MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2014-0351

Jefferson City, Missouri
February 11, 2015

** **Denotes Highly Confidential Information** **

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Table of Contents

I. Executive Summary

The Staff's recommended increase in revenue requirement is based upon an adjusted test year for the twelve months ending April 30, 2014, including true-up estimates through December 31, 2014. The Staff's recommended revenue requirement increase for The Empire District Electric Company ("Empire") is $3,883,448 to $8,521,840 based on a return of equity ("ROE") range of 9.25% to 9.75%. The Staff's revenue requirement as presented in its Accounting Schedules filed January 29, 2015, includes expected changes for a true-up ending December 31, 2014, based on current information. The Staff's final amount recommendation will be based on its true-up audit.

Empire has twelve (12) active service classifications.[1] The active service classifications are (1) residential service schedule RG ("RG"), (2) commercial service schedule CB ("CB"), (3) small heating service schedule SH ("SH"), (4) general power service schedule GP ("GP"), (5) special transmission service contract: Praxair schedule SC-P ("SC-P"), (6) total electric building service schedule TEB ("TEB"), (7) feed mill and grain elevator service schedule PFM ("PFM"), (8) large power service schedule LP ("LP"), (9) miscellaneous service schedule MS[2] ("MS"), (10) municipal street lighting service schedule SPL[3] ("SPL"), (11) private lighting service schedule PL ("PL"), and (12) special lighting service schedule LS ("LS"). Staff combined the MS, SPL, PL and the LS rate classifications for purposes of its class cost-of-service ("CCOS") study because these rate schedules pertain to lighting functions.

[1] Empire has Special Transmission Service Schedule ST ("ST") but no customers are currently served from this service classification.
[2] Schedule is available to electric service to signal systems or similar unmetered service and to temporary of seasonal use.
[3] Includes LED street lighting pilot.

As explained in its CCOS Report, Staff recommends that the allocation of any rate increase for Empire will be accomplished with a five-step process:

1. Based on CCOS results, Staff recommends to increase/decrease the current base retail revenue on a revenue-neutral basis to various classes of customers. Specifically, Staff recommends the RG class receive a positive 0.75% adjustment; and the TEB, GP, and LP classes of customers receive a negative adjustment of approximately 0.85%.

2. Staff directly assigns to applicable customer classes the portion of the revenue increase/decrease that is attributable to energy efficiency ("EE") programs from Pre-MEEIA ("Missouri Energy Efficiency Investment Act") program costs.[4]

3. Staff determined the amount of revenue increase awarded to Empire not associated with the EE revenue from Pre-MEEIA revenue requirement assigned in Step 2, by subtracting the total amount in Step 2 from the total increase awarded to Empire. Staff recommends allocating this amount to various customer classes as an equal percent of current base revenues after making the adjustment in Step 1. Based on CCOS results, Staff recommends that the PFM and combined lighting classes receive no retail increase as existing revenues received from these classes are providing more revenue to Empire than Empire's cost to serve.

4. Staff recommends that each rate component of each class be increased across-the-board for each class on an equal percentage after consideration of steps 1 through 3 above. Included in this recommendation, Staff recommends that, based on CCOS results and policy considerations, the residential and all other customer charges be increased by the average increase for each applicable class.

5. Adopt Rider Fuel and Purchased Power Adjustment Clause ("FAC") tariff sheets consistent with Staff CCOS Report.

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

1. To present an overview of Staff's CCOS study and the study results based upon the test year of May 1, 2013 through April 30, 2014, updated through August 31,2014.

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

3. Provide methods to implement any Commission-ordered overall change in customer revenue responsibility in rates.

4. 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.

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[4] The Pre-MEEIA program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of Pre-MEEIA program costs.

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
- Fuel and Purchased Power Cost Adjustments
- Residential Customer Charge
- Non-residential Customer Charges
- Miscellaneous Tariff Revisions

Current Class Revenues and Cost to Serve

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 as filed in Staff's Cost of Service Report.

Table 1

Results of Staff's CCOS Study - Empire District Electric Company

Customer Class		**Revenue Deficiency**	**CCOS % Increase**
Residential	$	21,734,894	10.37%
Commercial Building	$	(831,914)	-1.91%
Commercial Space Heating	$	(2,599)	-0.02%
General Power	$	(6,201,655)	-7.24%
Special Transmission Service Contract: Praxair	$	136,818	3.62%
Total Electric Building	$	(1,743,853)	-4.54%
Feed Mill and Grain Elevator	$	(43,000)	-37.50%
Large Power	$	(5,404,546)	-8.84%
Lighting and Miscellaneous (Street, Private, Special, Miscellaneous)	$	(1,450,460)	-18.43%
Total (Rounding)	$	6,193,690	1.39%

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 the Staff Accounting Schedules filed in this case on January 29, 2015. Staff's recommended revenue requirement increase for Empire is $3,883,448 to $8,521,840 based on a ROE range of 9.25% to 9.75%. Staff supports the mid-point of its ROE recommendation of 9.50% and a corresponding revenue requirement increase of $6,193,690. Staff's revenue requirement as presented in its Accounting Schedules includes expected changes for a true-up ending December 31, 2014, based on current information.

The results of a CCOS study can be presented either in terms of (1) the rate of return realized for providing service to each class or (2) in terms of the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class. Staff prefers to present its results in the latter format, i.e., negative or positive dollar amounts or percentages. The results of Staff's analysis are presented in terms of the shifts in revenue that produce an equal rate of return for Empire from each customer class. [5]

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

Staff recommends that CCOS studies should serve as a guide to setting revenue requirements and thus are not precise. Staff's CCOS study revealed that, on a revenue-neutral basis, Empire's current RG class rate(s) do not cover Empire's cost to serve that class and should receive a positive revenue-neutral adjustment. Staff recommends a negative revenue-neutral adjustment for the TEB, GP, and LP classes to bring these classes closer to their cost to serve by Empire. Two of the customer classes (PFM and combined lighting are more than 18% above Empire's cost (investment and expenses) to serve them and should receive no increase in this case. Empire's CB, SH, and SC-P classes are close to their cost to serve and no revenue-neutral adjustment is recommended. These adjustments bring certain classes closer to cost of serving them, while still maintaining rate continuity, rate stability, revenue stability; and minimizing rate shock to any one customer class.

[5] The customer classes used in Staff's study correspond to Empire's current rate schedules, except its lighting rate schedules, which Staff combined into one customer class for its study.

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

The purpose of a Class Cost-of-Service ("CCOS") study is to determine whether each class of customers is providing the utility with the level of revenue necessary to cover (1) the utility's ongoing expenses required or allocated to provide electric service to that class of customers, and (2) a return on the utility's investments required or allocated to provide service to that class of customers. A CCOS study provides a basis for allocating and/or assigning the utility's total cost of providing electric service to all the customer classes in a manner reasonably reflecting cost causation. Staff's CCOS study is a continuation and refinement of Staff's cost-of-service revenue requirement study, resulting in a reasonable allocation of the costs incurred in providing electric service to each of Empire's customer classes. Since those costs equate to the utility's revenue requirement as determined by Staff in its Cost of Service Report filed January 29, 2015, the results of Staff's CCOS study are the initial basis for Staff's recommended class revenue requirements of each customer class for an equitable share of the utility's total annual cost of providing electric service. As discussed in the sections of this report concerning rate design, consideration of policy, subsidy, and promotional practices are also taken into account in Staff's ultimate recommendation of class revenue recovery through rate design.[6]

Staff Expert: Robin Kliethermes

[6] Schedule CCOS-1 provides fundamental concepts, terminology, and definitions used in CCOS studies and rate design. It addresses functionalization, classification, and allocation as used in CCOS studies.

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

Staff performed a Detailed Base, Intermediate, and Peak (BIP) study that is the basis for Staff's recommended cost-causation results. The results of Staff's CCOS study appear in Table 1 above and are outlined in Table 2 below.[7]

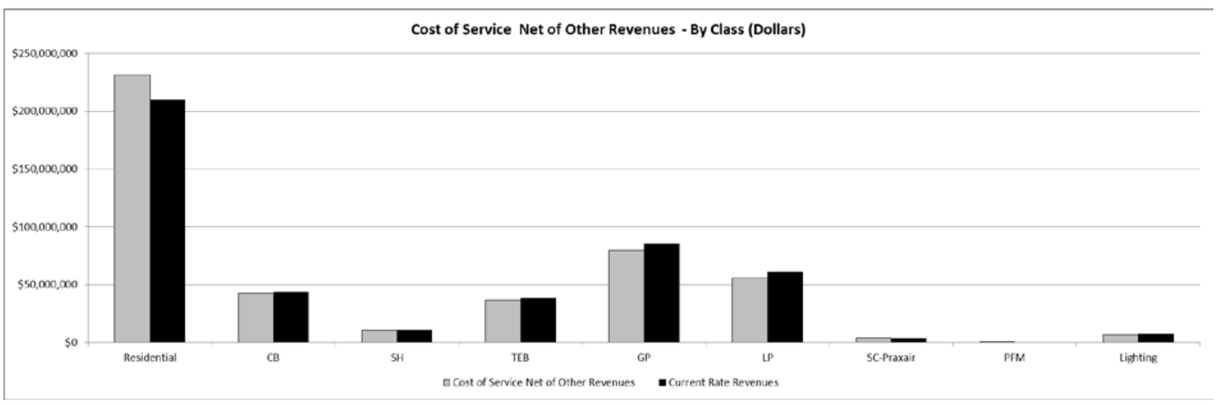
Table 2

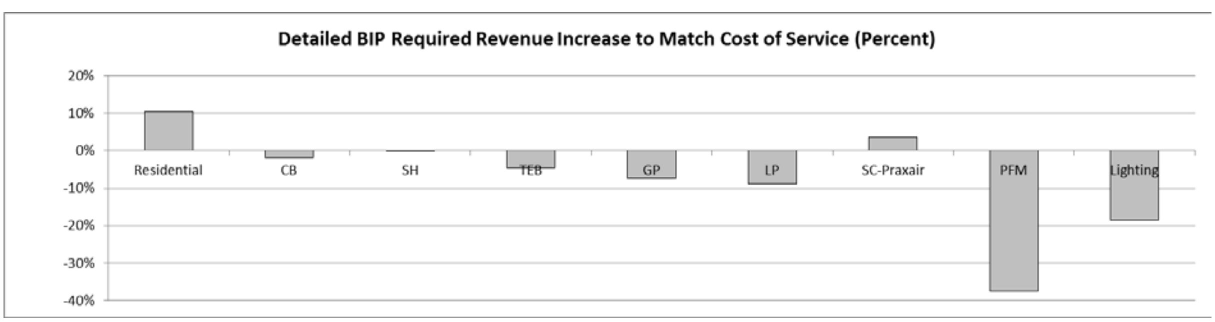
Summary Results of Staff's CCoS Study									
	Residential	CB	SH	TEB	GP	LP	SC-Praxair	PFM	Lighting
Cost of Service	$228,810,301	$42,401,259	$10,567,927	$36,214,243	$78,574,534	$55,027,865	$3,855,117	$71,032	$6,389,373
Other Revenues and True-Up Allowance	-$2,525,215	-$374,788	-$123,087	-$479,478	-$905,070	-$701,797	-$57,571	-$625	-$31,230
Net Class Cost of Service	**$231,335,516**	**$42,776,047**	**$10,691,014**	**$36,693,721**	**$79,479,604**	**$55,729,662**	**$3,912,688**	**$71,657**	**$6,420,603**
Current Rate Revenues	**$209,600,623**	**$43,607,782**	**$10,693,614**	**$38,437,069**	**$85,675,743**	**$61,140,407**	**$3,775,876**	**$114,652**	**$7,871,060**
Required Increase	**$21,734,893**	**-$831,735**	**-$2,600**	**-$1,743,348**	**-$6,196,139**	**-$5,410,745**	**$136,812**	**-$42,995**	**-$1,450,457**
CCoS % Increase	10.37%	-1.91%	-0.02%	-4.54%	-7.24%	-8.84%	3.62%	-37.50%	-18.43%
Less System Average	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1 39%	1.39%	1.39%
Revenue Neutral % Increase	8.98%	-3.30%	-1.41%	-5.93%	-8.63%	-10.23%	2 23%	-38.89%	-19.82%

The changes shown in Table 2 are 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. The results are also presented, on a revenue-neutral basis, as the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class.

[7] Empire has twelve (12) active service classifications. The active service classifications are (1) residential service schedule RG ("RG"), (2) commercial service schedule CB ("CB"), (3) small heating service schedule SH ("SH"), (4) general power service schedule GP ("GP"), (5) special transmission service contract: Praxair schedule SC-P ("SC-P"), (6) total electric building service schedule TEB ("TEB"), (7) feed mill and grain elevator service schedule PFM ("PFM"), (8) large power service schedule LP ("LP"), (9) miscellaneous service schedule MS ("MS"), (10) municipal street lighting service schedule SPL ("SPL"), (11) private lighting service schedule PL ("PL"), and (12) special lighting service schedule LS ("LS"). For its CCOS study, Staff examined each of these service schedules, other than lighting, as a stand-alone rate classes. Staff placed the lighting service schedules into a rate group. Staff's CCOS study provided the investment and costs associated for Empire to provide service to these classes and the lighting group, as compared to the revenues currently provided by these classes and the lighting group.

"Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues. 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. The overall revenue increase recommended as described in Staff's COS Report was 1.39%. For CCOS purposes, Staff calculates the revenue neutral increase that would be necessary for each class to match its cost of service by subtracting the overall system average increase of 1.39% from each customer class's required percentage increase.[8] This provides the revenue-neutral adjustment to rate revenue that would be necessary to match the revenues Empire should receive from that class to Empire's cost to serve that class shown in Table 2. The required revenue increase to match cost of service is provided below expressed graphically in both dollars and percent.



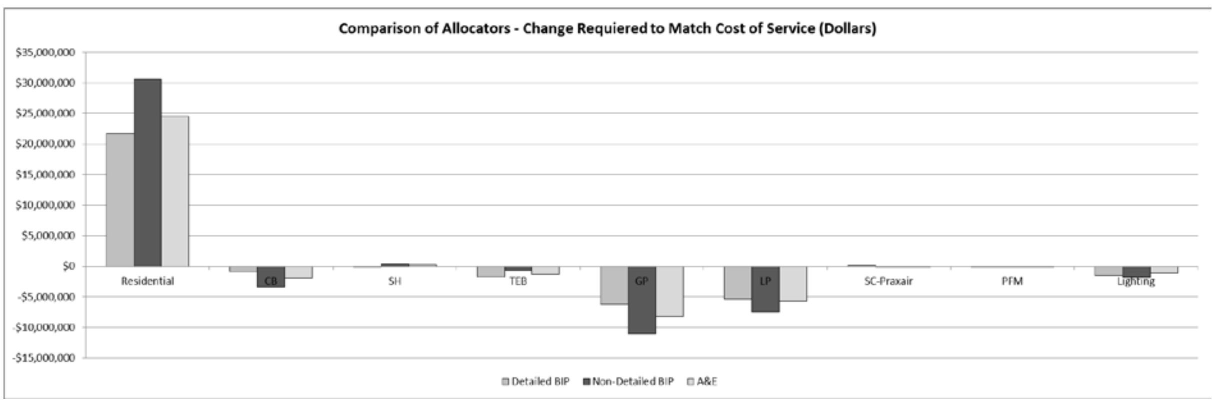


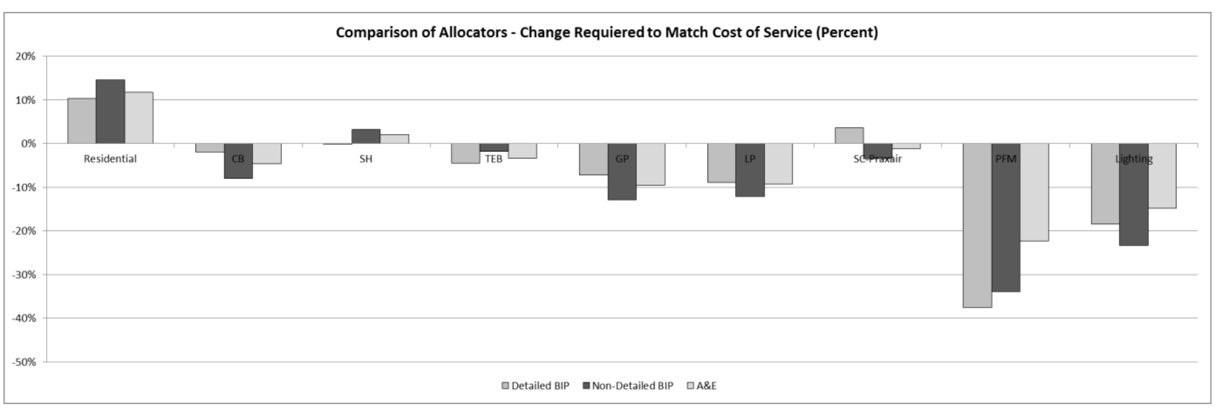
[8] Incorporating the accounting schedules into the CCOS software results in a slight mis-identification of the overall increase percentage, due to the manner identifying the denominator of the increase. The CCOS identifies the system average increase as 1.34%.

Staff also studied allocation of production and other related costs (capacity, energy, O&M, fuel in storage, and other revenues) using alternate production allocation methods of a Modified BIP study similar to that used by Staff in Empire's last general rate case, and an Average and Excess 4 Non-Coincident Peak (A&E 4 NCP) study to assess the reasonableness of the A&E 12 CP study performed by Dr. Overcast on behalf of Empire. These results are presented in Table 3 and the associated graph, below.

Table 3

Comparison of Production-Related Allocators									
	Residential	CB	SH	TEB	GP	LP	SC-Praxair	PFM	Lighting
Detailed BIP	$21,734,893	-$831,735	-$2,600	-$1,743,348	-$6,196,139	-$5,410,745	$136,812	-$42,995	-$1,450,457
	10.37%	-1 91%	-0.02%	-4 54%	-7.24%	-8.84%	3.62%	-37 50%	-18.43%
Non-Detailed BIP	$30,589,763	-$3,457,142	$346,367	-$683,573	-$11,084,625	-$7,510,731	-$131,778	-$39,410	-$1,835,185
	14.63%	-7 98%	3.23%	-1.77%	-12.95%	-12.13%	-3.45%	-33 99%	-23.41%
A&E	$24,505,389	-$1,990,830	$218,209	-$1,315,534	-$8,207,945	-$5,778,805	-$44,082	-$25,881	-$1,166,832
	11.72%	-4.60%	2.04%	-3.41%	-9.59%	-9.33%	-1.15%	-22.33%	-14.89%





Because the Detailed BIP most reasonably recognizes the relationship between the cost of the plants required to serve various levels of demand and energy requirements relative to the cost producing energy at those plants, Staff recommends reliance on its Detailed BIP study. However, Staff notes that its Non-Detailed BIP and A&E study results are generally consistent with the Detailed BIP study results to a level of precision typically relied on for interclass allocation purposes.

A CCOS study is not precise and is used only as a guide for designing rates. For example, other factors such as bill impacts, simplicity, rate stability, fairness among different consumers, customer understandability, and public policy considerations are also considered. Staff's CCOS study used costs and revenues from Staff's accounting information and other sources as outlined below. Staff's allocation of costs and revenues to the customer classes is described in the sections that follow.

Staff Experts: Sarah Kliethermes and Robin Kliethermes

A. Data Sources

Staff's CCOS study utilized the Staff's revenue -requirement recommendations as filed on January 29, 2015, in Staff's direct revenue requirement cost-of-service recommendation for Empire's retail cost-of-service. This data includes:

- Adjusted Missouri investment and expense data by FERC account;
- Normalized and annualized rate revenues;
- Net fuel and purchased power costs and revenues;
- Other operating and maintenance expenses;
- Depreciation and amortizations;
- Taxes; and
- For each class, Staff's determination of weather-adjusted, customer-coincidental peaks, customer-non-coincidental peaks, customer-maximum peaks, and annual energy.

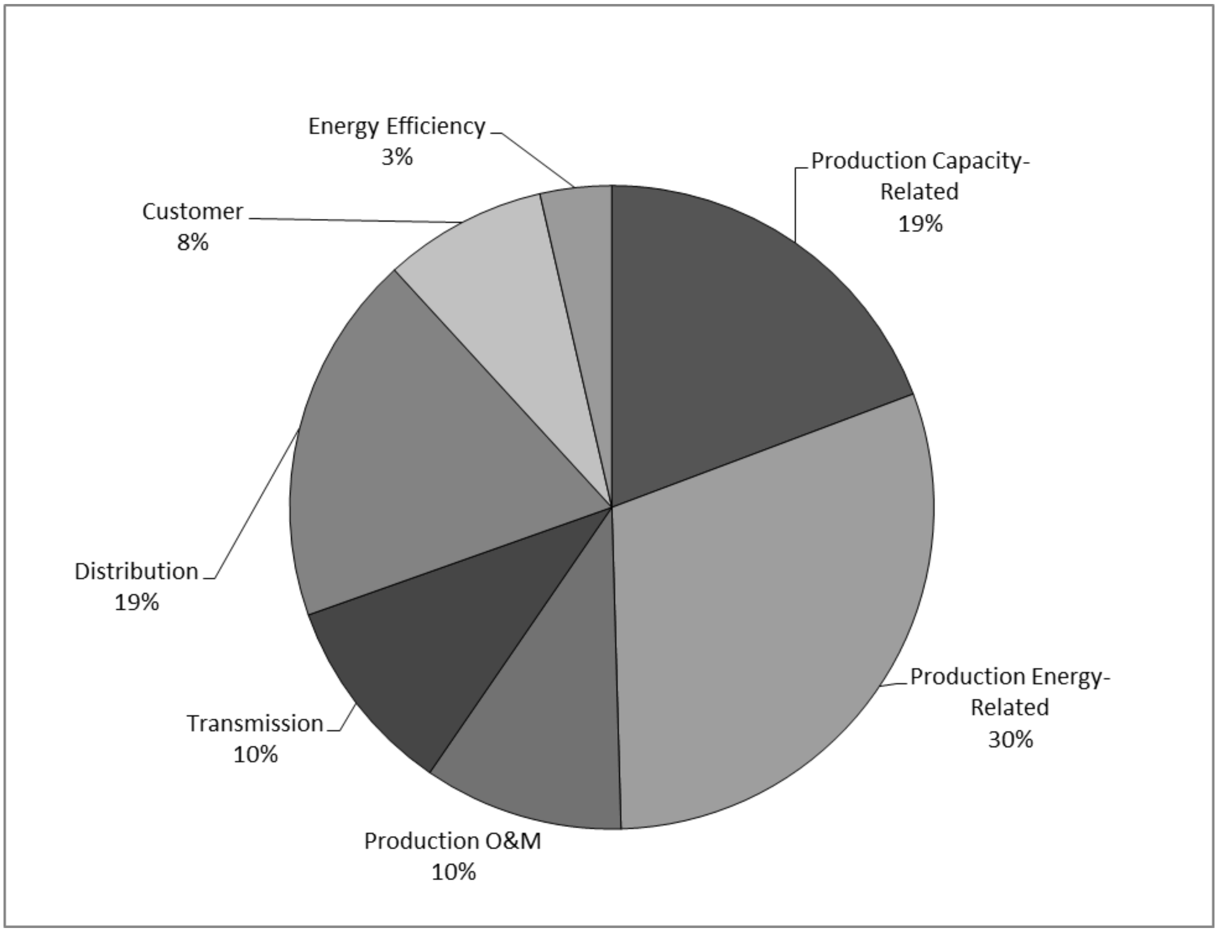
In addition, data was also obtained from Dr. Overcast's direct testimony and workpapers from this case, which includes allocation factors for specific customer allocations.

These allocation factors relate to information on services, meters, meter reading, uncollectible accounts, customer service, and customer deposits.

Staff Experts: Sarah Kliethermes and Robin Kliethermes

B. 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" costs are those costs directly related to the capital cost of generation. "Production-Energy" costs are those costs related directly to the customer’s consumption of electrical energy (i.e., kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs. The pie chart below shows the approximate percentage of total costs associated with each major function.



Staff Experts: Sarah Kliethermes and Robin Kliethermes

C. Allocation of Production Costs

For CCOS purposes, Staff assumes that all of Empire's generation facilities are primarily used to produce electricity for Empire's retail customers. Empire's costs for plant investment and the production expenses appearing on its income statement are appropriately allocated by a production-capacity (demand) or a production-energy (energy) allocator. Empire's generation facilities are predominantly considered fixed assets, and so the costs of these assets are considered demand-related and apportioned to the rate classes on the basis of the production-capacity allocator. Fuel expense related to running the generation plants and net purchased power used to serve load are considered energy-related and allocated to rate classes on the basis of the production-energy allocator. The demand and energy characteristics of Empire's load requirement are both important determinants of production cost and expense allocations, since load must be served efficiently over time throughout the day and year.

To establish class revenue responsibilities for production costs and expenses, Staff relied on the relationship between Empire's generation fleet characteristics and its load characteristics. Because Empire's generation fleet is well-suited to serving its load efficiently over the course of a year, Staff relied on unadjusted Detailed BIP allocators for allocating Empire's production-capacity and production-energy investment and expense to the retail classes. This BIP method most reasonably recognizes that some plants will run virtually year round (Base), only part of the year (Intermediate), and rarely during the year (Peak). The BIP method also recognizes the fact that Base plants tend to be more expensive to install, but with a lower average cost of energy, while Peak plants tend to be less expensive to install, but with a high average cost of energy, and that Intermediate plants tend to be somewhere between the two.

Staff's application of the BIP method takes into consideration the differences in the capacity/energy cost trade-off that exists across a company's generation mix, giving weight to both considerations. Because it reasonably allocates the investment and expenses of Empire's generation fleet among the retail classes, Staff recommends using these BIP allocation factors to reasonably allocate the return on production related plant investment and production related expenses to the retail classes.

Empire's generation fleet characteristics

Empire's "Base" generating plants are the Ozark Beach hydroelectric facility, the Iatan 2 supercritical coal plant, the Iatan 1 coal plant, the Plum Point coal plant, and the Asbury coal plant.[9],[10],[11] Each of these coal plants has emissions control equipment that increases the capacity costs and the operating costs of these plants, while also slightly decreasing the net amount of electrical energy produced by burning the same amount of coal. Staff determined that the average capacity cost, net of depreciation reserve, for Empire's Base generation is approximately $1,350,000/MW. However, Staff found that the average fuel cost for these plants was only $18.50/MWh. Taken together, Empire's Base generation ran at an 83% capacity factor in Staff's fuel model.

Empire's "Intermediate" generating plants are the State Line combined cycle unit, and the Riverton 12 gas boiler.[12] Staff determined that the average capacity cost, net of depreciation reserve, for Empire's Intermediate generation is approximately $340,000/MW, and the average fuel cost for these plants was $28.50/MWh. Taken together, Empire's Intermediate generation ran at a 32% capacity factor in Staff's fuel model.

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[9] These types of units tend to be ideal for meeting the around-the-clock capacity needs; however, they are slow-ramping and cannot quickly react to changes in the level of demand. These units can be ramped as needed to provide regulating services to SPP, but aside from this sort of ancillary service activity, Staff would expect these plants to be "price takers" in the SPP market.

[10] Empire's interest in Plum Point consists of a 50MW joint ownership, as well as a 50MW Purchase Power Agreement (PPA). As in prior cases, in this case, Staff modeled the PPA as part of Empire's capacity in its fuel run. For capacity valuations, Staff treated the PPA as additional ownership interest, so that weightings would be consistent among production-capacity allocators. The compliment of the wind energy shape to Empire's load profile is discussed below.

[11] Empire also has a wind PPA. Staff did allocate the expense of the PPA to the classes using the BIP allocators; however, Staff did not include the PPA in allocator development.

[12] These units can be dispatched to meet the changing system demand in a matter of hours, and are capable of operating at high capacity factors. However, as a practical matter, these units are rarely operated at a high capacity factor, because the role of intermediate units to the generation fleet is to meet the demand requirements of load that occur often, but not constantly. Intermediate units can be dispatched in the SPP to follow load and to provide regulating reserves, but given current gas prices, it would not be surprising if these units were offered into the SPP as price takers.

Empire's "Peaking" generating plants that ran in Staff's fuel model are Energy Center Units 3 & 4, and Riverton Units 8, 9, and 10.[13],[14] These units are all simple cycle gas turbines. Staff determined that the average capacity cost, net of depreciation reserve, for Empire's Peaking generation is only approximately $207,000/MW. However, Staff found that the average fuel cost for these plants was $52.50/MWh. Taken together, Empire's Peaking generation that did run in Staff's fuel model ran at a 1.17% capacity factor.

Empire's load characteristics

Empire has a larger electric space heating load relative to its total load relative to other electric utilities. Space heating generally helps to increase load at night when plants would otherwise run at minimum capacities, and when wind energy tends to be more plentiful. Due in part to the impact of its residential space heating load, Empire's overall load is relatively diverse. For example, Empire's residential class's highest peak occurred in January, and various Empire class's experienced peaks during the shoulder months of March, May, October, and November. Taken together, this diversity allows Empire to require less generation capacity than if all of its customers used energy at the same times.

The interaction of class energy requirements over the course of a year is generally studied in terms of class coincident and non-coincident peak demands. Coincident-peak demand is the demand of each customer class and each customer at the hour when the overall system peak occurs. Coincident-peak demand reflects the maximum amount of diversity

[13] Empire's fleet includes two additional simple cycle units at Energy Center, and an additional simple cycle at Riverton. The State Line combined cycle facility consists of two gas turbines, and a Heat Recovery Steam Generator (HRSG) that can be powered with waste heat from either or both turbines.

[14] Gas turbines are quick ramping, and because they can be cold-dispatched quickly, they are ideal for meeting spiky changes in the level of load – for example – when air conditioners fire on as a heat wave moves into an area. Gas turbines are capable of high capacity factors, but tend to have the lowest capacity factors of any units, as operated. However, because Empire participates in the SPP integrated energy market; its generation is dispatched as part of the larger SPP fleet, so its turbines may be dispatched at night to assist in wind integration, as opposed to operating at times of peak demand when another utility may have less expensive energy available.

because most customer classes are not at their individual class peaks at the time of the coincident peak. Class peak demand, which is the maximum hourly demand of all customers within a specific class, often does not occur at the same hour, i.e., does not coincide with, the system peak. Although not all customers peak at the same time, due to intra-class diversity, to achieve the class peak a significant percentage of the customers in the class will be at or near their peak. Therefore, class-peak demand will have less diversity than the class' load at the time of system peak.

Finding Class Demands

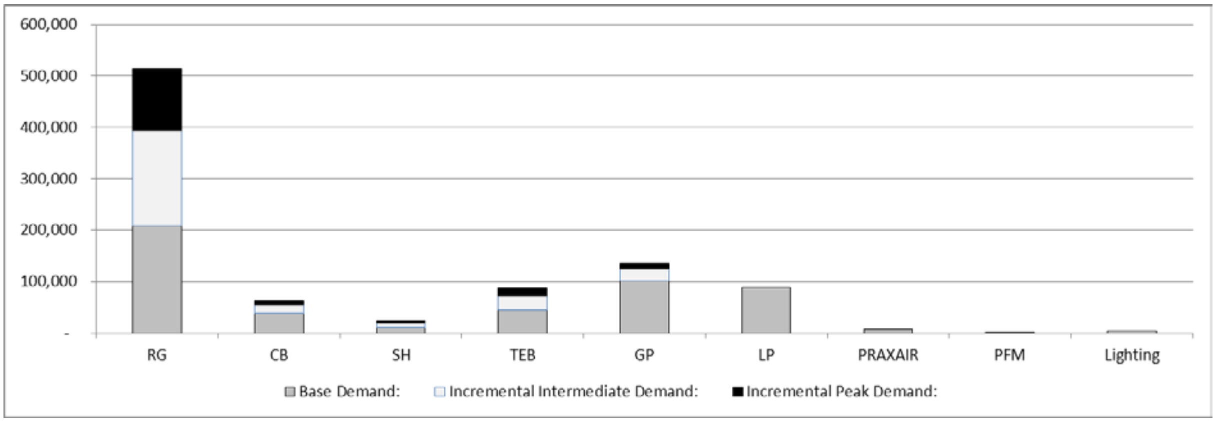
1. Staff found each class's average demand in MW. That MW of demand value is the "base demand" used for each class in the BIP calculation.

2. Staff found each class's demand in MW at the time of each month's system peak. Staff then averaged each class's 12 demands to a single MW value. That additional MW value over the base demand MW value is each class's intermediate demand. The difference between each class's base demand and its intermediate demand is its incremental peak demand.

3. Staff found each class's demand in MW at the time of the four system peaks. Staff then averaged each class's 4 demands to a single MW value. That MW value is each class's peak demand. The difference between each class's intermediate demand and its peak demand is its incremental peak demand.

The BIP Demand Characteristics of each class (in MW) are provided in the table and graph below:

	RG	CB	SH	TEB	GP	LP	PRAXAIR	PFM	Lighting
Base Demand:	208,550	38,587	11,270	45,507	102,117	88,879	7,291	79	3,955
Incremental Intermediate Demand:	184,855	15,713	7,024	26,244	23,580	-	-	-	-
Incremental Peak Demand:	120,766	8,054	4,937	14,934	8,963	-	-	-	-



Finding Class Energy Usage

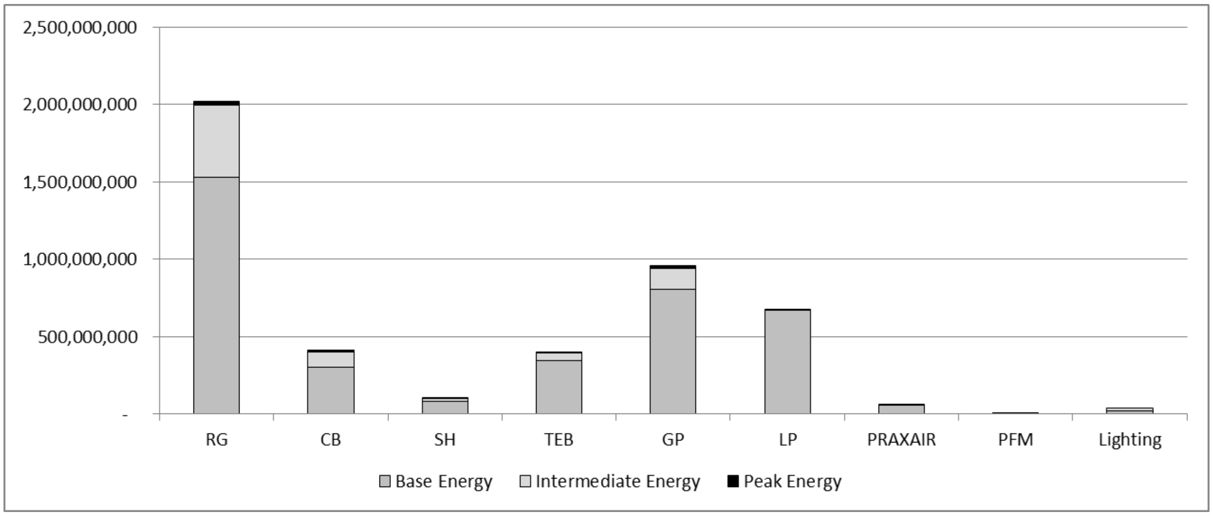
1. Staff analyzed each class's weather-normalized energy usage for each hour of the year. In a given hour, if a class had energy usage (MWh) equal to or below its base demand (MW), then Staff recorded that energy usage as base usage. If in that hour a class had energy usage in excess of its base demand, Staff recorded that hour's energy usage for that class as being equal to that class's base demand.

2. Staff then analyzed if in each hour a class had energy usage in excess of its intermediate demand. If so, Staff recorded that hour's energy usage (less the previously allocated base usage) for that class as being equal to that class's intermediate demand.

3. Finally, Staff recorded all energy usage in excess of a particular class's intermediate demand as peak usage.

The BIP Energy Characteristics of each class (in MWh) are provided in the table and graph below:

	RG	CB	SH	TEB	GP	LP	PRAXAIR	PFM	Lighting
Base Energy	1,527,678,095	300,962,640	82,285,156	344,427,568	802,728,784	666,927,842	56,661,217	318,934	16,518,164
Intermediate Energy	465,057,086	95,716,515	16,536,994	51,850,956	139,556,207	9,994,364	2,545,385	48,614	22,095,131
Peak Energy	26,171,275	14,687,546	1,083,322	1,526,585	12,507,159	-	-	-	-



Calculating BIP Allocators

The BIP method is described in the NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL ("NARUC Manual"), in Part IV, C, Section 2.[15],[16] Staff developed production-capacity and production-energy allocators by matching the average capacity cost of each with the BIP demands of each customer class, and by matching the average energy cost of each with the BIP energy requirements of each class.

Staff relied on the demand characteristics of each customer class to appropriately assign (1) the relatively expensive capacity costs of base generation on each class' base level of demand, (2) the relatively moderate capacity costs of intermediate generation on each class' intermediate level of demand, and (3) the relatively inexpensive capacity costs of peaking generation on each class' peak level of demand. Under this approach, Empire's net investment in each of the plants assigned to each of the BIP components is allocated to the classes based on each class's base, intermediate, and peak demand (in MW). The relative

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[15] Published, January 1992.
[16] Schedule CCOS-2 details the BIP method as described in the NARUC Manual.

value – by class – of the investment allocated to each class is used as the Production-Capacity allocator.[17]

Staff relied on the energy characteristics of each customer class to appropriately assign (1) the relatively inexpensive fuel costs of base generation on each class' base energy usage, (2) the relatively moderate fuel costs of intermediate generation on each class' intermediate energy usage, and (3) the relatively expensive fuel costs of peaking generation on each class' peak energy usage. The fuel cost on a per MWh basis for each plant, as used in the Staff revenue requirement, is used as the relative prices to serve each class's base, intermediate, and peak load (in MWh). The relative value – by class – of the fuel to serve the load requirements of each class is used as the Production-Energy allocator.[18]

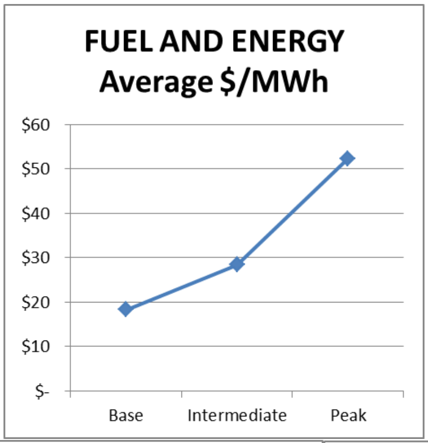
Staff also used the assignments of generating plant to BIP components to develop allocators for Empire's production related operating and maintenance expense and fuel stored on site. This method expressly assigns the expenses of each plant to follow that plant. Production plant operating and maintenance expenses are caused by each of the generating plants. Staff found the level of expense for each plant assigned under the BIP components, and developed allocation factors to apply to all production-related O&M based on each customer class's assigned plant responsibility. Similarly, fuel stored at each plant is associated with particular plants, so Staff has developed factors to allocate the fuel associated with particular plants with the plant allocated to each customer class.

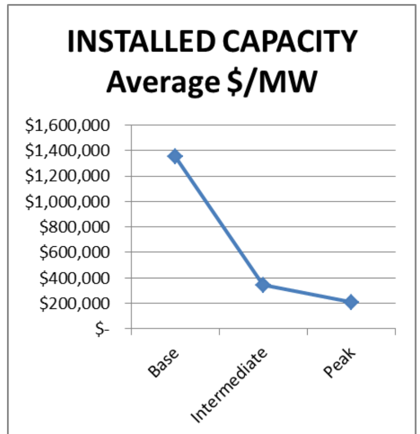
Staff's Detailed BIP study reasonably balances the offsetting impacts of the relative costs of energy, capacity, O&M, and fuel in storage associated with meeting the demand and

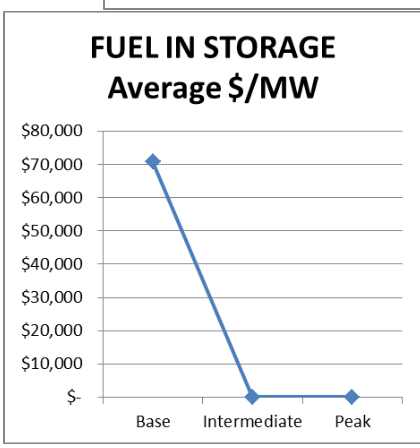
[17] A separate capacity-related allocator is used to allocate the return on investment associated with fuel stored at the various generation stations.

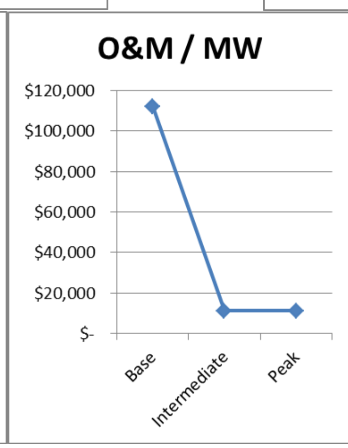
[18] A separate energy-related allocator is used to allocate the operations and maintenance expense associated with each of the various generation stations.

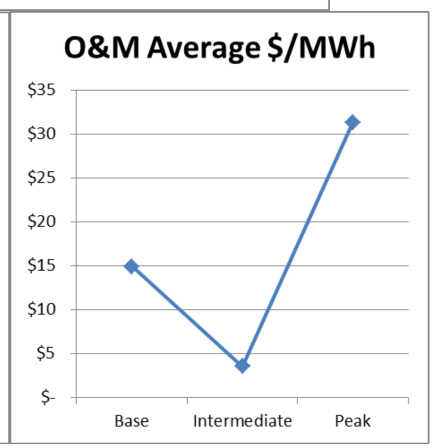
usage characteristics of Empire's load. Thus, Staff's use of the BIP is a reasonable method for allocating the production-related costs and expenses as well as the capacity-related and energy-related portions of off- system sales revenues. This consistency is appropriate as production plant expenses and production plant investment are interrelated. The relative values of each of these items are indicated in the graphs provided below.











The allocators that result from applying these values to Empire's BIP load characteristics are provided in the tables below.

BIP Installed Capacity Allocator

	Total	RG	CB	SH	TEB	GP	LP	PRAXAIR	PFM	Lighting
Base Capacity	$ 684,677,270	$ 282,061,581	$ 52,188,493	$ 15,242,551	$ 61,547,717	$ 138,112,119	$ 120,207,870	$ 9,860,997	$ 106,847	$ 5,349,094
Incremental Intermediate Capacity	$ 87,733,062	$ 63,002,670	$ 5,355,338	$ 2,393,934	$ 8,944,535	$ 8,036,585	$ -	$ -	$ -	$ -
Incremental Peak Capacity	$ 32,648,942	$ 25,009,718	$ 1,667,922	$ 1,022,415	$ 3,092,718	$ 1,856,169	$ -	$ -	$ -	$ -
Totals	$ 805,059,274	$370,073,969	$59,211,753	$18,658,901	$73,584,970	$148,004,874	$120,207,870	$9,860,997	$106,847	$5,349,094
BIP Installed Capacity Allocator		45.97%	7.35%	2.32%	9.14%	18.38%	14.93%	1.22%	0.01%	0.66%

BIP Fuel for Energy Allocator (annual)

	Total	RG	CB	SH	TEB	GP	LP	PRAXAIR	PFM	Lighting
Base Energy Usage	$ 69,514,825	$ 27,957,362	$ 5,507,784	$ 1,505,864	$ 6,303,217	$ 14,690,385	$ 12,205,152	$ 1,036,932	$ 5,837	$ 302,292
Incremental Intermediate Usage	$ 22,846,264	$ 13,224,795	$ 2,721,884	$ 470,261	$ 1,474,482	$ 3,968,550	$ 284,209	$ 72,383	$ 1,382	$ 628,318
Incremental Peak Usage	$ 2,927,081	$ 1,368,544	$ 768,039	$ 56,649	$ 79,828	$ 654,022	$ -	$ -	$ -	$ -
Totals	$ 95,288,170	$42,550,701	$8,997,707	$2,032,775	$7,857,527	$19,312,957	$12,489,361	$1,109,315	$7,219	$930,609
BIP Fuel for Energy Allocator		44.65%	9.44%	2.13%	8.25%	20.27%	13.11%	1.16%	0.01%	0.98%

BIP Fuel in Storage Allocator										
	Total	RG	CB	SH	TEB	GP	LP	PRAXAIR	PFM	Lighting
Base Capacity	$ 35,813,177	$ 14,753,697	$ 2,729,805	$ 797,287	$ 3,219,355	$ 7,224,183	$ 6,287,671	$ 515,796	$ 5,589	$ 279,793
Incremental Intermediate Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental Peak Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	$ 35,813,177	$14,753,697	$2,729,805	$797,287	$3,219,355	$7,224,183	$6,287,671	$515,796	$5,589	$279,793
BIP Fuel in Storage Allocator (Capacity)		41.20%	7.62%	2.23%	8.99%	20.17%	17.56%	1.44%	0.02%	0.78%

BIP O&M Allocator										
	Total	RG	CB	SH	TEB	GP	LP	PRAXAIR	PFM	Lighting
Base Usage	$ 56,654,438	$ 22,785,192	$ 4,488,833	$ 1,227,276	$ 5,137,109	$ 11,972,633	$ 9,947,174	$ 845,097	$ 4,757	$ 246,367
Incremental Intermediate Usage	$ 2,862,062	$ 1,656,734	$ 340,984	$ 58,912	$ 184,715	$ 497,159	$ 35,604	$ 9,068	$ 173	$ 78,712
Incremental Peak Usage	$ 1,752,865	$ 819,544	$ 459,935	$ 33,924	$ 47,804	$ 391,657	$ -	$ -	$ -	$ -
Totals	$ 61,269,366	$25,261,471	$5,289,752	$1,320,112	$5,369,629	$12,861,450	$9,982,778	$854,165	$4,930	$325,079
BIP O&M Allocator (Energy)		41.23%	8.63%	2.15%	8.76%	20.99%	16.29%	1.39%	0.01%	0.53%

Staff Experts: Sarah Kliethermes and Robin Kliethermes

D. Allocation of Transmission Costs

The transmission system moves electricity, at a very high voltage, from generating plants over long distances to local service areas. Transmission costs consist of costs for high voltage lines and transmission substations, and labor to operate and maintain these facilities. Empire's transmission investment and transmission costs comprise approximately 10% 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 based on the class loads at the time of the 12 CP.[19] Staff recommends the 12 CP allocation method for this purpose because, by including periods of normal use and intermittent peak use throughout all twelve months of the year, it takes into account the need for a transmission system that is designed both to transmit electricity during peak loads and to transmit electricity throughout the year.

Staff Experts: Sarah Kliethermes and Robin Kliethermes

[19] Coincident peak refers the load of each class at the time of the system peak. A 12 CP is the average of each class' load at the times of the system peak for each of the 12 months of the year.

E. Allocation of Distribution and Customer Service Costs

The distribution system converts high voltage power from the transmission system into lower primary voltage and delivers it to large industrial complexes, and further converts it into even lower secondary voltage power which can be delivered into homes for lights and appliances. Distribution is the final link in the chain built to deliver electricity to customers' homes or businesses. A utility's distribution plant includes distribution substations, poles, wires, and transformers, as well as service and labor expenses incurred for the operation and maintenance of these distribution facilities. Voltage level is a factor that Staff considered when allocating distribution costs to customer classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level needs of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, substation, or transmission level voltages. Only those customers in customer classes served at substation voltage or below were included in the calculation of the allocation factor for distribution substations. Staff used each class's annual non-coincident peak (as measured at substation voltage) to allocate substation costs.

Empire conducted a minimum distribution study to split the cost of poles, towers, fixtures; and overhead ("OH") and underground ("UG") distribution lines, conductors, and conduit between primary, secondary and customer related. Staff relied on information from this study in allocating investment to the classes.[20]

Staff allocated the costs of the primary distribution facilities on the basis of each customer class's annual non-coincident peak demand measured at primary voltage. All customers, except those served at transmission level, (i.e., primary and secondary customers),

[20] Staff does not draw the same conclusion as Dr. Overcast in assuming all costs allocated to the classes on customer count are necessarily "customer-related" for purposes of determining the cost to be recovered through the customer charge.

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 allocated the costs of distribution secondary on the basis of each customer class's annual non-coincident peak demand at secondary voltage. Staff allocated the cost of line transformers on the basis of each class's annual-peak demand at secondary voltage and on customer maximum demands at secondary voltage. Consideration of 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. Load diversity exists when the peak demands of customers do not occur at the same time. The spread of individual customer peaks over time within a customer class reflects the diversity of the class load. Therefore, when allocating demand-related distribution costs that are shared by groups of customers, it is important to choose a measure of demand that corresponds to the proper level of diversity. The following table summarizes the types of demand 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	Non-Coincident Peak	Moderate to High
Primary	Non-Coincident Peak	Moderate to High
Secondary	Non-Coincident Peak	Low to Moderate
Line Transformers	Diversified Peak[21]	Low to Moderate

[21] Class non-coincident peak and customer maximum demands

Customer costs include labor expenses incurred for billing and customer services. Customer-related costs are 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 allocating distribution service lines using each class's maximum daily demand at secondary voltage. Staff recommends allocating services and meter costs using the same allocator that Empire used to allocate these costs. These allocators are based on an Empire study that weights the number of installations taking service by class, and by the cost of the meter and service used to serve that class. Also, Staff recommends using the same allocators that Empire used for allocating meter reading costs, uncollectible accounts, customer services expense, and for allocating customer deposits. These allocators are derived using Empire studies that directly assign the costs of meter reading, uncollectible accounts, customer service expense, and customer deposits to the customer classes. The allocators are the fraction of total costs in these accounts assigned to each class, respectively.

Staff Expert: Robin Kliethermes

F. Revenues

Operating revenues consist of (1) the revenue that the utility collects from the sale 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 will be used to develop the rate schedules required to implement the Commission's ordered revenue requirement and rate design for Empire in this case. The normalized and annualized class rate revenues in Staff's COS Report filed January 29, 2015, were used in Staff's CCOS Study.

Other Electric Revenues were allocated to the rate classes depending on the source of those revenues. Unlike other Missouri electric utilities, at this time, Empire is a net purchaser of energy in the SPP Integrated Marketplace (IM). Because Empire was a net purchaser of off-system energy in Staff's direct fuel run, it was not necessary to separately allocate the cost of fuel and purchased power to make off-system sales to the classes. All off-system revenues from the sale of energy through the IM were allocated on dollar-weighted energy, and all other off-system revenues, such as from the provision of ancillary services, were allocated on dollar-weighted capacity. Because these values are imported as separate line items into the CCOS software, it was not necessary to develop a weighted off-system sales allocator to weight the fuel-related and capacity-related components of off-system sales.

Because Empire was a net purchase of energy in the IM and because Staff provided its calculation of Empire's adjusted test year energy sales in the IM as a revenue for CCOS purposes, those revenues are treated as a negative expense, and are most reasonably allocated to the classes using Staff's Production-Energy allocator.

The balance of Empire's off system-sales revenues are caused by the provision of ancillary services or are related to other SPP functions. Because these revenues are enabled by Empire's investment in generation and transmission capacity, it is appropriate to allocate these revenues to the retail classes consistent with the allocation of capacity costs, using the BIP Production-Capacity allocator.

Finally, Staff's revenue requirement recommendation presented in the COS Report included a line item adjusting the overall recommendation for the expected changes in cost of service that will occur if the Asbury generation station environmental retrofit is included in Staff's true-up revenue requirement. Staff's CCOS software was unable to detect this additional line item, so for CCOS purposes only, this increase to cost of service is treated as a negative revenue adjustment. This amount consists almost entirely of an estimate for the Asbury plant additions and associated depreciation expense, and is appropriately allocated using the Production-Capacity allocator.

Staff Experts: Sarah Kliethermes and Robin Kliethermes

G. Allocation of Taxes

Taxes consist of real estate and property taxes, payroll tax expenses and income taxes. Real estate and property tax expenses are directly related to Empire's original cost investment in plant, so these expenses are allocated to customer classes on the basis of the sum of the previously allocated production, transmission, distribution and general plant investment.

Payroll tax expenses are directly related to Empire's payroll expenses, so these expenses are allocated to customer classes on the basis of previously allocated payroll expenses.

Staff estimated income tax liability separately for each customer class as a function of the return-based revenues provided by each customer class. Staff has allocated Empire's income taxes based on class earnings.

Staff Expert: Robin Kliethermes

H. Allocation of Energy Efficiency Costs

Empire does not currently offer energy efficiency programs pursuant to the Missouri Energy Efficiency Investment Act. Accordingly, all Empire energy efficiency costs are allocated to each customer class based on each class's energy usage minus the energy usage of customers who opt-out of participation in those programs. These historical costs are included in rate base and amortized.

Staff Experts: Sarah Kliethermes and Robin Kliethermes

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 implement in rates any Commission-ordered overall change in customer revenue responsibility.
- Retain, to the extent possible, existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock.

Staff's rate design recommendations in this case are based on a five-step process:

1. Based on CCOS results, Staff first recommends to increase/decrease the current base retail revenue on a revenue-neutral basis for the various classes of customers. The Empire Residential Service Schedule ("RG") class should receive a positive 0.75% adjustment; and the Total Electric Building Service Schedule ("TEB"), General Power Service Schedule ("GP"), and Large Power Service Schedule ("LP") classes of customers should receive a negative adjustment of approximately 0.85%. (See Schedule BJF-D1)

2. After having made the recommended revenue-neutral adjustments, Staff recommends assigning the portion of the revenue increase/decrease that is attributable to Energy Efficiency ("EE") programs from Pre-MEEIA program costs directly to applicable customer classes.[22]

3. Staff then determined the amount of revenue increase awarded to Empire that is not associated with the EE revenue from Pre-MEEIA revenue requirement assigned in Step 2, by subtracting the total amount in Step 2 from the total increase awarded to Empire. Staff recommends that this amount be allocated to various customer classes as an equal percent of current base revenues after making the adjustment in Step 1. Based on CCOS results, Staff recommends that the Feed Mill and Grain Elevator Service Schedule ("PFM") and combined lighting classes receive no retail increase as existing revenues received from these classes are providing more revenue to Empire than Empire's cost to serve. (See Schedule BJF-D1)

4. Also, Staff recommends that each rate component of each class be increased across-the-board for each class on an equal percentage after consideration of steps 1 through 3 above. Included in this recommendation, based on CCOS results and policy considerations, Staff recommends that the residential, as well as all other customer charges, be increased by the average increase for the applicable class.

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[22] The Pre-MEEIA program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of Pre-MEEIA program costs. (See Schedule BJF-D2 and Schedule BJF-D3).

5. Finally, Staff recommends adopting Rider Fuel and Purchased Power Adjustment Clause ("FAC") tariff sheets consistent with Staff CCOS Report.

Current Rate Schedules

The Residential Service Schedule (RG) consists of the following elements:

- Residential Service Rates
- Customer Charge – per month
- Energy Charge – per kWh per season
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

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

The Commercial Service Schedule (CB) consists of the following elements:

- Small General Service Rates
- Customer Charge – per month
- Energy Charge – per kWh per season
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Small Heating Service Schedule (SH) consists of the following elements:

- Small Heating Service Rates
- Customer Charge – per month per season
- Energy Charge – per kWh per season
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The General Power Service Schedule (GP) consists of the following elements:

- General Power Service Rates
- Customer Charge – per month per season
- Energy Charge – hours use of metered demand - per kWh per season
- Demand Charge – per kW of billing demand per season
- Facilities Charge – per kW of facilities demand per season
- Transformer Ownership – reduction per kW to Facilities Charge
- Metering Adjustment – for service metered at primary voltage
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Large Power Service Schedule (LP) consists of the following elements:

- Large Primary Service Rates
- Customer Charge – per month per season
- Energy Charge – hours use of metered demand - per kWh per season
- Demand Charge – per kW of billing demand per season
- Facilities Charge – per kW of facilities demand per season
- Transformer Ownership – secondary facility charge per kW of facilities demand
- Substation Facilities Credit – facilities charge does not apply if stepdown-substation and transformer owned by Customer
- Metering Adjustment – for service metered at secondary voltage
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Feed Mill and Grain Elevator Service Schedule (PFM) consists of the following elements:

- Feed Mill and Grain Elevator Service Rates
- Customer Charge – per month per season
- Energy Charge – per kWh per season
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

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

- Total Electric Building Service Rates
- Customer Charge – per month per season
- Energy Charge – hours use of metered demand - per kWh per season
- Demand Charge – per kW of billing demand per season
- Facilities Charge – per kW of facilities demand per season
- Transformer Ownership – reduction per kW to Facilities Charge
- Metering Adjustment – for service metered at primary voltage
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Special Transmission Service Contract: Praxair Schedule (SC-P) consists of the following elements:

- Special Transmission Service Contract Service Rates
- Customer Charge – per month per season
- Energy Charge – per kWh per season
- On-Peak Demand Charge – per kW of billing demand per season

- Monthly Credit – demand reduction per kW of contracted interruptible demand
- Substation Facilities Charge – per kW of facilities demand
- Substation Facilities Charge – substation facilities charge does not apply if stepdown-substation and transformer owned by Customer
- Metering Adjustment – for service metered at substation voltage
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Special Transmission Service Schedule (ST) consists of the following elements:

- Special Transmission Service Rates
- Customer Charge – per month per season
- Energy Charge – per kWh per season
- On-Peak Demand Charge – per kW of billing demand per season
- Substation Facilities Charge – per kW of facilities demand
- Substation Facilities Charge – substation facilities charge does not apply if stepdown-substation and transformer owned by Customer
- Metering Adjustment – for service metered at substation voltage
- Fuel Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Lighting rate schedules are:

- Municipal Street Lighting Service Schedule (SPL)
- Private Lighting Service Schedule (PL)
- Special Lighting Service Schedule (LS)
- Miscellaneous Service Schedule (MS)

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

- Commercial Building Service Schedule (CB): Electric load is not in excess of 40 kW.
- Small Heating Service Schedule (SH): Average load is not in excess of 40kW 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 others whose utilization is purely for residential

purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 40kW, whichever is greater.

- Large Power Service Schedule (LP): Available for service to any general service customer except those who are conveying electric service 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 1000kW, whichever is greater.
- Feed Mill and Grain Elevator Service Schedule (PFM): Available for electric service to any customer feed mill or grain elevator.
- Total Electric Building Service Schedule (TEB): Available to any general service 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 40kW, 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 6000kW 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 Empire.

Empire's charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. 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.). Also, within each rate schedule, where applicable, demand and energy rates should continue to be seasonally differentiated (i.e., summer rates are higher than winter rates). The remaining rates (customer and facilities) should be constant year-round.

For its CCOS study, Staff examined each of these service schedules, other than lighting, as a stand-alone rate class. Staff did group the lighting service schedules into a rate group. Staff's CCOS study provided the investment and costs associated for Empire to provide service to these classes and the lighting group, as compared to the revenues currently provided by these classes and the lighting group. Staff's recommended rate design reasonably allocates Staff's recommended revenue requirement increase among the rate classes and lighting group.

Staff's CCOS study revealed that, on a revenue-neutral basis, Empire's current RG class rate(s) do not cover Empire's cost to serve that class and should receive a positive revenue-neutral adjustment. Staff recommends a negative revenue-neutral adjustment for the TEB, GP, and LP classes to bring these classes closer to their cost to serve by Empire. Two of the customer classes (PFM and combined lighting) are more than 18% above Empire's cost (investment and expenses) to serve them and should receive no increase in this case. Empire's CB, SH, and SC-P classes are close to their cost to serve and no revenue-neutral adjustment is recommended. These adjustments bring certain classes closer to cost of serving them, while still maintaining rate continuity, rate stability, revenue stability, and minimizing rate shock to any one customer class.

Staff Expert: Brad J. Fortson

V. Fuel and Purchased Power Adjustment Clause Tariff Sheet Recommendations

In its Revenue Requirement Cost of Service Report ("COS Report") in this case, Staff provided its recommendations for the following issues which have an impact on Empire's fuel adjustment clause ("FAC") rate design and tariff sheets:

1 Continue Empire's FAC with modifications;

2. Modify the FAC to reflect the replacement of Southwest Power Pool's ("SPP") Energy Imbalance Service ("EIS") Market with the Integrated Marketplace ("IM"); and

3. Include a revised Base Factor[23] in the FAC tariff sheets calculated from the Base Energy Cost and Revenues[24] that the Commission includes in the revenue requirement upon which it sets Empire's general rates in this case.

In its COS Report, Staff also recommended the Commission approve the exemplar FAC tariff sheets provided in Schedule DCR-1, and Staff's method for calculating the Base Factor shown in HC Schedule DCR- 3 of this report.

Fuel Adjustment Tariff Sheet Changes

Staff used the current Ameren Missouri FAC tariff sheets as a guide for its proposed revisions to the Empire FAC tariff sheets in this case. The Ameren Missouri FAC tariff sheets were chosen as a guide because parts of Empire's FAC tariff sheets, from Case No. ER-2012-0345, were modelled after Ameren Missouri's FAC tariff sheets from Case No. ER-2012-0166, and because Ameren Missouri has been a participant in the Midcontinent Independent System Operator ("MISO") day ahead and real time markets since 2005, and MISO costs and revenues have been flowing through Ameren Missouri's FAC since January 2009. The SPP IM is similar to MISO's day ahead and real time markets.

Schedule DCR-1 contains exemplar tariff sheets with Staff's proposed changes to Empire's FAC tariff sheets which are discussed below. Schedule DCR-2 is a redline/strikeout comparison of Staff's exemplar FAC tariff sheets with the Empire FAC tariff sheets numbered 17 through 17e. Staff is proposing a new series of original tariff sheets (17l through 17q) so that the first two series of tariff sheets (17 through 17e and 17f through 17k) remain in effect for the next FAC prudence review. Staff used the series 17 through 17e, for

[23] Base Factor is defined in Empire's 8th Revised Sheet No. 17 as "BASE FACTOR ("BF"): The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case.

[24] Base Energy Cost and Revenues is defined in Empire's 8th Revised Sheet No. 17 as "Base energy cost are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchased Power Adjustment ("FPA") and include fuel costs incurred to support sales ("FC") plus purchased power costs ("PP") plus net emission costs ("E") minus off-system sales revenues ("OSSR") minus renewable energy credit revenue ("REC").

service on and after April 1, 2013, to show Staff's proposed changes to the FAC tariff sheets. The exemplar tariff sheets also include some "clean up" changes to remove typographical errors from the FAC tariff sheets.

Base Factor ("BF")

Staff changed the Base Factor to $0.02393 per kWh. This is a decrease from the current Base Factor of $0.02831 per kWh. Staff used the Base Energy Costs and Revenues from Staff's accounting schedules found in Staff's COS Report to calculate the Base Factor. Staff will update the Base Factor as part of the test year true-up in this case. The Base Factor Calculation Section provides the Staff's method for determining the Base Factor.

Fuel Costs Incurred to Support Sales ("FC")

Fuel costs incurred to support sales include the variable cost of fuel used in the production of electricity in FERC accounts 501, 506, 547 and 548. It also includes combustion product disposal revenues and expenses and the expense for air quality control systems (AQCS) consumables such as limestone, ammonia and powdered activated carbon that are used to treat the air emissions from generating electricity. Staff made no changes to this section of the tariff.

Purchased Power Costs and Revenues ("PP")

Staff sought guidance on the suitability and selection of transmission costs and revenues to flow through Empire's FAC from the Report and Orders of the Commission in the Ameren Missouri Rate Case No. ER-2012-0166; the joint Report and Order of the Commission in the Kansas City Power & Light Company ("KCPL") and KCP&L Greater Missouri Operations Company ("GMO") Rate Case Nos. ER-2012-0174 and ER-2012-0175; and the Report and Order of the Commission regarding the KCPL and GMO Application for the Issuance of an Accounting Authority Order in Case No. EU-2014-0077. These prior cases demonstrated that:

1. SPP transmission costs have not been shown to meet the standards for a transmission tracker in Missouri.[25]
2. SPP transmission costs have not been shown to meet the standard for an Accounting Authority Order.[26]
3. Certain SPP transmission costs may be recovered though a Commission approved FAC.[27]
4. MISO Transmission costs should continue to flow through Ameren Missouri's FAC.[28]
5. The Commission has previously made Findings of Fact on specific tariff language for costs of purchased power in accounts 555, 565, and 575.[29]
6. There are Commission approved tariff sheets that provide for transmission costs and revenues to be recovered through an electric utility's FAC[30].

Staff's proposed tariff sheets include the purchased power costs and revenues in FERC accounts 555, 565, and 457, which include purchased power costs and costs and revenues from SPP's energy and transmission service markets. Staff included SPP Schedules 1, 2, 7, 8, 9, 10 and 11 in this section. This selection of transmission costs and revenues is very similar to the type of transmission costs and revenues that are in the Ameren Missouri FAC tariff

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[25] P.32 Commission *Report and Order* KCP&L and GMO Rate Case Nos. ER-2012-0174 and ER-2012-0175.
[26] P. 11 Commission *Report and Order* KCPL and GMO Application for the Issuance of an Accounting Authority Order EU-2014-0077.
[27] P. 8 Finding of Fact #12 Commission *Report and Order* KCPL and GMO Application for the Issuance of an Accounting Authority Order EU-2014-0077.
[28] P. 89 Commission *Report and Order* Ameren Missouri Rate Case No. ER-2012-0166.
[29] Pp.84-86 Findings of Facts #4-7 Commission *Report and Order* Ameren Missouri Rate Case No. ER-2012-0166.
[30] See pp. 2-4 Order Approving Compliance Tariff Sheets in Ameren Missouri Rate Case No.ER-2012-0166.

sheets. Staff excluded SPP Schedule 1-A, Tariff Administration Service, and SPP Schedule 12, FERC Assessment Charge. These charges are excluded because the intent of Empire's FAC, like Ameren Missouri's, is not to recover administrative costs, but fluctuating fuel and purchased power costs.

Additional language has been added to this section to account for changes and additions of market settlement charge types by SPP or another market participant. The Company may include the new charge type cost or revenue in its fuel adjustment rate ("FAR") filings if the Company believes the new charge type cost or revenue possesses the characteristics of the costs or revenues listed in the Company's FAC tariff sheets. The Company will provide notice in its monthly reports required by the Commission's fuel adjustment clause rules and provide enough information for the transparent determination of current period and cumulative costs or revenues. A party may challenge the inclusion, or failure to include a new charge type cost or revenue in the FAR filing. A complete list of the components of Purchased Power Costs and Revenues and the additional language concerning new charge types is provided in Schedules DCR-1 and DCR-2.

<u>Net Emission Costs ("E")</u>

Staff made no changes to this section.

<u>Revenue from Off-System Sales ("OSSR")</u>

Staff's proposed tariff sheets includes revenues and costs reflected in FERC Account 447 for all revenues from off-system sales but excludes revenues from full and partial requirements sales to municipalities that are served through bilateral contracts with Empire. Staff included revenues from the SPP energy market revenues from: energy, ancillary services, revenue sufficiency, losses, revenue neutrality, demand reduction, grandfathered agreements, pseudo-ties, miscellaneous revenues and hedging. The exclusion of revenues from full and partial requirements sales to municipalities that are associated with Empire remains the same as the current tariff.

Renewable Energy Credit Revenue ("REC")

Staff made one capitalization change in this section.

Other Changes to Empire's FAC Tariff Sheets

While each electric utility's FAC complies with the same Commission rules, each electric utility had unique FAC tariff sheets with unique acronyms and definitions. This issue was addressed in Empire's last general rate case, and the Commission-approved tariff sheets are a refinement from previous tariff sheets. However, some language was included in the current tariff sheets that does not directly apply to Empire's current operations. Empire's reply to the Office of Public Counsel's Data Request 8008, in this rate case, in part states that "Several of the costs defined in Empire's tariff as includible may not have been incurred by Empire historically due to the differences between it and Ameren…".

Staff proposes to work with interested parties during this rate case to remove language that is not applicable to Empire's current operations. It is not Staff's intent to change the meaning of Empire's FAC tariff sheets, but to include language only descriptive of Empire's current operations.

Revised Base Factor Calculation

Staff calculated the Base Factor of $0.02393 per kWh using the Base Energy Costs and Revenues from Staff's accounting schedules found in Staff's COS Report in this rate case, and the proposed changes to the FAC tariff sheets discussed above which Staff is recommending. SPP EIS costs and revenues from the test year were removed and annualized SPP IM costs and revenues, excluding labor and administrative charges, were added to the calculation. HC Schedule DCR- 3 is Staff's calculation of the Base Factor. The Base Factor calculation is broken down into fuel costs incurred to support sales, purchased power costs, net emission costs, revenues from off-system sales and renewable energy credit revenue.

<u>Fuel Costs Incurred to Support Sales ("FC")</u>

Fuel costs incurred to support sales include the variable cost of fuel used in the production of electricity in FERC accounts 501, 506, 547, 548, and includes combustion product disposal revenues and expenses and the expense for air quality control systems (AQCS) consumables. Staff has excluded the administrative and labor expenses in subaccounts 501.011, 501.400, 501.601, 501.604, 501.605, 547.605, and 547.606 that are also excluded in Empire's current FAC. Staff has also excluded the convention and seminar costs in account 501.011 because Empire's FAC is designed to flow through variable fuel and purchased power expenses, emission allowance expenses and revenues, not administrative, seminar, and labor expenses. Staff added each of these subaccounts, which equals **** ________ ****, and made a negative adjustment to Staff's calculation to remove the administrative, seminar and labor expenses from Fuel Costs Incurred to Support Sales.

NP

Purchased Power Costs and Revenues (“PP”)

Staff’s Base Factor calculation includes the purchased power costs and revenues in Staff’s accounting schedules for FERC accounts 555, 565, and 457 which include purchased power costs and costs and revenues from SPP’s energy and transmission service markets. Staff excluded costs from subaccounts 565.414 reflecting SPP Schedule 1-A, Tariff Administration Service, and 565.415 SPP Schedule 12, FERC Assessment Charges from the calculation because these two Schedules are administrative charges, they are not fluctuating fuel and purchased power costs, and therefore these costs do not belong in Empire’s FAC.

Revenue from Off-System Sales (“OSSR”)

Staff’s Base Factor includes revenues and costs reflected in FERC Account 447 for all revenues from off-system sales but excludes revenues from full and partial requirements sales to municipalities that are served through bilateral contracts with Empire. It also includes revenues from the SPP energy market revenues from capacity, energy, ancillary services, revenue sufficiency, losses, revenue neutrality, demand reduction, grandfathered agreements, pseudo-tie, miscellaneous revenues and hedging.

Renewable Energy Credit Revenue (“REC”)

The amount of Renewable Energy Credit Revenues found in Staff’s accounting schedules was used in the Base Factor calculation.

Net Emission Costs (“E”)

The amount of net emission costs found in Staff’s accounting schedules was used in the Base Factor calculation.

Other Excluded Costs

Staff has excluded the following fixed costs which are also excluded from Empire's current FAC: fixed costs for natural gas transportation, and fixed costs for natural gas storage. These costs are known and fixed and are not related to the amount or cost of fuel. Staff has also excluded the fixed purchased power demand charges from Plum Point. The Plum Point demand charges are known, with measurable changes and are a function of long-term (greater than one year) generation capacity. The Plum Point capacity charges are not variable fuel and purchased power costs. The Company has the opportunity to recover all of these costs in permanent rates.

Staff Expert/Witness: David Roos

VI. Residential Customer Charge

Based on Staff's CCOS study results and rate design principles regarding rate simplicity, stability, and customer understandability, Staff recommends that the residential customer charge increase by the same percentage increase as the energy charges for the Residential Service class.[31] Using Staff's recommended revenue requirement and rate design proposal, this would be a 2.18% or approximately $0.27 increase in the Residential customer charge at the time of this filing.[32]

Costs included in the calculation of the Residential customer charge costs are the costs necessary to make electric service available to the customer, regardless of the level of electric service utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting service expenses, as well as a portion of the costs associated with the

[31] Empire's current residential customer charge is $12.52.
[32] The amount of the increase in the residential customer charge will vary with any approved interclass shifts and the level of overall system average increase.

required investment in a meter, the service line ("drop"), and other billing costs. The costs included for recovery through the customer charge consist of the following:

- Distribution – services (investment and expenses)
- Distribution – meters (investment and expenses)
- Distribution – customer installations
- Customer deposit
- Customer meter reading
- Other customer billing expenses
- Uncollectible accounts (write-offs)
- Customer service & information expenses
- Sales expense
- Portion of income taxes

Staff recommends allocating services and meter costs using the same allocator that Empire used to allocate these costs. These allocators are based on an Empire study that weights the number of installations taking service by class, and by the cost of the meter and service used to serve that class. Also, Staff recommends using the same allocators that Empire used for allocating meter reading costs, uncollectible accounts, customer services expense, and for allocating customer deposits. These allocators are derived using Empire studies that directly assign the costs of meter reading, uncollectible accounts, customer service expense, and customer deposits to the customer classes. The allocators are the fraction of total costs in these accounts assigned to each class, respectively.

The sum of the residential class's costs allocated to the customer charge determines a residential monthly customer charge sufficient to collect those costs from the customers within the class. Staff's CCOS study and calculation of the residential customer charge resulted in a customer charge of approximately $18.50 per month. However, weighing the factors of rate simplicity, stability, customer understandability, and public policy consideration relating to energy efficiency, Staff recommends limiting the residential customer charge to the level of the average residential class increase.[33]

Staff Expert: Robin Kliethermes

VII. Non-residential Customer Charges

Based on Staff's CCOS study results and policy considerations, Staff recommends that the non-residential customer charge be increased by the system average increase for that class.

Customer-related costs are the costs necessary to make electric service available to the customer, regardless of the level of electric service utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting service expenses, as well as a portion of the costs associated with the required investment in a meter, the service line, and other billing costs. The costs included for recovery through the customer charge consist of the following:

- Distribution – services (investment and expenses)
- Distribution – meters (investment and expenses)
- Distribution – customer installations
- Customer deposit
- Customer meter reading
- Other customer billing expenses
- Uncollectible accounts (write-offs)
- Customer service & information expenses
- Sales expense
- Portion of income taxes

[33] In the last Ameren Missouri rate case, Case No. ER-2012-0166, the Commission found that there were strong public policy considerations in favor of not increasing the customer charges, particularly, that a lower customer charge enables customers to see greater impact from conservation efforts and therefore encourages customers to engage in conservation efforts. In that case, the Commission rejected a proposed increase to the residential customer charge, noting that increasing the customer charge would send exactly the wrong message to customers and would discourage efforts to conserve electricity. The same concern is raised in considering raising the residential customer charge in this case. Any increase to the residential customer charge would slightly decrease the bill impact (and cost-effectiveness) of any conservation efforts that customers may have implemented or be considering.

As mentioned in the allocation of customer-related costs report section, Staff recommends allocating distribution service lines using each class's maximum daily demand at secondary voltage and other costs and investment outlined above.

The Commission has recently rejected proposed customer charge increases for policy considerations. The Commission found[34] that it is not bound to set the customer charges based solely on the details of the cost of service studies. There are strong public policy considerations in favor of not increasing customer charges. One example noted by the Commission is that energy efficiency plans under the Missouri Energy Efficiency Investment Act ("MEEIA"), by customers are a public policy consideration. Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed charges, will tend to reduce a customer's incentive to save electricity. Increasing customer charges at this time would send the wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.

Empire recently filed its MEEIA plan in File No. EO-2014-0030. Even though this MEEIA filing is ongoing, Staff recommends that the non-residential customer charges be modestly increased by the system average increase for that class.

Staff Expert/Witness: Michael Scheperle

VIII. Miscellaneous Tariff Revisions

Empire has requested changes to its non-residential line extension policy. Empire proposes to lengthen the revenue test from 1 year to 3 years, and allowing underground facility costs to be included in the extension. Staff does not oppose this change.

[34] Report and Order, File No. ER-2012-0166, page 108 – 111.

Empire has requested changes to its Residential line extension policy. Empire requests removing the rural customer designation to acknowledge changes in practice for customers requesting meter poles. Staff does not oppose this change.

Empire has requested changes to its Praxair tariff relating to the hours of interruption allowed in a given year. It does not appear that Empire is requesting to recover the interruptible credit in rates. Because non-Praxair customers will not be adversely impacted by this change, Staff does not oppose Empire's decision to alter its shareholder's liability for imputed revenues under the Praxair tariff.

Staff Expert/Witness: Sarah Kliethermes

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)))))	Case No. ER-2014-0351

AFFIDAVIT OF MICHAEL S. SCHEPERLE

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

Michael S. Scheperle, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1-69 43-44; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael S. Scheperle
Michael S. Scheperle

Subscribed and sworn to before me this 11th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)))))	Case No. ER-2014-0351

AFFIDAVIT OF ROBIN KLIETHERMES

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

Robin Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 7-27 & 41-43; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Robin Kliethermes

Subscribed and sworn to before me this 11th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)))))	Case No. ER-2014-0351

AFFIDAVIT OF SARAH L. KLIETHERMES

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

Sarah L. Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 8-22, 25-27 + 44-45; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Sarah L. Kliethermes
Sarah L. Kliethermes

Subscribed and sworn to before me this 11th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)))))	Case No. ER-2014-0351

AFFIDAVIT OF BRAD J. FORTSON

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

Brad J. Fortson, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 28-33; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Brad J. Fortson

Brad J. Fortson

Subscribed and sworn to before me this 11th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)))))	Case No. ER-2014-0351

AFFIDAVIT OF DAVID C. ROOS

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

David C. Roos, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 34 – 41; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David C Roos
David C. Roos

Subscribed and sworn to before me this 11th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L Sundermeyer
Notary Public

STAFF RATE DESIGN AND CLASS COST-OF-SERVICE REPORT

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

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

customer-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 describe the availability requirements, prices, and terms applicable to a particular type of retail electric service. A customer class used in a class cost-of-service study may consist of one or more rate schedules.

[2] A customer class 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:

> 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

The first step of a CCOS study is functionalization. Functionalization of costs involves categorizing plant investment and operation cost accounts by the type of function with which an account is associated. 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

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

The second step of a CCOS study is to separate the functionalized costs into classifications based on the components of utility service being provided. Classification is a means to divide the functionalized, cost-defining components into a: 1) customer component, 2) demand component, and 3) 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 certain 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.

3. Allocation

The third step of performing a CCOS study is called 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.

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

Missouri Public Service Commission
Case No. ER-2014-0351
Rate Design

Illustrative Purposes Only

	Total Current Revenue	Pre-MEEIA Revenue	Step 1 Retail Revenue	Step 1 Revenue Shift	Adjusted Retail	Step 2 Pre-MEEIA Increase	Step 3 Retail Increase	Total Revenue Requirement	Percent Increase	Revenue Neutral
RG	$ 202,230,912	$ 461,989	$ 201,768,923	$ 1,513,267	$ 203,282,190	$ 215,955	$ 2,671,959	$ 206,632,094	2.18%	0.75%
CB	$ 42,049,394	$ 85,166	$ 41,964,228	$ -	$ 41,964,228	$ 39,811	$ 551,582	$ 42,640,786	1.41%	0.00%
SH	$ 10,341,541	$ 24,637	$ 10,316,904	$ -	$ 10,316,904	$ 11,516	$ 135,606	$ 10,488,664	1.42%	0.00%
TEB	$ 37,076,158	$ 96,810	$ 36,979,348	$ (314,460)	$ 36,664,888	$ 45,254	$ 481,927	$ 37,288,878	0.57%	-0.85%
GP	$ 82,330,771	$ 209,267	$ 82,121,504	$ (698,335)	$ 81,423,169	$ 97,821	$ 1,070,233	$ 82,800,491	0.57%	-0.85%
LP	$ 58,977,270	$ 123,739	$ 58,853,531	$ (500,472)	$ 58,353,059	$ 57,841	$ 766,998	$ 59,301,638	0.55%	-0.85%
SC-P	$ 3,583,744	$ -	$ 3,583,744	$ -	$ 3,583,744	$ -	$ 47,105	$ 3,630,849	1.31%	0.00%
PFM	$ 113,402	$ 174	$ 113,228	$ -	$ 113,228	$ 81	$ -	$ 113,483	0.07%	0.00%
MS	$ 13,847	$ -	$ 13,847	$ -	$ 13,847	$ -	$ -	$ 13,847	0.00%	0.00%
SPL	$ 3,252,312	$ -	$ 3,252,312	$ -	$ 3,252,312	$ -	$ -	$ 3,252,312	0.00%	0.00%
PL	$ 4,305,087	$ -	$ 4,305,087	$ -	$ 4,305,087	$ -	$ -	$ 4,305,087	0.00%	0.00%
LS	$ 138,634	$ -	$ 138,634	$ -	$ 138,634	$ -	$ -	$ 138,634	0.00%	0.00%
Total	$ 444,413,072	$ 1,001,782	$ 443,411,290	$ (0)	$ 443,411,290	$ 468,280	$ 5,725,410	$ 450,606,762	1.39%	0.00%

Retail Increase at Staff Mid-Point $ 5,725,410

Total Increase at Staff Mid-Point $ 6,193,690

Empire District Electric Company **ILLUSTRATIVE PURPOSES ONLY**

Case No. ER-2014-0351

Revenue Requirement for Energy Efficiency (Pre-MEEIA)

Energy Efficiency Calculation

Current Revenue Requirement	$ 1,470,062	
Revenue Requirement - Existing	$ 1,001,782	Staff Proposal worksheet
Additional Pre-MEEIA	$ 468,280	

Class	Pre-MEEIA Revenue ER-2014-0351	Additional Pre-MEEIA	Total Pre-MEEIA
RG	$ 461,989	$ 215,955	$ 677,944
CB	$ 85,166	$ 39,811	$ 124,977
SH	$ 24,637	$ 11,516	$ 36,153
TEB	$ 96,810	$ 45,254	$ 142,064
GP	$ 209,267	$ 97,821	$ 307,088
LP	$ 123,739	$ 57,841	$ 181,580
SC-P	$ -	$ -	$ -
PFM	$ 174	$ 81	$ 255
MS	$ -	$ -	$ -
SPL	$ -	$ -	$ -
PL	$ -	$ -	$ -
LS	$ -	$ -	$ -
Total	$ 1,001,782	$468,280	$1,470,062

Class	Kwh	Opt-Out	kWh Less Opt-out	Calculated Pre-MEEIA Revenue
RG	1,711,070,624	0	1,711,070,624	$ 461,989
CB	316,593,078	1,162,045	315,431,033	$ 85,166
SH	92,468,626	1,220,418	91,248,208	$ 24,637
TEB	373,363,724	14,705,001	358,658,723	$ 96,838

GP	837,830,349	60,534,088	777,296,261	$ 209,870
LP	729,220,809	272,763,900	456,456,909	$ 123,243
SC-P	59,817,292	59,817,292	0	$ -
PFM	645,595	0	645,595	$ 174
MS	132,631	132,631	0	$ -
SPL	18,187,739	18,187,739	0	$ -
PL	13,442,987	13,442,987	0	$ -
LS	683,634	683,634	0	$ -
Total	4,153,457,088	442,649,735	3,710,807,353	$ 1,001,918

Annualized Pre-MEEIA Rate	0.00027
Annualized Pre-MEEIA Revenue	$ 1,001,918

Empire District Electric Company **ILLUSTRATIVE PURPOSES ONLY**

Case No. ER-2014-0351

Revenue Requirement for Energy Efficiency (Pre-MEEIA)

AMORTIZATIONS (1)	Annualized Amortization (1)	
DSM/Pre-MEEIA	$ 987,834	Staff Amortization analysis
	$ -	
Total	$ 987,834	

RATE BASE (2)	Amount (2)	
Reg Asset/DSM - Pre-MEEIA Costs	$ 4,524,565	Rate Base Schedule
	$ -	
Total	$ 4,524,565	

Effective Return and Income Tax Effect Calculation - ROE at 9.50%		
Total Pre-Tax Rate	10.658%	Empire Rate of Return - Tax weighted at Staff Mid-Point

Total Revenue Requirement		
Amortization	$ 987,834	Calculation from above
Return plus Income tax (3)	$ 482,228	See footnote (3)
Total Revenue Requirement	$ 1,470,062	

(1) Staff Accounting schedules in Case No. ER-2014-0351 (Through True-Up). Income Statement Detail

(2) Staff Accounting schedules in Case No. ER-2014-0351(Through True-Up). Rate Base Schedule

(3) Rate Base * Total Pre-Tax Rate

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

The two six-month accumulation periods, the two six-month recovery periods and filing dates are set forth in the following table:

Accumulation Periods	**Filing Dates**	**Recovery Periods**
September – February	By April 1	June – November
March – August	By October 1	December – May

The Company will make a Fuel Adjustment Rate ("FAR") filing by each Filing Date. The new FAR rates for which a filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FAR 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 and revenues subject to this rider will be accumulated for the purpose of determining the FAR.

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

BASE ENERGY COST AND REVENUES:
Base energy cost are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchase Power Adjustment ("FPA").

BASE FACTOR ("BF"):
The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case. BF = $0.0XXXX~~2831~~ per kWh for each accumulation period.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

APPLICATION
FUEL & PURCHASE POWER ADJUSTMENT

$$FPA = \{[(FC + PP + E – OSSR - REC - B) * J] * 0.95\} + T + I + P$$

Where:

FC = Fuel Costs Incurred to Support Sales:

The following costs reflected in Federal Energy Regulatory Commission (FERC) Accounts 501 and 506: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuels (i.e. tires, bio-fuel and landfill gas), fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments assessed by coal suppliers, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, propane costs, combustion product disposal revenues and expenses, consumable costs related to Air Quality Control Systems (AQCS) operation, such as ammonia, lime, limestone, powdered activated carbon, urea, sodium bicarbonate, and trona and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

The following costs reflected in FERC Accounts 547 and 548: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge purchased power, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees.

PP = Purchased Power Costs:

Costs and revenues for purchased power~~The following costs or revenues~~ reflected in FERC Accounts 555 and 575, excluding all charges under Southwest Power Pool (“SPP”) schedules 1-A and 12. Such costs and revenues include: purchased power costs, purchased power demand costs associated with purchased power contracts with a duration of one year or less, settlements, insurance recoveries, and subrogation recoveries for purchased power expenses, virtual energy charges, generating unit price adjustments, load/export charges, energy position charges, ancillary services including penalty and distribution charges, broker commissions, fees and margins and SPP energy market charges.including:~~(see Note A. below)~~

A. SPP costs or revenues for SPP’s energy and operating market settlement charge types and market settlement clearing costs or revenues including:

i. Energy;
ii. Ancillary Services;
a. Regulating Reserve Service
b. Energy Imbalance Service
c. Spinning Reserve Service
d. Supplemental Reserve Service

iii. Revenue Sufficiency;
iv. Losses;
v. Revenue Neutrality;
vi. Congestion Management including:
 a. Congestion
 b. Financial Transmission Rights
vii. Demand Reduction;
viii. Grandfathered Agreements;
ix. Virtual Transaction Fee;
x. Pseudo-tie;
xi. Miscellaneous;

B. Non-SPP costs or revenue as follows:

i. If received from a centrally administered market (e.g. PJM / MISO), costs or revenues of an equivalent nature to those identified for the SPP costs or revenues specified in subpart A of part 1 above;

ii. If not received from a centrally administered market:
 a. Costs for purchases of energy; and
 b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and
 c. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist; and

2. Insurance premiums in FERC Account 924 for replacement power insurance. Costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles; and

3. All transmission service costs and revenues reflected in FERC Account 565 and all transmission service revenues reflected in FERC Account 457. Such transmission service costs and revenues include:

A. SPP costs and revenues associated with:

i. SPP NITS Service charges (SPP Schedule 11, or its successors);

ii. SPP Point-to-point transmission service revenue (SPP Schedules 1, 7 and 8 or their successors);

iii SPP Network Integration Transmission Service (SPP schedule 9 or its successor)

iv SPP Wholesale Distribution Service (SPP schedule 10 or its successor)

v, SPP Reactive Supply and Voltage Control (SPP schedule 2 or its successor)

B. Non-SPP costs and revenues associated with:

i. Network transmission service;

ii. Point-to-point transmission service;

iii. System control and dispatch; and

iv. Reactive supply and voltage control

4. Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which SPP or another market participant bills / credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another market participant implement a charge type not listed in Empire's FAC:

A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to another party's right to challenge the inclusion (or failure to include) as outlined in E. below;

B. The Company will include in its monthly reports required by the Commission's fuel adjustment clause rules, notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such notice shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the existing market charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues; and

E. If the Company includes a new charge type cost or revenue in a FAR filing and a party

RIDER FAC

For service on and after July xx, 2015

challenges the inclusion (or if the Company does not include a new charge type cost or revenue and a party challenges the failure to include it), such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. To challenge the failure to include a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should have been included, because they do possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. In the event of a challenge, the Company shall bear the burden of proof to support its decision to include or exclude or its failure to include or exclude a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor PP.

E = Net Emission Costs:

The following costs and revenues reflected in FERC Accounts 509, 411.8 and 411.9 (or any other account FERC may designate for emissions expense in the future): emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging costs, broker commissions, fees, commodity based services and margins.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

OSSR = Revenue from Off-System Sales:

The following revenues or costs reflected in FERC Account 447: all revenues from off-system sales but excluding revenues from full and partial requirements sales to municipalities that are associated with Empire, and SPP energy and operating market revenues,~~.~~ (see Note A. below)

i. Energy
ii. Ancillary Services including:
a. Regulating Reserve Service
b. Energy Imbalance Service
c. Spinning Reserve Service
d. Supplemental Reserve Service
iii. Revenue Sufficiency;
iv. Losses;
v. Revenue neutrality;
vi. Demand Reduction;
vii. Grandfathered Agreements;
viii. Pseudo-tie;
ix. Miscellaneous;
x. Hedging

REC = Renewable Energy Credit R~~r~~evenue:

Revenues reflected in FERC Account 456 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

HEDGING COSTS:

Hedging costs are defined as realized losses and costs (including broker commission fees and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances and purchased power costs, including but not limited to, the Company's use of derivatives whether over-the-counter or exchanged traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars and swaps.

Note A. Should FERC require any item covered by factors FC, PP, E, REC or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E, REC or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = Net base energy cost is calculated as follows:

FUEL &PURCHASE POWER ADJUSTMENT CLAUSE
Rider FAC
For service on or after July xx, 2015

B = (S_{AP} * $0.XXXX)

S_{AP} = Actual net system input at the generation level for the accumulation period.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

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

Where Total system kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

T = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission.

I = Interest applicable to (i) the difference between Total energy cost (FC + PP + E – OSSR – REC) and Net base energy costs (“B”) multiplied by the Missouri energy ratio (“J”) for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company’s short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

FUELADJUSTMENTRATE

The FAR is the result of dividing the FPA by estimated recovery period S_{RP} kWh, rounded to the nearest \$0.00000. The FAR shall be adjusted to reflect the differences in line losses that occur at primary and secondary voltage by multiplying the average cost at the generator by 1.0466 and 1.0662, respectively. Any FAR authorized by the Commission shall be billed based upon customers’ energy usage on and after the authorized effective date of the FAR. The formula for the FPA is displayed below.

$$FAR = \frac{FPA}{S_{RP}}$$

Where:

S_{RP} = Forecasted Missouri NSI kWh for the recovery period.

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

Where Forecasted total system NSI kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

PRUDENCEREVIEW

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

TRUE-UPOFFPA

In conjunction with an adjustment to its FAR, the Company will make a true-up filing 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 FPA revenues billed and the FPA revenues authorized for collection during the true-up recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item T 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 ~~4th~~ Original Sheet No. 17t

Canceling P.S.C. Mo. No. ~~5~~ Sec. 4 ~~3rd~~ Original Sheet No.

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

	Accumulation Period Ending		~~Feb 28, 2014~~
1	Total Energy Cost (TEC) = (FC+PP+E-OSSR-REC)		~~83,236,791~~
2	Net Base Energy Cost (B)	-	~~78,366,213~~
	2.1 Base Factor (BF)		~~0.02831~~
	2.2 Accumulation Period NSI (S_{AP})		~~2,768,146,000~~
3	(TEC-B)		~~4,870,578~~
4	Missouri Energy Ratio (J)	*	~~83.46%~~
5	(TEC-B)*J		~~4,064,779~~
6	Fuel Cost Recovery	*	~~95.00%~~
7	(TEC-B)*J*0.95		~~3,861,540~~
8	True-Up Amount (T)	+	~~(231,336)~~
9	Prudence Adjustment Amount (P)	+	
10	Interest (I)	+	~~(329)~~
11	Fuel and Purchased Power Adjustment (FPA)	=	~~3,629,875~~
12	Forecasted Missouri NSI (S_{RP})	÷	~~2,233,896,883~~
13	Current Period Fuel Adjustment Rate (FAR) to be applied Beginning 06-01-2014	=	~~0.00162~~
14	Current Period FAR_{PRIM} = FAR x VAF_{PRIM}		~~0.00170~~
15	Current Period FAR_{SEC} = FAR x VAF_{SEC}		~~0.00173~~
16	VAF_{PRIM} = 1.0466		1.0466
17	VAF_{SEC} = 1.0622		1.0622

DATE OF ISSUE ~~April 1, 2014~~ DATE EFFECTIVE ~~June 1, 2014~~
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

~~FILED Missouri Public Service Commission ER-2014-0264, EO-2014-0265, JE-2014-0378~~

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FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

The two six-month accumulation periods, the two six-month recovery periods and filing dates are set forth in the following table:

Accumulation Periods	**Filing Dates**	**Recovery Periods**
September – February	By April 1	June – November
March – August	By October 1	December – May

The Company will make a Fuel Adjustment Rate ("FAR") filing by each Filing Date. The new FAR rates for which a filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FAR 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 and revenues subject to this rider will be accumulated for the purpose of determining the FAR.

RECOVERY PERIOD:

The billing months during which a FAR is applied to retail customer usage on a per kilowatt-hour (kWh) basis.

BASE ENERGY COST AND REVENUES:

Base energy cost are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchase Power Adjustment ("FPA").

BASE FACTOR ("BF"):

The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case. BF = $0.0XXXX per kWh for each accumulation period.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

APPLICATION
FUEL & PURCHASE POWER ADJUSTMENT

FPA = {[(FC + PP + E – OSSR - REC - B) * J] * 0.95} + T

+ I + P Where:

FC = Fuel Costs Incurred to Support Sales:

The following costs reflected in Federal Energy Regulatory Commission (FERC) Accounts 501 and 506: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuels (i.e. tires, bio-fuel and landfill gas), fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments assessed by coal suppliers, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, propane costs, combustion product disposal revenues and expenses, consumable costs related to Air Quality Control Systems (AQCS) operation, such as ammonia, lime, limestone, powdered activated carbon, urea, sodium bicarbonate, and trona and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

The following costs reflected in FERC Accounts 547 and 548: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge purchased power, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees.

PP = Purchased Power Costs:

Costs and revenues for purchased power reflected in FERC Accounts 555 and 565, excluding all charges under Southwest Power Pool ("SPP") schedules 1-A and 12. Such costs and revenues include: purchased power costs, purchased power demand costs associated with purchased power contracts with a duration of one year or less, settlements, insurance recoveries, and subrogation recoveries for purchased power expenses, virtual energy charges, generating unit price adjustments, load/export charges, energy position charges, ancillary services including penalty and distribution charges, broker commissions, fees and margins and SPP energy market charges.including:

A. SPP costs or revenues for SPP's energy and operating market settlement charge types and market settlement clearing costs or revenues including:

i. Energy;
ii. Ancillary Services;
  a. Regulating Reserve Service
  b. Energy Imbalance Service
  c. Spinning Reserve Service
  d. Supplemental Reserve Service

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

iii. Revenue Sufficiency;
iv. Losses;
v. Revenue Neutrality;
vi. Congestion Management including:
   a. Congestion
   b. Financial Transmission Rights
vii. Demand Reduction;
viii. Grandfathered Agreements;
ix. Virtual Transaction Fee;
x. Pseudo-tie;
xi. Miscellaneous;

B. Non-SPP costs or revenue as follows:

i. If received from a centrally administered market (e.g. PJM / MISO), costs or revenues of an equivalent nature to those identified for the SPP costs or revenues specified in subpart A of part 1 above;

ii. If not received from a centrally administered market:
   a. Costs for purchases of energy; and
   b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and
   c. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist; and

2. Insurance premiums in FERC Account 924 for replacement power insurance. Costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles; and

3. All transmission service costs and revenues reflected in FERC Account 565 and all transmission service revenues reflected in FERC Account 457. Such transmission service costs and revenues include:

A. SPP costs and revenues associated with:

i. SPP NITS Service charges (SPP Schedule 11, or its successors);
ii. SPP Point-to-point transmission service revenue (SPP Schedules 1, 7 and 8 or their successors);

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

iii SPP Network Integration Transmission Service (SPP schedule 9 or its successor)
iv SPP Wholesale Distribution Service (SPP schedule 10 or its successor)
v, SPP Reactive Supply and Voltage Control (SPP schedule 2 or its successor)

B. Non-SPP costs and revenues associated with:

i. Network transmission service;
ii. Point-to-point transmission service;
iii. System control and dispatch; and
iv. Reactive supply and voltage control

4. Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which SPP or another market participant bills / credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another market participant implement a charge type not listed in Empire's FAC:

A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to another party's right to challenge the inclusion (or failure to include) as outlined in E. below;

B. The Company will include in its monthly reports required by the Commission's fuel adjustment clause rules, notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such notice shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the existing market charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues; and

E. If the Company includes a new charge type cost or revenue in a FAR filing and a party challenges the inclusion (or if the Company does not include a new charge type cost or revenue and a party challenges the failure to include it), such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. To challenge the failure to include a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should have been included, because they do possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. In the event of a challenge, the Company shall bear the burden of proof to support its decision to include or exclude or its failure to include or exclude a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor PP.

E = Net Emission Costs:

The following costs and revenues reflected in FERC Accounts 509, 411.8 and 411.9 (or any other account FERC may designate for emissions expense in the future): emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

OSSR = Revenue from Off-System Sales:

The following revenues or costs reflected in FERC Account 447: all revenues from off-system sales but excluding revenues from full and partial requirements sales to municipalities that are associated with Empire, and SPP energy and operating market revenues, (see Note A. below)

i. Energy
ii. Ancillary Services including:
   a. Regulating Reserve Service
   b. Energy Imbalance Service
   c. Spinning Reserve Service
   d. Supplemental Reserve Service
iii. Revenue Sufficiency;
iv. Losses;
v. Revenue neutrality;
vi. Demand Reduction;
vii. Grandfathered Agreements;
viii. Pseudo-tie;
ix. Miscellaneous;
x. Hedging

REC = Renewable Energy Credit Revenue:

Revenues reflected in FERC Account 456 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

HEDGING COSTS:

Hedging costs are defined as realized losses and costs (including broker commission fees and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances and purchased power costs, including but not limited to, the Company's use of derivatives whether over-the-counter or exchanged traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars and swaps.

Note A. Should FERC require any item covered by factors FC, PP, E, REC or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E, REC or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

B = Net base energy cost is calculated as follows:

$B = (S_{AP} * \$0.XXXX)$

S_{AP} = Actual net system input at the generation level for the accumulation period.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

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

Where Total system kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

T = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission.

I = Interest applicable to (i) the difference between Total energy cost (FC + PP + E - OSSR - REC) and Net base energy costs (“B”) multiplied by the Missouri energy ratio (”J”) for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herin. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company;’s short-term debt, applied to the month-end balance of items (i) through (III) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

FUEL ADJUSTMENT RATE

The FAR is the result of dividing the FPA by estimated recovery period S_{RP} kWh, rounded to the nearest $0.00000. The FAR shall be adjusted to reflect the differences in line losses that occur at primary and secondary voltage by multiplying the average cost at the generator by 1.0466 and 1.0662, respectively. Any FAR authorized by the Commission shall be billed based upon customers’ energy usage on and after the authorized effective date of the FAR. The formula for the FPA is displayed below

$$FAR = \frac{FPA}{S_{RP}}$$

Where:

S_{RP} = Forecasted Missouri NSI kWh for the recovery period.

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

Where Forecasted total system NSI kWh sales includes sales to numicipalities that are associated with Empire and excludes off-system sales.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

PRUDENCE REVIEW

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

TRUE-UP OF FPA

In conjunction with an adjustment to its FAR, the Company will make a true-up filing 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 FPA revenues billed and the FPA revenues authorized for collection during the true-up recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item T 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. 17u
Canceling P.S.C. Mo. No. ______ Sec. ______ ________ Original Sheet No. ________
For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

	Accumulation Period Ending		
1	Total Energy Cost (TEC) = (FC+PP+E-OSSR-REC)		
2	Net Base Energy Cost (B)	-	
	2.1 Base Factor (BF)		
	2.2 Accumulation Period NSI (S_{AP})		
3	(TEC-B)		
4	Missouri Energy Ratio (J)	*	
5	(TEC-B)*J		
6	Fuel Cost Recovery	*	
7	(TEC-B)*J*0.95		
8	True-Up Amount (T)	+	
9	Prudence Adjustment Amount (P)	+	
10	Interest (I)	+	
11	Fuel and Purchased Power Adjustment (FPA)	=	
12	Forecasted Missouri NSI (S_{RP})	÷	
13	Current Period Fuel Adjustment Rate (FAR) to be applied Beginning XX-XX-XXXX	=	
14	Current Period FAR_{PRIM} = FAR x VAF_{PRIM}		
15	Current Period FAR_{SEC} = FAR x VAF_{SEC}		
16	VAF_{PRIM} = 1.0466		1.0466
17	VAF_{SEC} = 1.0622		1.0622

DATE OF ISSUE ______________________________ DATE EFFECTIVE______________________________
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after July xx, 2015

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Schedule DCR-3

Is Deemed

Highly Confidential

In Its Entirety