Exhibit No. 105P

Staff – Exhibit 105P
Staff class cost-of-service report
File No. ER-2021-0312

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

CLASS COST OF SERVICE

THE EMPIRE DISTRICT ELECTRIC COMPANY,
d/b/a Liberty

GENERAL RATE CASE

CASE NO. ER-2021-0312

Jefferson City, Missouri
November 2021

** Denotes Confidential Information **

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OF
THE EMPIRE DISTRICT ELECTRIC COMPANY, d/b/a Liberty

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Executive Summary

Based on Staff's corrected Accounting Schedules filed on November 4, 2021, in conjunction with the Staff Cost of Service Report filed on October 29, 2021 ("COS Report"), Empire's gross revenue requirement is $589,531,779, annually. However, this amount is offset by $16 million related to tax impacts and prepayment of taxes by ratepayers, and further offset by $8.897 million in other revenues.[1] Netting these values results in an annual amount of revenues to be collected from ratepayers of $564,085,253.[2] Staff's calculated normalized and annualized revenues provided in the COS Report were $537,285,406, indicating that an increase to the rate schedules of $26,204,866, or 4.8719%%, is cost justified.

Given the newly-acquired ability of Empire to rely on AMI-metering infrastructure for rendering customer bills, but lack of adequate individual customer usage history, Staff recommends this case be taken as an opportunity to begin implementation of modernized rate structures for Empire's customers. In beginning this process, mitigation of customer impact is Staff's chief objective.[3] Due to the predominance of this objective, the anticipated rate switching that is attendant to rate-schedule realignment, and the limited time available to develop its recommendation in this case primarily in light of the competing Ameren Missouri rate case and Empire Electrification dockets, Staff has not performed a Class Cost of Service Study in this case. Staff recommends that the non-pre-MEEIA revenue requirements of each

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[1] Other revenues includes sales of energy and capacity through the integrated marketplace, rental proceeds, and what are typically referred to as "miscellaneous revenues," which are the product of tariff charges such as disconnection charges, bad check charges, and other charges that are not contained on class rate schedules.

[2] Including lighting revenue, but not including miscellaneous revenues.

[3] Empire's October 16 supplemental response to Staff DR 235, indicated that essentially all Missouri electric customers are equipped with AMI meters as of October of 2021.

existing rate schedule be increased on an equal percentage basis to determine the revenue responsibility of the classes and consolidated classes at the conclusion of this case.[4]

<u>As will be discussed in greater detail here-in, Staff recommends:</u>

1. Staff recommends consolidation of the Commercial Building "CB" and Small Heating "SH" rate schedules into a new "Small General" rate schedule.
2. Staff recommends consolidation of the General Power Service "GP," and Total Electric Building Service "TEB" rate schedules into a Medium General Service rate schedule, or into two new rate schedules, Large General Secondary Service and Small General Primary Service. The Feed Mill and Grain Elevator Service "PFM" rate schedule should be eliminated, with customers transitioned to the Medium General Service rate schedule, or the appropriate voltage-specific rate schedule, as applicable.
3. Staff recommends that the Large Power rate schedule be restructured from a two-block hours' use structure to a multi-part ToU structure, with retention of the facilities charge and with modification of the demand charge to a coincident peak demand charge.
4. Staff recommends that the increase applicable to residential customers be applied only to daytime consumption. Pursuant to Staff's recommendation, residential customers would see their monthly customer charge remain at $13.00. A residential customer using 1,000 kWhs of electricity in a month would see an increase of approximately $7.76 per month if all usage were during the daytime. A residential customer using 1,000 kWh of electricity in a month all during nighttime hours would see no increase. A typical residential user consuming 1,000 kWh of electricity per month would see an average increase of approximately $3-$5 per month.

[4] Pre-MEEIA refers to the revenue requirement of existing demand side management and conservation programs. These revenue requirements are collected from customers who have not opted out of payment of these charges pursuant to the Missouri Energy Efficiency Investment Act.

5. Staff recommends certain studies be implemented or continued to better align revenue responsibility with cost causation.
6. Concerning Empire's Renewable Energy Purchase Plan, the proposed tariff references execution of a Renewable Energy Purchase ("REP") service agreement, which has not yet been developed by Empire. Staff recommends that any REP schedule approved in this case incorporate the provisions intended for the service agreement. Additionally, Staff recommends a percentage cap on the number of RECs available to the program to ensure REC availability for the statutory RES standard is prioritized.
7. Staff proposes the Base Factor (BF) rate be set at \$0.00953 per kWh. This is a decrease from the current Base Factor of \$0.02338 per kWh established in Case No. ER-2019-0374.

<u>In addition, Staff recommends the following changes to Ameren Missouri's FAC tariffs:</u>

1. Replace the current Base Factor of \$0.02338 with the revised Base Factor of \$0.00953 per kWh.
2. Replace the current transmission percentage to be included in the FAC with 50% for MISO transmission costs and 19.39% for SPP transmission costs.
3. Continue the current voltage adjustment factors ("VAF's") of:

$$VAF_{PRIMARY} = 1.0429 \quad \text{and} \quad VAF_{SECONDARY} = 1.0625$$

4. Add language to Original Sheet No. 17k to include Auction Revenue Rights and Transmission Congestion Rights, to be consistent with what the Commission approved to be included in the FAC from Case No. ER-2019-0374.
5. Add language to Original Sheet No. 17n in the Off-System Sales Revenue ("OSSR") definition to include revenues from the Missouri Joint Municipal Electric Utility Commission ("MJMEUC") contract and include revenues from the North Folk Ridge, Neosho Ridge, and Kings Point Wind Farms.
6. Add language to Original Sheet No. 17n in the Renewable Energy Credit ("REC") definition that the Renewable Energy Credits must be sold or utilized

for compliance with the Missouri Renewable Energy Standard ("RES") before they expire.

Rate Structure and Rate Design

Background and Summary

As used in this Report, "Rate Structure" will refer to the elements included in a rate, such as an energy block for usage from 0-600 kWh, and "Rate Design" will refer to the relative sizes of the charges for each rate element, such as a $0.15 per kWh charge for the first energy block and a $0.10 charge per kWh for the second energy block.

Staff recommends this case be taken as an opportunity to begin the modernization of Empire's rate structures. Staff recommends that all rate schedules be transitioned to simple time of use ("ToU") rate structures in this case, with an eye towards eventual transition to more complex time-variant rate structures that better reflect cost causation. As will be discussed below, a design that reflects the marginal cost of energy and access to energy infrastructure is most reflective of cost-causation and thus provides the most accurate price signals to customers to avoid uneconomic consumption of energy, but there are a number of impediments to implementation of these designs. For this case, Staff is recommending implementation of embedded cost design time of use rate structures for all rate schedules.

There are two different approaches to time-variant rates that arise from two different price-causation theories and align with two different primary intended effects.

Embedded cost designs price the rate elements relative to the average cost associated with each determinant. The primary intended effect of an embedded cost design is to improve alignment of revenue recovery with cost causation. There are minimal barriers to implementation of an embedded cost designed time-variant rate structure today for Empire's electric customers.[5]

[5] As of this case, AMI metering is available for billing customers the elements of a time-variant rate structure.

Marginal cost designs price the most variable determinants at the marginal cost of acquiring an additional unit. The primary intended effect of a marginal cost design rate is to induce behavior changes that result in a relative reduction (or limitation) of consumption of the variable determinant. There are significant barriers to implementation of these designs on a wide-spread basis.

- The existing FAC statute and implemented structure provide a counterincentive to the utility for designs that induce changes in behavior, and will lead to significant cost over/under recovery when usage varies from normal for any reason. Further, because the FAC removes the diurnal variation in energy costs, rates that reflect that variation will not recover the embedded cost revenue requirement.
- Implementation of more aggressively-priced rate elements than indicated by the embedded costs (except for those that directly vary with the incurred utility expense)[6] requires some sort of true-up or reconciliation to ensure the utility recovers adequate but not excessive revenues, while ensuring that some customers do not overpay while other customers receive the refunding as a windfall (or vice versa). The inclusion of marginal distribution and transmission costs, or administrative costs, and other non-variable cost recovery on a time-differentiated rate may result in inequities between the utility and customers as a whole, or between customers.
- The language within the existing net metering statues may not be directly compatible with time-variant rate structures.
- Some level of individual customer interval data is needed to develop relevant determinants. There is not yet substantial history of this data available for Empire's customers.
- Rates priced on marginal cost may negatively impact economically disadvantaged customers or customers within certain industries so that it may be appropriate (and necessary as a matter of regulatory policy) to defer those rate designs until such a

[6] An important consideration in rate design, especially a marginal cost design, is whether a cost is directly variable or not, and that there can be a difference between the cost of causing new investment or expense with new usage or demand, and the savings that are achievable (or not) by avoiding usage or demand.

time as there is legislation to provide resources to those customers from general revenue or until there is an opportunity to design an explicit rate relief mechanism, which may require additional legislation.

Staff recommends moving forward at this time with embedded-cost design ToU rate structures for all customer classes, and consolidating several customer classes. Given the customer impact attendant to these two activities, Staff recommends mitigation of customer impact be prioritized, and therefore does not recommend any changes to class revenue responsibility be pursued in this case.[7] This case presents an opportunity to roll-out a ToU framework and to begin the process of re-structuring Empire's rates. In rolling out the ToU framework, customer impact mitigation takes precedence over adherence to an imprecise cost study.

Empire's Energy Pricing and System Usage Characteristics

Factors in designing ToU rates include physical characteristics of the utility system, system loads, and class loads as a surrogate for estimates of geographic dispersal of load, and economic factors such as the market price of energy or of market participation. In general, times of high usage are also times of relatively higher energy cost, and conditions during those times may drive need for additional infrastructure. In general, times of low usage are also times of relatively lower energy costs, and more capacity may be available on existing infrastructure during these conditions than is being utilized. This is not entirely straightforward, for example, integrated market prices may be driven by load or generation availability outside of the utility's footprint, and equipment like transformers need periods of reduced load – especially during times of hot weather – to cool off to avoid significant reduction in capacity for daytime operation. But, setting aside utility-specific subtleties that require rigorous study to quantify, when designing time of use rates it is reasonable to assume that (a) aligning greater revenue responsibilities with times when much of the system's capacity is utilized and energy costs are higher can be used to (b) reduce revenue responsibilities with times when additional capacity is available and when energy costs are lower. In other words, whether

[7] Staff will provide its concerns with the reliability of the Empire CCOS in Staff's rebuttal testimony.

proceeding from an embedded-cost or marginal-cost approach, the basic concept of ToU design is to price energy consumed during high-cost and/or high-utilization times higher than the energy consumed during low-cost and/or low-utilization times.

As a first step in identifying the times Empire experiences relatively high and low energy prices and the times the Empire system experiences relatively high and low utilization, Staff reviewed (a) the Locational Marginal Prices ("LMPs") used in Staff's fuel model LMPs in this case, (b) the system loads used in Staff's fuel model, and (c) the product of LMPs and system loads to preliminarily identify potential time periods for further refinement into ToU rate periods. This exercise facilitated identification of time periods during the day (diurnal) and during the year (seasonal) when Empire's Cost of obtaining energy to serve its load is higher than average, as well as the diurnal and seasonal time periods when Empire's Cost of obtaining energy to serve its load is lower than average. It also facilitated identification of the seasonal and diurnal time periods that could drive the need to expand the capacity of distribution facilities, and the time periods when there is more than adequate capacity across the distribution system.[8] Under a marginal cost approach, the time periods with high energy costs and high load conditions would be priced to cause customers to reduce or avoid consumption during those hours. Under an embedded cost approach, those time periods would be priced to cause customers using more energy in those hours to absorb a higher level of revenue responsibility than customers using less energy in those hours. Conversely, in hours with low energy prices and low system utilization, a marginal-cost approach may price retail energy low to encourage increased consumption, and an embedded-cost approach may price retail energy low to align the cost causation and revenue responsibility among customers who are using or not using energy at these times.

Energy prices are low enough to potentially drive a decrease in average energy cost, and when loads are low enough that there are likely to be few if any distribution constraints from about 11:00 PM through about 5:00 AM during Weeks 11 – 41 (mid-March to mid-October). These time periods are targets for a "Super Off-Peak" rate that is lower than the average price of

[8] Local facilities in a given geographic area of the distribution system may be constrained at times when system usage is below average.

retail energy, and are indicated in dark green in the graphic below. Energy prices are high enough to potentially cause noticeable increases in average energy cost and loads are high enough to potentially drive a need for expansion of distribution facilities during Weeks 22-42 (June to mid-October) from about noon until about 8:00 PM, and during Weeks 1-6 (January to mid-February) and 41-52 (October through December) for the morning hours of 6:00 – 11:00 AM, and again in the evening from 5:00 PM to around 8:00 or 9:00 PM. These time periods are targets for a "Super On-Peak" rate that is higher than the average price of retail energy, and are indicated in red in the graphic below.

Beyond those hours, "Off-Peak" hours are generally overnight, and "On-Peak" hours are generally during the day, although exceptions occur, particularly with a block of Off-Peak characteristics present until about 10:00 AM during Weeks 21 – 40, (mid-May through September) and again from about Noon until about 4:00 PM during the first and last weeks of the year. Potential Off-Peak hours and On-Peak hours are indicated in light green and yellow, respectively, in the graphic below.

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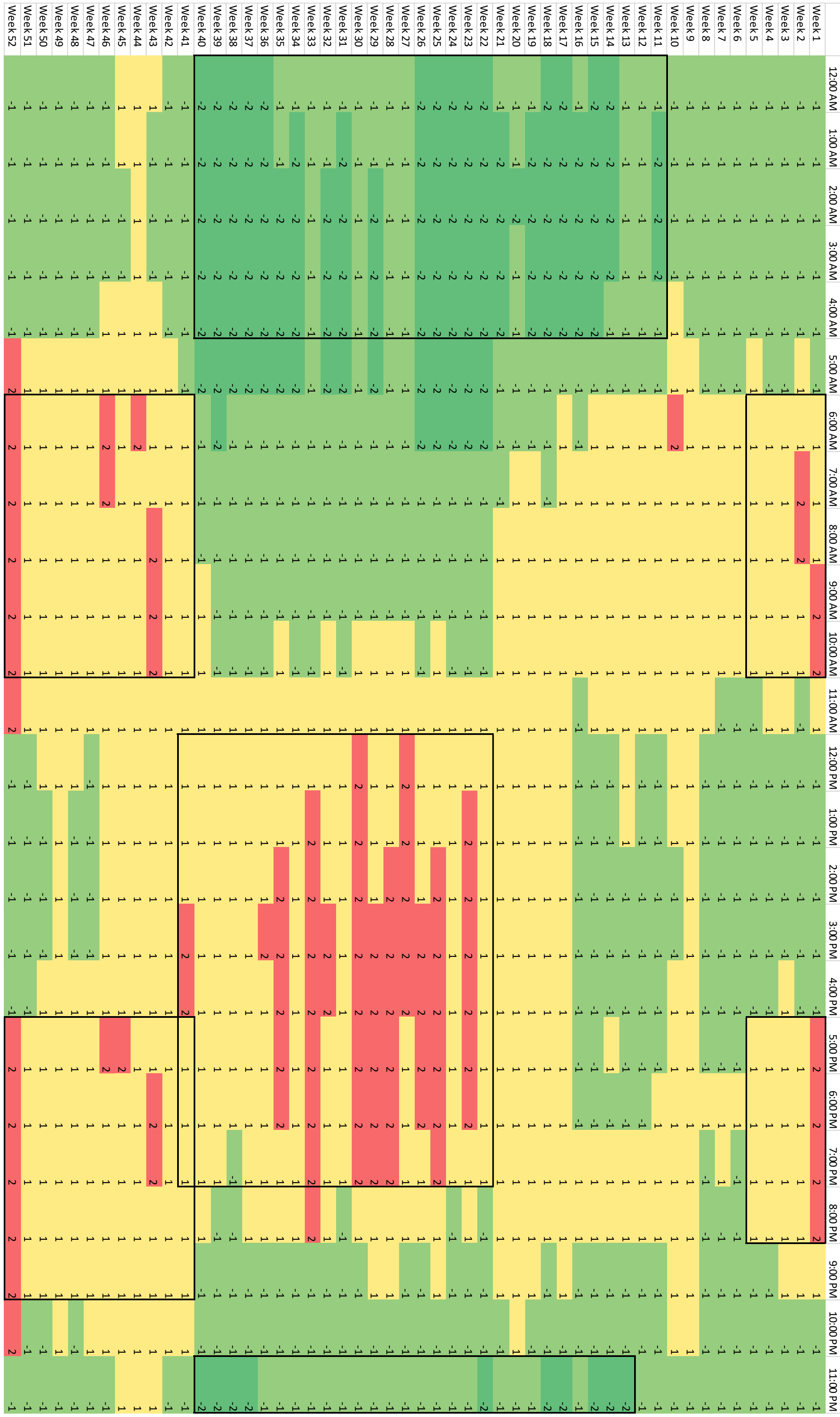

Residential General Use Rate

Staff recommends this case be taken as an opportunity to begin to better align energy consumption with cost causation within the Residential class. While Empire customers are essentially all now equipped with AMI metering, only a brief usage history is available for most customers. Also, although time-variant rates have been in use in Missouri for fifty years or more, many of Empire's customers are new to this rate structure.[9] Staff recommends in this case that the generally-applicable residential rate schedule for Empire's residential customers be restructured to a ToU structure that minimizes initial customer impact, and improves (or creates) awareness of (1) time-variant rates, and (2) the seasonal and diurnal differences in energy cost causation.

Staff has developed four alternative approaches to consider, and provides the rates for each alternative that would result from Staff's recommended residential revenue requirement with the customer charge retained at the current level of $13.00 per month. The selected rate structure and design would be applicable to all Empire residential customers. At or around the level of Staff's recommended revenue requirement, Staff does not recommend inclusion of an "opt-out" provision to enable customers to be served by a non-time-variant rate. If the residential revenue requirement ordered in this case is at the level requested by Empire, incorporation of an opt-out provision or a cost-justified increase to the residential customer charge may be appropriate.

The time periods selected by Staff are consistent with Staff's review of the Empire system-wide fuel model LMPs, fuel model system loads, and the product of LMPs and system loads discussed above.[10] A heat map of the average[11] residential load by season and diurnal

[9] Over the last approximately 15 years, several Missouri cooperative electric utilities have converted their generally-applicable residential rate designs to a time-variant structure.
[10] The time periods are also consistent with Empire's requested time-variant elements in its pending electrification case, ET-2020-0390, and overlays the non-summer on-peak period selected by the company for its proposed ToU opt-in rates in this case, ER-2021-0312.
[11] These values are based on the residential hourly load provided by Empire adjusted to the level of Staff's residential billing determinants. As multiple years of aggregated residential AMI data become available, the accuracy of normalized hourly determinants will be

time period is provided below, where the highest load hours are shaded red, and the lowest load hours are shaded green:

	Summer	Shoulder	Winter
12:00 AM	156,843	130,743	194,099
1:00 AM	135,797	123,873	190,305
2:00 AM	123,218	121,897	190,799
3:00 AM	114,947	122,470	195,934
4:00 AM	108,176	121,492	200,000
5:00 AM	112,495	131,368	214,178
6:00 AM	124,912	157,642	246,096
7:00 AM	138,656	171,119	262,465
8:00 AM	159,902	175,634	257,221
9:00 AM	179,583	171,572	242,903
10:00 AM	198,835	164,977	231,969
11:00 AM	223,116	162,348	220,825
12:00 PM	248,107	162,315	214,279
1:00 PM	269,063	159,042	199,172
2:00 PM	286,708	158,959	192,049
3:00 PM	300,500	160,858	194,732
4:00 PM	316,614	174,720	210,519
5:00 PM	325,880	189,799	233,182
6:00 PM	316,619	193,615	244,609
7:00 PM	299,896	191,349	245,521
8:00 PM	276,146	190,519	246,133
9:00 PM	256,024	182,515	238,894
10:00 PM	220,699	164,524	221,863
11:00 PM	182,900	141,943	202,878

All of the options described below are based on embedded costs, however, the structure of Option 4 is consistent with the elements Staff recommends be included in a marginal cost design. However, at this time and at Staff's current recommended residential revenue requirement, Staff ranks Option 2 as most preferable, followed by Option 1 and Option 3. At this time, significant additional work would be needed to fully develop Option 4, and the hourly loads available at this time may not be at a level of precision to facilitate its adoption. Further, the deployment of Option 4 would require significantly more customer education than the other options. However, Option 4 is worth considering as an opportunity to acquaint all customers

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improvable. While Empire's current summer season begins June 15, average monthly data was provided by Empire, and this analysis is based on that data.

with the elements of a rate structure that would be necessary to effectively deploy a marginal Cost time-variant rate design with a reasonably high level of precision.

Staff anticipates working with Empire and other stakeholders to ensure that the treatment of net metering customers for billing purposes is reasonable and compliant with applicable Missouri law under the rate structure promulgated in compliance with the Commission's order in this case.

Residential Option 1

The existing residential rate structure is retained,[12] and the increase determined in this case is applied to an on-peak rider. This preserves the explicit benefit of the declining block design during non-summer months for high-usage customers, and is similar to the approach taken with the default ToU roll-out for Ameren Missouri which began in File No. ER-2019-0335. This general design is useful to educate customers by equipping them with price signals that the cost for energy consumed during the daytime is higher when demand is higher and when less lower-variable cost generation is available. This approach would encourage customers to limit daytime consumption, but not be punitive to those who cannot.

Residential Option 1		
Rate Element	**Rate**	**Revenue**
On-Peak Premium:	$ 0.0106	$ 12,504,844
Summer 1st 600:	$ 0.125350	$ 34,463,173
Summer Over 600:	$ 0.125350	$ 39,561,816
Non-Summer 1st 600:	$ 0.125350	$ 68,062,514
Non-Summer Over 600:	$ 0.100930	$ 59,891,979
Peak hours are 6:00 am - 8:59 pm, every day		

Estimates of current and proposed bills by season at various levels of usage are provided below, as well as the possible percentage of Non-Pre-MEEIA bill impact.

[12] The Pre-MEEIA charge and the FAC are omitted from these calculations and discussion.

Customer Impact - Residential Option 1						
Season	Usage	Current	Proposed - All On	Proposed - All Off	% Change if All On	% Change if All Off
Summer	750	$ 107.01	$ 114.97	$ 107.01	7.44%	0.00%
Non-Summer	750	$ 103.35	$ 111.31	$ 103.35	7.70%	0.00%
Summer	1,000	$ 138.35	$ 148.96	$ 138.35	7.67%	0.00%
Non-Summer	1,000	$ 128.58	$ 139.19	$ 128.58	8.25%	0.00%
Summer	1,250	$ 169.69	$ 182.95	$ 169.69	7.81%	0.00%
Non-Summer	1,250	$ 153.81	$ 167.08	$ 153.81	8.62%	0.00%
Summer	2,000	$ 263.70	$ 284.92	$ 263.70	8.05%	0.00%
Non-Summer	2,000	$ 229.51	$ 250.73	$ 229.51	9.24%	0.00%
Summer	2,500	$ 326.38	$ 352.90	$ 326.38	8.13%	0.00%
Non-Summer	2,500	$ 279.98	$ 306.50	$ 279.98	9.47%	0.00%

Residential Option 2

Essentially the same result as under Option 1 can be achieved by increasing all energy charges but incorporating an off-peak discount to revert off-peak consumption to effectively current rates.[13] In general, Staff views the structure of Option 1 as more understandable to customers if presented with the messaging that focuses on the concept that electricity is more expensive when everyone is using it. Option 1 is more supportive of an overall conservation approach. However, Option 2 could be used to emphasize that during times of excess supply, wholesale energy is less expensive. This second approach is generally more supportive of load-shifting. This concept may be more readily understandable to customers in this case given the inclusion of significant wind generation, which is predominantly available in the overnight hours and during the non-summer months.

[13] To achieve consistency across rate elements, the increase to the Non-Summer tail block needs to be increased by the same amount (not percentage) as the other rate blocks. This results in a very slight reduction in the declining block disparity.

Residential Option 2		
Rate Element	**Rate**	**Revenue**
Off-Peak Discount:	$ (0.007761)	$ (897,150)
Summer 1st 600:	$ 0.133111	$ 36,596,838
Summer Over 600:	$ 0.133111	$ 42,011,146
Non-Summer 1st 600:	$ 0.133111	$ 72,276,363
Non-Summer Over 600:	$ 0.108691	$ 64,497,128
Peak hours are 6:00 am - 8:59 pm, every day		

Estimates of current and proposed bills by season at various levels of usage are provided below, as well as the possible percentage of Non-Pre-MEEIA bill impact.

Customer Impact - Residential Option 2						
Season	**Usage**	**Current**	**Proposed - All On**	**Proposed - All Off**	**% Change if All On**	**% Change if All Off**
Summer	750	$ 107.01	$ 112.83	$ 107.01	5.44%	0.00%
Non-Summer	750	$ 103.35	$ 109.17	$ 103.35	5.63%	0.00%
Summer	1,000	$ 138.35	$ 146.11	$ 138.35	5.61%	0.00%
Non-Summer	1,000	$ 128.58	$ 136.34	$ 128.58	6.04%	0.00%
Summer	1,250	$ 169.69	$ 179.39	$ 169.69	5.72%	0.00%
Non-Summer	1,250	$ 153.81	$ 163.52	$ 153.81	6.31%	0.00%
Summer	2,000	$ 263.70	$ 279.22	$ 263.70	5.89%	0.00%
Non-Summer	2,000	$ 229.51	$ 245.03	$ 229.51	6.76%	0.00%
Summer	2,500	$ 326.38	$ 345.78	$ 326.38	5.94%	0.00%
Non-Summer	2,500	$ 279.98	$ 299.38	$ 279.98	6.93%	0.00%

Residential Option 3

Under this option, the residential rate structure is revised to simple on-peak and off-peak rates, and the winter declining block is eliminated. To minimize bill impact for space heating, the On-Peak Non-Summer rate would be held constant to the current rate for the first Non-Summer Block.

Residential Option 3		
Rate Element	**Rate**	**Revenue**
Summer On-Peak:	$ 0.132887	$ 59,231,653
Summer Off-Peak:	$ 0.112887	$ 19,376,331
Non-Summer On-Peak:	$ 0.125350	$ 91,883,220
Non-Summer Off-Peak:	$ 0.117114	$ 43,993,121
Peak hours are 6:00 am - 8:59 pm, every day		

Estimates of current and proposed bills by season at various levels of usage are provided below, as well as the possible percentage of Non-Pre-MEEIA bill impact.

Customer Impact - Residential Option 3						
Season	**Usage**	**Current**	**Proposed - All On**	**Proposed - All Off**	**% Change if All On**	**% Change if All Off**
Summer	750	$ 107.01	$ 112.67	$ 97.67	5.28%	-8.73%
Non-Summer	750	$ 103.35	$ 107.01	$ 100.84	3.54%	-2.43%
Summer	1,000	$ 138.35	$ 145.89	$ 125.89	5.45%	-9.01%
Non-Summer	1,000	$ 128.58	$ 138.35	$ 130.11	7.60%	1.19%
Summer	1,250	$ 169.69	$ 179.11	$ 154.11	5.55%	-9.18%
Non-Summer	1,250	$ 153.81	$ 169.69	$ 159.39	10.32%	3.63%
Summer	2,000	$ 263.70	$ 278.77	$ 238.77	5.72%	-9.45%
Non-Summer	2,000	$ 229.51	$ 263.70	$ 247.23	14.90%	7.72%
Summer	2,500	$ 326.38	$ 345.22	$ 295.22	5.77%	-9.55%
Non-Summer	2,500	$ 279.98	$ 326.38	$ 305.78	16.57%	9.22%

Residential Option 4

A more complex structure including shoulder months and super on and off -peaks could be developed.[14] Under this approach, a "hold harmless" tariff provision may be appropriate for the introductory period when customers are transitioning to this rate. At this time, Staff has not developed and reviewed the cost information and determinants necessary to fully develop rates

[14] Potentially, the customer charge could be varied based on the highest energy consumption in one hour during the prior summer during the hours of 2-8 pm. However, at this time these determinants have not been developed.

that would appropriately recover the class revenue requirement under this structure,[15] however, Staff provides below the design resulting from differentials targeted based on Staff's general familiarity with the cost structure of Missouri utilities in general as applied to Empire's determinants:

Residential Option 4		
Rate Element	**Rate**	**Revenue**
Summer Super-Off:	$ 0.065350	$ 4,219,322
Summer Off-Peak:	$ 0.080796	$ 8,651,466
Summer On-Peak:	$ 0.125350	$ 23,619,041
Summer Super-On:	$ 0.175350	$ 45,118,155
Shoulder Super-Off:	$ 0.055350	$ 3,380,773
Shoulder Off-Peak:	$ 0.068217	$ 6,196,997
Shoulder On-Peak:	$ 0.125350	$ 39,682,136
Winter Off-Peak:	$ 0.115350	$ 25,806,423
Winter On-Peak:	$ 0.125350	$ 29,663,904
Winter Super-On:	$ 0.175350	$ 31,526,882

The relevant seasonal and diurnal time periods are provided below:

Dec 16+	Jan - 15	Jan 16+	Feb - 15	Feb 16+	Mar - 15	Mar 16+	Apr - 15	Apr 16+	May - 15	May 16+	Jun - 15
Winter	Winter	Winter	Winter	Winter	Winter	Winter	Winter	Shoulder 1	Shoulder 1	Shoulder 1	Shoulder 1
Jun 16+	Jul - 15	Jul 16+	Aug - 15	Aug 16+	Sep - 15	Sep 16+	Oct - 15	Oct 16+	Nov - 15	Nov 16+	Dec - 15
Summer	Summer	Summer	Summer	Summer	Summer	Summer	Summer	Shoulder 2	Shoulder 2	Shoulder 2	Shoulder 2

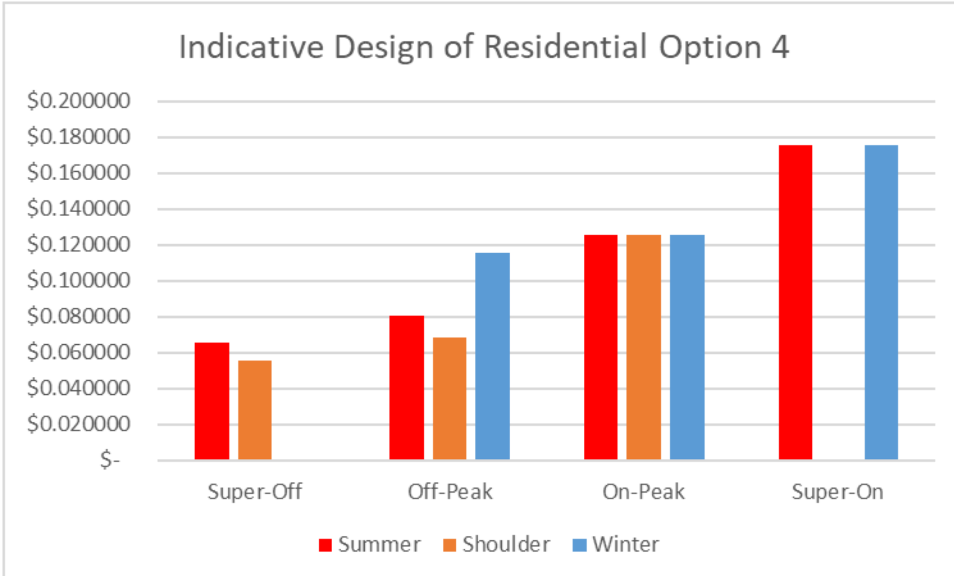
continued on next page

[15] A design of this nature requires a high level of confidence in the accuracy of the hourly loads and in the precision of the application of the normalization and annualization revenue adjustments to the hourly loads.

	Summer	Shoulder 1	Winter	Shoulder 2
12:00 AM	Super-Off	Super-Off	Off-Peak	Super-Off
1:00 AM	Super-Off	Super-Off	Off-Peak	Super-Off
2:00 AM	Super-Off	Super-Off	Off-Peak	Super-Off
3:00 AM	Super-Off	Super-Off	Off-Peak	Super-Off
4:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
5:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
6:00 AM	On-Peak	On-Peak	On-Peak	On-Peak
7:00 AM	On-Peak	On-Peak	**Super-On**	On-Peak
8:00 AM	On-Peak	On-Peak	**Super-On**	On-Peak
9:00 AM	On-Peak	On-Peak	**Super-On**	On-Peak
10:00 AM	On-Peak	On-Peak	On-Peak	On-Peak
11:00 AM	On-Peak	On-Peak	On-Peak	On-Peak
12:00 PM	On-Peak	On-Peak	On-Peak	On-Peak
1:00 PM	**Super-On**	On-Peak	On-Peak	On-Peak
2:00 PM	**Super-On**	On-Peak	On-Peak	On-Peak
3:00 PM	**Super-On**	On-Peak	On-Peak	On-Peak
4:00 PM	**Super-On**	On-Peak	On-Peak	On-Peak
5:00 PM	**Super-On**	On-Peak	**Super-On**	On-Peak
6:00 PM	**Super-On**	On-Peak	**Super-On**	On-Peak
7:00 PM	**Super-On**	On-Peak	**Super-On**	On-Peak
8:00 PM	On-Peak	On-Peak	On-Peak	On-Peak
9:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
10:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
11:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak

continued on next page

A graphic depiction is provided below:



Community Solar Charges for Use of Distribution System

At this time Staff recommends these charges be increased consistent with the related residential revenue requirement increase ordered in this case.

Commercial Building "CB" and Small Heating "SH"

Staff recommends consolidating the CB and SH rate schedules into a new "Small General" rate schedule. The differentials between like elements of the existing designs have become misaligned from the causational theory that the winter usage patterns of SH customers results in consumption of more energy at an average lower cost, such that the SH rate is simply cheaper than the CB rate.

Rate Element	CB	SH
Customer Charge:	$ 22.69	$ 22.69
Summer Flat Energy:	$ 0.12712	$ 0.12441
Non-Summer 1st 700:	$ 0.12712	$ 0.12441
Non-Summer Over 700:	$ 0.11377	$ 0.09172

Staff first reviewed the customer impact resulting from consolidation of CB and SH rate elements at the current level of recovery, with application of an on-peak premium to incorporate the increase ordered for the combined class in this rate case. This will initially result in a higher average increase to SH customers than to CB customers, but to the extent SH customers use a larger portion of their energy off-peak than do CB customers, those customers will avoid more of the revenue requirement increase than will CB customers. Note, at this time Empire has provided ToU determinants for only the CB class. Staff has extrapolated that shape to the SH class, but additional information and further work will be necessary to develop rates in this case.

Small General - Option 1		
Rate Element	**Rate**	**Revenue**
On-Peak Premium:	$ 0.01066	$ 3,026,561
Summer Flat Energy:	$ 0.12665	$ 18,585,908
Non-Summer 1st 700:	$ 0.12683	$ 15,567,164
Non-Summer Over 700:	$ 0.10683	$ 13,915,004
Peak hours are 6:00 am - 8:59 pm, every day		

Customer Impact - CB Customers - Option 1						
Season	**Usage**	**Current**	**Proposed - All On**	**Proposed - All Off**	**% Change if All On**	**% Change if All Off**
Summer	1,000	$ 149.81	$ 160.00	$ 149.34	6.80%	-0.32%
Non-Summer	1,000	$ 145.81	$ 154.18	$ 143.52	5.74%	-1.57%
Summer	1,500	$ 213.37	$ 228.65	$ 212.66	7.16%	-0.33%
Non-Summer	1,500	$ 202.69	$ 212.92	$ 196.93	5.05%	-2.84%
Summer	2,000	$ 276.93	$ 297.30	$ 275.98	7.36%	-0.34%
Non-Summer	2,000	$ 259.58	$ 271.67	$ 250.35	4.66%	-3.55%
Summer	5,000	$ 658.29	$ 709.22	$ 655.93	7.74%	-0.36%
Non-Summer	5,000	$ 600.89	$ 624.13	$ 570.84	3.87%	-5.00%
Summer	7,500	$ 976.09	$ 1,052.49	$ 972.55	7.83%	-0.36%
Non-Summer	7,500	$ 885.31	$ 917.86	$ 837.91	3.68%	-5.35%

Customer Impact - SH Customers - Option 1						
Season	**Usage**	**Current**	**Proposed - All On**	**Proposed - All Off**	**% Change if All On**	**% Change if All Off**
Summer	1,000	$ 147.10	$ 160.00	$ 149.34	8.77%	1.52%
Non-Summer	1,000	$ 137.29	$ 154.18	$ 143.52	12.30%	4.53%
Summer	1,500	$ 209.31	$ 228.65	$ 212.66	9.24%	1.60%
Non-Summer	1,500	$ 183.15	$ 212.92	$ 196.93	16.25%	7.52%
Summer	2,000	$ 271.51	$ 297.30	$ 275.98	9.50%	1.65%
Non-Summer	2,000	$ 229.01	$ 271.67	$ 250.35	18.63%	9.32%
Summer	5,000	$ 644.74	$ 709.22	$ 655.93	10.00%	1.74%
Non-Summer	5,000	$ 504.17	$ 624.13	$ 570.84	23.79%	13.22%
Summer	7,500	$ 955.77	$ 1,052.49	$ 972.55	10.12%	1.76%
Non-Summer	7,500	$ 733.47	$ 917.86	$ 837.91	25.14%	14.24%

As an alternative and to lessen the impact on former SH customers, the existing SH rates can be factored up for the rate increase, with a larger on-peak premium applied to achieve rate parity with the shortfall in revenues caused by decreasing CB customers' rates to the level of the increased SH rates:

Small General - Option 2		
Rate Element	**Rate**	**Revenue**
On-Peak Premium:	$ 0.00133	$ 377,798
Summer Flat Energy:	$ 0.13047	$ 19,147,043
Non-Summer 1st 700:	$ 0.13047	$ 16,014,286
Non-Summer Over 700:	$ 0.09619	$ 12,528,949
Peak hours are 6:00 am - 8:59 pm, every day		

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Customer Impact - CB Customers - Option 2						
Season	**Usage**	**Current**	**Proposed - All On**	**Proposed - All Off**	**% Change if All On**	**% Change if All Off**
Summer	1,000	$ 149.81	$ 154.49	$ 153.16	3.13%	2.24%
Non-Summer	1,000	$ 145.81	$ 144.21	$ 142.88	-1.10%	-2.01%
Summer	1,500	$ 213.37	$ 220.39	$ 218.40	3.29%	2.36%
Non-Summer	1,500	$ 202.69	$ 192.97	$ 190.97	-4.80%	-5.78%
Summer	2,000	$ 276.93	$ 286.29	$ 283.63	3.38%	2.42%
Non-Summer	2,000	$ 259.58	$ 241.73	$ 239.06	-6.88%	-7.90%
Summer	5,000	$ 658.29	$ 681.70	$ 675.05	3.56%	2.55%
Non-Summer	5,000	$ 600.89	$ 534.28	$ 527.63	-11.08%	-12.19%
Summer	7,500	$ 976.09	$ 1,011.20	$ 1,001.22	3.60%	2.57%
Non-Summer	7,500	$ 885.31	$ 778.08	$ 768.10	-12.11%	-13.24%

Customer Impact - SH Customers - Option 2						
Season	**Usage**	**Current**	**Proposed - All On**	**Proposed - All Off**	**% Change if All On**	**% Change if All Off**
Summer	1,000	$ 147.10	$ 154.49	$ 153.16	5.02%	4.12%
Non-Summer	1,000	$ 137.29	$ 144.21	$ 142.88	5.04%	4.07%
Summer	1,500	$ 209.31	$ 220.39	$ 218.40	5.30%	4.34%
Non-Summer	1,500	$ 183.15	$ 192.97	$ 190.97	5.36%	4.27%
Summer	2,000	$ 271.51	$ 286.29	$ 283.63	5.44%	4.46%
Non-Summer	2,000	$ 229.01	$ 241.73	$ 239.06	5.55%	4.39%
Summer	5,000	$ 644.74	$ 681.70	$ 675.05	5.73%	4.70%
Non-Summer	5,000	$ 504.17	$ 534.28	$ 527.63	5.97%	4.65%
Summer	7,500	$ 955.77	$ 1,011.20	$ 1,001.22	5.80%	4.76%
Non-Summer	7,500	$ 733.47	$ 778.08	$ 768.10	6.08%	4.72%

At Staff's recommended CB/SH combined class revenue requirement, this second option appears to produce the most reasonable results based on the load data available at this time.

General Power Service "GP," Total Electric Building Service "TEB," and Feed Mill and Grain Elevator Service "PFM"

Staff recommends a similar approach be taken to consolidate the GP/TEB rate schedules into a Medium General Service rate schedule, or into two new rate schedules, Large General Secondary Service and Small General Primary Service. Currently, the TEB and GP rate schedules each contain a provision that "The above rate applies for service metered at secondary voltage. Where service is metered at the voltage of the primary line feeding to such location, metered kilowatts and kilowatt-hours will be reduced prior to billing by multiplying metered kilowatts and kilowatt-hours by 0.9806." The rates for the Primary and Secondary schedules should differ by an approximation of the energy losses experienced in the transformation from primary to secondary voltages. Further, the facilities charge rate for the Secondary schedule should reflect inclusion of appropriate portions of the costs and related expenses associated with an allocable or assigned portion of the line transformers and services accounts, while the Primary schedule facility charge rate should reflect inclusion of appropriate portions of the costs and related expenses associated with an allocable or assigned portion of the conductors and devices accounts, poles and conduit accounts, and substation accounts related to the customer-specific infrastructure recorded in those accounts that serves the function of service drops and line transformers. Similarly, the customer charge for each schedule should reflect the differences in the cost and associated expense of metering and metering transformer equipment associated with metering at secondary voltage and metering at primary voltage, respectively.

The PFM rate schedule should be eliminated, with customers transitioned to the Medium General Service rate schedule, or the appropriate voltage-specific rate schedule, as applicable.

If sufficient hourly data becomes available, these new General Service rate schedules should be restructured to a multi-season and multi-period rate comparable to that described as Residential Option 4, above, and the recommended LP structure and design, described below, with time periods established applicable to these General Service determinants.

Large Power

Staff recommends that the Large Power rate schedule be restructured from a two-block hours' use structure to a ToU structure similar to that described above as Residential Option 4, but with retention of the facilities charge and with modification of the demand charge to a coincident peak demand charge. Staff recommends that the increase in revenue requirement ordered in this case be applied to the energy charges. The facilities charges would remain unchanged at this time. New determinants would be developed for the demand charge, to be revised to provide "the monthly Metered Demand will be determined from the highest fifteen-minute integrated kilowatt demand registered during the month **between the times of 6:00 am and 9:00 pm** by a suitable demand meter. The monthly Billing Demand will be the monthly Metered Demand, or 1000 kW, whichever is greater." The demand charges by summer and non-summer season would be revised to generate the same level of revenue as is currently generated by those seasons based on estimates of the new determinants.

Staff has reviewed the average daily LP load by hour, provided by Empire and scaled to the level of the Staff LP energy billing determinants by summer and non-summer season. A heat map of those loads, by weekday and weekend/holiday is provided below:

Hour	January	February	March	April	May	June	July	August	September	October	November	December
WKDY 1	80,435	78,794	79,301	83,619	86,809	89,604	92,729	95,653	92,261	82,176	80,201	75,319
WKDY 2	79,955	78,348	78,084	82,793	86,178	88,688	91,501	94,780	91,390	81,138	79,770	74,709
WKDY 3	79,987	78,030	77,910	82,190	85,409	88,223	90,738	94,024	90,438	80,291	79,216	74,580
WKDY 4	79,905	78,374	78,088	82,026	84,575	87,928	90,234	93,380	89,650	80,233	78,558	74,446
WKDY 5	80,924	79,550	79,274	83,966	85,427	88,725	91,507	94,504	91,575	81,516	80,689	76,046
WKDY 6	83,370	82,169	81,447	86,224	87,827	91,793	94,008	96,652	94,401	84,291	83,329	78,139
WKDY7	85,672	84,154	83,280	88,577	89,347	93,071	95,365	98,029	96,292	86,416	85,518	80,232
WKDY 8	86,940	85,616	84,206	90,213	90,974	95,124	97,770	99,299	97,314	88,077	86,990	81,854
WKDY 9	87,842	86,385	85,483	92,258	93,471	97,230	100,302	101,469	99,966	89,323	88,024	82,923
WKDY 10	87,721	86,963	85,525	92,332	94,551	98,463	102,004	102,703	101,618	89,808	88,362	83,172
WKDY 11	87,765	87,076	85,615	93,293	94,587	99,121	102,463	103,533	102,861	90,486	87,865	82,967
WKDY 12	88,093	87,713	86,034	94,425	95,419	100,423	103,273	104,883	104,229	90,847	88,388	83,265
WKDY 13	88,670	88,182	86,098	94,986	96,576	101,601	103,539	106,087	105,447	91,457	88,454	83,641
WKDY 14	88,366	87,758	85,382	95,227	96,631	102,026	103,444	105,978	105,459	91,476	88,897	82,586
WKDY 15	88,101	87,769	85,357	94,427	96,867	102,409	103,674	105,974	105,650	91,854	89,487	82,631
WKDY 16	87,092	87,415	85,119	93,982	96,607	101,585	102,853	105,372	104,525	90,978	88,336	81,423
WKDY 17	86,134	86,517	84,725	93,512	95,798	100,543	102,151	104,972	103,944	90,526	87,285	80,792
WKDY 18	85,937	85,485	84,251	92,705	93,742	99,192	101,271	104,260	102,498	88,873	86,837	80,266
WKDY 19	85,519	84,625	83,787	90,965	92,317	97,000	99,522	102,988	100,464	87,256	85,658	79,792
WKDY 20	85,223	84,331	83,857	90,245	92,151	96,171	98,468	101,429	100,034	86,604	85,412	79,456
WKDY 21	85,408	84,678	83,887	90,968	92,200	96,477	98,126	101,078	99,614	86,577	85,249	79,554
WKDY 22	85,172	84,110	83,128	90,418	91,681	95,917	97,892	100,601	98,552	86,089	84,991	79,005
WKDY 23	84,366	82,861	81,764	88,233	90,317	94,290	96,092	98,594	96,242	84,912	83,407	77,543
WKDY 24	82,573	81,290	80,220	86,050	88,911	92,314	94,382	96,050	94,574	83,843	82,253	76,366
WKND 1	72,028	72,556	69,732	72,732	75,252	81,345	82,530	83,780	80,005	71,961	70,347	67,766
WKND 2	71,187	70,938	68,646	71,071	74,042	80,118	81,619	82,727	78,861	70,623	69,255	66,841
WKND 3	70,884	70,705	68,870	69,683	73,834	79,086	80,925	82,230	77,826	69,420	68,594	66,032
WKND 4	70,573	70,205	67,906	68,699	73,307	77,720	80,054	81,290	76,970	68,667	68,193	65,727
WKND 5	70,213	69,750	67,862	68,815	73,962	77,487	79,543	81,612	76,631	68,451	68,390	65,979
WKND 6	70,840	70,157	67,902	68,862	74,333	77,836	79,137	81,453	77,038	68,423	68,571	67,279
WKND 7	71,364	70,760	67,837	68,504	74,662	78,049	78,612	81,348	77,613	68,774	69,128	68,118
WKND 8	72,138	70,990	68,019	67,930	74,356	78,083	79,000	80,862	77,240	68,676	69,347	68,410
WKND 9	71,879	71,037	67,841	68,725	74,987	79,211	79,860	81,606	77,831	68,497	68,995	67,915
WKND 10	71,630	69,974	68,377	69,353	74,746	79,889	80,787	83,051	78,690	68,602	69,620	67,860
WKND 11	71,209	70,069	68,721	70,059	74,896	79,912	81,916	83,513	79,969	68,822	69,674	67,381
WKND 12	71,417	70,516	68,765	71,227	75,874	80,719	83,375	83,877	81,215	69,001	70,052	67,612
WKND 13	71,423	70,736	68,192	72,004	76,415	81,871	84,271	84,382	82,538	69,704	69,713	67,631
WKND 14	71,831	70,814	68,040	72,403	76,293	81,972	84,615	84,581	82,267	70,455	69,544	67,402
WKND 15	72,082	70,173	67,731	71,544	75,818	82,489	84,682	84,783	82,824	71,336	69,629	68,153
WKND 16	72,068	69,494	67,635	72,237	76,514	83,165	84,446	85,641	83,418	71,726	69,916	67,752
WKND 17	71,297	69,573	67,415	71,838	76,548	83,306	84,665	85,699	83,728	71,476	69,888	67,267
WKND 18	71,244	70,121	67,376	71,430	76,517	82,569	83,820	85,464	82,983	71,303	70,571	67,287
WKND 19	70,983	70,721	66,805	70,593	76,201	82,155	83,610	84,532	81,942	70,492	69,765	66,372
WKND 20	70,938	69,359	67,082	70,422	75,903	81,711	83,159	83,752	81,832	70,197	69,179	66,407
WKND 21	71,711	69,787	67,571	72,079	75,435	81,114	83,738	83,409	81,683	69,766	69,173	66,773
WKND 22	71,685	69,855	67,194	72,049	74,477	79,146	83,339	82,756	81,170	69,328	68,287	66,613
WKND 23	71,042	69,348	66,294	70,795	73,326	77,954	82,728	81,559	80,001	68,958	67,119	66,670
WKND 24	70,908	68,945	66,687	69,829	72,587	77,261	82,306	81,093	79,801	69,226	66,526	66,785

Based only on this load data, a weekday-only on peak time period of approximately 9:00 AM to 6:59 PM appears the most appropriate. However, a review of the biweekly average LMP by hour indicates that given system energy costs, a broader period that includes weekends is advisable:

Average LPM	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	$ 21	$ 20	$ 21	$ 20	$ 21	$ 23	$ 27	$ 29	$ 28	$ 29	$ 27	$ 24	$ 23	$ 22	$ 21	$ 21	$ 23	$ 30	$ 29	$ 27	$ 26	$ 25	$ 23	$ 21
8	$ 21	$ 20	$ 20	$ 21	$ 22	$ 26	$ 31	$ 33	$ 30	$ 31	$ 29	$ 26	$ 24	$ 23	$ 22	$ 22	$ 24	$ 31	$ 30	$ 28	$ 26	$ 25	$ 23	$ 21
15	$ 22	$ 22	$ 22	$ 22	$ 23	$ 27	$ 35	$ 37	$ 35	$ 37	$ 33	$ 29	$ 27	$ 26	$ 25	$ 25	$ 27	$ 37	$ 36	$ 33	$ 31	$ 28	$ 26	$ 22
22	$ 22	$ 22	$ 21	$ 22	$ 23	$ 27	$ 33	$ 34	$ 32	$ 33	$ 30	$ 28	$ 26	$ 24	$ 22	$ 23	$ 25	$ 31	$ 33	$ 29	$ 29	$ 26	$ 25	$ 23
29	$ 19	$ 18	$ 19	$ 20	$ 20	$ 24	$ 30	$ 30	$ 29	$ 31	$ 28	$ 24	$ 23	$ 21	$ 21	$ 20	$ 22	$ 27	$ 32	$ 29	$ 28	$ 26	$ 22	$ 20
36	$ 20	$ 19	$ 19	$ 20	$ 21	$ 24	$ 31	$ 31	$ 29	$ 31	$ 28	$ 25	$ 23	$ 22	$ 21	$ 21	$ 22	$ 26	$ 31	$ 26	$ 26	$ 23	$ 21	$ 19
43	$ 18	$ 17	$ 18	$ 19	$ 21	$ 25	$ 33	$ 34	$ 32	$ 33	$ 30	$ 26	$ 24	$ 23	$ 21	$ 21	$ 22	$ 26	$ 33	$ 28	$ 27	$ 24	$ 21	$ 20
50	$ 20	$ 19	$ 19	$ 19	$ 21	$ 24	$ 32	$ 32	$ 29	$ 29	$ 27	$ 24	$ 22	$ 21	$ 20	$ 19	$ 20	$ 25	$ 32	$ 27	$ 27	$ 26	$ 23	$ 20
57	$ 25	$ 24	$ 24	$ 24	$ 26	$ 30	$ 41	$ 42	$ 39	$ 41	$ 38	$ 35	$ 33	$ 30	$ 29	$ 28	$ 29	$ 33	$ 42	$ 40	$ 37	$ 34	$ 30	$ 27
64	$ 26	$ 27	$ 25	$ 27	$ 30	$ 38	$ 47	$ 46	$ 42	$ 39	$ 35	$ 31	$ 29	$ 27	$ 27	$ 26	$ 28	$ 30	$ 35	$ 39	$ 37	$ 34	$ 32	$ 26
71	$ 18	$ 17	$ 17	$ 17	$ 19	$ 23	$ 30	$ 32	$ 29	$ 32	$ 31	$ 30	$ 27	$ 27	$ 25	$ 24	$ 24	$ 25	$ 27	$ 32	$ 30	$ 26	$ 22	$ 18
78	$ 19	$ 18	$ 16	$ 16	$ 19	$ 23	$ 29	$ 30	$ 29	$ 31	$ 30	$ 27	$ 26	$ 26	$ 23	$ 23	$ 24	$ 25	$ 27	$ 32	$ 31	$ 25	$ 21	$ 17
85	$ 18	$ 18	$ 17	$ 18	$ 19	$ 24	$ 32	$ 33	$ 34	$ 35	$ 32	$ 30	$ 28	$ 28	$ 27	$ 26	$ 25	$ 25	$ 25	$ 29	$ 29	$ 24	$ 21	$ 15
92	$ 16	$ 13	$ 11	$ 13	$ 15	$ 20	$ 28	$ 28	$ 30	$ 30	$ 28	$ 28	$ 27	$ 27	$ 26	$ 26	$ 27	$ 27	$ 26	$ 31	$ 33	$ 26	$ 21	$ 15
99	$ 14	$ 13	$ 13	$ 14	$ 16	$ 20	$ 28	$ 30	$ 30	$ 32	$ 29	$ 27	$ 26	$ 26	$ 27	$ 25	$ 27	$ 26	$ 26	$ 30	$ 31	$ 25	$ 19	$ 14
106	$ 18	$ 16	$ 15	$ 15	$ 17	$ 21	$ 26	$ 28	$ 30	$ 31	$ 28	$ 26	$ 25	$ 25	$ 25	$ 25	$ 26	$ 26	$ 26	$ 30	$ 35	$ 26	$ 23	$ 18
113	$ 17	$ 15	$ 14	$ 15	$ 18	$ 21	$ 28	$ 29	$ 31	$ 31	$ 30	$ 30	$ 32	$ 33	$ 32	$ 32	$ 33	$ 32	$ 31	$ 33	$ 37	$ 29	$ 24	$ 18
120	$ 17	$ 14	$ 12	$ 13	$ 15	$ 19	$ 23	$ 27	$ 31	$ 32	$ 30	$ 31	$ 32	$ 32	$ 32	$ 32	$ 34	$ 34	$ 32	$ 31	$ 32	$ 27	$ 21	$ 15
127	$ 18	$ 16	$ 14	$ 14	$ 16	$ 19	$ 24	$ 28	$ 31	$ 30	$ 29	$ 28	$ 29	$ 30	$ 31	$ 31	$ 31	$ 29	$ 29	$ 30	$ 33	$ 28	$ 24	$ 19
134	$ 22	$ 19	$ 17	$ 18	$ 20	$ 23	$ 25	$ 28	$ 30	$ 30	$ 31	$ 32	$ 35	$ 38	$ 40	$ 41	$ 44	$ 43	$ 40	$ 38	$ 39	$ 35	$ 31	$ 25
141	$ 20	$ 17	$ 17	$ 16	$ 17	$ 19	$ 20	$ 23	$ 27	$ 26	$ 28	$ 30	$ 34	$ 36	$ 38	$ 38	$ 40	$ 39	$ 37	$ 34	$ 32	$ 29	$ 25	$ 19
148	$ 16	$ 14	$ 13	$ 13	$ 14	$ 16	$ 16	$ 19	$ 22	$ 24	$ 25	$ 29	$ 32	$ 33	$ 36	$ 39	$ 38	$ 37	$ 33	$ 28	$ 26	$ 23	$ 19	$ 16
155	$ 16	$ 14	$ 12	$ 12	$ 12	$ 14	$ 16	$ 19	$ 21	$ 23	$ 26	$ 30	$ 34	$ 39	$ 41	$ 43	$ 42	$ 39	$ 34	$ 29	$ 26	$ 23	$ 20	$ 17
162	$ 16	$ 14	$ 12	$ 11	$ 10	$ 13	$ 14	$ 18	$ 21	$ 22	$ 25	$ 29	$ 32	$ 35	$ 38	$ 40	$ 41	$ 38	$ 34	$ 30	$ 27	$ 24	$ 20	$ 17
169	$ 15	$ 14	$ 13	$ 12	$ 13	$ 14	$ 15	$ 18	$ 21	$ 22	$ 26	$ 29	$ 36	$ 36	$ 36	$ 39	$ 40	$ 37	$ 33	$ 29	$ 27	$ 24	$ 20	$ 17
176	$ 14	$ 12	$ 10	$ 9	$ 10	$ 12	$ 14	$ 18	$ 20	$ 23	$ 27	$ 32	$ 37	$ 40	$ 41	$ 44	$ 43	$ 40	$ 36	$ 32	$ 27	$ 24	$ 20	$ 16
183	$ 16	$ 15	$ 14	$ 14	$ 15	$ 15	$ 16	$ 19	$ 21	$ 24	$ 27	$ 32	$ 35	$ 38	$ 40	$ 46	$ 44	$ 40	$ 35	$ 31	$ 26	$ 23	$ 20	$ 17
190	$ 17	$ 16	$ 15	$ 15	$ 15	$ 16	$ 16	$ 19	$ 23	$ 26	$ 31	$ 38	$ 40	$ 44	$ 47	$ 55	$ 52	$ 48	$ 42	$ 37	$ 30	$ 26	$ 21	$ 19
197	$ 17	$ 16	$ 15	$ 14	$ 14	$ 15	$ 16	$ 18	$ 22	$ 25	$ 29	$ 33	$ 36	$ 39	$ 41	$ 48	$ 48	$ 43	$ 37	$ 34	$ 29	$ 26	$ 21	$ 18
204	$ 16	$ 15	$ 14	$ 13	$ 14	$ 15	$ 16	$ 18	$ 20	$ 23	$ 27	$ 31	$ 34	$ 36	$ 36	$ 41	$ 41	$ 37	$ 34	$ 31	$ 26	$ 23	$ 20	$ 17
211	$ 16	$ 14	$ 13	$ 13	$ 13	$ 14	$ 16	$ 17	$ 20	$ 21	$ 24	$ 28	$ 31	$ 33	$ 35	$ 38	$ 39	$ 35	$ 32	$ 28	$ 25	$ 22	$ 19	$ 17
218	$ 17	$ 16	$ 16	$ 15	$ 15	$ 16	$ 17	$ 18	$ 21	$ 24	$ 28	$ 33	$ 37	$ 40	$ 44	$ 48	$ 48	$ 42	$ 38	$ 35	$ 31	$ 26	$ 21	$ 19
225	$ 17	$ 16	$ 16	$ 15	$ 15	$ 16	$ 17	$ 18	$ 21	$ 23	$ 26	$ 30	$ 34	$ 37	$ 41	$ 47	$ 47	$ 40	$ 35	$ 31	$ 28	$ 24	$ 20	$ 18
232	$ 16	$ 14	$ 14	$ 14	$ 14	$ 16	$ 17	$ 18	$ 21	$ 23	$ 26	$ 30	$ 35	$ 37	$ 42	$ 46	$ 46	$ 39	$ 34	$ 30	$ 28	$ 24	$ 20	$ 17
239	$ 16	$ 14	$ 14	$ 13	$ 14	$ 15	$ 17	$ 18	$ 20	$ 22	$ 25	$ 29	$ 34	$ 36	$ 38	$ 45	$ 44	$ 37	$ 33	$ 28	$ 25	$ 22	$ 19	$ 17
246	$ 17	$ 15	$ 14	$ 13	$ 13	$ 15	$ 17	$ 18	$ 21	$ 23	$ 25	$ 29	$ 35	$ 38	$ 41	$ 47	$ 46	$ 41	$ 34	$ 30	$ 26	$ 22	$ 20	$ 18
253	$ 16	$ 13	$ 12	$ 12	$ 13	$ 16	$ 18	$ 18	$ 20	$ 21	$ 25	$ 29	$ 33	$ 37	$ 39	$ 43	$ 43	$ 36	$ 31	$ 30	$ 26	$ 22	$ 19	$ 17
260	$ 15	$ 12	$ 11	$ 11	$ 12	$ 14	$ 17	$ 18	$ 20	$ 21	$ 25	$ 28	$ 32	$ 35	$ 36	$ 38	$ 37	$ 32	$ 29	$ 27	$ 24	$ 20	$ 18	$ 14
267	$ 15	$ 13	$ 11	$ 10	$ 11	$ 14	$ 17	$ 18	$ 20	$ 22	$ 24	$ 27	$ 32	$ 35	$ 37	$ 39	$ 40	$ 34	$ 31	$ 29	$ 25	$ 20	$ 18	$ 14
274	$ 17	$ 16	$ 15	$ 14	$ 15	$ 17	$ 22	$ 22	$ 25	$ 29	$ 31	$ 33	$ 36	$ 41	$ 42	$ 44	$ 44	$ 38	$ 35	$ 34	$ 28	$ 24	$ 21	$ 17
281	$ 24	$ 21	$ 19	$ 20	$ 23	$ 26	$ 32	$ 33	$ 34	$ 35	$ 35	$ 36	$ 39	$ 41	$ 43	$ 48	$ 49	$ 40	$ 41	$ 41	$ 38	$ 35	$ 30	$ 25
288	$ 24	$ 22	$ 21	$ 22	$ 24	$ 30	$ 40	$ 42	$ 38	$ 40	$ 39	$ 35	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 39	$ 41	$ 35	$ 33	$ 30	$ 25
295	$ 28	$ 26	$ 26	$ 26	$ 28	$ 34	$ 44	$ 45	$ 48	$ 50	$ 48	$ 44	$ 41	$ 42	$ 41	$ 43	$ 43	$ 43	$ 49	$ 49	$ 43	$ 38	$ 33	$ 30
302	$ 31	$ 31	$ 31	$ 30	$ 32	$ 38	$ 48	$ 46	$ 44	$ 46	$ 43	$ 38	$ 36	$ 36	$ 34	$ 33	$ 35	$ 41	$ 43	$ 42	$ 41	$ 39	$ 34	$ 30
309	$ 29	$ 28	$ 27	$ 26	$ 28	$ 34	$ 45	$ 44	$ 42	$ 46	$ 41	$ 38	$ 37	$ 37	$ 36	$ 35	$ 39	$ 50	$ 45	$ 41	$ 41	$ 37	$ 32	$ 27
316	$ 27	$ 26	$ 26	$ 27	$ 30	$ 37	$ 49	$ 50	$ 44	$ 44	$ 39	$ 35	$ 32	$ 32	$ 30	$ 29	$ 34	$ 48	$ 44	$ 41	$ 40	$ 35	$ 30	$ 27
323	$ 24	$ 23	$ 22	$ 22	$ 24	$ 29	$ 40	$ 38	$ 35	$ 36	$ 32	$ 28	$ 26	$ 25	$ 25	$ 26	$ 30	$ 39	$ 34	$ 33	$ 32	$ 29	$ 28	$ 23
330	$ 23	$ 23	$ 23	$ 23	$ 25	$ 29	$ 36	$ 37	$ 36	$ 38	$ 35	$ 31	$ 28	$ 26	$ 25	$ 25	$ 29	$ 36	$ 33	$ 32	$ 30	$ 28	$ 25	$ 23
337	$ 25	$ 24	$ 22	$ 23	$ 25	$ 28	$ 34	$ 35	$ 34	$ 35	$ 34	$ 31	$ 29	$ 28	$ 27	$ 27	$ 32	$ 40	$ 35	$ 34	$ 34	$ 32	$ 29	$ 26
344	$ 25	$ 24	$ 24	$ 24	$ 25	$ 28	$ 36	$ 37	$ 35	$ 35	$ 34	$ 31	$ 28	$ 27	$ 25	$ 25	$ 29	$ 36	$ 32	$ 31	$ 31	$ 29	$ 27	$ 24
351	$ 22	$ 22	$ 22	$ 22	$ 25	$ 30	$ 36	$ 38	$ 34	$ 34	$ 31	$ 27	$ 25	$ 23	$ 23	$ 22	$ 24	$ 30	$ 28	$ 31	$ 32	$ 30	$ 26	$ 22
358	$ 20	$ 19	$ 19	$ 20	$ 22	$ 23	$ 26	$ 29	$ 29	$ 29	$ 27	$ 25	$ 23	$ 22	$ 21	$ 21	$ 23	$ 29	$ 27	$ 27	$ 26	$ 24	$ 23	$ 20

At this time, and pending provision of more detailed determinants, Staff recommends establishing an on-peak rate for the weekday hours of 9:00 AM to 6:59 PM during the summer billing months and an intermediate-peak rate for all days during all billing seasons from 6:00 AM to 9:00 PM (excluding on-peak hours). The schedule for week days and for weekends is provided below:

	Summer	Shoulder 1	Winter	Shoulder 2
12:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
1:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
2:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
3:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
4:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
5:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
6:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
7:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
8:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
9:00 AM	On-Peak	Intermediate	Intermediate	Intermediate
10:00 AM	On-Peak	Intermediate	Intermediate	Intermediate
11:00 AM	On-Peak	Intermediate	Intermediate	Intermediate
12:00 PM	On-Peak	Intermediate	Intermediate	Intermediate
1:00 PM	On-Peak	Intermediate	Intermediate	Intermediate
2:00 PM	On-Peak	Intermediate	Intermediate	Intermediate
3:00 PM	On-Peak	Intermediate	Intermediate	Intermediate
4:00 PM	On-Peak	Intermediate	Intermediate	Intermediate
5:00 PM	On-Peak	Intermediate	Intermediate	Intermediate
6:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
7:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
8:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
9:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
10:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
11:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak

	Summer	Shoulder 1	Winter	Shoulder 2
12:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
1:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
2:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
3:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
4:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
5:00 AM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
6:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
7:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
8:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
9:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
10:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
11:00 AM	Intermediate	Intermediate	Intermediate	Intermediate
12:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
1:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
2:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
3:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
4:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
5:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
6:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
7:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
8:00 PM	Intermediate	Intermediate	Intermediate	Intermediate
9:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
10:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak
11:00 PM	Off-Peak	Off-Peak	Off-Peak	Off-Peak

continued on next page

A potential rate design for this structure, based on the information available at this time, is provided below:

Summer On-Peak:	$	0.07043
Summer Intermediate:	$	0.05996
Summer Off-Peak:	$	0.03400
Shoulder Intermediate:	$	0.05778
Shoulder Off-Peak:	$	0.03270
Winter Intermediate:	$	0.06450
Winter Off-Peak:	$	0.03400

Transmission Rate Schedule

The rate structure and general rate design of the proposed Empire transmission tariff appears largely reasonable. In addition to adjusting the rates to collect the ordered class revenue requirement, Staff anticipates minor revisions may be appropriate to incorporate feedback from transmission service customers and to align like elements across rate schedules, if applicable.

FAC Base Factor Adjustments for ToU Structures

The designs of the ToU rate structures recommended by Staff in this case are sized to better align cost-causation with revenue recovery, but are not designed to encourage changes in customer behaviors. An exception to this may be that EV charging or net increases in load due to thermal energy storage appliances may induce a net increase in load. However, future rate designs may be of a magnitude that could cause changes in customer behavior. Staff recommends the Company retain information and calculate on an ongoing basis outside of the operable FAC the modifications the Company has proposed to the FAC. This will enable refinement of the design and approach of this potential mechanism to align seasonal and diurnal variations in energy cost with revenue recovery for future implementation if and when it is appropriate to do so.

Recommended Studies

Pursuant to the Company's "Special or Excess Facilities Rider XC," customers pay additional monthly charges in specified circumstances associated with the installation of transformers or other distribution facilities. Several existing rate schedules contain varying provisions for "Transformer Ownership" that reduce the otherwise applicable Facilities Charge by a fixed $/kW rate. The Company's facility extension policy includes provisions for prepayment of the costs of certain facilities associated with a new customer taking service.

Staff suggests the Commission order Empire to file testimony in its next case describing how these investments and charges are tracked for internal accounting purposes, and how these facilities and related costs, expenses, and revenues are flowed through the company's class costs t of service study. Moving forward, Staff recommends development of customer charges and/or facilities charges for all customers that better reflect the revenue responsibility of a given customer's customer-specific facilities than the current framework under which the fixed portion of a customer's bill is largely determined by the rate schedule under which the customer takes service. To that end, a better understanding of (1) the customer-specific investment in each account and (2) the interaction of the facility extension, Rider XC, transformer ownership rate adjustments, and metering adjustments.

Stipulation commitments

Staff continues to work with Empire to review and develop data related to assignment or allocation of distribution infrastructure to the service voltage classifications, and to identify the costs of customer-specific infrastructure recorded to various distribution accounts. This will be further addressed in rebuttal.

Staff Expert/Witness: Sarah L.K. Lange

Renewable Energy Purchase Tariff Sheet Recommendation

Renewable Energy Purchase Plan/ Green Energy Tariff

In the Non-Unanimous Stipulation and Agreement, filed April 22, 2019, in Case No. EA-2019-0010, Empire agreed to allow non-residential customers to purchase a portion of Renewable Energy Credits[16] (RECs) received from wind projects that are not needed for

[16] A Renewable Energy Credit (REC) is a tradable certificate, that is either certified by an entity approved as an acceptable authority by the commission or as validated through the Commission's approved REC tracking system or a generator's attestation. Each REC

compliance with the Missouri Renewable Energy Standard. Empire is proposing a new schedule, Renewable Energy Purchase ("REP"), in order to comply with the Agreement. The REP schedule will allow non-residential customers to purchase RECs to offset the carbon emissions of up to 100% of their total monthly billed electricity consumption in increments of 25% (limited by the availability of RECs) at the average weighted price for the Company's REC sales for the previous calendar year. Proceeds from REC sales will be credited to customers through the FAC rider. The Company is proposing a minimum term of one year, which will automatically renew at the end of each term unless specifically requested with at least 30 days' notice. The schedule states,

On a quarterly basis, the Company shall perform a review of the previous three months' average weighted price ("Quarterly Review") for the Company's REC sales to the schedule's REC Rate. If the REC Rate is outside a five percent threshold as compared to the Quarterly Review, the REC Rate will be recalculated as the weighted average price for the most recent 12-month ending period. This updated REC Rate shall become effective with the first billing cycle of the following month.

The proposed tariff references execution of a REP service agreement, which has not yet been developed by Empire. Staff recommends that any REP schedule approved in this case incorporate the provisions intended for the service agreement. Additionally, Staff recommends a percentage cap on the number of RECs available to the program to ensure REC availability for the statutory RES standard is prioritized.

Staffv Expert/ Witness: Amanda Coffer

Fuel and Purchased Power Adjustment Clause Tariff Sheet Recommendations

In its *Staff Report - Cost of Service* in this case, Staff's recommendations for issues impacting Empire's fuel adjustment clause ("FAC") and FAC tariff sheets included the following:

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represents that one (1) megawatt-hour of electricity has been generated from renewable energy resources.

1. Continue Empire's FAC with modifications;
2. Include a revised Base Factor[17] in the FAC tariff sheets calculated from the Base Energy Cost[18] that the Commission includes in the revenue requirement upon which it sets Empire's general rates in this case;
3. Order Empire to continue providing monthly filings that will aid the Staff in performing FAC tariff, prudence, and true-up reviews;
4. Order Empire to include Schedule BM-d1,[19] either within the tariff or as an attachment to the tariff, to clarify the list of sub-accounts included and excluded within the Fuel Adjustment Clause;[20] and
5. Clarify that only transmission costs and revenues that are included in Empire's FAC are those that Empire incurs for Purchased Power and Off-System Sales.[21]

Staff indicated in its direct report[22] that it did not have its estimate for the Base Factor, but would provide it in its CCOS Report. Staff's method for calculating the Base Factor is shown in Appendix 2, Confidential Schedule BM-d2 of this report.

Fuel Adjustment Tariff Sheet Modifications

Staff reviewed the current Empire FAC tariff sheets the Commission approved in Case No. ER-2021-0332, which became effective June 1, 2021. The current FAC tariff sheets reflect Empire's participation in the Southwest Power Pool's ("SPP") Integrated Market and account for transmission costs consistently with the treatment of transmission costs in Ameren Missouri's, Evergy Missouri West's, and Evergy Missouri Metro's current FACs.

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[17] Base Factor is defined in Empire's Original Tariff Sheet No. 17i 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."
[18] Base Energy Cost is defined in Empire's Original Revised Tariff Sheet No. 17i as "Base energy cost is 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")."
[19] Staff witness Brooke Mastrogiannis created Appendix 2, Schedule BM-d1 from Empire witness Zachary Quintero's Schedule zq-06, with modifications.
[20] Staff *Direct Report,* pg. 113, lines 4-6.
[21] Staff *Direct Report*, pg. 113, lines 1-3.
[22] Staff *Direct Report,* pg. 113, lines 8-10.

<u>Staff proposes the following modifications to the Empire tariff:</u>

1. Replace the current Base Factor of $0.02338 with the revised Base Factor of $0.00953 per kWh.
2. Replace the current transmission percentage to be included in the FAC with 50% for MISO transmission costs and 19.39% for SPP transmission costs.
3. Continue the current voltage adjustment factors ("VAF's") of:

   $VAF_{PRIMARY} = 1.0429$ and $VAF_{SECONDARY} = 1.0625$
4. Add language to Original Sheet No. 17k to include Auction Revenue Rights and Transmission Congestion Rights, to be consistent with what the Commission approved to be included in the FAC from Case No. ER-2019-0374.
5. Add language to Original Sheet No. 17n in the Off-System Sales Revenue ("OSSR") definition to include revenues from the Missouri Joint Municipal Electric Utility Commission ("MJMEUC") contract and include revenues from the North Folk Ridge, Neosho Ridge, and Kings Point Wind Farms.
6. Add language to Original Sheet No. 17n in the Renewable Energy Credit ("REC") definition that the Renewable Energy Credits must be sold or utilized for compliance with the Missouri Renewable Energy Standard ("RES") before they expire.

<u>Revised Base Factor</u>

Staff calculated the Base Factor of $0.00953 per kWh. This is a decrease from the current Base Factor of $0.02338 per kWh established in Case No. ER-2019-0374, which is a further decrease from the previous Base Factor of $0.02415 established in Case No. ER-2016-0023. Staff used the Base Energy costs and Revenues from Staff's accounting, fuel model, and fuel and purchased power work papers developed in this rate case when calculating the Base Factor.

<u>Revised Base Factor Calculation</u>

Staff calculated the Base Factor of $0.00953 per kWh using the Base Energy Costs and Revenues from Staff's accounting schedules found in Staff's COS Report in this rate case.

Appendix 2, Confidential Schedule BM-d2 contains Staff's calculation of the Base Factor. Components of the Base Factor calculation are fuel costs incurred to support sales, purchased power costs, native load costs, net emission allowances costs, transmission costs, net auction revenue rights and transmission congestion rights (ARR/TCR), revenues from off-system sales, and renewable energy credit revenues.

Empire's fuel costs include the variable cost of fuel used in the production of electricity. Staff excluded administrative and labor expenses, which are also excluded in Empire's current FAC. The amount of fuel costs incurred to support sales, found in Staff's accounting and fuel and purchased power workpapers, was used in the Base Factor calculation.

Staff's Base Factor calculation includes the purchased power energy costs from long term purchased power agreements ("PPAs") for energy from the Plum Point, Elk River, and Meridian facilities. Purchased power energy costs also include variable Operations and Maintenance ("O&M") costs from the 50 MW Plum Point contract.

Native load cost is the cost of energy purchased through the SPP's Integrated Market to meet Empire's native load. Native load costs are found in Staff's fuel model summary work papers.

Transmission Costs used to transmit energy from non-company sources to Empire's service territory are included in the FAC. These costs are developed using Staff's accounting and fuel model summary work papers. Staff calculated the percentage of MISO transmission service costs to be included in the FAC to be 50% and the percentage of SPP transmission service costs to be included in the FAC to be 19.39%. Staff excluded SPP Schedule 1A-1, 1A-2, 1A-3 and 1A-4, Tariff Administration Service, and SPP Schedule 12, FERC Assessment Charge from its Base Factor calculation. These charges are excluded in the current FAC tariff sheets, because they are administrative costs, not variable fuel and purchased power costs.

As described above, Staff also included in its Base Factor calculation auction revenue rights and transmission congestion rights as components of Empire's FAC, and they are included in the Base Factor calculation. The amounts are found in Staff accounting work papers.

The amount of Renewable Energy Credit Revenues found in Staff's accounting work papers was used in the Base Factor calculation. Energy from Empire's generation resources is sold into the SPP's Integrated Market. Revenue from Off-System Sales is taken from Staff's fuel model summary work papers.

FAC Voltage Adjustment Factors

As provided in *Staff's Report - Cost of Service* filed in this case, Staff witness Alan J. Bax used the information in Empire's line loss study to develop the following primary and secondary voltage level adjustment factors:[23]

Voltage Level	Voltage Adjustment Factor
Primary	1.0429
Secondary	1.0625

These voltage adjustment factors adjust for energy losses in the delivery of electricity from the generator to customers at primary and secondary voltage levels. Staff will use these factors to determine Fuel Adjustment Rates (FARs) on the FAC tariff sheets for the two voltage service levels.

Staff Expert/Witness: Brooke Mastrogiannis

Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Other Staff Schedules

[23] Staff *Direct Report*, pg 122.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2021-0312

AFFIDAVIT OF AMANDA COFFER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW AMANDA COFFER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Report – Class Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Amanda Coffer

AMANDA COFFER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 16th day of November 2021.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2023
Commission Number: 15207377

Dianna L. Vaught

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2021-0312

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Report – Class Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange
SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 15th day of November 2021.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2023
Commission Number: 15207377

Dianna L. Vaught
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2021-0312

AFFIDAVIT OF BROOKE MASTROGIANNIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW BROOKE MASTROGIANNIS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Report – Class Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Brooke Mastrogiannis
BROOKE MASTROGIANNIS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 16th day of November 2021.

Dianna L. Vaught
Notary Public

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2023
Commission Number: 15207377