36,022.42	$29,247.22	$378,259.44	$378,067.44	($192.00)	-0.05%
900 kW with 25% Load Factor	$21,300.92	$13,425.92	$18,546.92	$14,775.92	$192,611.04	$192,395.04	($216.00)	-0.11%
900 kW with 50% Load Factor	$32,806.52	$22,554.62	$30,052.52	$23,904.62	$311,663.04	$311,447.04	($216.00)	-0.07%
900 kW with 75% Load Factor	$43,271.72	$31,545.62	$40,517.72	$32,895.62	$425,451.84	$425,235.84	($216.00)	-0.05%

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 ~~7~~8th Revised Sheet No. 17

Canceling P.S.C. Mo. No. 5 Sec. 4 ~~6~~7th Revised
Sheet No. 17

For ALL TERRITORY

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service in Accumulation Periods prior to September 10, 2010; and for service in that portion of Accumulation Period 5 prior to September 10, 2010.

The two six-month accumulation periods, the two six-month recovery periods and filing dates will be as follows:

	ACCUMULATION PERIOD	RECOVERY PERIOD	ACCUMULATION PERIOD	RECOVERY PERIOD
	SEPTEMBER	JUNE	MARCH	DECEMBER
	OCTOBER	JULY	APRIL	JANUARY
	NOVEMBER	AUGUST	MAY	FEBRUARY
	DECEMBER	SEPTEMBER	JUNE	MARCH
	JANUARY	OCTOBER	JULY	APRIL
	FEBRUARY	NOVEMBER	AUGUST	MAY
Filing date:		April 1st		October 1st

DEFINITIONS

ACCUMULATION PERIOD:
The six calendar months during which the actual costs subject to this rider will be accumulated for purposes of determining the Cost Adjustment Factor.

RECOVERY PERIOD:
The billing months during which Cost Adjustment Factor (CAF) is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS:
Costs eligible for Fuel Adjustment Clause (FAC) will be the Company's total book costs as allocated to Missouri for fuel consumed in Company generating units, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, and emission allowance costs during the Accumulation Period. Eligible costs do not include the purchased power demand costs. These costs will be off-set by off-system sales margin and any emission allowance revenues collected in the Accumulation Period.

BASE ENERGY COST:
Company generated energy and purchased energy cost per kWh at the generator, established by season in the most recent base rate case. The base cost per kWh for the summer months of June through September is $0.03001. For all other months the base cost per kWh is $0.02744.

DATE OF ISSUE August 30, 2010 DATE EFFECTIVE September ~~29~~10, 2010
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service in Accumulation Periods prior to September 10, 2010; and for service in that portion of Accumulation Period 5 prior to September 10, 2010.

APPLICATION
FUEL ADJUSTMENT CLAUSE

The average price per kWh of electricity generated or purchased will be adjusted subject to application of the FAC, and approved by the Public Service Commission. The price will reflect 95 percent of the accumulation period costs either above or below base costs specified below for:

1. fuel consumed in Company electric generating plants,
2. purchased energy (excluding demand),
3. off-system sales margin,
4. net of emission allowance costs and revenues.

It will also include:

5. an adjustment for the prior recovery period sales variation.
6. Interest: Interest at a rate equal to the Company's short-term interest rate will be applied to the average monthly deferred electric energy costs and will be accumulated during the accumulation period. Deferred electric energy cost shall be determined monthly. The monthly deferred amount may be negative or positive during the accumulation period.

The formula and components are displayed below.

$$FAC = \{[(F + P + E - O - B) * J] * 0.95\} + C + I$$

Where:

F = Actual total net system input cost of fuel - FERC Accounts 501 & 547

P = Actual total net system input cost of purchased energy - FERC Account 555 (excluding purchase power demand charges)

E = Actual total system net emission allowance cost and revenues - FERC Accounts 509 & 254.103

O = Actual total system off-system sales margin

B = Base cost of fuel and purchased power energy calculated as follows:

1. For the months of June through September B = (NSI kWh * $0.03001)
2. For all other months B = (NSI kWh * $0.02744)

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service in Accumulation Periods prior to September 10, 2010; and for service in that portion of Accumulation Period 5 prior to September 10, 2010.

J = Missouri energy ratio calculated as follows:

$$\text{Missouri Energy Ratio} = \frac{\text{Missouri Retail kWh sales}}{\text{Total System kWh sales}}$$

Where Total System kWh Sales excludes off-system sales

C = True-up of Under/Over recovery of FAC balance from prior Recovery period as included in the deferred energy cost balancing account. This factor will reflect any modifications made due to prudence reviews

I = Interest

COST ADJUSTMENT FACTOR

The Cost Adjustment Factor ("CAF") is the result of dividing the FAC by estimated recovery period Missouri net system input (NSI) kWh, rounded to the nearest $.00000. The CAF shall be adjusted to reflect the differences in line losses that occur at primary and above voltage and secondary voltage by multiplying the average cost at the generator by 1.0520 and 1.0728, respectively. Any CAF authorized by the Commission shall be billed based upon customers' energy usage on and after the authorized effective date of the CAF. The formula and components are displayed below.

$$CAF = \frac{FAC}{S}$$

Where:

S = Forecasted Missouri NSI kWh for the Recovery Period. Missouri NSI kWh is calculated as:

$$\text{Missouri NSI} = \text{Forecasted NSI} * \frac{\text{Forecasted Missouri Retail kWh sales}}{\text{Forecasted Total System kWh sales}}$$

Where Forecasted Total System kWh Sales excludes off-system sales

PRUDENCE REVIEW

There shall be a periodic review of fuel and energy costs subject to the FAC, and a comparison of the FAC revenue collected. In addition, the review shall determine if the costs subject to the FAC were prudently incurred by the Company. FAC cost and the FAC charges are subject to adjustment if found to be imprudent by the Commission. The normal true-up of over/under recovery of FAC cost occurs at the end of each Recovery period. Prudence reviews shall occur no less frequently than at eighteen (18) month internvals.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 6th~~45th~~ Revised Sheet No. 17c

Canceling P.S.C. Mo. No. 5 Sec. 4 5th~~4th~~~~3rd~~ Revised Sheet No. 17c

For ALL TERRITORY

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service in Accumulation Periods prior to September 10, 2010; and for service in that portion of Accumulation Period 5 prior to September 10, 2010.

ACCUMULATION PERIOD ENDING, Feb-28-2010

1.	Total energy cost (F + P + E - O)	$79,431,215
2.	Base energy cost (B)	$75,540,365
3.	Missouri Energy Ratio (J)	0.8303
4.	Fuel Cost Recovery [(F + P + E - O) – B] * J	$3,139,134
5.	Adj for Over/Under recovery for the Recovery period ending 11-30-2009 (C)	$338,622
6.	Interest (I)	$2,142
7.	Fuel Adjustment Clause (FAC)	$3,479,898
8.	Forecasted Missouri NSI for the Recovery Period (S)	2,289,022,607
9.	Cost Adjustment Factor (CAF) to be applied to bills beginning 06-01-2010	$0.00152 / kWh
10.	CAF - Primary and above (Line 9 x Primary Expansion Factor)	$0.00160 / kWh
11.	CAF - Seconday (Line 9 x Secondary Expansion Factor)	$0.00163 / kWh

Primary Expansion Factor = 1.0520
Secondary Expansion Factor = 1.0728

DATE OF ISSUE August 30, 2010 DATE EFFECTIVE September ~~29~~10, 2010
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

Schedule MJB-1-4

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st~~Original~~Revised	Sheet No.	17d
Canceling P.S.C. Mo. No.	5	Sec.	4	Original	Sheet No.	17d

For ALL TERRITORY

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5 on and after September 10, 2010 and prior to Month Day, 2011.

The two six-month accumulation periods, the two six-month recovery periods and filing dates will be as follows:

	ACCUMULATION PERIOD	RECOVERY PERIOD	ACCUMULATION PERIOD	RECOVERY PERIOD
	SEPTEMBER	JUNE	MARCH	DECEMBER
	OCTOBER	JULY	APRIL	JANUARY
	NOVEMBER	AUGUST	MAY	FEBRUARY
	DECEMBER	SEPTEMBER	JUNE	MARCH
	JANUARY	OCTOBER	JULY	APRIL
	FEBRUARY	NOVEMBER	AUGUST	MAY
Filing date:		April 1st		October 1st

The Company will make a Cost Adjustment Factor ("CAF") filing by each Filing Date. The new CAF rates for which the filing is made will be applicable starting with the recovery period that begins following the Filing Date. All CAF filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

DEFINITIONS

ACCUMULATION PERIOD:
The six calendar months during which the actual costs subject to this rider will be accumulated for purposes of determining the CAF.

RECOVERY PERIOD:
The billing months during which CAF is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS:
Costs eligible for Fuel Adjustment Clause (FAC) will be the Company's total book costs as allocated to Missouri for fuel consumed in Company generating units, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control System ("AQCS") consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs during the accumulation period. Eligible costs do not include the purchased power demand costs. These costs will be off-set by off-system sales revenue, any emission allowance revenues collected, and renewable energy credit revenues in the accumulation period.

BASE COST:
Company generated energy and purchased energy cost per kWh at the generator, established by season in the most recent base rate case. The base cost per kWh for the summer months of June through September is $0.03182. For all other months the base cost per kWh is $0.02857.

DATE OF ISSUE August 30, 2010 DATE EFFECTIVE September ~~29~~10, 2010
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 ~~Original~~1stRevised Sheet No. 17e

Canceling P.S.C. Mo. No. 5 Sec. 4 Original Sheet No. 17e

For ALL TERRITORY

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5 on and after September 10, 2010 and prior to Month Day, 2011.

APPLICATION

FUEL ADJUSTMENT CLAUSE

The average price per kWh of electricity generated or purchased will be adjusted subject to application of the FAC, and approved by the Public Service Commission. The price will reflect 95 percent of the accumulation period costs either above or below base costs specified below for:

1. Fuel and AQCS consumables consumed in Company electric generating plants;
2. Purchased energy (excluding demand);
3. Off-system sales revenue;
4. Emission allowance costs and revenues; and
5. Renewable energy credit revenues.

It will also include:

6. An adjustment for the prior recovery period's over/under recovery of FAC Costs;
7. Interest at a rate equal to the Company's short-term interest rate will be applied to the average monthly deferred electric energy costs and will be accumulated during the accumulation period. Deferred electric energy cost shall be determined monthly. The monthly deferred amount may be negative or positive during the accumulation period.

The formula and components are displayed below.

$$FAC = \{[(F + P + E - O - R - B) * J] * 0.95\} + C + I$$

Where:

F = Actual total cost of fuel - FERC Accounts 501 & 547, and AQCS consumables – FERC Account 506.2.

P = Actual total net system input cost of purchased energy - FERC Account 555 (excluding purchase power demand charges).

E = Actual total system net emission allowance cost and revenues - FERC Accounts 509 & 254.103.

O = Actual total system off-system sales revenue.

B = Base cost of fuel and purchased power energy calculated as follows:

1. For the months of June through September	B = (NSI kWh * $0.03182)
2. For all other months	B = (NSI kWh * $0.02857)

DATE OF ISSUE August 30, 2010 DATE EFFECTIVE September ~~29~~10, 2010
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5 on and after September 10, 2010 and prior to Month Day, 2011.

R = Renewable energy credit revenues.
J = Missouri energy ratio calculated as follows:

$$\text{Missouri energy ratio} = \frac{\text{Missouri retail kWh sales}}{\text{Total system kWh sales}}$$

Where Total system kWh sales excludes off-system sales.

C = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. This factor will reflect any modifications made due to prudence reviews.

I = Interest.

COST ADJUSTMENT FACTOR

The CAF is the result of dividing the FAC by estimated recovery period Missouri net system input (NSI) kWh, rounded to the nearest $.00000. The CAF shall be adjusted to reflect the differences in line losses that occur at primary and above voltage and secondary voltage by multiplying the average cost at the generator by 1.0502 and 1.0686, respectively. Any CAF authorized by the Commission shall be billed based upon customers' energy usage on and after the authorized effective date of the CAF. The formula and components are displayed below.

$$CAF = \frac{FAC}{S}$$

Where:

S = Forecasted Missouri NSI kWh for the recovery period. Missouri NSI kWh is calculated as:

$$\text{Missouri NSI} = \text{Forecasted NSI} * \frac{\text{Forecasted Missouri retail kWh sales}}{\text{Forecasted total system kWh sales}}$$

Where Forecasted Total System kWh Sales excludes off-system sales

PRUDENCE REVIEW

There shall be a periodic review of fuel and energy costs subject to the FAC and a comparison of the FAC revenue collected. Prudence reviews shall occur no less frequently than at eighteen (18) month inter~~n~~vals.

TRUE-UP OF FAC

After completion of each recovery period, the Company will make a true-up filing in conjunction with an adjustment to its FAC on the first Filing Date that occurs after completion of each recovery period. The true-up adjustment shall be the difference between the revenues billed in the recovery period to the costs authorized for collection in the recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item C above and shall include interest calculated as provided for in item I above.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st~~Original~~Revised Sheet No.	17g
Canceling P.S.C. Mo. No. 5	Sec.	4	Original	~~Revised~~ Sheet No.	17g

For ALL TERRITORY

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5 on and after September 10, 2010 and prior to Month Day, 2011.

ACCUMULATION PERIOD ENDING, (Month, Day, Year)

1.	Total energy cost [(F + P + E – O - R) – B] * J * 0.95	$XX,XXX,XXX
2.	Base energy cost (B)	$XX,XXX,XXX
3.	Missouri energy ratio (J)	X.XXXX
4.	Fuel cost recovery [(F + P + E – O - R) – B] * J * 0.95	$XXX,XXX
5.	Adj for over/under recovery for the recovery period ending 00-00-0000 (C)	$X
6.	Interest (I)	$XX,XXX
7.	Fuel Adjustment Clause (FAC)	$XXX,XXX
8.	Forecasted Missouri NSI for the recovery period (S)	X,XXX,XXX,XXX
9.	Cost Adjustment Factor (CAF) to be applied to bills beginning 00-00-0000	$(X.XXXXX) / kWh
10.	CAF - Primary and above (Line 9 x Primary Expansion Factor)	$(X.XXXXX) / kWh
11.	CAF - Secondary (Line 9 x Secondary Expansion Factor)	$(X.XXXXX) / kWh

Primary Expansion Factor = 1.0502
Secondary Expansion Factor = 1.0686

DATE OF ISSUE August 30, 2010 DATE EFFECTIVE September ~~29~~10, 2010
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service on and after Month Day, 2011~~in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5 on and after September 10, 2010~~.

The two six-month accumulation periods, the two six-month recovery periods and filing dates will be as follows:

	ACCUMULATION PERIOD	RECOVERY PERIOD	ACCUMULATION PERIOD	RECOVERY PERIOD
	SEPTEMBER	JUNE	MARCH	DECEMBER
	OCTOBER	JULY	APRIL	JANUARY
	NOVEMBER	AUGUST	MAY	FEBRUARY
	DECEMBER	SEPTEMBER	JUNE	MARCH
	JANUARY	OCTOBER	JULY	APRIL
	FEBRUARY	NOVEMBER	AUGUST	MAY
Filing date:		April 1st		October 1st

The Company will make a Cost Adjustment Factor ("CAF") filing by each Filing Date. The new CAF rates for which the filing is made will be applicable starting with the recovery period that begins following the Filing Date. All CAF filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

DEFINITIONS

ACCUMULATION PERIOD:
The six calendar months during which the actual costs subject to this rider will be accumulated for purposes of determining the CAF.

RECOVERY PERIOD:
The billing months during which CAF is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS:
Base Cost factors in this FAC are calculated using the costs included in the revenue requirement upon which Empire's general rates are set for fuel including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control System consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs, but not purchased power demand costs as off-set by off-system sales revenue, any emission allowance revenues, and renewable energy credit revenues ~~Costs eligible for Fuel Adjustment Clause (FAC) will be the Company's total book costs as allocated to Missouri for fuel consumed in Company generating units, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control System ("AQCS") consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs during the accumulation period. Eligible costs do not include the purchased power~~

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service on and after Month Day, 2011~~in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5 on and after September 10, 2010~~.

~~demand costs. These costs will be off-set by off-system sales revenue, any emission allowance revenues collected, and renewable energy credit revenues~~ in the accumulation period.

BASE ENERGY COST:

Company generated energy and purchased energy cost per kWh at the generator, established ~~by season~~ in the most recent base rate case. The base cost per kWh is $0.02731 for all 12 months.~~the summer months of June through September is $0.03182. For all other months the base cost per kWh is $0.02857~~.

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service ~~in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5~~ on and after Month Day, 2011~~September 10, 2010~~.

APPLICATION

FUEL ADJUSTMENT CLAUSE

The average price per kWh of electricity generated or purchased will be adjusted subject to application of the FAC, and approved by the Public Service Commission. The price will reflect 85~~95~~ percent of the accumulation period costs either above or below base costs specified below for:

1. Fuel and AQCS consumables consumed in Company electric generating plants;
2. Purchased energy (excluding demand);
3. Off-system sales revenue;
4. Emission allowance costs and revenues; and
5. Renewable energy credit revenues.

It will also include:

6. An adjustment for the prior recovery period's over/under recovery of FAC Costs;
7. Interest at a rate equal to the Company's short-term interest rate will be applied to the average monthly deferred electric energy costs and will be accumulated during the accumulation period. Deferred electric energy cost shall be determined monthly. The monthly deferred amount may be negative or positive during the accumulation period.

The formula and components are displayed below.

$$FAC = \{[(F + P + E - O - R - B) * J] * 0.85\cancel{95}\} + C + I$$

Where:

F = Actual total cost of fuel - FERC Accounts 501 & 547, and AQCS consumables – FERC Account 506.2.

P = Actual total net system input cost of purchased energy - FERC Account 555 (excluding purchase power demand charges).

E = Actual total system net emission allowance cost and revenues - FERC Accounts 509 & 254.103.

O = Actual total system off-systemsales revenue.

B = Base cost of fuel and purchased power energy calculated as follows:

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 Original Sheet No. 17~~ei~~

Canceling P.S.C. Mo. No.______Sec. ______________ _________Sheet No. ________________________

For ALL TERRITORY

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service ~~in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5~~ on and after Month Day, 2011~~September 10, 2010~~.

1. For all 12 months~~the months of June through September~~	B = (NSI kWh * $0.02731~~03182~~)
~~2. For all other months~~	~~B = (NSI kWh * $0.02857)~~

DATE OF ISSUE ~~August 30, 2010~~Month Day, 2011 DATE EFFECTIVE ~~September 29, 2010~~Month Day, 2011

ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service ~~in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5~~ on and after Month Day, 2011~~September 10, 2010~~.

R = Renewable energy credit revenues.
J = Missouri energy ratio calculated as follows:

$$\text{Missouri energy ratio} = \frac{\text{Missouri retail kWh sales}}{\text{Total system kWh sales}}$$

Where Total system kWh sales excludes off-system sales.

C = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. This factor will reflect any modifications made due to prudence reviews.

I = Interest.

COST ADJUSTMENT FACTOR

The CAF is the result of dividing the FAC by estimated recovery period Missouri net system input (NSI) kWh, rounded to the nearest $.00000. The CAF shall be adjusted to reflect the differences in line losses that occur at primary and above voltage and secondary voltage by multiplying the average cost at the generator by 1.0502 and 1.0686, respectively. Any CAF authorized by the Commission shall be billed based upon customers' energy usage on and after the authorized effective date of the CAF. The formula and components are displayed below.

$$CAF = \frac{FAC}{S}$$

Where:

S = Forecasted Missouri NSI kWh for the recovery period. Missouri NSI kWh is calculated as:

$$\text{Missouri NSI} = \text{Forecasted NSI} * \frac{\text{Forecasted Missouri retail kWh sales}}{\text{Forecasted total system kWh sales}}$$

Where Forecasted Total System kWh Sales excludes off-system sales.

PRUDENCE REVIEW

There shall be a periodic review of fuel and energy costs subject to the FAC and a comparison of the FAC revenue collected. Prudence reviews shall occur no less frequently than at eighteen (18) month internvals.

TRUE-UP OF FAC

After completion of each recovery period, the Company will make a true-up filing in conjunction with an adjustment to its FAC on the first Filing Date that occurs after completion of each recovery period. The true-up adjustment shall be the difference between the revenues billed in the recovery period to the costs authorized for collection in the recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item C above and shall include interest calculated as provided for in item I above.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	Original	Sheet No.	17~~kg~~
Canceling P.S.C. Mo. No.		Sec.			Sheet No.	

For ALL TERRITORY

FUEL ADJUSTMENT CLAUSE
SCHEDULE FAC
For service ~~in Accumulation Periods after September 10, 2010; and for service in that portion of Accumulation Period 5~~ on and after Month Day, 2011~~September 10, 2010~~.

ACCUMULATION PERIOD ENDING, (Month, Day, Year)

1.	Total energy cost [(F + P + E – O - R) – B] * J * 0.~~9~~85	$XX,XXX,XXX
2.	Base energy cost (B)	$XX,XXX,XXX
3.	Missouri energy ratio (J)	X.XXXX
4.	Fuel cost recovery [(F + P + E – O - R) – B] * J * 0.~~9~~85	$XXX,XXX
5.	Adj for over/under recovery for the recovery period ending 00-00-0000 (C)	$X
6.	Interest (I)	$XX,XXX
7.	Fuel Adjustment Clause (FAC)	$XXX,XXX
8.	Forecasted Missouri NSI for the recovery period (S)	X,XXX,XXX,XXX
9.	Cost Adjustment Factor (CAF) to be applied to bills beginning 00-00-0000	$(X.XXXXX) / kWh
10.	CAF - Primary and above (Line 9 x Primary Expansion Factor)	$(X.XXXXX) / kWh
11.	CAF - Secondary (Line 9 x Secondary Expansion Factor)	$(X.XXXXX) / kWh

Primary Expansion Factor = 1.0502
Secondary Expansion Factor = 1.0686

DATE OF ISSUE ~~August 30, 2010~~Month Day, 2011 DATE EFFECTIVE ~~September 29, 2010~~Month Day, 2011
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

ELECTRIC SCHEDULE LS-2
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

APPLICABILITY: This schedule is applicable to services for lighting installations which illuminate streets, highways, and other outdoor ways and places where the Customer is a Governmental Agency (Agency) and owns the lighting fixtures, poles and interconnecting circuits. This schedule is also applicable for service to those installations where service is initially established in the name of a developer who has installed such systems as required by an Agency and, where ownership of facilities and responsibility for service will be transferred to an Agency. Where the Agency does not accept facilities or where no transfer is intended, service will be provided under an otherwise appropriate rate schedule and rule. Class C is closed to new installations and additional lamps in existing accounts. (D)

TERRITORY: The entirety of PG&E's service territory.

RATES: The total monthly charge per lamp is equal to the sum of the facility charge and the energy charge. The monthly charge per lamp used for billing is calculated using unrounded facility and energy charges.

Monthly facility charges include the costs of owning, operating and maintaining the various lamp types and size. Monthly energy charges are based on the kWh usage of each lamp.

Monthly energy charges per lamp are calculated using the following formula: (Lamp wattage + ballast wattage) x 4,100 hours/12 months/1000 x streetlight energy rate per kilowatt hour (kWh). Ballast wattage = ballast factor x lamp wattage.

Total bundled monthly facility and energy charges are shown below.

The various ballast wattages used in the monthly energy charge calculations can be found in the Ballast Factor table following the monthly energy charges. Ballast factors are averaged within each grouping (range of wattages). The same ballast factor is applied to all of the lamps that fall within its watt range. Applicant or Customer must provide third party documentation where manufacturer's information is not available for rated wattage consumption before PG&E will accept lamps for this schedule.

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with Condition 13, Billing, below.

(Continued)

ELECTRIC SCHEDULE LS-2
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

Facilities Charge Per Lamp Per Month

CLASS:	A	C***
	PG&E supplies energy and service only.	PG&E supplies the energy and maintenance service as described in Special Condition 8
	$0.187	$2.688

Energy Charge Per Lamp Per Month
All Night Rates

Nominal Lamp Rating:

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS*	Per Lamp Per Month: All Classes		Per Lamp Per Month: Half-Hour Adjustment	
INCANDESCENT LAMPS:						
58	20	600	$2.431	(I)	$0.111	(I)
92	31	1,000	$3.767	(I)	$0.171	(I)
189	65	2,500	$7.899	(I)	$0.359	(I)
295	101	4,000**	$12.275	(I)	$0.558	(I)
405	139	6,000**	$16.893	(I)	$0.768	(I)
620	212	10,000**	$25.764	(I)	$1.171	(I)
860	294	15,000**	$35.730	(I)	$1.624	(I)
MERCURY VAPOR LAMPS:						
40	18	1,300	$2.188	(I)	$0.099	(I)
50	22	1,650	$2.674	(I)	$0.122	(I)
100	40	3,500	$4.861	(I)	$0.221	(I)
175	68	7,500	$8.264	(I)	$0.376	(I)
250	97	11,000	$11.788	(I)	$0.536	(I)
400	152	21,000	$18.473	(I)	$0.840	(I)
700	266	37,000	$32.327	(I)	$1.469	(I)
1,000	377	57,000	$45.817	(I)	$2.083	(I)

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* Latest published information should be consulted on best available lumens.

** Service for incandescent lamps over 2,500 lumens will be closed to new installations after September 11, 1978.

*** Closed to new installations and new lamps on existing circuits, see Condition 8A.

(Continued)

ELECTRIC SCHEDULE LS-2

Sheet 3

CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS	All Classes		Half-Hour Adjustment	
HIGH PRESSURE SODIUM VAPOR LAMPS AT: 120 VOLTS						
35	15	2,150	$1.823	(I)	$0.083	(I)
50	21	3,800	$2.552	(I)	$0.116	(I)
70	29	5,800	$3.524	(I)	$0.160	(I)
100	41	9,500	$4.983	(I)	$0.227	(I)
150	60	16,000	$7.292	(I)	$0.331	(I)
200	80	22,000	$9.722	(I)	$0.442	(I)
250	100	26,000	$12.153	(I)	$0.552	(I)
400	154	46,000	$18.716	(I)	$0.851	(I)
HIGH PRESSURE SODIUM VAPOR LAMPS AT: 240 VOLTS						
50	24	3,800	$2.917	(I)	$0.133	(I)
70	34	5,800	$4.132	(I)	$0.188	(I)
100	47	9,500	$5.712	(I)	$0.260	(I)
150	69	16,000	$8.386	(I)	$0.381	(I)
200	81	22,000	$9.844	(I)	$0.447	(I)
250	100	25,500	$12.153	(I)	$0.552	(I)
310	119	37,000	$14.462	(I)	$0.657	(I)
360	144	45,000	$17.500	(I)	$0.795	(I)
400	154	46,000	$18.716	(I)	$0.851	(I)
LOW PRESSURE SODIUM VAPOR LAMPS:						
35	21	4,800	$2.552	(I)	$0.116	(I)
55	29	8,000	$3.524	(I)	$0.160	(I)
90	45	13,500	$5.469	(I)	$0.249	(I)
135	62	21,500	$7.535	(I)	$0.343	(I)
180	78	33,000	$9.479	(I)	$0.431	(I)

(Continued)

ELECTRIC SCHEDULE LS-2
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS	All Classes		Half-Hour Adjustment	
METAL HALIDE LAMPS:						
70	30	5,500	$3.646	(I)	$0.166	(I)
100	41	8,500	$4.983	(I)	$0.227	(I)
150	63	13,500	$7.656	(I)	$0.348	(I)
175	72	14,000	$8.750	(I)	$0.398	(I)
250	105	20,500	$12.761	(I)	$0.580	(I)
400	162	30,000	$19.688	(I)	$0.895	(I)
1,000	387	90,000	$47.032	(I)	$2.138	(I)
INDUCTION LAMPS:						
23	9	1,840	$1.094	(I)	$0.050	(I)
35	13	2,450	$1.580	(I)	$0.072	(I)
40	14	2,200	$1.701	(I)	$0.077	(I)
50	18	3,500	$2.188	(I)	$0.099	(I)
55	19	3,000	$2.309	(I)	$0.105	(I)
65	24	5,525	$2.917	(I)	$0.133	(I)
70	27	6,500	$3.281	(I)	$0.149	(I)
80	28	4,500	$3.403	(I)	$0.155	(I)
85	30	4,800	$3.646	(I)	$0.166	(I)
100	36	8,000	$4.375	(I)	$0.199	(I)
120	42	8,500	$5.045	(I)	$0.229	(I)
135	48	9,450	$5.833	(I)	$0.265	(I)
150	51	10,900	$6.198	(I)	$0.282	(I)
165	58	12,000	$7.049	(I)	$0.320	(I)
200	72	19,000	$8.750	(I)	$0.398	(I)

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 5

CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT EMITTING DIODE (LED) LAMPS: 120-240 VOLTS

LAMP WATTS****	kWh per MONTH*****	Energy Rates Per Lamp Per Month		Half-Hour Adjustment		(T) (T)
0.00-5.00	0.9	$0.109	(I)	$0.005		
5.01-10.00	2.6	$0.316	(I)	$0.014		
10.01-15.00	4.3	$0.523	(I)	$0.024	(I)	
15.01-20.00	6.0	$0.729	(I)	$0.033	(I)	
20.01-25.00	7.7	$0.936	(I)	$0.043	(I)	
25.01-30.00	9.4	$1.142	(I)	$0.052	(I)	
30.01-35.00	11.1	$1.349	(I)	$0.061	(I)	
35.01-.40.00	12.8	$1.556	(I)	$0.071	(I)	
40.01-45.00	14.5	$1.762	(I)	$0.080	(I)	
45.01-50.00	16.2	$1.969	(I)	$0.090	(I)	
50.01-55.00	17.9	$2.175	(I)	$0.099	(I)	
55.01-60.00	19.6	$2.382	(I)	$0.108	(I)	
60.01-65.00	21.4	$2.601	(I)	$0.118	(I)	
65.01-70.00	23.1	$2.807	(I)	$0.128	(I)	
70.01-75.00	24.8	$3.014	(I)	$0.137	(I)	
75.01-80.00	26.5	$3.221	(I)	$0.146	(I)	
80.01-85.00	28.2	$3.427	(I)	$0.156	(I)	
85.01-90.00	29.9	$3.634	(I)	$0.165	(I)	
90.01-95.00	31.6	$3.840	(I)	$0.175	(I)	
95.01-100.00	33.3	$4.047	(I)	$0.184	(I)	
100.01-105.00	35.0	$4.254	(I)	$0.193	(I)	
105.01-110.00	36.7	$4.460	(I)	$0.203	(I)	
110.01-115.00	38.4	$4.667	(I)	$0.212	(I)	
115.01-120.00	40.1	$4.873	(I)	$0.222	(I)	
120.01-125.00	41.9	$5.092	(I)	$0.231	(I)	
125.01-130.00	43.6	$5.299	(I)	$0.241	(I)	
130.01-135.00	45.3	$5.505	(I)	$0.250	(I)	
135.01-140.00	47.0	$5.712	(I)	$0.260	(I)	
140.01-145.00	48.7	$5.919	(I)	$0.269	(I)	

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 6
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

LAMP WATTS****	kWh per MONTH*****	Energy Rates Per Lamp Per Month		Half-Hour Adjustment		(T) (T)
145.01-150.00	50.4	$6.125	(I)	$0.278	(I)	
150.01-155.00	52.1	$6.332	(I)	$0.288	(I)	
155.01-160.00	53.8	$6.538	(I)	$0.297	(I)	
160.01-165.00	55.5	$6.745	(I)	$0.307	(I)	
165.01-170.00	57.2	$6.952	(I)	$0.316	(I)	
170.01-175.00	58.9	$7.158	(I)	$0.325	(I)	
175.01-180.00	60.6	$7.365	(I)	$0.335	(I)	
180.01-185.00	62.4	$7.583	(I)	$0.345	(I)	
185.01-190.00	64.1	$7.790	(I)	$0.354	(I)	
190.01-195.00	65.8	$7.997	(I)	$0.364	(I)	
195.01-200.00	67.5	$8.203	(I)	$0.373	(I)	
200.01-205.00	69.2	$8.410	(I)	$0.382	(I)	
205.01-210.00	70.9	$8.616	(I)	$0.392	(I)	
210.01-215.00	72.6	$8.823	(I)	$0.401	(I)	
215.01-220.00	74.3	$9.030	(I)	$0.410	(I)	
220.01-225.00	76.0	$9.236	(I)	$0.420	(I)	
225.01-230.00	77.7	$9.443	(I)	$0.429	(I)	
230.01-235.00	79.4	$9.649	(I)	$0.439	(I)	
235.01-240.00	81.1	$9.856	(I)	$0.448	(I)	
240.01-245.00	82.9	$10.075	(I)	$0.458	(I)	
245.01-250.00	84.6	$10.281	(I)	$0.467	(I)	
250.01-255.00	86.3	$10.488	(I)	$0.477	(I)	
255.01-260.00	88.0	$10.695	(I)	$0.486	(I)	
260.01-265.00	89.7	$10.901	(I)	$0.496	(I)	
265.01-270.00	91.4	$11.108	(I)	$0.505	(I)	
270.01-275.00	93.1	$11.314	(I)	$0.514	(I)	
275.01-280.00	94.8	$11.521	(I)	$0.524	(I)	
280.01-285.00	96.5	$11.728	(I)	$0.533	(I)	

(Continued)

ELECTRIC SCHEDULE LS-2

Sheet 7

CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

LAMP WATTS****	kWh per MONTH*****	Energy Rates Per Lamp Per Month		Half-Hour Adjustment		(T) (T)
285.01-290.00	98.2	$11.934	(I)	$0.542	(I)	
290.01-295.00	99.9	$12.141	(I)	$0.552	(I)	
295.01-300.00	101.6	$12.347	(I)	$0.561	(I)	
300.01-305.00	103.4	$12.566	(I)	$0.571	(I)	
305.01-310.00	105.1	$12.773	(I)	$0.581	(I)	
310.01-315.00	106.8	$12.979	(I)	$0.590	(I)	
315.01-320.00	108.5	$13.186	(I)	$0.599	(I)	
320.01-325.00	110.2	$13.393	(I)	$0.609	(I)	
325.01-330.00	111.9	$13.599	(I)	$0.618	(I)	
330.01-335.00	113.6	$13.806	(I)	$0.628	(I)	
335.01-340.00	115.3	$14.012	(I)	$0.637	(I)	
340.01-345.00	117.0	$14.219	(I)	$0.646	(I)	
345.01-350.00	118.7	$14.426	(I)	$0.656	(I)	
350.01-355.00	120.4	$14.632	(I)	$0.665	(I)	
355.01-360.00	122.1	$14.839	(I)	$0.675	(I)	
360.01-365.00	123.9	$15.058	(I)	$0.684	(I)	
365.01-370.00	125.6	$15.264	(I)	$0.694	(I)	
370.01-375.00	127.3	$15.471	(I)	$0.703	(I)	
375.01-380.00	129.0	$15.677	(I)	$0.713	(I)	
380.01-385.00	130.7	$15.884	(I)	$0.722	(I)	
385.01-390.00	132.4	$16.091	(I)	$0.731	(I)	
390.01-395.00	134.1	$16.297	(I)	$0.741	(I)	
395.01-400.00	135.8	$16.504	(I)	$0.750	(I)	

(L)

**** Wattage based on total consumption of lamp and driver. Customer may be required to provide verification of total energy consumption of lamp and driver upon request by PG&E.

***** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is: (high wattage in range-2.5 watts)x(4,100 hours/12 months/1000) (L)

(Continued)

ELECTRIC SCHEDULE LS-2
Sheet 8

CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

Ballast Factors by Lamp Type and Wattage Range

(L)

Watt Range			Ballast Factor
MERCURY VAPOR			
1	to	75	31.00%
76	to	125	17.07%
126	to	325	13.69%
326	to	800	11.22%
801	+		10.34%
LOW PRESSURE SODIUM VAPOR			
1	to	40	75.61%
41	to	75	54.32%
76	to	110	46.34%
111	to	160	34.42%
161	+		26.83%
METAL HALIDE			
1	to	85	25.44%
86	to	200	20.39%
201	to	375	22.93%
376	to	700	18.54%
701	+		13.27%

Watt Range			Ballast Factor
HIGH PRESSURE SODIUM VAPOR			
120 Volts			
1	to	40	25.44%
41	to	60	22.93%
61	to	85	21.25%
86	to	125	20.00%
126	+		17.07%
240 Volts			
1	to	60	40.49%
61	to	85	42.16%
86	to	125	37.56%
126	to	175	34.63%
176	to	225	18.54%
226	to	280	17.07%
281	to	380	12.35%
381	+		12.68%

(L)

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 9

CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

TOTAL ENERGY RATES

Total Energy Charge Rate ($ per kWh)	$0.12153	(I)

UNBUNDLING OF TOTAL ENERGY CHARGES

The total energy charge is unbundled according to the component rates shown below.

Energy Rate by Components ($ per kWh)		
Generation	$0.06336	
Distribution	$0.02937	(R)
Transmission*	$0.00812	(I)
Transmission Rate Adjustments*	$0.00148	(I)
Reliability Services*	$0.00025	
Public Purpose Programs	$0.00733	
Nuclear Decommissioning	$0.00066	
Competition Transition Charge	$0.00119	
Energy Cost Recovery Amount	$0.00472	
DWR Bond	$0.00505	

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 10
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

SPECIAL CONDITIONS:

1. **TYPE OF SERVICE**: This schedule is applicable to multiple lighting systems to which PG&E will deliver current at secondary voltage. Multiple current will normally be supplied at 120/240 Volt, single-phase. In certain localities PG&E may supply service from 120/208 Volt, wye-systems, polyphase lines in place of 240 Volt service. Unless otherwise agreed, existing series current will be delivered at 6.6 amperes. Single-phase service from 480 Volt sources and series circuits will be available in certain areas at the option of PG&E when this type of service is practical from PG&E's engineering standpoint. All currents and voltages stated herein are nominal, reasonable variations being permitted. (L)

   New lights will normally be supplied as multiple systems. Series service to new lights will be made only when it is practical from PG&E's engineering standpoint to supply them from existing series systems.

2. **SERVICE REQUIREMENTS**:

   a) **PHOTO CONTROLS**

   This rate schedule is predicated on an electronic type photo controls meeting ANSI standard C136.10, with a turn on value of 1.0 foot-candles and a turn off value of 1.5 foot-candles. Electro-mechanical or thermal type photo controls are not acceptable for this rate schedule.

   b) **LIGHT or POLE NUMBERING**

   As agreed upon by the parties, pole number sequencing and coding for single lights or multiple lights on a single pole, shall be provided by either party and must conform to PG&E's billing system. Customer will provide physical numbering on lights or poles for LS-2 installations in order to facilitate accurate billing and inventory reporting. Numbering is required prior to energizing facilities. Numbering must be legible from the ground.

   c) **SERVICE REQUESTS**

   Service requests for installation and energizing of Customer's facilities may be submitted on forms 79-1007 or 79-1107. Removal or de-energizing of Customer's facilities may be requested on form 79-1008.

   d) **WATTAGE STICKERS REQUIRED**

   A wattage sticker, visible from the ground, of a size and type acceptable to PG&E showing total fixture energy use in watts for LED, nominal wattage rating (in watts) for induction lighting, or stickers meeting requirements of ANSI Standard C136.15 for other lamp types must be installed on each fixture. (L)

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 11
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

SPECIAL CONDITIONS: (Cont'd.)

3. **SERVICE INSTALLATION** (L)

PG&E will establish service delivery points within close proximity to its distribution system.

a) **Overhead:** In an overhead area, a single drop will be installed. For an overhead to underground system, service will be established in a PG&E box at the base of the riser pole or other agreed upon location within close proximity. PG&E will connect Customer's conductors at the service delivery point.

b) **Underground:** In an underground area, service will be established at the nearest existing secondary box. Where no secondary facilities exist, a new service, transformer and secondary splice box, as required, will be installed in the shortest most practical configuration from the connection on the distribution line source. Customer shall install and own all facilities from the service delivery point on PG&E's system.

c) **Customer Installation Responsibility:** Customer shall install, own and maintain all facilities beyond the service delivery point. For PG&E's serving facilities, Customer or Applicant, at its expense, shall perform all necessary trenching, backfill and paving, and shall furnish and install all necessary conduit and substructures (including substructures for transformer installations, if necessary, for street lights only) in accordance with PG&E's specifications. Riser material shall be installed by PG&E at the Customer's expense. Upon acceptance by PG&E, ownership of the conduit and substructures shall vest in PG&E. Customer shall provide rights of way as provided in electric Rule 16.

d) **PG&E Installation Responsibility:** PG&E shall furnish and install the underground or overhead service conductor, transformers and necessary facilities to complete the service to the distribution line source, subject to the payment provisions of Special Condition 4. Only duly authorized employees of PG&E shall connect Customer's loads to, or disconnect the same from, PG&E's electrical distribution facilities.

e) **Rearrangements:** Customer or Applicant shall pay, in advance, PG&E's estimated cost for any relocation or rearrangement of PG&E's existing street light or service facilities requested by Customer or Applicant and agreed to by PG&E.

f) **Non-Conforming Load:** Applicant or Customer must be a governmental agency. Any load, other then the lighting loads listed in the Rate table above, is non conforming load. Non conforming load may be connected to customer circuits not to exceed 150 watts per circuit, or light for individually connected lights. Loads will conform to the requirements of Agreement form 79-1048 available on PG&E's web site, http://www.pge.com/tariffs/EF.SHTML#EF for electric forms. All other non conforming load connected to unmetered LS-2 facilities exceeding this limitation requires metering of the Customer's system at PG&E's service delivery point. (L)

(Continued)

ELECTRIC SCHEDULE LS-2
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

SPECIAL CONDITIONS: (Cont'd.)

4. **NON REFUNDABLE PAYMENT FOR SERVICE INSTALLATION**: (L)

   a) Customer or Applicant shall pay in advance the estimated installed cost necessary to establish a service delivery point. A one-time revenue allowance will be provided based on Customer's kWh usage and the distribution component of the energy rate posted in the Rate Schedule for the lamps installed. The total allowance shall be determined by taking the annual equivalent kWh times the Distribution component of this rate divided by the cost of service factor shown in Electric Rule 15.C.

   b) The allowance will only be provided where PG&E must install capital assets to connect load. No allowance will be provided where a simple connection is required. Only lights on a minimum 11 hour All Night (AN) schedule for permanent service shall be granted an allowance. Where Applicant received allowances based upon 11 hour AN operation, no billing adjustments, as otherwise provided for in Special Condition 7, shall be made for the first three (3) years following commencement of service.

   Line or service extensions in excess of the above shall be installed under special condition 9.

5. **TEMPORARY SERVICE:** Temporary services will be installed under electric Rule 13.

6. **ANNUAL OPERATING SCHEDULES**: The above rates for AN service assume 11 hours operation per night and apply to lamps which will be turned on and off once each night in accordance with a regular operating schedule selected by the Customer but not exceeding 4,100 hours per year. (L)

(Continued)

ELECTRIC SCHEDULE LS-2

Sheet 13

CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

SPECIAL CONDITIONS: (Cont'd.)

7. **OPERATING SCHEDULES OTHER THAN ALL-NIGHT:** Rates for regular operating schedules other than full all-night will be the AN rate, plus or minus, respectively, the half-hour adjustment for each half-hour more or less than an average of 11 hours per night. This adjustment will apply only to lamps on regular operating schedules of not less than 1,095 hours per year, or 3 hours per night, and may be applied for 24-hour operation. Photo control devices used for more or less than AN must be approved by PG&E prior to adjustments in billing. (L)

8. **MAINTENANCE, ACCESS, CLEARANCES**

   a) Maintenance

      The C rates include all labor and material necessary for the inspection, cleaning, or replacement by PG&E of lamps and glassware. Replacement is limited to certain glassware such as is commonly used and manufactured in reasonably large quantities. A commensurate extra charge will be made for maintenance of glassware of a type entailing unusual expense. The Class C rate also includes all labor and material necessary for replacement by PG&E of photoelectric controls. Class C rates are closed to new installations and to additional lamps in existing accounts as of March 1, 2006.

   b) Under the grand fathered Class C rates, the following shall apply:

      1) At Customer's request, where PG&E's resources permit, PG&E will paint poles for Customer on a time and material basis. This service will only be offered for poles that have been designed to be painted.

      2) PG&E will Isolate any trouble in the Customer's system which has resulted in an outage or diminished light output.

      3) PG&E will make necessary repairs which do not require wiring replacement on accessible wiring between poles and on equipment and wiring in and on poles to keep the system in operating condition.

      4) PG&E will provide labor for the replacement of material such as ballasts, relays, fixtures, individual cable runs between poles where such runs are in conduit, and other individual parts of the system that are not capital items.

      5) Customer shall compensate PG&E for any material furnished by PG&E not included in 8.A. above. Customer must have been on Class C for this service.

      6) PG&E shall not be responsible for excavation or any major replacement of circuits, conduits, poles, or fixtures owned by the Customer.

      7) Tree trimming is the responsibility of the Customer for installation of new lights or for maintaining lighting patterns of existing lights. (L)

(Continued)

ELECTRIC SCHEDULE LS-2
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

SPECIAL CONDITIONS: (Cont'd.)

8. **MAINTENANCE, ACCESS, CLEARANCES** (Cont'd.): (L)

   c) Access

   Customer will maintain adequate access for PG&E's standard equipment used in maintaining facilities and for installation of its facilities. PG&E reserves the right to collect additional maintenance costs due to obstructed access or other conditions preventing PG&E from maintaining its equipment with standard operating procedures. Applicant or Customer shall be responsible for rearrangement charges as provided for in Special Condition 3.e.

   d) Clearances

   Customer applicant shall, at its expense, correct all access or clearance infractions, or pay PG&E its total estimated cost for PG&E to relocate facilities to a new location which is acceptable to PG&E. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service in accordance with electric Rule 11. Applicant or Customer shall be responsible for tree trimming to maintain lighting patterns of existing lights. (L)

(Continued)

ELECTRIC SCHEDULE LS-2
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

SPECIAL CONDITIONS: (Cont'd.)

9. **LINE EXTENSIONS** (L)

   A. Where PG&E extends its facilities to street light installations in advance of subdivision projects where subdivision maps have been approved by local authorities, extensions will be installed under the provisions of electric Rule 15, except as noted below.

   B. Where PG&E extends its facilities to street light installations in the absence of any approved subdivision maps, applicant shall pay PG&E's estimated cost, plus cost of ownership and applicable tax. Standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work, shall be used for these installations.

10. **STREET LIGHT LAMPS – STANDARD AND NONSTANDARD RATINGS:** The rates under Class C are applicable to both standard and group replacement street (T) lamps. Standard and group replacement street lamps have reference only to street lamps having wattage and operating life ratings within three percent of those specified in the EEI-NEMA Standards for Filament Lamps Used in Street Lighting. Where Class A service is supplied to lamps of other ratings than those specified in EEI-NEMA Standards an adjustment will be made in the lamp rates proportionate to the difference between the wattage of the lamps and the standard lamps of the same lumen rating.

11. **ENERGY EFFICIENT STREET LIGHTS:** Where Customer permanently installs energy efficient street lights and total energy use cannot be verified through industry standard test results and customer requests that the energy efficient street lights be added to this tariff, customer may be required to provide specific performance data on the total energy consumption of the fixture (which includes controls, lamp and ballast or driver) as requested by PG&E.

12. **CONTRACT:** Except as otherwise provided in this rate schedule, or where lighting service is installed in conjunction with facilities installed under the provisions of Rules 15 or 16, standard form contract 62-4527, Agreement to Perform Tariff Schedule Related Work shall be used for installations, rearrangements or relocations.

13. **POLE CONTACT AGREEMENT:** Where Customer requests to have a portion or all Customer owned street lighting facilities in contact with PG&E's distribution poles, a Customer-Owned Streetlights PG&E Pole Contact Agreement (Form 79 938) will be required.

(L)

(Continued)

ELECTRIC SCHEDULE LS-2
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

Sheet 16

SPECIAL CONDITIONS: (Cont'd.)

14. **BILLING:** This Rate Schedule is subject to PG&E's other rules governing billing issues, as may be applicable. PG&E performs regular auditing as part of this rate schedule. (L)

Limited testing of Energy Efficient Street Light Technology will be allowed under this Rate Schedule where a light of the type and wattage of the fixture and lamp to be tested are not presently included in the rate tables. Such test installations are subject to approval by PG&E. Following approval, test installations will be billed at the customer's currently billed rate. Customer will provide a monthly inventory of streetlights that will be tested. The format and content of the inventory must be approved by PG&E. The Company reserves the right to audit customer. PG&E also reserves the right to collect the cost of any such audit from the customer. Testing is limited to existing street light fixtures and the total energy consumption per fixture must not exceed current energy use per fixture. Additional energy efficient street light fixtures installed will also be subject to billing under the current rate upon the approval of PG&E. The test period will not exceed 12 months.

Bundled Service Customers receive supply and delivery service solely from PG&E. The Customer's bill is based on the Total Rate set forth above.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00472	(I)
DWR Bond Charge (per kWh)	$0.00505	(R)
CTC Charge (per kWh)	$0.00119	(I)
Power Charge Indifference Adjustment (per kWh)		
Pre-2009 Vintage	($0.00115)	(R)
2009 Vintage	$0.00243	(I)
2010 Vintage	$0.00263	(I)
2011 Vintage	$0.00263	(N)

15. **DWR BOND CHARGE:** The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts. (L)

LED Street Light Rebates

Program Components

Pacific Gas and Electric Company's (PG&E) LED Street Light Program will offer street light customers on our LS-2 rate two ways to save energy and money when replacing traditional street lighting.

Rate Change

Customers who have installed or replaced existing street light fixtures after May 1st, 2009 with LED fixtures will be able to switch to a lower billing rate under the LS-2 rate schedule.

Potential LED Replacement Savings

Customers who have purchased and installed pre-qualified LED fixtures after May 1, 2009, may be eligible for rebates. Read below to learn more about which fixtures qualify.

Rebate/fixture	
Replace 70 watt fixture with new LED fixture	$50
Replace 100 watt fixture with new LED fixture	$75
Replace 150 watt fixture with new LED fixture	$100
Replace 200 watt fixture with new LED fixture	$125
Replace 250 watt fixture with new LED fixture	$150
Replace 310 watt fixture with new LED fixture	$175
Replace 400 watt fixture with new LED fixture	$200

Please email led@pge.com to request a street light rebate and rate change application.

Qualified LED Street Light Fixtures

Only well-designed LED products using the latest in LED technology that are appropriate for the application will offer the energy savings, lighting quality, and lifetime benefits sought. To help customers select quality LED street light fixtures, PG&E has worked with the U.S. Department of Energy and other utility partners to develop stringent performance standards. To qualify for the PG&E LED Street Light Program rebate, LED products must provide a variety of independent tests that help ensure they will deliver as promised.

Schedule HK 2 - 1

The Design Lights Consortium (DLC) maintains a listing of all non-Energy Star LED products meeting the performance standards required of our programs. In addition to these specifications, PG&E requires that LED Street Light products also meet the following service requirements:

> Photo Controls: Fixtures must be socket ready for electronic type photo controls meeting American National Standards Institute (ANSI) standard C136.10 with a turn on value of 1.0 foot-candles and a turn off value of 1.5 foot-candles. Electro-mechanical or thermal type photo controls are not acceptable.
>
> Manufacturer Labeling: Wattage Stickers identifying the fixture technology (LED) and total fixture wattage that follows ANSI Standard C136.15, already used by nearly all manufacturers and customers for identification of light types currently included in the standard.

If you are a manufacturer wishing to submit LED Street Light products for inclusion in PG&ampE's program, please review information on the DLC's Manufacturer Application Overview and then follow the requirements as outlined on the DLC's Manufacturer Application Process.

Customers who install non-qualified LED fixtures will still be able to switch to the lower LS-2 rate schedule, but will not be eligible for the rebates.

Customer wishing to install Induction Street Lighting may be eligible for both the lower LS-2 rate as well as a calculated incentive. See information on our Customized Retrofit Incentives page for information.

If you have any questions please contact us at led@pge.com.

Schedule LS-2 Sheet 1

LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE

APPLICABILITY

Applicable to unmetered service for the lighting of streets, highways, other public thoroughfares, and publicly-owned and publicly-operated automobile parking lots which are open to the general public, where the customer owns the street lighting equipment including, but not limited to, the pole, mast arm, luminaire and lamp, and all connecting cable in a street light system.

TERRITORY

Within the entire territory served.

RATES

	Delivery Service								Generation[9]	
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	DWRBC[6]	PUCRF[7]	Total[8]	URG**	DWR
Energy Charge* - $/kWh/Lamp/Month										
All Night Service	0.00414 (I)	0.01385	0.00069	0.00064	0.00773	0.00505	0.00024	0.03234 (I)	0.05041	0.03952
Midnight Service	0.00414 (I)	0.01385	0.00069	0.00064	0.00773	0.00505	0.00024	0.03234 (I)	0.05041	0.03952

Multiple Service - Rate A

The following rates are applicable where SCE is requested to provide a single feed point to service a customer-owned street light system where the customer provides a point of connection for a single SCE owned photo-controller to control all street lights in the system.

	Trans	Distrbtn	NSGC	NDC	PPPC	DWRBC	PUCRF	Total	URG**	DWR
All Night/Midnight Service Charge										
Incandescent Extended Service Lamps - $/Lamp/Month		1.97						1.97		
Mercury Vapor Lamps - $/Lamp/Month		1.97						1.97		
Light Emitting Diode (LED) Lamps - $/Lamp/Month		1.97						1.97		
High Pressure Sodium Vapor Lamps - $/Lamp/Month		1.97						1.97		
Low Pressure Sodium Vapor Lamps - $/Lamp/Month		1.97						1.97		
Metal Halide Lamps - $/Lamp/Month		1.97						1.97		
Induction Lamps - $/Lamp/Month		1.97						1.97		
All Other Lamps - $/Lamp/Month		1.97						1.97		

* The kilowatt hours used to determine the Energy Charge for the lamp types and sizes served under this Schedule are shown in the Special Conditions section, below.
** The ongoing Competition Transition Charge (CTC) of $0.00010 per kWh is recovered in the URG component of Generation.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00027) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00003 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00036 per kWh.
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.
7 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
8 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
9 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule LS-2 Sheet 2

LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

RATES (Continued)

	Delivery Service								Generation[9]	
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	DWRBC[6]	PUCRF[7]	Total[8]	URG**	DWR
Multiple Service - Rate B										
The following rates are applicable where SCE is requested to provide a service connection point to feed a customer-owned street light with a customer-owned photocell.										
All Night/Midnight Service Charge										
Incandescent Extended Service Lamps - $/Lamp/Month		4.05						4.05		
Mercury Vapor Lamps - $/Lamp/Month		4.05						4.05		
Light Emitting Diode (LED) Lamps - $/Lamp/Month		4.05						4.05		
High Pressure Sodium Vapor Lamps - $/Lamp/Month		4.05						4.05		(T)
Low Pressure Sodium Vapor Lamps - $/Lamp/Month		4.05						4.05		
Metal Halide Lamps - $/Lamp/Month		4.05						4.05		
Induction Lamps - $/Lamp/Month		4.05						4.05		
All Other Lamps - $/Lamp/Month		4.05						4.05		

** The ongoing Competition Transition Charge (CTC) of $0.00010 per kWh is recovered in the URG component of Generation. (T)
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved.
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.
7 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
8 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS. (T)
9 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule LS-2 — Sheet 3

LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

RATES (Continued)

	Delivery Service								Generation[9]	
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	DWRBC[6]	PUCRF[7]	Total[8]	URG**	DWR
Series Service										
All Night/Midnight Service Charge										
Incandescent Extended Service Lamps - $/Lar		9.04						9.04		
Mercury Vapor Lamps - $/Lamp/Month		9.04						9.04		
High Pressure Sodium Vapor Lamps - $/Lamp/		9.04						9.04		
Low Pressure Sodium Vapor Lamps - $/Lamp/I		9.04						9.04		
Metal Halide Lamps - $/Lamp/Month		N/A						N/A		
All Other Lamps - $/Lamp/Month		9.04						9.04		
Series Service Power Factor Charge* - $/kVar		0.29 (I)						0.29 (I)		
Series Service Voltage Discount, Energy - $/kWh		0.00000						0.00000	(0.00164)	

* kVAR losses for the Series Service Power Factor Charge are calculated in accordance with Special Condition 14.
** The ongoing Competition Transition Charge (CTC) of $0.00010 per kWh is recovered in the URG component of Generation.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved.
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.
7 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
8 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
9 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule LS-2 Sheet 4

LIGHTING - STREET AND HIGHWAY

CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE

(Continued)

RATES (Continued)

	Delivery Service								Generation[9]	
	Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	DWRBC[6]	PUCRF[7]	Total[8]	URG**	DWR
Optional Relamp Service Charge										
Incandescent Extended Service Lamps- $/Lamp/Month		N/A						N/A		
Mercury Vapor Lamps- $/Lamp/Month		N/A						N/A		
High Pressure Sodium Vapor Lamps - $/Lamp/Month										
50 Watt		0.51						0.51		
70 Watt		0.51						0.51		
100 Watt		0.51						0.51		
150 Watt		0.51						0.51		
200 Watt		0.52						0.52		
250 Watt		0.52						0.52		
310 Watt		N/A						N/A		
400 Watt		0.53						0.53		
Low Pressure Sodium Vapor Lamps- $/Lamp/Month		N/A						N/A		
Metal Halide Lamps- $/Lamp/Month		N/A						N/A		
All Other Lamps- $/Lamp/Month		N/A						N/A		

** The ongoing Competition Transition Charge (CTC) of $0.00010 per kWh is recovered in the URG component of Generation. (T)
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved.
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.
7 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
8 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) customers, except DA and CCA Service customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
9 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule LS-2 Sheet 5 (T)
LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

SPECIAL CONDITIONS

1. Ownership of Facilities:

   a. For multiple systems SCE will deliver service at 120, 120/240 volts, or, at the option of SCE, at 240/480 or 277/480 volts, three wire, single phase. For existing series systems (installed prior to October 25, 1981) SCE will furnish and maintain constant current regulating transformers and deliver service at the secondary side of such transformers.

   b. The customer will furnish and maintain all utilization equipment beyond the point of delivery except for switching equipment and where the customer has elected the Optional Relamp Service provided by SCE in accordance with Special Condition 5.

   c. New or modified installations normally shall be multiple service installations. New or modified series installations shall be made only where, in the opinion of SCE, it is practical to supply series service.

   d. For new or modified series installations requiring a new constant current regulating transformer, the customer shall furnish and maintain the transformer; and service will be delivered at the primary side of the transformer.

(Continued)

Schedule LS-2 Sheet 6 (T)

LIGHTING - STREET AND HIGHWAY

CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE

(Continued)

SPECIAL CONDITIONS (Continued)

2. Service Connections and Distribution Extensions:

   a. The point or points of service connection shall be mutually agreed upon by SCE and the customer.

   b. Distribution line extensions to reach a street light or a street light system shall be in accordance with the applicable Rule 15.

3. Switching and Related Facilities: For All Night or Midnight Service under SCE's standard operating schedules, SCE will furnish, operate, and maintain, the necessary switching facilities. All auxiliary relay equipment, irrespective of voltage, not furnished by SCE, but required in connection with providing street lighting service, shall be furnished, installed, and maintained by the customer in accordance with SCE's requirements.

4. Hours of Service: Under SCE's standard All Night Service operating schedule approximately 4,140 hours of service per year will be furnished, and under SCE's standard Midnight Service operating schedule approximately 2,170 hours of service per year will be furnished. Service for other operating schedules is not available under this Schedule.

5. Optional Relamp Service: Closed to all new installations. Optional relamp service will be provided at the request of the customer. The charges thereunder shall be in addition to any other applicable charges. After the original lamp installation, relamp service will be furnished by SCE as soon as practicable after notification by the customer. Relamp service is provided only for the high pressure sodium vapor lamps listed on this Schedule for which charges are shown. At the time of relamping, SCE will clean the refractor, or install replacement refractors furnished by the customer, as required. This service will be provided only where, in the opinion of SCE, no undue hazard or expense will result because of location, mounting height, or other reason.

(Continued)

Schedule LS-2 Sheet 7 (T)

LIGHTING - STREET AND HIGHWAY

CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE

(Continued)

SPECIAL CONDITIONS (Continued)

6. Removal of Equipment: Where SCE-owned street lighting service and/or facilities were ordered removed by a customer and such service and/or facilities, or their equivalent, are ordered reinstalled within 36 months from the date of the order to remove, the customer shall pay to SCE in advance of reinstallation a nonrefundable amount equal to the cost of removal of the prior facilities and the estimated cost of such reinstallation. SCE-owned facilities removed or installed remain the sole property of SCE.

7. Modification of Facilities: Where the customer requests a modification of SCE-owned facilities serving customer-owned street light facilities, and such modifications are acceptable to SCE, SCE will perform the requested modifications, provided the customer agrees to pay the cost of said modifications.

8. Midnight Service: Where the customer requests the installation and/or removal of equipment in order to take Midnight Service, and such request is acceptable to SCE, SCE will comply with such request provided the customer first agrees to pay to SCE the estimated cost installed of any additional equipment required and/or the removal cost of any equipment currently installed. Such payments will not be refunded and shall be paid in advance or in installments acceptable to SCE over a period not to exceed three years. Facilities installed in connection with such requests become and remain the sole property of SCE .

9. Contract: In accordance with Rule 4, a written contract for a term of not less than one year and not more than five years is required in order to receive street light service under the provisions of this Schedule. Should the customer terminate service within 36 months of the date service is first supplied, the customer shall pay to SCE the cost of installation plus the cost of removal less salvage for any SCE-owned facilities installed to supply the customer's street light service.

(Continued)

Schedule LS-2 Sheet 8 (T)
LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

10. Kilowatthours: The kilowatthours used to determine the Energy Charge and the Voltage Discount shall be as follows:

Nominal Lamp Rating		Lamp Load Including Ballast - Watts		kWh per Lamp Per Month*			
				Multiple Service kWh		Series Service kWh	
Lamp Wattage	Average Initial Lumens	Multiple Service	Series Service	A All Night	B Midnight	C All Night	D Midnight
Incandescent Lamps Extended Service **							
103	1,000	103	75	35.535	18.633	29.528	15.488
202	2,500	202	164	69.690	36.542	64.567	33.866
327	4,000	327	248	112.815	59.154	97.638	51.212
448	6,000	448	347	154.560	81.043	136.614	71.656
690	10,000	690	578	238.050	124.821	227.559	119.357
Mercury Vapor Lamps							
100	4,000	131	125	45.195	23.698	51.675	27.113
175	7,900	216	207	74.520	39.074	85.574	44.898
250	12,000	301	285	103.845	54.451	117.819	61.817
400	21,000	474	445	163.530	85.747	183.963	96.521
700	41,000	803	760	277.035	145.263	314.184	164.844
1,000	55,000	1,135	1,070	391.575	205.322	442.338	232.083

* When an account has more than one lamp, the total kWh will be the kWh per lamp per month lamp rating to three decimal places multiplied by the number of lamps.

** Represents Extended Service lamps only. For Group Replacement and Regular Service Lamps see Special Condition 11.

(Continued)

Schedule LS-2 Sheet 9

LIGHTING - STREET AND HIGHWAY

CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE

(Continued)

SPECIAL CONDITIONS (Continued)

10. Kilowatthours: (Continued)

Nominal Lamp Rating		Lamp Load Including Ballast/Generator - Watts		kWh per Lamp Per Month*				
				Multiple Service kWh		Series Service kWh		
Lamp Wattage	Average Initial Lumens	Multiple Service	Series Service	A All Night	B Midnight	C All Night	D Midnight	
High Pressure Sodium Vapor Lamps								
50	4,000	58	64	20.010	10.492	30.746	16.134	
70	5,800	83	85	28.635	15.015	40.834	21.429	
100	9,500	117	121	40.365	21.165	58.128	30.504	
150	16,000	193	174	66.585	34.914	83.590	43.865	
200	22,000	246	233	84.870	44.501	111.933	58.739	
250	27,500	313	N/A	107.985	56.622	N/A	N/A	
310	37,000	383	N/A	132.135	69.285	N/A	N/A	
400	50,000	485	N/A	167.325	87.737	N/A	N/A	
Low Pressure Sodium Vapor Lamps								
35	4,800	63	51	21.735	11.397	24.225	12.709	
55	8,000	84	72	28.980	15.196	34.200	17.942	
90	13,500	131	130	45.195	23.698	61.750	32.396	
135	22,500	182	185	62.790	32.924	87.875	46.102	
180	33,000	229	219	79.005	41.426	104.025	54.575	
Metal Halide								
70	5,500	94	N/A	32.430	16.998	N/A	N/A	
100	8,500	129	N/A	44.505	23.328	N/A	N/A	
175	12,000	215	N/A	74.175	38.879	N/A	N/A	
250	19,500	295	N/A	101.775	53.346	N/A	N/A	
400	32,000	458	N/A	158.010	82.822	N/A	N/A	
1000	100,000	1080	N/A	372.600	195.300	N/A	N/A	
1500	150,000	1605	N/A	553.725	290.238	N/A	N/A	
Induction Lamps								(N)
23	N/A	25	N/A	8.625	4.521	N/A	N/A	|
40	N/A	41	N/A	14.137	7.410	N/A	N/A	|
55	N/A	56	N/A	19.185	10.056	N/A	N/A	|
65	N/A	69	N/A	23.805	12.478	N/A	N/A	|
80	N/A	82	N/A	28.428	14.901	N/A	N/A	|
85	N/A	88	N/A	30.293	15.878	N/A	N/A	|
100	N/A	105	N/A	36.225	18.988	N/A	N/A	|
120	N/A	123	N/A	42.410	22.229	N/A	N/A	|
150	N/A	155	N/A	53.303	27.939	N/A	N/A	|
165	N/A	170	N/A	58.566	30.698	N/A	N/A	|
200	N/A	210	N/A	72.450	37.975	N/A	N/A	(N)

(L)

* When an account has more than one lamp, the total kWh will be the kWh per lamp per month lamp rating to three decimal places multiplied by the number of lamps.

(Continued)

Schedule LS-2 Sheet 10
LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

10. Kilowatthours: (Continued)

Light Emitting Diode (LED) Lamps

Lamp Watts Including Driver**	Lamps Watts Including Driver Mid-Point Range***	kWh per Lamp per Month Multiple Service kWh**** All Night	Midnight
0-5	2.50	0.9	0.5
5.01-10	7.50	2.6	1.4
10.01-15	12.50	4.3	2.3
15.01-20	17.50	6.0	3.2
20.01-25	22.50	7.8	4.1
25.01-30	27.50	9.5	5.0
30.01-35	32.50	11.2	5.9
35.01-40	37.50	12.9	6.8
40.01-45	42.50	14.7	7.7
45.01-50	47.50	16.4	8.6
50.01-55	52.50	18.1	9.5
55.01-60	57.50	19.8	10.4
60.01-65	62.50	21.6	11.3
65.01-70	67.50	23.3	12.2
70.01-75	72.50	25.0	13.1
75.01-80	77.50	26.7	14.0
80.01-85	82.50	28.5	14.9
85.01-90	87.50	30.2	15.8
90.01-95	92.50	31.9	16.7
95.01-100	97.50	33.6	17.6
100.01-105	102.50	35.4	18.5
105.01-110	107.50	37.1	19.4
110.01-115	112.50	38.8	20.3
115.01-120	117.50	40.5	21.2
120.01-125	122.50	42.3	22.2
125.01-130	127.50	44.0	23.1
130.01-135	132.50	45.7	24.0
135.01-140	137.50	47.4	24.9
140.01-145	142.50	49.2	25.8
145.01-150	147.50	50.9	26.7
150.01-155	152.50	52.6	27.6
155.01-160	157.50	54.3	28.5
160.01-165	162.50	56.1	29.4
165.01-170	167.50	57.8	30.3
170.01-175	172.50	59.5	31.2

(Continued)

Schedule LS-2 Sheet 11
LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

10. Kilowatthours: (Continued)

Light Emitting Diode (LED) Lamps (Continued)

Lamp Watts Including Driver**	Lamps Watts Including Driver Mid-Point Range***	kWh per Lamp per Month Multiple Service kWh**** All Night	Midnight
175.01-180	177.50	61.2	32.1
180.01-185	182.50	63.0	33.0
185.01-190	187.50	64.7	33.9
190.01-195	192.50	66.4	34.8
195.01-200	197.50	68.1	35.7
200.01-205	202.50	69.9	36.6
205.01-210	207.50	71.6	37.5
210.01-215	212.50	73.3	38.4
215.01-220	217.50	75.0	39.3
220.01-225	222.50	76.8	40.2
225.01-230	227.50	78.5	41.1
230.01-235	232.50	80.2	42.0
235.01-240	237.50	81.9	42.9
240.01-245	242.50	83.7	43.9
245.01-250	247.50	85.4	44.8
250.01-255	252.50	87.1	45.7
255.01-260	257.50	88.8	46.6
260.01-265	262.50	90.6	47.5
265.01-270	267.50	92.3	48.4
270.01-275	272.50	94.0	49.3
275.01-280	277.50	95.7	50.2
280.01-285	282.50	97.5	51.1
285.01-290	287.50	99.2	52.0
290.01-295	292.50	100.9	52.9
295.01-300	297.50	102.6	53.8
300.01-305	302.50	104.4	54.7
305.01-310	307.50	106.1	55.6
310.01-315	312.50	107.8	56.5
315.01-320	317.50	109.5	57.4
320.01-325	322.50	111.3	58.3
325.01-330	327.50	113.0	59.2
330.01-335	332.50	114.7	60.1
335.01-340	337.50	116.4	61.0
340.01-345	342.50	118.2	61.9
345.01-350	347.50	119.9	62.8
350.01-355	352.50	121.6	63.7

(Continued)

Schedule LS-2 Sheet 12

LIGHTING - STREET AND HIGHWAY

CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE

(Continued)

10. Kilowatthours: (Continued) (N)

Light Emitting Diode (LED) Lamps (Continued)

Lamp Watts Including Driver**	Lamps Watts Including Driver Mid-Point Range***	kWh per Lamp per Month Multiple Service kWh**** All Night	Midnight
355.01-360	357.50	123.3	64.6
360.01-365	362.50	125.1	65.6
365.01-370	367.50	126.8	66.5
370.01-375	372.50	128.5	67.4
375.01-380	377.50	130.2	68.3
380.01-385	382.50	132.0	69.2
385.01-390	387.50	133.7	70.1
390.01-395	392.50	135.4	71.0
395.01-400	397.50	137.1	71.9

(N)

** Lamp Wattage is based on the total wattage consumption of the lamp and driver. Customer may be required to provide verification of total energy consumption of lamp and driver upon request by SCE. (N)

*** The Mid-Point Range of the Lamp Watts including driver, is established by deducting 2.5 Watts from the highest wattage of the corresponding range in the “Lamp Watts Including Driver” column.

**** The energy use calculation for All Night Service is (Mid-Point Range watts) x (4,140 hours/12 months/1000). The same calculation is used for Midnight service except that the hours of service is replaced with 2,170 hours. (N)

11. Lamp Loads: SCE will provide service under this Schedule to street light lamps which are not listed on this Schedule provided that a lamp load, including lamp wattage and ballast, can be reliably established by SCE. (L)

In addition to the extended service incandescent lamps listed above in Special Condition 10, SCE has determined a lamp load wattage rating for the following lumen rated regular and group replacement incandescent lamps to be used to determine the Energy Charge Components. (L)

(Continued)

Schedule LS-2 Sheet 13 (T)
LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

11. Lamp Loads: (Continued)

Incandescent Wattage Per Lamp

Average Initial Lumens	Multiple Service Regular	Multiple Service Group Replacement	Series Service Regular	Series Service Group Replacement
600	55	58	42	44
800	N/A	N/A	57	N/A
1,000	85	92	61	64
2,500	175	189	143	152
4,000	268	295	213	226
6,000	370	405	316	332
10,000	575	620	525	565
15,000	800	860	755	822
25,000	N/A	N/A	1,275	N/A

The kilowatthours for the above regular and group replacement lamps or any unlisted lamps shall be determined in accordance with the provisions of Special Condition 12, below.

12. Kilowatthour Per Lamp per Month For Nonstandard Lamps: The total monthly kWh usage for each type of service shall be computed by applying the following Hours per kW billing factors to the applicable lamp load (including ballast/driver/generator, if applicable) wattage rating. The kWh shall be computed to the nearest Watt-hour. (C)

Hours Per Month Per kW of Lamp Load (C)

Type of Service:	Incandescent	Mercury Vapor	High Pressure Sodium Vapor	Low Pressure Sodium Vapor	Metal Halide	Other Lamps	
All Night Service							
Multiple Service*	345.0	345.0	345.0	345.0	345.0	345.0	(N)
Series Service***	393.7	413.4	480.4	475.0	N/A	N/A	(N)
Midnight or Equivalent Service							
Multiple Service**	180.9	180.9	180.9	180.9	180.9	180.9	(N)
Series Service***	206.5	216.9	252.1	249.2	N/A	N/A	

kWh Per Lamp Per Month=Hours Per Month Per kW of Lamp Load x kW Per Lamp (including ballast/driver/generator if applicable)

* All Night Service Multiple Service Hours Per Month Per kW of Lamp Load = (4,140 hours/12 months) = 345 hours

** Midnight Service Multiple Service Hours Per Month Per kW of Lamp Load = (2,170 hours/12 months) = 180.9 hours

*** Series Services Hours Per Month Per kW of Lamp Load applies the same formula as Multiple Service except that it is adjusted for Line Loss Factor. (N)

(Continued)

Schedule LS-2 Sheet 14 (T)
LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

13. Charges for Nonstandard Lamps: Nonstandard Lamps are lamps for which a monthly charge is not listed in this Schedule. Where a lamp is not listed in this Schedule, the monthly charge is computed by first computing the applicable kWh for the lamp. The kWhs are computed by applying the method provided in Special Condition 12 for Other Lamps. Where manufacturer's information is not available for rated wattage consumption, the customer must provide third party documentation before SCE will accept lamps for this Schedule. The Energy Charge is calculated using the rates shown in the Rates section, above. The total monthly lamp charge for nonstandard lamps is the sum of the monthly lamp charge as shown in the Rates section for all other lamps, plus the Energy Charge. For Series Service Lamps, the Energy Charge is adjusted for Voltage Discount, and the total lamp charge increased for Series Service Power Factor. (T)

14. Energy Efficient Street Lights – Where Customers permanently install energy efficient streetlights under the terms of this Schedule and the total energy use cannot be verified through industry standards or other documentation acceptable to SCE, the customer may be required to provide verifiable documentation to SCE's satisfaction regarding the total energy consumption of the lamp and driver. All fixtures that include the capability of adjustable light wattage settings will be billed at the maximum wattage setting. (N)

15. Limited testing of emerging Streetlight technologies will be allowed under this Schedule. Such test installations are subject to approval by SCE. Testing is limited to existing streetlight fixtures and the total energy consumption per fixture must not exceed current energy use per fixture. Additional energy efficient streetlight fixtures installed will also be subject to billing under the current rate upon the approval of SCE. The test period will not exceed 12 months. (N)

16. Series Service Power Factor: The kVAR losses for the Series Service Power Factor charge shall be calculated by multiplying the applicable series service kW lamp load from Special Condition 10 by the applicable kVAR demand loss factor shown below: (T)

kVAR Demand Loss Factor (kVAR Loss/kW load)

Incandescent	Mercury Vapor	High Pressure Sodium Vapor	Low Pressure Sodium Vapor
2.133	2.953	5.270	7.067

17. Voltage Discount: Bundled Service, CCA Service, and Direct Access customers will have the Distribution rate component of the applicable Delivery Charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section above. In addition, Bundled Service Customers will have the Utility Retained Generation (URG) rate component of the applicable Generation charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section. (T)

(Continued)

Schedule LS-2 Sheet 15 (T)
LIGHTING - STREET AND HIGHWAY
CUSTOMER-OWNED INSTALLATION - UNMETERED SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

18. Billing Calculation: A customer's bill is calculated according to the rates and conditions above. (T)

Except for the Energy Charge, the charges listed in the Rates section are calculated by multiplying the Total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatthour [kWh], kilovar [kVa] etc.),

The Energy Charge, however, is determined by multiplying the total kWhs by the Total Delivery Service per kWh rates to calculate the Delivery Service amount of the Charge. To calculate the Generation amount, SCE determines what portion of the total kWhs is supplied by the Utility Retained Generation (URG) and the Department of Water Resources (DWR). The kWhs supplied by the URG are multiplied by the URG per kWh rates and the kWhs supplied by the DWR are multiplied by the DWR per kWh rate and the two products are summed to arrive at the Generation amount. The Energy Charge is the sum of the Delivery Service amount and the Generation amount.

For each billing period, SCE determines the portion of total kWhs supplied by SCE's URG and by the DWR. This determination is made by averaging the daily percentages of energy supplied to SCE's Bundled Service Customers by SCE's URG and by the DWR.

a. Bundled Service Customers receive Delivery Service from SCE and receive supply (Gen) service from both SCE's URG and the DWR. The customer's bill is the sum of the charges for Delivery Service and Gen determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

b. Direct Access Customers receive Delivery Service from SCE and purchase energy from an Energy Service Provider. The customer's bill is the sum of the charges for Delivery Service determined as described in this Special Condition except that the DWRBC rate component is subtracted from the Total Delivery Service rates before the billing determinants are multiplied by such resulting Total rates; plus the applicable charges as shown in Schedule DA-CRS and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

c. CCA Service Customers receive Delivery Service from SCE and purchase energy from their Community Choice Aggregator (CCA). SCE will read the meters and present the bill for both Delivery and Generation Services to the CCA Service Customer. The customer's bill is the sum of the charges for Delivery Service as displayed in this Rate Schedule and Generation charges determined by the CCA plus the applicable charges as shown in Schedule CCA-CRS, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.