Exhibit No.: Issue: Minimum Filing Requirements; Annualized/Normalized Revenues; Class Cost of Service; and Rate Design Witness: Marisol E. Miller Type of Exhibit: Direct Testimony Sponsoring Party: Kansas City Power & Light Company Case No.: ER-2018-0145 Date Testimony Prepared: January 30, 2018

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2018-0145

DIRECT TESTIMONY

OF

MARISOL E. MILLER

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri January 2018

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DIRECT TESTIMONY

OF

MARISOL E. MILLER

Case No. ER-2018-0145

- 1 Q: Please state your name and business address.
- A: My name is Marisol E. Miller. My business address is 1200 Main, Kansas City, Missouri
 64105.
- 4 Q: By whom and in what capacity are you employed?
- 5 A: I am employed by Kansas City Power & Light Company ("KCP&L" or "Company") as
- 6 Supervisor Regulatory Affairs.
- 7 Q: On whose behalf are you testifying?
- 8 A: I am testifying on behalf of KCP&L.
- 9 Q: What are your responsibilities?

A: My general responsibilities are to provide support for the Company's regulatory activities
 in the Missouri and Kansas jurisdictions. Specifically, my duties include class cost of
 service support, rate design, tariff management, filing preparation, and load research
 support. I also manage certain analytical activities for the department including rate
 change implementation, billing determinant calculation, and retail revenue calculation.

15 Q: Please describe your education, experience and employment history.

A: I hold a Masters of Business Administration degree from Rockhurst University with an
 emphasis in Management. I also was awarded a Bachelor of Science in Business
 Administration Magna Cum Laude with an emphasis in Business Finance and
 Banking/Financial Markets from the University of Nebraska at Omaha. In addition to

those academic credentials, the Institute of Internal Auditor's ("IIA") and the Association
 of Certified Fraud Examiners ("ACFE") have certified me as a Certified Internal Auditor
 and Certified Fraud Examiner respectively.

I began my career at First Data Corporation working as Financial Analyst/Senior
Financial Analyst from October of 1999 until June of 2003. My primary responsibilities
included Financial Analysis, Forecasting, & Reporting. I then joined the Sprint
Corporation working there from 2003 until 2006, where my role evolved from work as a
Financial Analyst to Internal Audit work focused on Sarbanes Oxley Compliance.

9 I joined KCP&L in August of 2006 working as a Senior/Lead Internal Auditor. I
 10 led various projects of increasing complexity and most notably was the on-site Internal
 11 Auditor for the approximately \$2 billion Comprehensive Energy Plan Iatan 2
 12 Construction project.

I have worked in the Regulatory Affairs Department since 2011 holding various
 positions covering areas including Integrated Resource Planning ("IRP"), Missouri
 Energy Efficiency Investment Act ("MEEIA")/Demand-Side Management ("DSM"),
 compliance reporting for multiple areas in transmission and delivery, and rate case
 support.

18 Q: Have you previously testified in a proceeding before the Missouri Public Service
19 Commission ("Commission" or "MPSC") or before any other utility regulatory
20 agency?

A: Yes, I provided written testimony before the Kansas Corporation Commission ("KCC")
and testified in a proceeding before the Missouri Public Service Commission in Docket
No. ER-2016-0285 supporting the Company's request for a rate increase.

2

1	Q:	What is the purpose of your testimony?						
2	A:	The purpose of my testimony is to:						
3		Explain how the Company satisfied the MPSC's minimum filing requirements						
4		("MFR") under 4 CSR 240-3.030 for this rate case filing;						
5		II. Explain and support the Company's annualized/normalized revenues;						
6		III. Provide an update on MPSC-ordered Rate Design Studies;						
7		IV. Explain the Electric Class Cost of Service ("CCOS") Study; and						
8		V. Explain and support the Company's Electric Rate Design.						
9	I. MINIMUM FILING REQUIREMENTS							
10	Q:	What is the purpose of this part of your testimony?						
11	A:	The purpose of this part of my testimony is to confirm that KCP&L has satisfied the						
12		MPSC's MFR, as set forth in 4 CSR 240-3.030.						
13	Q:	How did KCP&L satisfy the MFR?						
14	A:	The following information was prepared and attached to the Company's Application filed						
15		concurrently with this testimony, to address the specific requirements of the MFR as						
16		outlined in 4 CSR 240-3.030(3):						
17		A. Letter of transmittal;						
18		B. General information, including:						
19		1. The dollar amount of the aggregate annual increase and percentage over						
20		current revenues;						
21		2. Names of counties and communities affected;						
22		3. The number of customers to be affected;						

1		4. The average change requested in dollars and percentage change from						
2		current rates;						
3		5. The proposed annual aggregate change by general categories of service						
4		and by rate classification;						
5		6. Press releases relative to the filing; and						
6		7. A summary of reasons for the proposed changes.						
7		II. ANNUALIZED/NORMALIZED REVENUES						
8	Q:	Were the retail revenues included in this filing prepared by you or under your						
9		supervision?						
10	A:	Yes, they were.						
11	Q:	Will you describe the method used in developing the revenues for this case?						
12	A:	Both the weather-normalized kWh sales and customer growth levels by rate class (i.e.						
13		Residential, Small General Service, Medium General Service and Large General Service)						
14		were developed by Company witness Albert R. Bass, Jr Mr. Bass explains those figures						
15		in his Direct Testimony. The test year used by the Company in this case was the 12						
16		months ending June 30, 2017, which we expect will be updated for known and						
17		measurable changes through June 30, 2018. The monthly bill frequencies for the 12						
18		months ending June 30, 2017, that contain the billing units for each of the billing blocks						
19		for the various rate components, were developed under my supervision. These bill						
20		frequencies were developed by collecting the actual usage and customer counts billed in						
21		each month of the test period and applying them to the existing rate structures. By						
22		applying the existing rates to the usage in each of the billing blocks, the revenues were						
23		reproduced, providing a basis for determining the overall revenues to be used in this case.						

1 The Company determined monthly revenues by applying the normalized sales and 2 customer levels for each month represented in the test period to the corresponding billing 3 frequency. The normalized sales and customer levels from this were then multiplied by 4 the rates that took effect on June 8, 2017 to obtain the weather normalized and customer 5 growth adjusted monthly revenues available. The sum of the monthly revenues was 6 compared to the actual revenues for the test year ending June 30, 2017 to determine the 7 revenue adjustment contained in the Summary of Adjustments attached to the Direct 8 Testimony of Company witness Ronald A. Klote as Schedule RAK-4 (adjustment no. R-9 20).

10 **O**:

Q: Were all class revenues developed as described above?

A: Yes, except for the Large Power Class. The Large Power class revenues generally
followed the methodology outlined above, but were developed on an individual customer
basis. Customer growth was accounted for by the annualization of usage for new
customers switching (or starting new service) to the Large Power Class or customers
leaving the Large Power Class (either due to switching or stopping service) through the
end of the test year period.

17 Q: The Company has several riders in place to recover particular costs. How will these 18 mechanisms affect the requested increase in this case?

A: The Demand-Side Investment Mechanism ("DSIM") is separate from the revenue
requirement requested in this case and thus the associated DSIM revenues have been
removed from the total revenues available. The fuel adjustment clause ("FAC") rider
base amount has been re-based within the current revenue requirement. In addition to my

1		testimony on the FAC, please see the Direct Testimony of Tim M. Rush for the primary
2		details concerning the continuation of the FAC in this case.
3		III. RATE DESIGN STUDIES-UPDATE
4	Q:	Rate Design studies were ordered in GMO's last rate case. Can you explain what
5		was ordered and the status of the studies?
6	A:	In GMO's last rate case ("ER-2016-0156"), a Stipulation & Agreement ("S&A") was
7		filed on September 20, 2016 outlining several studies to be completed by KCP&L
8		Greater Missouri Operations Company's ("GMO") next rate case or rate design case.
9		The specific S&A language included the following:
10		"Agree to study 1) modifying GMO's seasonal rates in a future rate proceeding to
11		establish rates for Peak months and Shoulder months, as opposed to GMO's
12		current Summer/Non-Summer seasonal split, including applicable determinants;
13		and 2) responsible energy use as related to residential block rates. The Company
14		will work with the Signatories to define the scope of study. GMO will file the
15		results of this study as part of its direct testimony in GMO's next general rate
16		case or rate design case, whichever occurs first."
17		"GMO will include in its direct filing in its next rate case or rate design case a
18		study of TOU rates for GMO including TOU residential and SGS rates, critical
19		peak rates, Electric Vehicle TOU rates for stand-alone charging stations, TOU
20		rates applicable to Electric Vehicle charging associated with an existing account,
21		Real Time Pricing, Peak Time Rebates, and other rate types which could
22		encourage load shifting/efficiency. GMO will propose rates based on this study no
23		later than its next rate case or rate design case."

- 1 **O**: If the order was a GMO specific order, why is it being discussed in the KCP&L 2 case?
- 3 A: While the GMO studies resulted from a GMO rate case order, the results from the studies 4 were used to inform rate design offerings in the KCP&L jurisdiction.
- 5 **O**:
 - Are these studies filed in this rate case filing?
- 6 The GMO studies are filed in the concurrent GMO rate case ("ER-2018-0146"). A:
- 7 What were the overall results of the studies? 0:

8 Residential Seasonal Study - The purpose of this study was to consider alternate A: 9 methods for representing the seasons within the residential rates, specifically a peak and 10 shoulder month seasonal rate structure, as opposed to the current summer/winter seasons, 11 if the change would better reflect the current drivers of system capacity needs, the market 12 energy price variation, and any other relevant drivers.

- 13 Based on the overall analysis, this study does not support modifying the current 14 seasons used by GMO. The cost analysis documents higher average costs in the summer 15 months supporting the current two season rate structure, and the review of regional utility 16 rates indicates that the GMO summer/winter seasons is consistent with the seasonal 17 structure used by other utilities. Furthermore, introducing additional seasons would lead 18 to greater complexity and create potentially confusing price signals for customers due to 19 the cyclical nature of the billing process.
- 20 Residential Block Study - The purpose of this study was to evaluate the role of 21 residential energy blocks in promoting responsible energy use. This analysis was not 22 intended to determine which rate structures should be offered, but rather to identify

7

appropriate rate block thresholds to promote responsible energy use for a variety of rate structures that will be considered in future Company rate design analysis.

Review of electric block rate structures in the region show that many of the neighboring, summer peaking utilities, like GMO, continue to use a block rate design during the winter season to achieve price segmentation reflective of the benefits of improved load factor and the reduced costs of off season uses.

1

2

7 Policy goals are shifting from the simple energy conservation focus of yesteryear 8 toward achieving greenhouse gas ("GHG") reductions. Many are recognizing the need 9 to assess the GHG emissions associated with various ways to power end-uses, as 10 opposed to simply managing the number of kilowatt-hours consumed. To that end, 11 "emissions efficiency" may be as or more important than "energy efficiency" moving 12 forward and ultimately may be the best measure of responsible energy use. Some rate 13 designs that can deviate from a cost basis, like the inclining block rate ("IBR"), create an 14 economic disincentive to pursue beneficial electrification.

Two types of alternative residential rate designs are often proposed to meet rapidly evolving customer needs in the near-term; time based rates and demand based rates. Based on literature review and considerations discussed in the study, Time of Use ("TOU") and Demand rate options are the best rate designs for the Company to pursue to meet the objectives of responsible energy use, demand-side management, and beneficial electrification.

<u>TOU Study</u> - GMO retained the consulting services of Burns & McDonnell
 ("BMcD") to conduct a TOU Rate Study and to prepare a report which addresses the
 MPSC's order in the 2016 GMO rate case.

8

1	The TOU Rate Study ("Study") consisted of collecting information and
2	conducting qualitative and quantitative analyses of the existing GMO Residential and
3	Small General Service rates and analyzing new Residential and Small General Service
4	TOU rate designs.
5	The development and design of rates for the Residential and Small General
6	Service classes was based upon consideration of Company goals, application of good
7	rate making principles, consideration of the qualitative ratings, comparison to common
8	practice, and the experience of BMcD in this area. Further, the designs were evaluated
9	using load research and CCOS analysis, designed to be revenue neutral to the existing
10	rates in each class, reflect the utility's CCOS by season and time-period, and to meet
11	GMO and KCP&L's rate design objectives described in the report.
12	The Study recommendations include offering three new Residential rate options:
13	(1) a Demand Rate, (2) a TOU Energy rate, and (3) a combination TOU Energy and

Demand Rate. Results of the pilot should be used to make informed decisions about the rate design and the required system configurations before rolling out other rate modifications to a larger number of Residential and Small General Service customers.

The Study also includes the recommendation that MEEIA be used as the foundation for the optional rates and that they be MEEIA programs in the next MEEIA Filing. The recent DSM potential study analyzed these rate options as demand side measures to address requirements outlined in the Missouri Chapter 22 Electric Utility Resource Planning (IRP). These rates are proposed, in part, to attempt to achieve the potential demand side benefit identified in the IRP process. However, the IRP process largely ignores the ratemaking process, particularly, the treatment of revenue recovery, as it assumes perfect rate making. Since that is not a reasonable outcome and since
these rate design options align with the goals of MEEIA, it would be appropriate to
explore possible inclusion as a MEEIA program that recognizes the need for the
Company to be kept whole when promoting energy efficiency, demand response
programs, and demand-side rates that are expected to impact the company's revenue
requirement and ability to recover fixed costs.

7

Q: How were the study results used in this case?

8 A: The Company is including a proposal to offer to Residential Customers a Demand Rate
9 Pilot, a TOU Energy Pilot, and a pilot for a combination TOU Energy Rate and a
10 Demand Rate in this rate case filing.

11 Q: Did you propose every single Burns & McDonnell recommendation in this case?

12 A: No. There were many recommendations that were made over an extended timeline 13 contingent upon many external factors and assumptions. Those factors include 14 technology limitations (e.g. 100% Advanced Metering Infrastructure ("AMI") roll-out), 15 rate case outcomes, and pilot results over time, etc. The most significant 16 recommendation that was not included in this filing is a pilot offering for the Small 17 General Service class. Given the expected demand response and limited impact to the 18 SGS Summer Load, it was decided that the focus would be on the Residential pilot 19 offerings at this time.

20 Q: Why are the TOU proposals only being filed as pilots?

A: The Company plans to ensure pilot success by tracking and analyzing pilot program
 results/progress. This data will be used to assess future rate design modifications, as well
 as, learn more about customer needs and wants, given available technology and

information, and to help improve customer education. It will take some time to analyze,
as well as, modify the pilot into a broader implementation that will be beneficial to most
customers in the Residential class. In the meantime, these pilot programs should be
beneficial and effective, following sound rate design principles that include supporting
efficient use of energy, utilization of cost of service based rate designs, providing revenue
sufficiency and stability and providing customer value and satisfaction, while minimizing
negative customer impact, including rate shock.

8 Q: Did the Company include the exact rates from the TOU study in the proposed pilot 9 tariffs?

A: No, while the TOU study utilized the latest available CCOS studies and load research, it
was not current data when the Company developed its pilot rates. The Company used the
latest available load research and CCOS information in this case for purposes of
proposing the pilot rates. Those rates should be refined as better information is made
available.

15 Q: Could the offering of TOU Pilots result in a negative impact to the Company's16 financials?

17 A: Yes. Please see Company Witness Tim Rush testimony for information on the potential 18 financial impact to the Company and why the effective date of the tariffs needs to be 19 delayed.

20

IV. ELECTRIC CLASS COST OF SERVICE STUDY

- 21 Q: Please give an overview of the Company's testimony supporting the electric Class
 22 Cost of Service study.
- 23 A: The CCOS study is supported by the following Company witnesses:

1		• Brad Lutz's direct testimony includes a summary of past CCOS studies and
2		production allocation methodologies used and provides an explanation of the
3		process resulting in a recommended change in the production allocation method.
4		• Tom Sullivan's direct testimony provides a discussion and support for utilization
5		of the Average & Excess production allocation method.
6		• This testimony includes discussion of the preparation of the CCOS study filed in
7		this proceeding.
8	Q:	Has the Company performed a CCOS study for this case?
9	A:	Yes, the Company performed a CCOS study representative of the KCP&L jurisdiction.
10		A summary of the results of the Company's CCOS studies are attached and marked as
11		Schedule MEM-1.
12	Q:	Was the study prepared by you or under your direct supervision?
13	A:	Yes, it was. Consistent with prior filings, the Company retained the services of
14		Management Applications Consulting who performed the primary CCOS modeling using
15		their proprietary software and data provided by the Company.
16	Q:	Has the Company filed a CCOS in previous rate cases?
17	A:	Yes. In all rate cases filed since 2005, the Company has filed a CCOS study.
18	Q:	What is the purpose of the CCOS study?
19	A:	The purpose of the CCOS study is to directly assign or allocate each relevant component
20		of cost on an appropriate basis in order to determine the contribution that each customer
21		class and rate makes toward the Company's overall rate of return. The CCOS analysis
22		strives to attribute costs in relationship to the cost-causing factors of demand, energy and
23		customers.

Q: Would the CCOS study serve as the basis for the determination of increasing or decreasing overall revenue levels for KCP&L?

A: No. Determination of the revenue requirement requested in this case is accomplished
using the jurisdictional model sponsored by Company witness Ronald A. Klote. The
CCOS model uses the information from the jurisdictional model as an input for the
primary purpose of evaluating the possible distribution of costs to the respective classes.

7

Q: What classes are used as a basis for this CCOS study?

8 A: The primary classes the Company used in its analysis are Residential, Small General
9 Service, Medium General Service, Large General Service, Large Power Service, and
10 Lighting.

11 Q: Do these classes and rates conform to the proposed electric rate tariffs?

12 A: Generally, they do. The Residential class has several rate classifications available to it 13 that include general use, one-meter general use and heat, and a two-meter rate with 14 general use on one meter and a separate meter for space heating. The Small General 15 Service, Medium General Service and Large General Service classes also have general 16 usage rates and all electric rates, plus they can be specific to the voltage level at which 17 the customer receives service. The Large Power Service class is distinguished by the 18 specific voltage at which the customer receives service. In total, the Company has five 19 classes of service (plus Lighting), but has approximately 56 rates to meet the specific 20 needs of the customer and reporting and billing requirements.

21 Q: What test year was used for the CCOS study?

A: The study is based on a historical test year of the 12 months ending June 30, 2017, withknown and measurable changes projected through June 30, 2018.

Q: What general categories of cost were examined and considered in the development of the CCOS study?

A: An analysis was made of all elements of cost as defined by the Federal Energy
Regulatory Commission Uniform System of Accounts, including investment (rate base)
and expense (cost of service) for the purpose of allocating these items to the customer
classes. To achieve this allocation we begin by functionalizing and classifying costs.

7

O:

Please explain what you mean.

A: In order to make the appropriate assignment of costs to the appropriate class of customer,
it is necessary to first group the costs according to their function. The functions used in
the CCOS study were production, transmission, distribution, and other costs. The next
step was to classify the costs. Costs are classified as customer-related, energy-related, or
demand-related.

13 Q: What do you mean by customer-related, energy-related and demand-related?

A: Customer-related costs are those costs necessary to provide electric service to the
customer independent of any usage by the customer. Some examples of these costs
include meter reading, customer accounting, billing and some investment in plant
equipment such as the meter and service line, facilities that are all necessary to make
service available. Portions of the distribution facility are separated between the customer
costs and the demand costs.

Energy-related costs are directly related to the generation and consumption of energy and consist of such things as fuel and purchased power and certain transmission costs.

14

Demand-related costs relate to the investment and expenses associated with the
 Company's facilities necessary to supply the customer's full load requirements
 throughout the year. The majority of demand-related costs consist of generation,
 transmission plant and the non-customer portion of distribution plant.

- 5 Q: After the above classification of plant investment and operating costs into customer-6 energy- and demand-related components, what was the next step in the CCOS 7 study?
- 8 A: The next step was to allocate each of the three categories of cost to each customer class
 9 utilizing allocation factors appropriate for each of the above categories of cost.

10

Q: How are the allocation factors generally determined?

A: Costs are evaluated to determine the cause driving the cost to be incurred and to establish an allocation method that best distributes the cost based on that causation. Customerrelated costs are generally allocated on the basis of the number of customers within each class. Data for the development of the customer-related allocation factors came from Company billing and accounting records. Some of the customer-related accounts were allocated based on a weighted number of customers to reflect the weighting associated with serving those customers.

Energy-related allocation factors were derived on the basis of each customer classes' respective energy (kilowatt hour) requirements. Kilowatt-hour ("kWh") sales to each customer class were available from Company records. The sales data was adjusted to reflect normal weather, system losses and unaccounted for, in order to assign the Company's total system output. 1

Q:

How are class demand allocation factors generally determined?

- A: The data necessary to develop class demand allocation factors (production and transmission) were derived from the Company's load research data. Such data consisted of the hour-by-hour use of electricity by each customer class throughout the study period.
- 5 Q: Was KCP&L's load research data used to develop any other allocators?
- 6 A: Yes, it was used to develop distribution plant allocators based on customer's non-7 coincident loads within each class.
- 8 Q: Are any costs assigned directly to classes?

9 A: Yes. In instances where the costs are clearly attributable to a specific class, they are10 directly assigned to that class.

11 Q: What method do you propose to allocate production plant?

12 A: After considering all allocation theories and ensuring that the selected method aligned 13 with the principles of reflecting actual planning and operating characteristics, cost 14 causation, recognizing the broad set of customer class characteristics and their usage, and 15 producing stable results on a year to year basis, the Company selected the utilization of 16 the Energy Weighted approach, specifically the Average & Excess Production Plant 17 Allocation method, incorporating a four (4) Coincident Peak ("CP") component. An 18 Energy Weighted approach was viewed to be cost effective, balanced through its 19 incorporation of energy, and less subjective than other methods. Utilization of the 20 Average & Excess method is an energy-weighted method of production plant allocation 21 that gives classes a reasonable balance between the energy and capacity function of 22 generating facilities. Please see direct Testimonies of Company witnesses' Brad Lutz

1		and Tom Sullivan for more information on other factors that contributed to the decision
2		to move to the Average & Excess method and the reasonableness of that decision.
3	Q:	Has this allocation method been proposed before?
4	A:	Yes. Company witness Tom Sullivan identifies in his direct testimony other companies
5		in the region that have proposed this method. In addition, other parties have proposed
6		variations of this method in testimony through many KCP&L rate case dockets.
7	Q:	How were the fuel costs associated with the production plant allocated in the CCOS
8		study?
9	A:	Fuel costs were allocated using a monthly kWh allocator. Based on monthly fuel costs
10		from the Company for the 12 months ended June 30, 2017, each month's fuel costs were
11		allocated to each customer class's corresponding calendar month kWh sales adjusted for
12		losses. These allocated results were summed by rate and major customer class to identify
13		a proxy fuel allocator which was then used to allocate the actual fuel costs shown in the
14		CCOS study.
15	Q:	How were the off system sales margins that KCP&L receives from its external sales
16		of energy allocated?
17	A:	They were allocated using the Energy allocator.
18	Q:	What method did you use to allocate transmission plant costs?
19	A:	Transmission plant costs were allocated using Average & Excess - 4 four coincident
20		peaks ("4CP").
21	Q:	What method did you use to allocate Distribution Plant?
22	A:	Distribution Plant was primarily allocated using a Non-Coincident Peak ("NCP") demand
23		allocator based on the use of NCP class demands for Primary Plant in Accounts 360

1		through 367, with the exception of Account 363, which used a 12-CP demand allocation.
2		Also, Accounts 364, 365, 366 and 367 included methods to recognize primary and
3		secondary voltage cost separation.
4	Q:	What method did you use to allocate Line Transformers and secondary plant?
5	A:	Line Transformers and secondary plant costs were allocated to customers receiving
6		secondary service based on the weighted average of the diversified class demands (NCP)
7		and undiversified individual customer maximum demands.
8	Q:	What method did you use to allocate Services?
9	A:	Since we consider services customer-related, these costs were allocated based on the
10		customers total diversified maximum customer demands.
11	Q:	What method did you use to allocate Meters?
12	A:	Meter costs, recorded to Account 370, are also customer-related and were allocated using
13		an assignment of all meters and metering devices to customer rates.
14	Q:	Did you include any other rate base elements in the study?
15	A:	Yes, multiple rate base elements have been included. The following details their
16		allocation:
17		• Additions to net plant included cash working capital, materials and supplies,
18		prepayments, fuel inventory, and various regulatory assets.
19		• The cash working capital component of rate base was developed and allocated on
20		related expenses or plant in the CCOS study.
21		• Materials and supplies were allocated on total plant and demand allocation
22		factors.

1		• Prepayment items were allocated using total plant, customers, and demand
2		allocation factors.
3		• Fuel inventory was allocated on energy.
4		• The regulatory assets were allocated on labor, energy, or demand allocation
5		factors depending on the costs tracked.
6		• The accumulated deferred taxes were allocated on total plant.
7		• Customer advances for construction were allocated on total distribution plant.
8		• Customer deposits were developed using the data analysis by customer group
9		available from the Company.
10	Q:	What revenues did you use for this study?
11	A:	The class and rate revenues were developed under my supervision and were discussed
12		earlier in this testimony. Other sources of revenues such as Miscellaneous Revenues
13		were allocated consistent with the revenue source.
14	Q:	How were Operation and Maintenance ("O&M") Expenses allocated?
15	A:	O&M Expenses were allocated using various methods dependent of the cost causation.
16		O&M for production, transmission and distribution plant were allocated to customer
17		classes following plant. Customer Accounts Expenses, Customer Services and
18		Information Expenses, Sales Expenses, and Administrative and General Expenses were
19		allocated based on the results of individual allocation studies. Administrative & General
20		expenses were primarily allocated on the labor allocator with the exception of the
21		following:
22		• Account 930.1, General Advertising, which was allocated based on the number of

- Account 930.1, General Advertising, which was allocated based on the number of customers

1 2 • Account 928, Regulatory Commission expenses, which was primarily allocated to classes on revenues at the uniform claimed rate of return

3

• Account 935 Maintenance of General Plant, which was allocated on general plant.

4 Q: What is the next step after the allocations are applied?

5 A: The next step is to determine the relative return on rate base for each of the classes and 6 rates in the study. The ratio of class revenues less expense (net operating income) 7 divided by class rate base will indicate the rate of return being earned by the Company 8 that is attributable to a particular class. It is necessary to keep in mind that this 9 calculation only represents a snapshot in time. The results of the CCOS study will most 10 likely vary over time. The results of the study will also vary if you apply different 11 allocation factors to the study. By applying different methods to the allocation process, 12 you can change the outcome of the CCOS study.

13 Q: What were the results of the CCOS study?

A: The overall jurisdictional rate of return was calculated to be 7.0%. Individual classes'
rates of return at current rates vary, and based on the current costs, are shown in the
following table.

Residential	Small	Medium	Large	Large	Other
	General	General	General	Power	Lighting
	Service	Service	Service	Service	
3.4%	11.9%	9.0%	10.5%	10.0%	12.7%

- Q: If rates were changed so that KCP&L earned the same rate of return from each
 customer class, how much would each class's rates need to change?
- 3 A: To achieve an overall the jurisdictional revenue increase of 1.9%, the classes should be
 4 adjusted by the percentages in the table below.

Residential	Small	Medium	Large	Large	Other
	General	General	General	Power	Lighting
	Service	Service	Service	Service	
19.7%	-14.8%	-5.9%	-10.7%	-8.5%	-14.8%

5 Q: What general conclusion can be made from these results?

A: The results of the CCOS study show that each class of customers recovers the cost of
service to that class and provides a return on investment. The results also show the
Residential class revenue is well below the Total Missouri ("MO") Retail rate of return
level while the Medium General, Large Power, and Large General Service class revenues
are above. The results also show the Small General and Lighting class revenues are well
above the Total MO Retail rate of return level.

12 Q: In addition to the class results, was the study used to provide any additional13 information?

- 14 A: Yes, another element of the study was to explore costs at the rate level. This data
 15 provides additional information to aid the Company in preparing its rate design.
 16 Schedule MEM-2 is attached and contains this rate level information.
- 17 (

Q: Is seasonality still reflected in the study?

- 18 A: No. Seasonality has been removed from the study because it more closely relates to rate
 19 design and is discussed in the rate design section of this testimony.
- 20 Q: Are you proposing changes to the class revenues based on the results of the study?
- 21 A: Yes.

Q: Are you proposing changes to class revenues that are reflective of an equalized rate
 of return by class?

A: No. The exact application of changes in rates that aim for an equalized rate of return by
class would have been extremely detrimental to our residential customers and not in line
with sound rate design principles. Instead, the Company opted for a gradual approach to
adjusting revenues and rates. Utilizing the results from the study prepared based on the
Average & Excess production allocation; the Company has identified the following
recommended changes to class revenues:

- Apply no increase to the Lighting class (unmetered),
- 10

•

- Apply a 0.97% increase equally to the remaining classes
- Application of these proposals to the electric rates is discussed further in the rate designsection of this testimony.

Apply a 3.34% increase to the Residential class, and

14 Q: In proposing class revenue shifts, is there an expectation of rate switchers that
15 should be considered and taken into account?

16 A: Yes. Revenue losses associated with potential rate switching resulting from the above
17 rate changes are possible. The Company plans to size this impact by the True-up and if
18 possible, sooner.

19

V. ELECTRIC RATE DESIGN

- 20 Q: Are you sponsoring the electric tariffs filed in this case?
- 21 A: Yes, I am.

1

2

Q: Please summarize the proposed rate design recommendation for the electric tariffs and any additional proposed changes to the tariffs?

A: The Company is requesting an annual aggregate increase over current revenues reflecting
impacts before the rebasing of fuel for the fuel adjustment clause, in the amount of \$8.9
million (1.02%). The aggregate annual increase over current revenues including the
rebasing of fuel for the fuel adjustment clause is \$16.4 million (1.88%).

7 Utilizing the results of the CCOS, the Company is proposing that an overall 8 increase of 3.34% be applied to Residential class revenues with a customer charge of 9 \$15.17. The \$15.17 proposed customer charge is based on the results of the CCOS, after 10 adjustment/removal of solar rebates and is consistent with prior Commission approved 11 customer charges. The remaining revenue shortfall/increase was then applied equally to 12 remaining Residential bill components. A 0.97% increase would be applied to all other 13 classes on an equal percentage basis, with the exception of the Lighting class, which 14 would get 0% increase. The Large General Service and Large Power classes would have 15 75% of the increase applied to the second energy block with the remainder of the increase 16 applied equally to the remaining components. The application of the above increases by 17 class by billing component can be found in attached schedule MEM-3. The summary of 18 revenues and proposed increase by class may be found in Schedules MEM-5 and MEM-

19

5A.

20

Q: Are there any new tariffs being filed as part of this case?

A: Yes, the Company is proposing a tariff for electric vehicle charging stations resulting
 from KCP&L's Clean Charge Network program. Company Witness Tim M. Rush
 explains this in detail in his Direct Testimony. Additionally, a new Renewable Energy

1 Rider is being proposed and a Solar Subscription Pilot Rider, as well as changes to our 2 existing Standby tariff. Company Witness Brad Lutz explains this in detail in his Direct 3 Testimony.

4 **Q**: Please summarize the proposed changes to rules & regulation tariffs or other non-5 base rate tariffs.

6 A: The specific, proposed changes to rules and regulations and non-base rate tariffs may be 7 found in Schedule MEM-4. Changes are proposed to better align the rules & regulations 8 with current costs, planned business practices, and are generally minimal in impact. The 9 most significant changes included elimination to of the frozen Real-Time Pricing 10 ("RTP") tariffs and modifications of the Special Contracts tariffs. The special contract 11 tariffs were streamlined to better align with business practices and the frozen RTP tariffs 12 are being proposed to be eliminated given the administratively burdensome nature to 13 maintain these frozen tariffs.

14 **Q**: Does the Company propose any changes to the KCP&L Lighting class?

15 No. As mentioned previously, the CCOS studies indicated the unmetered Lighting class A: 16 did not need to be increased. The Company is proposing to deploy Light Emitting Diode 17 ("LED") lighting as part of its Private Lighting tariff. For details on the Company's 18 Private Area Lighting initiative, see the Direct testimony of Company witness, Brad Lutz.

- 19 **Q**:
- Are you proposing any additional tariff changes?
- 20 A: Yes, there have also been changes to the FAC tariffs that are explained in detail in the 21 Direct Testimony of Company witness Tim. M. Rush.
- 22 Does that conclude your testimony? **Q**:
- 23 A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service

Case No. ER-2018-0145

AFFIDAVIT OF MARISOL E. MILLER

)

STATE OF MISSOURI)) ss

COUNTY OF JACKSON)

Marisol E. Miller, being first duly sworn on his oath, states:

1. My name is Marisol E. Miller. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Supervisor – Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of <u>twenty-four</u> (<u>24</u>) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Marisol E. Miller

Subscribed and sworn before me this $2^{\frac{2}{9}}$ day of January 2018. At When the provided HTML At When the provided HTML and the



Kansas City Power & Light Company 2018 RATE CASE - DIRECT TY 6/30/17; Update TBD; K&M 6/30/18 COST OF SERVICE - Missouri Jurisdiction

Allocation Method: Prod - Avg & Excess 4 CP, Tran - Avg & Excess 4 CP

SCH LINE NO. NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1 0010	SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BAS	E								
1 0020		Reference								
1 0030	OPERATING REVENUE									
1 0040	RETAIL SALES REVENUE	TSFR 9 90	870,989,124	338,121,886	58,411,963	132,367,581	190,095,339	141,652,131	10,340,224	
1 0050	OTHER OPERATING REVENUE	TSFR 9 360	303,325,239	96,404,901	15,441,996	44,453,630	74,691,529	69,249,304	3,083,880	
1 0060	TOTAL OPERATING REVENUE		1,174,314,363	434,526,788	73,853,958	176,821,211	264,786,867	210,901,434	13,424,104	
1 0070										
1 0080	OPERATING EXPENSES									
1 0090	FUEL	TSFR 9 4090	165,926,224	53,379,845	8,427,153	24,263,314	40,466,894	37,752,327	1,636,690	
1 0100	PURCHASED POWER	TSFR 9 4100	275,438,518	86,595,215	13,984,639	40,381,734	68,203,206	63,480,981	2,792,743	
1 0110	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR 9 4110	299,498,569	151,126,121	17,726,941	38,122,858	51,030,623	38,817,951	2,674,075	
1 0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	TSFR 5 1420	124,617,389	58,845,381	7,039,001	18,339,078	22,857,562	15,750,500	1,785,868	
1 0130	AMORTIZATION EXPENSES	TSFR 9 4590	25.525.373	11,735,311	1,415,867	3,769,815	4,919,125	3,449,120	236,135	
1 0140	TAXES OTHER THAN INCOME TAXES	TSFR 9 4710	64.993.344	30,469,547	3,659,239	9.383.915	12,240,444	8.636.539	603,660	
1 0150	CURRENT INCOME TAXES	TSFR 11 620	32.259.407	433.393	4,223,778	7,468,230	11,808,403	7,424,730	900.872	
1 0160	DEFERRED INCOME TAXES	TSFR 11 690	2.449.517	1.171.561	139,528	356.526	449.810	306.508	25.584	
1 0170	TOTAL ELECTRIC OPERATING EXPENSES		990,708,340	393,756,374	56.616.147	142.085.470	211.976.066	175.618.657	10.655.627	
1 0180			,,,	,,,			,,,	,,	,	
1 0190	NET ELECTRIC OPERATING INCOME		183.606.023	40,770,414	17.237.812	34,735,741	52.810.801	35,282,777	2,768,477	
1 0200			,,		,,	,,	, ,		_,,	
1 0210	RATE BASE									
1 0220	TOTAL ELECTRIC PLANT	TSFR 3 190	5 564 493 533	2 598 855 070	312 391 787	810 336 219	1 053 547 398	737 945 909	51 417 151	
1 0220	LESS: ACCUM PROV FOR DEPREC	TSFR 6 1700	2 245 853 467	1 051 302 484	126 564 795	322 839 125	423 128 344	299 040 798	22 977 921	
1 0240	NET PLANT		3 318 640 066	1 547 552 585	185 826 992	487 497 094	630 419 053	438 905 111	28 439 230	
1 0250	PLUS		0,010,010,000	1,017,002,000	100,020,002	107,107,001	000,110,000	100,000,111	20, 100,200	
1 0260	CASH WORKING CAPITAL	TSER 2 30	(58 635 031)	(26 382 537)	(3 519 964)	(8 644 775)	(11 461 442)	(8 038 208)	(588 105)	
1 0200	MATERIALS & SUPPLIES	TSFR 2 100	64 704 386	28 803 303	3 525 254	9 582 207	12 800 784	9 288 758	514 990	
1 0280	DEDAVMENTS	TSER 2 170	7 053 628	3 000 460	381 218	1 03/ /81	1 /33 810	1 058 373	16 260	
1 0200		TSER 2 240	67 502 104	21 528 3/3	3 424 765	9,866,004	16 523 204	15 / 86 117	673 671	
1 0290		TSER 2 240	55 040 144	21,520,545	2 001 270	9,000,004	10,323,204	0 129 450	404 192	
1 0300	LESS.	13FK 2 330	55,949,144	22,729,400	2,991,270	0,430,390	12,247,177	9,130,439	404,102	
1 0310		TCED 2 200	1 669 576	049 764	106 122	240 996	220 100	100 400	22 204	
1 0320		TOFR 2 300	1,000,070	2 206 097	1 629 070	240,000	230,100	109,499	33,204	
1 0330		TSFR 2 390	4,337,009	2,300,007	1,030,070	330,702	54,077	3,004	7 207 740	
1 0340		TSFR 2 400	789,779,808	368,860,750	44,338,397	115,012,057	149,532,110	104,738,154	7,297,740	
1 0350		TOFR 2 410	31,794,060	9,995,752	1,014,250	4,001,295	1,012,140	7,327,030	322,300	
1 0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	15FR 2 420	0	0	0	0	0	0	0	
1 0370		ISFR 2 430	861,057	861,057	0	0	0	0	0	
1 0380	IUIAL RATE BASE		2,626,773,107	1,214,448,303	144,932,687	387,522,988	504,372,559	353,659,645	21,836,925	
1 0390			0.00000	0.0		0.00	10 1	0.0755	10.0705	
1 0400			6.990%	3.357%	11.894%	8.964%	10.471%	9.976%	12.678%	
1 0410	RELATIVE RATE OF RETURN		1.00	0.48	1.70	1.28	1.50	1.43	1.81	
1 0420										
1 0430										

- 1 0440
- 1 0450
- 1 0460
- 1 0470
- 1 0480
- 1 0490

Kansas City Power & Light Company 2018 RATE CASE - DIRECT TY 6/30/17; Update TBD; K&M 6/30/18 COST OF SERVICE - Missouri Jurisdiction

Allocation Method: Prod - Avg & Excess 4 CP, Tran - Avg & Excess 4 CP

SCH LINE NO. NO.	INE IO. DESCRIPTION		MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

1 0500

Kansas City Power & Light Company 2018 RATE CASE - DIRECT TY 6/30/17; Update TBD; K&M 6/30/18 COST OF SERVICE - Missouri Jurisdiction

Table 4

Cost of Service Results – Unbundled Customer, Demand and Energy Cost Components

		Uniform	n Rate of Return @	7.45%
Line		Monthly (\$) Customer	Energy Costs (\$/kWh)	Demand Costs (\$/kWh)
No.	Customer Class	Charge	Δnnual	Annual
	(a)	(b)	(c)	(d)
	DEOIDENTIAL	¢47.40	0.0000	0.4404
1	RESIDENTIAL	\$17.43	0.0226	0.1131
2	Regular	\$17.00	0.0229	0.1211
3	Time of Day	\$18.58	0.0226	0.1085
4	All Electric	\$17.96	0.0220	0.0933
5	Separately Metered	\$22.93	0.0215	0.0896
6		* • • • • •		
7	SMALL GS	\$18.12	0.0220	0.0829
8	Primary & Secondary	\$18.42	0.0220	0.0833
9	Other (Unmetered)	\$10.08	0.0218	0.0760
10	All Electric	\$20.79	0.0217	0.0777
11	Separately Metered	\$27.35	0.0214	0.0792
12				
13	MEDIUM GS	\$37.53	0.0219	0.0790
14	Primary	\$17.74	0.0222	0.0659
15	Secondary	\$36.36	0.0220	0.0801
16	All Electric	\$54.63	0.0215	0.0725
17	Separately Metered	\$50.68	0.0216	0.0806
18				
19	LARGE GS	\$35.62	0.0216	0.0609
20	Primary	\$35.07	0.0214	0.0588
21	Secondary	\$35.00	0.0218	0.0635
22	All Electric	\$34.88	0.0214	0.0573
23	Separately Metered	\$60.26	0.0216	0.0612
24				
25	LARGE POWER SERVICE	\$365.39	0.0214	0.0452
26	Primary	\$386.78	0.0214	0.0473
27	Secondary	\$323.03	0.0219	0.0510
28	Substation	\$385.80	0.0211	0.0383
29	Transmission	\$385.75	0.0206	0.0382
30				
31	TOTAL LIGHTING		0.0216	0.0385

Notes:

(1) Allocation Method: Prod - Avg & Excess 4 CP, Tran - Avg & Excess 4 CP

	AB	С	D	E
1	Kansas City Power and Light - Missouri			
2	Large Power Service			
3				
4	Case No. FR-2018-0145			
-				
5	Status: Direct	J .		
6			0.97%	0.01%
		Current Rates	Rates With	Proposed
7		ourient nates	Increase	Rates
8	JURISDICITIONAL INCREASE (%)		0.00%	0.98%
9				
11	A. CLISTOMER CHARGE - Rate Code (All)	1 149 23	1 149 23	1 160 53
12		1,140.20	1,140.20	1,100.00
13	B: FACILITIES CHARGE			
14	SECONDARY - Rate Code (1PGSE; 1PGSH):	3.849	3.849	3.887
15	PRIMARY - Rate Code (1PGSF; 1PGSG; 1POSF; 1POSG):	3.190	3.190	3.221
16	SUBSTATION - Rate Code (1PGSV; 1POSV):	0.963	0.963	0.972
17	TRANSMISSION - Rate Code (1PGSZ;1POSW; 1POSZ):	-	-	-
18				
19	C: DEMAND CHARGE			
20	Eiret 2442 KW	1/ 032	1/ 032	15.079
22	Next 2443 KW	11.944	11.944	12.061
23	Next 2443 KW	10.006	10.006	10.104
24	All KW over 7329 KW	7.304	7.304	7.376
25				
26	SECONDARY-WINTER - Rate Code (1PGSE; 1PGSH):			
27	First 2443 KW	10.150	10.150	10.250
28	Next 2443 KW	7.920	7.920	7.998
29	NEXT 2443 KW	6.987 5.370	6.987 5.370	7.056
31		5.575	5.575	0.402
32	PRIMARY-SUMMER - Rate Code (1PGSE: 1PGSG: 1POSE: 1POSG)			
33	First 2500 KW	14.589	14.589	14.732
34	Next 2500 KW	11.672	11.672	11.787
35	Next 2500 KW	9.776	9.776	9.872
36	All KW over 7500 KW	7.138	7.138	7.208
37				
38	PRIMARY-WINTER - Rate Code (1PGSF; 1PGSG; 1POSF; 1POSG);	0.045	0.045	10.010
39	Novi 2500 KW	9.915	9.915	10.012
40	Next 2500 KW	6.827	6 827	6 894
42	All KW over 7500 KW	5 257	5 257	5 309
43				
44	SUBSTATION-SUMMER - Rate Code (1PGSV; 1POSV);			
45	First 2530 KW	14.415	14.415	14.557
46	Next 2530 KW	11.532	11.532	11.645
47	Next 2530 KW	9.660	9.660	9.755
48	All KW over 7590 KW	7.054	7.054	7.123
49 50	SUBSTATION WINTER - Rate Code (1PCSV/ 1POSV)			
51	First 2530 KW	9.800	9.800	9,896
52	Next 2530 KW	7.649	7.649	7.724
53	Next 2530 KW	6.748	6.748	6.814
54	All KW over 7590 KW	5.195	5.195	5.246
55				
56	TRANSMISSION-SUMMER - Rate Code (1PGSZ;1POSW; 1POSZ):			
57	FIRST 2553 KW Next 2553 KW	14.291	14.291	14.431
59	Next 2503 KW	0.572	0.572	9,666
60	All KW over 7659 KW	6.990	6.990	7.059
61				
62	TRANSMISSION-WINTER - Rate Code (1PGSZ;1POSW; 1POSZ):			
63	First 2553 KW	9.712	9.712	9.807
64	Next 2553 KW	7.580	7.580	7.655
65	Next 2553 KW	6.688	6.688	6.754
66	All KW OVER / 659 KW	5.148	5.148	5.199
68	D: ENERGY CHARGE			
69	SECONDARY-SUMMER - Rate Code. (1PGSE: 1PGSH)			
70	First 180 Hours Use per month	0.09350	0.09350	0.09442
71	Next 180 Hours Use per month	0.05557	0.05598	0.05612
72	Over 360 Hours Use per month	0.02667	0.02667	0.02693
73				
74	SECONDARY-WINTER - Rate Code (1PGSE; 1PGSH):	0.07000	0.0700-	0.0000.1
/5	First 180 Hours Use per month	0.07926	0.07926	0.08004
/0 77	Over 360 Hours Use per month	0.05055	0.05092	0.05105
78		0.02040	0.02040	0.02000

	A	В	С	D	E
79		PRIMARY-SUMMER - Rate Code (1PGSF; 1PGSG; 1POSF; 1POSG):			
80		First 180 Hours Use per month	0.09136	0.09136	0.09226
81		Next 180 Hours Use per month	0.05432	0.05472	0.05485
82		Over 360 Hours Use per month	0.02604	0.02604	0.02630
83					
84		PRIMARY-WINTER - Rate Code (1PGSF: 1PGSG: 1POSF: 1POSG);			
85		First 180 Hours Use per month	0.07745	0.07745	0.07821
86		Next 180 Hours Use per month	0.04938	0.04974	0.04987
87		Over 360 Hours Use per month	0.02580	0.02580	0.02605
88					
89		SUBSTATION-SUMMER - Rate Code (1PGSV: 1POSV):			
90		First 180 Hours Use per month	0 09029	0.09029	0.09118
91		Next 180 Hours Use per month	0.05368	0.05407	0.05421
92		Over 360 Hours Lise per month	0.00000	0.00407	0.02598
02			0.02575	0.02373	0.02000
04		SUBSTATION-WINTED - Pata Code (1PGSV/: 1POSV/:			
94		Substantion-with the part month	0.07656	0.07656	0.07721
90		Next 190 Hours Use per month	0.07030	0.07050	0.07731
90			0.04660	0.04910	0.04928
97		Over 360 Hours Use per month	0.02549	0.02549	0.02574
90					
99		I KANSMISSION-SUMIVIER - KATE CODE (IPGS2;IPOSW; IPOSZ):	0.000.00	0 000 40	0 00007
100		First 180 Hours Use per month	0.08949	0.08949	0.09037
101		Next 180 Hours Use per month	0.05319	0.05358	0.05371
102		Over 360 Hours Use per month	0.02551	0.02551	0.02576
103					
104		TRANSMISSION-WINTER - Rate Code (1PGSZ;1POSW; 1POSZ):			
105		First 180 Hours Use per month	0.07585	0.07585	0.07660
106		Next 180 Hours Use per month	0.04837	0.04872	0.04885
107		Over 360 Hours Use per month	0.02525	0.02525	0.02550
108					
109	E: REACTIVE DE	EMAND ADJUSTMENT - Rate Code (All)	0.966	0.966	0.975
110	LGS Secondary		0.000%	0.150%	0.985%
111	LGS Primary		0.000%	0.156%	0.982%
112	LGS Substation	Voltage	0.000%	0.173%	0.980%
113	LGS Transmissi	on Voltage	0.000%	0.185%	0.986%
114	LGS Overall Cha	ange (*)	0.000%	0.159%	0.983%
115	Winter Price Bel	ow Summer (SUM-WIN)/SUM	14.076%	14.068%	14.076%
116	Overall Change			0.159%	0.983%
117					
118		Revenue ⁽¹⁾	\$144,354,374	\$144,584,321	\$145,773,073
119		Change in Revenue			\$1,415,438
120		•			
121		Proposed change per Revenue Summary			\$1,415,662
122		······································			(\$224)
123		Manual Bill	(\$331,687)	(\$331,687)	(\$334,948)
124		Overall Revenue	\$144 022 687	\$144 252 634	\$145 438 125
125		EDR credits	(\$1 884 376)	ψ1-1-,202,00 1	φ1+0,+00,120
126		EDivorouno	¢1/2 128 214		
120			J142,130,311		

	Δ	R	C	D	F
			U	D	L
1	Kansas Cit	y Power and Light - Missouri			
2	Large Gene	ral Service			
2	Ŭ				
3					
4	Case No:	ER-2018-0145			
5	Status	Direct			
5	Status.				
6					
				Rates w/ Rate	Proposed
7			Current Rates	Design	Rates
8		JURISDICTIONAL INCREASE (%)		0.000%	1.08%
9	A: CUSTOMER	CHARGE			
10		0-24 KW - Rate Code (All):	118.82	118.82	120.11
11		25-199 KW - Rate Code (All):	118.82	118.82	120.11
12		200-999 KW - Bate Code (All):	118.82	118.82	120.11
13		1000 KW or above - Rate Code (All):	1.014.44	1.014.44	1.025.43
14		Separately Metered Space Heat - Rate Code (1) GHE 11 GHH 11 SHE)	2 72	2 72	2 75
15			22	22	20
16	B: FACILITIES	CHARGE			
17	D. TAOLETTIEC	SECONDARY - Rate Code (1) GSE 1) GSH 11 GAE 11 GAH 11 GHE 11 GHH 11 SHE)	3 399	3 300	3 4 3 6
18		PRIMARY - Rate Code (1) GSE 11 GSE 11 GAE).	2 818	2 818	2 8/9
10			2.010	2.010	2.043
19					
20	O. DEMAND CH	SECONDARY SUMMER - Rate Code (1) GSE: 1) GSE: 11 GAE: 11 GAE: 11 CAE: 11 CHE:	6 700	6 700	6 960
21	1	SECONDARY POUNINELY - Nate Code (11 CSE, 11 CSE, 11 CAE, 11 CAE, 11 CHE, 11 CH	0.708	0./00	0.002
22		DECONDANT-WINTEN - Nate Code (1100E, 1100E, 110AE, 110AE, 110AE, 110AE, 110AE, 110AE):	3.052	3.002	3.092
23		PRIMARY MUNTER - Rate Code (1100F, 11000;110AF):	0.034	0.034	6.706
24	-		3.569	3.569	3.608
25	-	SECONDARY- WINTER - ALL ELEC ONLY (Frozen) - Rate Code (1LGAE; 1LGAH):	3.382	3.382	3.419
26		PRIMARY-WINTER - ALL ELEC UNLY (Frozen) - Rate Code (1LGAF):	3.302	3.302	3.338
27		1945			
28	D: ENERGY CH				
29		SECONDARY- SUMMER - Rate Code (1LGSE; 1LGSH; 1LGAE; 1LGAH; 1LGHE; 1LGHH; 1LSHE):			
30		First 180 Hours Use per month	0.09969	0.09969	0.10077
31		Next 180 Hours Use per month	0.06872	0.06922	0.06922
32		Over 360 Hours Use per month	0.04425	0.04425	0.04473
33					
34		SECONDARY- WINTER - Rate Code (1LGSE; 1LGSH; 1LGHE; 1LGHH; 1LSHE);			
35		First 180 Hours Use per month	0.09160	0.09160	0.09259
36		Next 180 Hours Use per month	0.05282	0.05321	0.05321
37		Over 360 Hours Use per month	0.03719	0.03719	0.03759
38					
39		PRIMARY-SUMMER - Rate Code (1LGSF; 1LGSG;1LGAF):			
40		First 180 Hours Use per month	0.09745	0.09745	0.09851
41		Next 180 Hours Use per month	0.06708	0.06757	0.06757
42		Over 360 Hours Use per month	0.04321	0.04321	0.04368
43					
44		PRIMARY-WINTER - Rate Code (1LGSF; 1LGSG);			
45		First 180 Hours Use per month	0.08951	0.08951	0.09048
46		Next 180 Hours Use per month	0.05156	0.05194	0.05194
47		Over 360 Hours Use per month	0.03646	0.03646	0.03686
48					
49		SECONDARY-WINTER - ALL ELECTRIC (Frozen) - Rate Code (1LGAE: 1LGAH):			
50		First 180 Hours Use per month	0.08808	0.08808	0.08903
51		Next 180 Hours Use per month	0.04726	0.04726	0.04726
52		Over 360 Hours Use per month	0.03689	0.03689	0.03729
53					
54		PRIMARY-WINTER - ALL ELECTRIC (Frozen) - Rate Code (1LGAF):			
55		First 180 Hours Use per month	0.08623	0.08623	0.08716
56		Next 180 Hours Use per month	0.04622	0.04622	0.04622
57		Over 360 Hours Use per month	0.03618	0.03618	0.03657
58					
59	E: SEPARATEL	Y METERED S/H-WINTER			
60	1	SECONDARY - Rate Code (1LGHE: 1LGHH: 1LSHE):	0.06162	0.06162	0.06229
61			0.001.02	0.00.02	5100220
62	F: REACTIVE D	EMAND ADJUSTMENT - Rate Code (All):	0.853	0.853	0.862
63	1				
64	G: TWO-PART	TIME-OF-USE PRICING ADJUSTMENT			
65		SECONDARY - SUMMER ON-PEAK	0.12770	0.12770	0.12908
66		SECONDARY - SUMMER OFF-PEAK	0.05000	0.05000	0.05054
67		SECONDARY - WINTER ON-PEAK	0.04701	0.04701	0.04752
68		SECONDARY - WINTER OFF-PEAK	0.03791	0 03791	0.03832
60		PRIMARY - SUMMER ON-PEAK	0 11789	0 11789	0.11916
70		PRIMARY - SUMMER OFF-PEAK	0.04725	0.11736	0.04776
71		PRIMARY - WINTER ON-PEAK	0.04725	0.04723	0.04610
72		PRIMARY - WINTER OFF-PEAK	0.04301	0.04501	0.04010
72	1		0.03076	0.03076	0.03710
7/	LGS Secondary		0.000%	0 150%	1.000%
76	LGS Overall Ch	ange (*)	0.000%	0.109%	1.009%
70	LGA Secondary		0.000%	0.102%	0.005%
79	LGA Primony		0.000%	0.009%	0.905%
70	LGA Winter Enc	rov Overall Change	0.000%	0.003%	0.312%

	A	В	С	D	E
80	LGA Overall Cha	inge (*)	0.000%	0.069%	0.906%
81	Winter Price Belo	bw Summer (SUM-WIN)/SUM	16.183%	16.238%	16.214%
82	Overall Change			0.134%	0.979%
83					
84		Revenue ⁽¹⁾	\$191,037,407	\$191,294,006	\$192,907,444
85		Change in Revenue			\$1,870,076
86					
87		Proposed change per Revenue Summary			\$1,871,381
88					(\$1,305)
89					
90		Manual Bill	\$3,577	\$3,577	\$3,616
91		Overall Revenue	\$191,040,983	\$191,297,583	\$192,911,059
92		EDR credits	(\$1,027,396)		
93		Mpower credits	(\$11,360)		
94			\$190,002,227		

	А	В	C	D	F
	Kanaga City	Power and Light Missouri	Ű	2	-
1	Nalisas Gity				
2	Medium Gene	eral Service			
3					
٨	Case No	FR-2018-0145	1		
4	Case NO.	ER-2018-0145			
5	Status:	Direct			
6					
				Rates With	Proposed
7			Current Rates	Increase	Rates
8		JURISDICITIONAL INCREASE (%)		0.975%	0.000%
9	A: CUSTOMER C	HARGE			
10		0-24 KW - Rate Code (All):	55.28	55.82	55.82
11		25-199 KW - Rate Code (All):	55.28	55.82	55.82
12		200-999 KW - Rate Code (All):	112.26	113.35	113.35
13		1000 KW or above - Rate Code (All):	958.56	967.90	967.90
14		Separately Metered Space Heat - Rate Code (1MGHE; 1MGHH):	2.58	2.61	2.61
15					
16	B: FACILITIES CH	IARGE			
17		SECONDARY - Rate Code (1MGSE; 1MGSH; 1MSSE; 1MGAE; 1MGAH;1MGHE; 1MGHH):	3.212	3.243	3.243
18		PRIMARY - Rate Code (1MGSF; 1MGSG; 1MGAF):	2.662	2.688	2.688
19					
20	C. DEMAND CHAI	SECONDARY SUMMER Rate Code (1MGSE: 1MCSH: 1MSSE: 1MCHE: 1MCHE: 1MCHH: 1MCAE: 1 MCAU	4 000	4.040	4.949
21		SECONDART-SUMMER - Rate Code (1MGSE, 1MGSE; 1MSSE; 1MGHE; 1MGHE; 1MGAE; 1MGAH):	4.202	4.243	4.243
22		DECONDART-WINTER - Rate Code (1MCSE, 1MCSOF, 1MOSE, 1MCHE; 1MCHH):	2.138	2.159	2.159
20		PRIMARY-WINTER - Rate Code (1MGSF: 1MGSG):	4.104	4.144	4.144
25		SECONDARY-WINTER - ALL FLEC - Rate Code (1MGAE: 1MGAH)	3.027	2.107	3.056
26		PRIMARY-WINTER - ALL ELEC - Rate Code (1MGAE).	2 962	2 991	2 991
27			2.002	2.001	2.001
28	D: ENERGY CHAP	RGE			
29		SECONDARY-SUMMER - Rate Code (1MGSE; 1MGSH; 1MSSE; 1MGHE; 1MGHH; 1MGAE: 1MGAH):			
30		First 180 Hours Use per month	0.10982	0.11089	0.11090
31		Next 180 Hours Use per month	0.07513	0.07586	0.07586
32		Over 360 Hours Use per month	0.06336	0.06398	0.06398
33					
34		SECONDARY-WINTER - Rate Code (1MGSE; 1MGSH; 1MSSE; 1MGHE; 1MGHH):			
35		First 180 Hours Use per month	0.09491	0.09583	0.09584
36		Next 180 Hours Use per month	0.05680	0.05735	0.05735
37		Over 360 Hours Use per month	0.04764	0.04810	0.04810
38					
39		PRIMARY-SUMMER - Rate Code (1MGSF; 1MGSG; 1MGAF):			
40		First 180 Hours Use per month	0.10721	0.10825	0.10825
41		Next 180 Hours Use per month	0.07343	0.07415	0.07415
42		Over 360 Hours Use per month	0.06191	0.06251	0.06251
43		DRIMADY WINTED Date Carla (MICCE: MICCO)			
44	-	PRIMARY-WINTER - Rate Code (1MGSF; 1MGSG): First 190 Hours Lice per menth	0.00269	0.00259	0.00259
45		Next 180 Hours Use per month	0.05208	0.09338	0.05503
40		Over 360 Hours Use per month	0.03543	0.03003	0.03003
48			0.04070	0.04710	0.04710
49		SECONDARY-WINTER - ALL ELECTRIC (Frozen) - Rate Code (1MGAE: 1MGAH):			
50		First 180 Hours Use per month	0.08327	0.08408	0.08408
51		Next 180 Hours Use per month	0.04764	0.04810	0.04810
52		Over 360 Hours Use per month	0.04137	0.04177	0.04177
53					
54		PRIMARY-WINTER - ALL ELECTRIC (Frozen) - Rate Code (1MGAF):			
55		First 180 Hours Use per month	0.08140	0.08219	0.08219
56		Next 180 Hours Use per month	0.04646	0.04691	0.04691
57		Over 360 Hours Use per month	0.04059	0.04099	0.04099
58					
59	E: SEPARATELY	METERED S/H-WINTER	0.0000	0.0000-	0.00000
60		SECUNDART - RATE CODE (1MGHE; 1MGHH):	0.06206	0.06266	0.06266
62		AND AD ILISTMENT - Rate Code (All):	0.905	0.013	0.913
62	MGS Secondary		0.803	0.013	0.013
64	MGS Primary		0.000%	0.571%	0.973%
65	MGS Overall Char	nge (*)	0.000%	0.971%	0.974%
66	MGA Secondary		0.000%	0.970%	0.972%
67	MGA Primary		0.000%	0.972%	0.972%
68	MGA Winter Ener	gy Overall Change	0.000%	0.961%	0.961%
69	MGA Overall Char	nge (*)	0.000%	0.970%	0.972%
70	MGS Secondary-S	Space Heat	0.000%	0.971%	0.973%
71	Winter Price Below	w Summer (SUM-WIN)/SUM	18.499%	18.503%	18.505%
72	Overall Change			0.971%	0.974%
73	4	- (1)	.		
74		Revenue	\$132,376,790	\$133,662,228	\$133,666,431
75	-	Change in Revenue			\$1,289,641
76	-				0.000
77	-	Proposed change per Revenue Summary		l	\$1,290,708
78	-				(\$1,067)
19	1	Manual Bill	¢0	¢0	¢0
81	1		⊅0 م0ح \$132 \$76 \$	0φ 900 caa sst	00 121 999 2212
82	1	Net Metering credits	ψ132,370,790 \$∩	ψ100,002,220	ψ155,000, 4 51
83	1	EDR Credits	(\$68 604)		
84	1	Mpower credits	(\$00,00 4) \$0		
85	1		\$132,308,186		
50			φ. 52,500, 100		

Kansas Ci	ty Power & Light - Missouri			
Small Gen	eral Service			
Case No.	ER-2018-0145			
Status:	Direct			
			Rates With	
		Current Rates	Increase	Proposed
	JURISDICTIONAL INCREASE (%)		0.975%	0.000%
A: CUSTOMER	R CHARGE Metered Service:			
3	0-24 KW - Rate Code (All)	19.08	19.27	
<u>-</u>	25-199 KW - Rate Code (All) 200-999 KW - Rate Code (All)	52.90 107.46	53.42 108.51	10
	1000 KW or above - Rate Code (All)	917.58	926.52	92
-	Separately Metered Space Heat - Rate Code (1SGHE; 1SGHH; 1SSHE):	2.46	2.48	
D: FAGILITIES	SECONDARY - Rate Code (1SGSE; 1SGSH; 1SSSE; 1SUSE; 1SGAE; 1SGAH; 1SSAE; 1SGHE; 1SGHH; 1SSHE):			
-	First 25 KW	-	- 2 104	
		3.074	3.104	
	PRIMARY - Rate Code (1SGSF; 1SGSG; 1SSSF; 1SGAF; 1SGAG): First 26 KW		-	
	All KW over 26 KW	3.002	3.031	:
C: ENERGY CH	IARGE			
	SECONDARY-SUMMER - Rate Code (1SGSE; 1SGSH; 1SSSE; 1SUSE; 1SGAE; 1SGAH; 1SSAE; 1SGHE; 1SGHH; 1SSHE):	C 1707 -	o -=	
	First 180 Hours Use per month Next 180 Hours Use per month	0.17032 0.08083	0.17198 0.08162	0.1
	Over 360 Hours Use per month	0.07200	0.07270	0.0
-	SECONDARY-WINTER - Rate Code (1SGSE; 1SGSH; 1SSSE; 1SUSE; 1SGHE; 1SGHH; 1SSHE):			
	First 180 Hours Use per month	0.13233	0.13362	0.1
	Over 360 Hours Use per month	0.05832	0.05889	0.0
]	DDIMADV-SLIMMED - Date Code (19095: 19090: 19095: 190AE: 190AE)			
	First 180 Hours Use per month	0.16642	0.16804	0.1
-	Next 180 Hours Use per month Over 360 Hours Use per month	0.07896	0.07973	0.0
•		0.07034	0.07103	0.0
	PRIMARY-WINTER - Rate Code (1SGSF; 1SGSG; 1SSSF): First 180 Hours Use per month	0.12932	0.13058	0.1
	Next 180 Hours Use per month	0.06313	0.06375	0.0
1	Over 360 Hours Use per month	0.05696	0.05752	0.0
2	SECONDARY-WINTER - ALL ELECTRIC (Frozen) - Rate Code (1SGAE; 1SGAH; 1SSAE):	0.40404	0.40000	
-	Next 180 Hours Use per month	0.12121 0.06461	0.12239	0.1
	Over 360 Hours Use per month	0.05832	0.05889	0.0
	PRIMARY-WINTER - ALL ELECTRIC (Frozen) - Rate Code (1SGAF; 1SGAG):			
	First 180 Hours Use per month	0.11844	0.11959	0.1
	Over 360 Hours Use per month	0.05696	0.05752	0.0
D: SEPARATE	Y METERED SPACE HEAT - WINTER			
	SECONDARY - Rate Code (1SGHE; 1SGHH; 1SSHE):	0.07087	0.07156	0.0
E: TWO-PART	TIME-OF-USE PRICING ADJUSTMENT			
_		0.14606	0.14748	0.1
	SECONDARY - WINTER ON-PEAK	0.06268	0.06329	0.0
-	SECONDARY - WINTER OFF-PEAK PRIMARY - SLIMMER ON-PEAK	0.04880	0.04928	0.0
	PRIMARY - SUMMER OFF-PEAK	0.05922	0.05980	0.0
_	PRIMARY - WINTER ON-PEAK PRIMARY - WINTER OFF-PEAK	0.05486	0.05539	0.0
0000				0.0
SGS Secondar SGS Primary		0.000%	0.977% 0.974%	0
SGS Overall Ch	nange (*)	0.000%	0.977%	0
SGA Secondary		0.000%	#DIV/0!	0. #DIV/0
SGA Winter En	ergy Overall Change	0.000%	0.974%	0.
SGS Secondar	y Space Heat	0.000%	0.975%	0.
Winter Price Be Overall Change	low Summer (SUM-WiN)/SUM	17.080%	17.080% 71.397%	17
			11.33176	
-		\$58,389,842	\$58,960,417	\$58,95
				φυ 00 ,6
-	Proposed change per Revenue Summary			\$56
				(
4	Manual Bill Overall Revenue	\$240 \$58.390.082	\$242 \$58 960 660	\$58 959
2	EDR Credit	(\$3,984)	<i>400,000,000</i>	400,000
1	Net Metering Credit	(\$115)		

Image: Ansame Schy Power and Light - Missouri 2 Residential Service Case No: ER-2018-0145 Status: ER-2018-0145 Case No: ER-2018-0145 Status: Direct Constant Charge Automation (Status) Proposed Rates Residential Service Direct Direct Direct Constant Charge Automation (Status) Residential Service Direct Constant Charge Automation (Status) Residential Service Direct Constant Charge Automation (Status) Residential Service Direct Constant Charge Question (Status) Residential Service Direct Constant Charge Question (Status) Residential Service) Direct Direct Question (S		А	В	С	D	F
Image: Control of the contro	4	Kansas Ci	ty Power and Light - Missouri	J. J	5	-
A Case No. ER.2016 -0145 B Case No. ER.2016 -0145 Case No. ER.2016 -0145 Case No. ER.2016 -0145 Case No. Exatus: Direct Case No. Exatus: Direct Direct Direct Case No. Exatus: Direct Direct Direct Case No. Exatus: Direct Direct Direct Direct Direct Direct Direct Direct Direct <td>ļ</td> <td>Nalisas Ci</td> <td></td> <td></td> <td></td> <td></td>	ļ	Nalisas Ci				
3 Case No. Ex.2018-0145 9 International Use (FESA) - False Code (FESA), FEEDA, FE	2	Residential	Service			
Column Character No: Status: ER:2019:0145 Current Res Passes With Increase Propende Reset 7	R					
Image: Amage:	0	0 N				
S Status: Direct Current Rese Non-Section 2 Current Rese Non-Section 200%	4	Case No:	ER-2018-0145			
0 0	5	Status:	Direct			
S Current Rate Process Rate Process Rate 0 JURSDUCTONAL INCREASE (%) Current Rate Process Rate 0 A Customer Charge Control (Ling RS), France Code (RS)A, IREXA, IRE	6					
Current Sector Current Sector Proposed Reset 0 Current Sector 0.0000 0.0000 0.0000 0 Current Sector 0.0000 0.0000 0.0000 12 Current Use (RSA), Hess Code (HSA), HSB Set) 12.22 0.0000 0.0000 12 Current Use (RSA), HSB Code (HSA), HSB Set) 12.22 0.0000 10.23 13 Current Use (RSA), HSB Code (HSA), HSB Set) 12.22 10.100 10.100 14 Corrent Use (RSA), HSB Code (HSA), HSB Set) 12.22 10.100 10.100 15 Corrent Use (RSA), HSB Code (HSA), HSB Set, HSB	0				Patos With	
B UNESDICTIONAL INCREASE (%) Description Description 10 A Customer (HESA): Nate Code (HESA): HESDE: HERDE: HESDE: HERDE: HESDE: HERDE: HESDE: HERDE: HESDE: HERDE:	7			Current Rates	Increase	Proposed Rates
0 Accessmer Charge 0.000 0.000 0 Construct Charge 12.00 0.000 11 Construct Charge 12.00 15.17 12 Construct Charge 12.00 15.17 13 Construct Charge 12.00 15.17 14 Construct Charge 12.00 15.17 15 Construct Charge 12.00 15.17 14 Construct Charge 12.00 15.17 15 Construct Charge 12.00 12.00 16 Other Use (ROU), Rate Code (IRS2A, ITS3A, IRVAR, IRV	8		IURISDICTIONAL INCREASE (%)	Culton nato	0.00%	0 34%
Image: Description Image:	a	A: Customer C			0.0070	0.0470
111 Conversite and SM (RESD) - Rate Code ((RSDA, TRSDA, TRSDA, TRNA, TRHTA): 1222 15.77 15.27 2 General Use and SM (RESD) - Rate Code ((RSDA, TRSDA, TRSDA, TRNA, TRHTA): 1232 12.37 14.35 17.58 31 Additional Meet ((RESD) - Rate Code ((RSDA, TRSDA, TRSDA), TRNTA): 12.32 12.37 14.35 17.58 111 Convertise (RSDA, TRSDA, TRSDA, TRSDA, TRSDA): 12.39 12.39 12.39 12.39 115 Energy Charge 13.300 0.126916 0.126926 0.126926 0.126926 115 Energy Charge 0.14916 0.14916 0.14966 0.14966 0.14966 0.14966 0.14966 0.14966 0.14966 0.14966 0.13986 <td>10</td> <td>A. Oustomer o</td> <td>General Lise (RESA) - Rate Code (1RS1A: 1RSDA: 1RS1R):</td> <td>12.62</td> <td>15 17</td> <td>15.22</td>	10	A. Oustomer o	General Lise (RESA) - Rate Code (1RS1A: 1RSDA: 1RS1R):	12.62	15 17	15.22
121 Generati Use and SH (FESG) - Rate Code (IRS2A: 1RS2A: 1RV7A: 1RH1A): 122 15:17 15:17 15:17 121 Generati Use and SH (FESG) - Rate Code (IRS2A: 1RS3A: 1RV7A: 1RH1A): 122 14:35 17:36 121 Other Use (ROU) - Rate Code (IRS2A: 1RS3A: 1RV7A: 1RH1A): 12:22 15:17 15:22 121 Decreg Charge IF IF 12:22 15:17 15:22 121 Decreg Charge IF IF <t< td=""><td>11</td><td></td><td>General Use and S/H (RESR). Date Code (11956). (1956).</td><td>12.02</td><td>15.17</td><td>15.22</td></t<>	11		General Use and S/H (RESR). Date Code (11956). (1956).	12.02	15.17	15.22
11 Additional Meter (HESQ) - Rate Code (HESQA, HESQA,	12		Constal Use and S/H (RESC). Pate Code (1953): 1953): 19W/7A: 19H1A):	12.02	15.17	15.22
1 1	12		Additional Mater (RESC) - Date Code (RESC) : 18530 : 18W7A : RWTA).	2 33	2 33	2 34
12 0hor Use (ROU) - Rate Code (IRO1A): 12.22 15.17 15.22 17 B: Energy Charge	14			1/ 95	1/ 95	17.56
Intersection Intersection Intersection Intersection Intersection 18 File Filesopy Charge 0.1288 0.1288 0.1288 0.1288 19 Filesopy Charge 0.1288 0.1288 0.1288 0.1288 19 Control Status Distant Intersection 0.14916 0.14966 0.14966 10 Control Status Distant Intersection 0.14916 0.14966 0.14966 10 Control Status Distant Intersection 0.14916 0.14966 0.14966 10 Control Status Distant Intersection 0.14966 0.14966 0.14966 10 Control Status Distant Intersection 0.12972 0.12271 0.12271 10 Control Status Distant Intersection 0.02738 0.02738 0.02738 10	15		Other Use (ROU) - Rate Code (1RO1A):	12.62	15.17	17.30
Total Energy Charge First 600 Whiper month 0.12883 0.12883 13 First 600 Whiper month 0.12883 0.12883 0.12883 14 First 600 Whiper month 0.12883 0.12883 0.12883 14 First 600 Whiper month 0.12883 0.12883 0.12883 15 First 600 Whiper month 0.13885 0.13885 0.13885 15 First 600 Whiper month 0.13886 0.13886 0.13886 16 First 600 Whiper month 0.13886 0.13886 0.13886 17 First 600 Whiper month 0.13885 0.13885 0.13885 17 First 600 Whiper month 0.01223 0.12221 0.12221 13 Over 100 Whiper month 0.01223 0.01223 0.01223 13 Over 100 Whiper month 0.00703 0.00703 0.00703 13 Over 100 Whiper month 0.00703 0.00703 0.00703 13 Over 100 Whiper month 0.00829 0.00829 0.00829 14	16		Other Use (NOU) - Nate Code (INO IA).	12.02	13.17	13.22
10 Childra LUSE (RESA) - SUMMER - Rate Code (IRS1A-1RS1B): 0.1295 0.1295 21 Over 1000 Why per month 0.14916 0.14916 0.14916 22 OPENEAL USE AND SHIESDS & RESC) - SUMMER - Rate Code (IRS5A, 1RESA, 1RSXA, 1RW7A, 1RH1A) 0.14916 0.14916 22 OPENEAL USE AND SHIESDS & RESC) - SUMMER - Rate Code (IRS5A, 1RESA, 1RSXA, 1RW7A, 1RH1A) 0.13906 0.13906 23 OPENEAL USE AND SHIESDS & RESC) - SUMMER - Rate Code (IRS5A, 1RESA, 1RSXA, 1RW7A, 1RH1A) 0.13906 0.13906 24 Freid 600 Why per month 0.13906 0.13906 0.13906 25 Next 400 Why per month 0.02736 0.13906 0.13906 27 OPEN 1000 Why per month 0.02736 0.02736 0.02736 26 OPEN 1000 Why per month 0.02736 0.02736 0.02736 27 OPEN 1000 Why per month 0.02736 0.02736 0.02736 27 OPEN 1000 Why per month 0.02736 0.02736 0.02736 28 GENEAL USE AND SPACE HEAT (RESO) - WINTER - Rate Code (IRS2A 1RS3A - IRW7A : IRH1A) 0.02636 0.06636 29 </td <td>17</td> <td>B. Energy Cha</td> <td>700</td> <td></td> <td></td> <td></td>	17	B. Energy Cha	700			
10 Pat 400 Why par month 0.12893 0.12893 0.12893 0.12893 0.12893 0.12895 20 Next 400 Why par month 0.14916 0.14936 0.13936 0.13936 0.13936 0.13936 0.13936 0.13936 0.13936 0.13936 0.13936 0.13936 0.13826 0.12826 0.12826 0.12826 0.12826 0.13826 0.13826 0.12827 <td>18</td> <td>D. Energy ona</td> <td>GENERAL LISE (RESA) - SLIMMER - Rate Code (1RS1A+1RSDA+1RS1R)+</td> <td></td> <td></td> <td></td>	18	D. Energy ona	GENERAL LISE (RESA) - SLIMMER - Rate Code (1RS1A+1RSDA+1RS1R)+			
1000000000000000000000000000000000000	10		SERVERAL GOL (REGAL) - COMMERCE Rate Code (REGAL, REGAL, REGAL)	0 12803	0 12803	0 12036
1 0.14915 0.14915 0.14915 0.14915 0.14915 0.14915 23 GENERAL USE AND SM RESS & RESD: SUMMER - Rute Code (IRSA: IRFE; IRS2A, IRSA: IRWA, IRWA 0.13906 0.13906 0.13906 23 GENERAL USE AND SM RESS & RESD: SUMMER - Rute Code (IRSA: IRFE; IRS2A, IRSA: IRWA, IRWA 0.13906 0.13906 0.13906 24 First 600 W/h per month 0.13906 0.13906 0.13906 0.13906 25 Next 400 W/h per month 0.012231 0.12231 0.12231 0.12231 26 First 600 W/h per month 0.07396 0.07396 0.07396 23 Okre 1000 W/h per month 0.07396 0.07396 0.07421 27 Okre 1000 W/h per month 0.09793 0.09793 0.09793 28 First 600 W/h per month 0.099733 0.09793 0.09793 0.09793 29 Next 400 W/h per month 0.099733 0.09793 0.09793 0.09793 0.09793 29 CenerAl USE AND SPACE HEAT (RESD: WINTER - Rute Code (IRS2A, IRS3A, IRWA, IRWA: IRWA: IRWA: USE (W/M SUME W/M SUM W/M PER methal SUM W/M SUM W/M PER methal SUM W/M SU	20		Not 400 kWb per month	0.12093	0.12093	0.12930
Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content (Content) Content) Content (Content) Content (Content) Content (Conten)	20			0.14910	0.14910	0.14900
Content Content <t< td=""><td>21</td><td></td><td></td><td>0.14910</td><td>0.14916</td><td>0.14900</td></t<>	21			0.14910	0.14916	0.14900
Design (MAR) Design (MAR)<	22		GENERAL LISE AND S/H (RESR & RESC) - SLIMMER - Pato Codo (1986) - 10000 - 10000 - 10000 - 10000 - 10000 - 10000	H1A		
1 1	23		First 600 kWb per month	0.13906	0 12906	0.13953
1 1 0.13806 0.13806 0.13806 20 0.041000 XMP per month 0.13806 0.13806 0.13806 21 FFERG 0M VM per month 0.07386 0.07376 0.07376 33 0.041000 XMP per month 0.07386 0.07376 0.07473 33 GENERAL USE AND SPACE HEAT (RESD) - WINTER - Rate Code (IRSA: 1RFEB): 0.08751 0.09773 0.09773 34 GENERAL USE AND SPACE HEAT (RESD) - WINTER - Rate Code (IRSA: 1RFEB): 0.09773 0.09773 0.09773 35 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (IRS2A: 1RSA: 1RW7A: 1RHA): 0.09773 0.09773 0.09773 36 Over 1000 XMP per month 0.09773 0.09773 0.09773 0.09773 37 First 60 AMP per month 0.09778 0.09773 0.09773 0.09773 38 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (IRS2A: 1RS3A: 1RW7A: 1RHA): 0.09778 0.09719 0.09719 39 First 60 AMP per month 0.02719 0.02719 0.02719 0.02719 30 First 60 AMP per month 0	24		Novt 400 kWh per month	0.13806	0.13800	0.13852
32 CVM 100 KWI per month 0.13800 0.13800 0.13800 33 CVM 100 KWI per month 0.02231 0.12221 0.02231 34 CVM 100 KWI per month 0.06561 0.06561 0.06563 35 CVM 100 KWI per month 0.06736 0.07973 0.09733 0.09733 35 CVM 100 KWI per month 0.067073 0.09733 0.09733 0.09733 36 CVM 100 KWI per month 0.06708 0.06086 0.06583 37 RExt 600 KWI per month 0.09733 0.09733 0.09733 37 Next 400 KWI per month 0.06788 0.06086 0.06688 38 CVM 1000 KWI per month 0.04741 0.07441 0.07441 39 CVM 1000 KWI per month 0.04741 0.07441 0.07441 40 Next 400 KWI per month 0.04741 0.07441 0.07441 41 Al KWI - SUMMER 0.06219 0.06239 0.06239 0.06240 42 Al KWI - SUMMER 0.04741 0.07441 0.07441 </td <td>20</td> <td></td> <td>Next 400 kWh per month</td> <td>0.13806</td> <td>0.13806</td> <td>0.13852</td>	20		Next 400 kWh per month	0.13806	0.13806	0.13852
23 GENERAL USE (RESA). VINTER - Rate Code (1RS1A: 1RSDA: 1RSDA: 1RSIB): 0.12237 0.12237 33 Hear 400 W/M per month 0.07366 0.07366 0.076581 34 Over 1000 K/M per month 0.07366 0.07373 0.087581 34 First 600 M/M per month 0.087581 0.087581 0.087581 35 Next 400 K/M per month 0.087581 0.087583 0.08758 36 Over 1000 K/M per month 0.087581 0.08758 0.08758 36 Over 1000 K/M per month 0.08758 0.08758 0.08758 37 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (1RS2A: 1RS3A: 1RW7A: 1RH1A): 0.08758 0.08758 37 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (1RS2A: 1RS3A: 1RW7A: 1RH1A): 0.12412 0.12412 0.12414 0.07441 0.07441 0.07441 0.07458 0.08259 0.06259 0.06259 0.06259 0.06259 0.06259 0.06259 0.06259 0.06259 0.07529 0.07529 0.07529 0.07529 0.07529 0.07529 0.07529 0.07529 <td< td=""><td>20</td><td></td><td>Over 1000 kwn per month</td><td>0.13806</td><td>0.13806</td><td>0.13852</td></td<>	20		Over 1000 kwn per month	0.13806	0.13806	0.13852
23 Control Loss Integory - unit fer - nate Code (IRSIA, IRSUP, IRSUB) 0.12231 0.12231 0.12231 33 Near 400 With per month 0.07365 0.07365 0.07365 34 First 500 With per month 0.09705 0.09703 0.09703 35 Over 1000 With per month 0.09703 0.09703 0.09703 35 Over 1000 With per month 0.09703 0.09703 0.09703 36 Over 1000 With per month 0.09703 0.09703 0.09703 36 Over 1000 With per month 0.09703 0.09703 0.09703 37 Septementh 0.09703 0.09703 0.09703 37 Over 1000 With per month 0.06219 0.06219 0.06219 38 GENERAL LISE AND SPACE HEAT : Rate Code (IRS2A: IRS3A: IRW7A: IRHIA): 0.06230 0.06230 41 Over 1000 With per month 0.06240 0.06239 0.06240 42 ALWITHER Rate Code (IRS2A: IRS3A: IRW7A: IRHIA): 0.06240 0.06240 43 Separatic Listrate Code (IRS2A: IRS3A: IRW7A: IRHIA): <	27					
23 - Frist 00 KWh per month 0.12231 0.12231 0.12231 0.12231 31 Over 1000 KWh per month 0.00565 0.00565 0.00565 32 CENERAL USE AND SPACE HEAT (RESS) - WINTER - Rate Code (1RS6A: 1RFEB): 0.00703 0.00703 0.00703 33 Over 1000 KWh per month 0.05656 0.05656 0.05656 34 Over 1000 KWh per month 0.06703 0.06703 0.06703 36 Over 1000 KWh per month 0.06696 0.06696 0.06698 0.06703 37 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (1RS2A: 1RS3A: 1RW7A: 1RH1A): 0.06629 0.06230 0.06703 38 GENERAL USE AND SPACE HEAT - Rate Code (1RS2A: 1RS3A: 1RW7A: 1RH1A): 0.06629 0.06230 0.06266 40 Next 400 KWh per month 0.06621 0.06230 0.06266 41 AtWh - WINTER 0.06621 0.06230 0.06266 42 AtWh - WINTER 0.13803 0.13803 0.13805 44 Math - WINTER 0.06621 0.06220 0.06220	28		GENERAL USE (RESA) - WINTER - Rale Code (IRSTA; IRSDA; IRSTB):	0.40004	0.40004	0 40070
33 Next 40 W/h per month 0.0738 0.0738 0.07421 33 Over 1000 K/h per month 0.06666 0.06651 0.06656 34 Over 1000 K/h per month 0.09703 0.09703 0.09703 36 Over 1000 K/h per month 0.06668 0.06658 0.06658 35 Next 400 K/h per month 0.06703 0.09703 0.09703 37 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (1RS2A: 1RS3A: 1RW7A: 1RH1A): 0.06098 0.06019 37 First 600 K/h per month 0.06219 0.06219 0.06219 38 SEPARATELY METERED SPACE HEAT - Rate Code (1RS2A: 1RS3A: 1RW7A: 1RH1A): 0.06219 0.06239 40 Next 400 K/h per month 0.06249 0.06269 0.06239 41 Over 1000 K/h per month 0.06249 0.06269 0.06269 42 A1 K/h - SUMAER 0.1306 0.1306 0.1306 43 MKM - WINTER 0.13033 0.13933 0.13933 0.13930 45 A1 K/h - SUMAER 0.13933 0.13933 0.13	29		First 600 kWh per month	0.12231	0.12231	0.12272
31 Over 1000 KWn per month 0.00601 0.00601 0.00601 33 GENERAL USE AND SPACE HEAT (RESB) - WINTER - Rate Code (IRS6A: IRFEB): 0.09703 0.09703 0.09703 34 First 600 KWn per month 0.00608 0.008708 0.09703 0.09703 0.09703 35 Next 400 KWn per month 0.008708 0.09703 0.09708 0.09708 36 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (IRS2A: IRS3A: 1RW7A: 1RH1A): 0.06828 0.08219 0.08219 37 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (IRS2A: IRS3A: 1RW7A: 1RH1A): 0.07441	30		Next 400 kWh per month	0.07396	0.07396	0.07421
32 33 GENERAL USE AND SPACE HEAT (RESB) - WINTER - Rate Code (1RS6A: 1RFEB): 0 0 009703 0.09703 0.09703 33 Over 1000 WM per month 0.09703 0.09703 0.09703 0.09703 33 Over 1000 WM per month 0.09703 0.09703 0.09703 0.09703 34 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (1RS2A: 1RS3A: 1RW7A: 1RH1A): 0.12412 </td <td>31</td> <td></td> <td>Over 1000 kWh per month</td> <td>0.06561</td> <td>0.06561</td> <td>0.06583</td>	31		Over 1000 kWh per month	0.06561	0.06561	0.06583
33 GENERAL USE AND SPACE HEAT (RESG) - WINTER - Rate Code (IRSSA: IRVED): 0.09733 0.09733 0.09733 33 Next 40 KWh per month 0.09733 0.09733 0.09733 0.09733 34 First 600 KWh per month 0.09733 0.09733 0.09733 0.09733 35 Over 1000 KWh per month 0.06733 0.09733 0.09733 37 First 500 KWh per month 0.07441 0.07441 0.07466 36 Over 1000 KWh per month 0.07411 0.07441 0.07466 37 First 500 KWh per month 0.06239 0.06239 0.06239 36 Over 1000 KWh per month 0.06239 0.06239 0.06239 47 All KWh - WINTER 0.086239 0.06239 0.06239 48 All KWh - WINTER 0.13833 0.13933 0.13933 49 SUMMER 0.13933 0.13933 0.13933 50 Customer Charge 15.44 15.44 15.44 51 Customer Charge 0.011773 0.21743 0.21743<	32					
34 First 600 KVh per month 0.09703 0.09703 0.09703 0.09703 35 Over 1000 KVh per month 0.09703 0.09703 0.09703 0.09703 36 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (IRS2A: IRS3A: IRW7A: IRHIA); 0.12412 0.117313 0.11733	33		GENERAL USE AND SPACE HEAT (RESB) - WINTER - Rate Code (IRS6A; IRFEB);			
35 Next 400 KWn per month 0.09703 0.09703 0.09703 37 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (IRS2A: 1RS3A, 1RW7A, 1RH1A); 0.12412 0.12412 0.12412 39 First 600 kWn per month 0.07441 0.07441 0.07441 0.07441 39 SEPARATELY METERED SPACE HEAT - Rate Code (IRS2A; 1RS3A, 1RW7A, 1RH1A); 0.06239 0.06239 43 SEPARATELY METERED SPACE HEAT - Rate Code (IRS2A; 1RS3A, 1RW7A, 1RH1A); 0.06239 0.06220 43 SEPARATELY METERED SPACE HEAT - Rate Code (IRS2A; 1RS3A, 1RW7A, 1RH1A); 0.06239 0.06220 44 WINTER 0.13933 0.13933 0.13933 45 WINTER 0.13933 0.13933 0.13933 46 WINTER 0.17931 0.17931 0.17931 47 Residential Time of Day (Frozen) - Rate Code (1TE1A); 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 15.94 <	34		First 600 kWh per month	0.09703	0.09703	0.09736
38 Over 1000 kWh per month 0.06098 0.06098 0.06098 0.06098 0.06098 0.06098 0.06119 38 GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (IRS2A; 1RS3A; 1RW7A; 1RH1A); 0.12412 0.12412 0.12412 0.12412 0.12412 0.12412 0.12412 0.12412 0.12412 0.12412 0.07461 0.07461 44 Next 400 kWh per month 0.06219 0.06239 0.06239 0.06239 0.06239 0.06239 0.06239 0.06239 0.03852 44 All kWh - WINTER 0.13930 0.13930 0.13930 0.13933 0.13933 0.13930 0.13933 0.13934 0.11796 0.11796	35		Next 400 kWh per month	0.09703	0.09703	0.09736
37 37<	36		Over 1000 kWh per month	0.06098	0.06098	0.06119
38 GENERAL USE AND SPACE HEAT (RESC): WINTER - Rate Code (IRS2A; IRS3A; IRW7A; IRHIA): 0<	37					
33 First 600 KWh per month 0.12412 0.12412 0.12412 0.12412 41 Over 1000 KWh per month 0.06219 0.06219 0.06230 43 SEPARATELY METERED SPACE HEAT - Rate Code (1RS2A: 1RS3A; 1RW7A; 1RH1A): 0 0 0.06239 0.05239 0.05333 0.13800 0.13806 0.13806 0.13806 0.13806 0.13806 0.13806 0.13806 0.17931 0.17931 0.17931 0.17931 0.17931 0.17931 0.17931 0.17931 0.17936 0.17166 0.17166 0.17166	38		GENERAL USE AND SPACE HEAT (RESC) - WINTER - Rate Code (1RS2A; 1RS3A; 1RW7A; 1RH1A):			
40 Next 400 kWh per month 0.07441 0.07461 0.07461 42 SEPARATELY METERED SPACE HEAT - Rate Code (1RS2A: 1RS3A: 1RW7A: 1RH1A); 0.06219 0.06229 44 All kWh - WINTER 0.06229 0.06229 45 All kWh - SUMMER 0.05829 0.06229 46 All kWh - SUMMER 0.05829 0.06229 47 All kWh - SUMMER 0.13806 0.13806 48 WINTER 0.13933 0.13933 49 SUMMER 0.17931 0.17931 49 SUMMER 0.17931 0.17931 40 UNTER 0.13933 0.13980 41 Customer Charge 15.94 15.94 15.94 50 On-Peak - SUMMER 0.01736 0.11736 0.11736 50 Customer Charge 0.08719 0.08719 0.08719 50 Customer Charge 0.08719 0.08719 0.08719 50 Fator RESA 9.08719 0.08719 0.08719 0.08719 0.08719	39		First 600 kWh per month	0.12412	0.12412	0.12454
41 Over 1000 kWh per month 0.06219 0.06219 0.06240 43 SEPARATELY METERED SPACE HEAT - Rate Code (IRS2A: 1RS3A: 1RW7A; 1RH1A); 0	40		Next 400 kWh per month	0.07441	0.07441	0.07466
42 SEPARATELY METERED SPACE HEAT - Rate Code (IRS2A: IRS3A: IRW7A: IRH1A): 44 AI KWh - WINTER 0.06239 0.06239 0.06239 0.06239 0.06239 0.06239 0.06239 0.06239 0.05339 0.13933 0.13933 0.13933 0.13933 0.13933 0.13933 0.13933 0.13931 0.1793 0.1793 0.21173 0.21173 0.21173 0.21173 0.21173 0.21173 0.21173 0.21173 0.21173 0.21173 0.21173 0.21173 0.21175 0.00719	41		Over 1000 kWh per month	0.06219	0.06219	0.06240
43 SEPARATELY METERED SPACE HEAT - Rate Code (IRS2A: 1RS3A: 1RW/A: 1RH1A); 44 0	42					
44 All kWh - WINTER 0.06229 0.06229 0.06229 45 All kWh - SUMMER 0.13806 0.13806 0.13806 46 All kWh - SUMMER 0.13933 0.13933 0.13933 0.13930 47 Residential Other Use - Rate Code (1R01A): 0.13933 0.13933 0.13930 0.13930 49 SUMMER 0.13933 0.13933 0.13930 0.13930 49 SUMMER 0.13933 0.13933 0.13930 0.13980 49 SUMMER 0.11796 0.11796 0.11796 0.11796 50 Customer Charge 15.94 15.94 0.06719 0.06719 51 Sector RESA SUMMER 0.01796 0.11796 0.01796 51 Getor RESA 0.06719 0.06719 0.06719 0.06719 56 Factor RESA Miter 1.1766 2.1784 2.1784 56 Factor RESA 1.1679% 2.013% 2.5778 2.5778 57 Factor RESC	43		SEPARATELY METERED SPACE HEAT - Rate Code (1RS2A; 1RS3A; 1RW7A; 1RH1A);			
45 All NWh - SUMMER 0.13806 0.13806 0.13806 0.13806 0.13806 47 Residential Other Use - Rate Code (1R01A): 0 0 0.13933 0.13933 0.13933 0.13933 48 WINTER 0.13906 0.13933 0.13930 0.17931 0.17931 0.17931 0.17931 0.17931 0.21214 50 Customer Charge 0.027173 0.21173 0.21244 0.11796 0.008748	44		All kWh - WINTER	0.06239	0.06239	0.06260
46 7 Nestlential Other Use - Rate Code (1RO1A): 47 8 47	45		All kWh - SUMMER	0.13806	0.13806	0.13852
47 Residential Other Use - Rate Code (1RO1A):	46					
48 WINTER 0.13933 0.13933 0.13930 49 SUMMER 0.17931 0.17931 0.17931 51 Residential Time of Day (Frozen) - Rate Code (1TE1A): 6 6 6 52 Customer Charge 15.94 15.94 15.94 0.17931 0.2173 0.21173 0.21173 0.21173 0.21173 0.21244 54 On-Peak - SUMMER 0.06719 0.06719 0.06719 0.06719 0.06719 0.06719 54 Other Sa Vinter 0.01796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.06719 0.06718 56 Factor RESA - Winter 0.01719 0.01791 0.06718 0.3013% 3.337% 0.218% 0.00719 0.06718 57 Factor RESA - Winter 0.00719 0.01796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.11796 0.10793 0.2077	47	Residential Ot	ner Use - Rate Code (1RO1A):			
49 SUMMER 0.17931 0.17931 0.17931 61 Residential Time of Day (Frozen) - Rate Code (1TE1A): 0 1 1 52 Customer Charge 15.94 15.94 15.94 15.94 53 On-Freak - SUMMER 0.21173 0.21173 0.21173 0.21173 54 Off-Freak - SUMMER 0.11796 0.11796 0.11796 54 Off-Freak - SUMMER 0.08719 0.08719 0.08719 55 Factor RESA 0.08719 0.08719 0.08719 0.08719 56 Factor RESA 1.17679 2.01874 3.3135 57 Factor RESA 1.17679 2.01874 58 Factor RESB 1.16799 2.01874 59 Factor RESB 1.16799 2.01874 61 Factor RESC 1.17814 2.12174 61 Factor RESC 1.17814 2.12174 62 Factor To-U 3.01337 3.03747 63 Factor Other Use 3.377970	48		WINTER	0.13933	0.13933	0.13980
50 Residential Time of Day (Frozen) - Rate Code (1TE1A): 50 51 51 52 Customer Charge 15.94 15.94 15.94 53 On-Peak - SUMMER 0.21173 0.21173 0.21173 54 On-Peak - SUMMER 0.11796 0.11386 0.08719 0.08719 55 All kWh - WINTER 0.08719 0.08719 0.08748 3.013% 3.357% 56 Factor RESA Winter 3.013% 3.357% 3.0587% 2.087% 2.088% 3.013% 3.357% 3.0587% 2.013% 3.357% 3.0587% 2.013% 3.357% 3.0587% 2.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013% 3.357% 3.013%	49		SUMMER	0.17931	0.17931	0.17991
51 Residential Time of Day (Frozen) - Rate Code (1TE1A): 15.94 15.94 15.94 52 Customer Charge 0.21173 0.21173 0.21173 0.21244 54 On-Peak - SUMMER 0.11796 0.11796 0.11796 0.11796 54 Off-Peak - SUMMER 0.08719 0.08719 0.08748 55 All KWh - WINTER 0.08719 0.08748 0.3013% 3.337% 56 Factor RESA 2.340% 2.602% 2.250% 2.250% 2.255% 57 Factor RESB - Winter 16.67% 2.018% 2.507% 2.955% 2.507% 2.955% 2.507% 2.255% 2.572%	50					
52 Customer Charge 15.94 15.94 15.94 53 On-Peak - SUMMER 0.21173 0.21173 0.21173 54 Off-Peak - SUMMER 0.11796 0.11796 0.11796 55 All kWh - WINTER 0.08719 0.08719 0.08748 56 Factor RESA 0.08719 0.08748 3.013% 3.357% 57 Factor RESA Winter 3.013% 3.357% 58 Factor RESA - Winter 2.662% 2.258% 59 Factor RESB - Winter 2.667% 2.955% 60 Factor RESC - Winter 2.226% 2.225% 61 Factor RESC - Winter 2.226% 2.227% 62 Factor T-0-U 0.0000% 0.034% 63 Factor RESC - Winter Price Below Summer (SUM-WIN/SUM 2.8451% 2.8451% 64 Overall Change (*) 2.295% 2.451% 2.8449% 66 Change in Revenue \$337,970,232 \$345,738,747 \$346,896,368 70 Proposed change per Re	51	Residential Tir	ne of Day (Frozen) - Rate Code (1TE1A):			
53 On-Peak - SUMMER 0.21173 0.21173 0.21173 0.21173 0.21244 54 Off-Peak - SUMMER 0.11796 0.11796 0.11836 55 All KWh - WINTER 0.08719 0.08719 0.08719 0.08719 56 Factor RESA 0.08719 0.08719 0.08719 0.08719 57 Factor RESA 1.6799% 2.083% 3.013% 3.3013% 58 Factor RESB 1.6799% 2.085% 2.607% 2.955% 59 Factor RESC - Winter 2.607% 2.955% 2.527% 2.527% 2.527% 2.527% 2.527% 2.527% 2.527% 2.641% 2.249% 2.424% 2.641% <td>52</td> <td></td> <td>Customer Charge</td> <td>15.94</td> <td>15.94</td> <td>15.99</td>	52		Customer Charge	15.94	15.94	15.99
54 Off-Peak - SUIMMER 0.11796 0.11796 0.11836 55 All KWh - WINTER 0.08719 0.08719 0.08719 0.08719 0.08719 0.08789 56 Factor RESA Winter 3.013% 3.357% 57 Factor RESA - Winter 1.679% 2.018% 58 Factor RESB 1.679% 2.018% 59 Factor RESC 2.607% 2.955% 60 Factor RESC - Winter 2.026% 2.225% 62 Factor RESC - Winter 2.026% 2.572% 62 Factor RESC - Winter 0.007% 0.037% 4.024% 63 Factor Other Use 3.07% 4.024% 2.299% 2.641% 64 Overall Change (*) 28.451% 28.449% \$36,96,368 \$8,926,136 67 Revenue ⁽¹⁾ \$337,970,232 \$345,738,747 \$346,896,368 \$8,926,136 72 Manual Bill \$337,970,232 \$345,738,747 \$346,896,368 \$36,896,368 \$36,990,368 \$36,990,368	53		On-Peak - SUMMER	0.21173	0.21173	0.21244
55 All kWh - WINTER 0.08719 0.08719 0.08749 56 Factor RESA 1 2,340% 2,682% 57 Factor RESA - Winter 3.013% 3.357% 58 Factor RESA 1 67% 2,018% 59 Factor RESA 1 67% 2,018% 59 Factor RESC 1 1.67% 2,018% 50 Factor RESC 1.781% 2,121% 61 Factor RESC 1.781% 2,125% 61 Factor RESC 1.781% 2,226% 2,572% 62 Factor RESC 0.000% 0.334% 0.034% 63 Factor Other Use 3.676% 4.024% 0.000% 0.334% 64 Overall Change (*) 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.451% 28.45	54		Off-Peak - SUMMER	0.11796	0.11796	0.11836
56 Factor RESA 2.340% 2.682% 57 Factor RESA 3.013% 3.357% 58 Factor RESB 1.679% 2.018% 59 Factor RESB 2.607% 2.295% 60 Factor RESC 1.781% 2.121% 61 Factor RESC 2.260% 2.226% 62 Factor RESC 0.000% 0.334% 63 Factor RESC 0.000% 0.334% 64 Overall Change (*) 0.000% 0.344% 65 Winter Price Below Summer (SUM-WINJ/SUM 28.451% 28.451% 28.451% 66 Revenue ⁽¹⁾ \$337,970.232 \$345,738,747 \$346,896,368 \$8,926,136 67 Revenue ⁽¹⁾ \$346,896,368 \$8,926,136 \$8,926,136 \$8,926,136 68 Change in Revenue \$337,970,232 \$345,738,747 \$346,896,368 \$8,926,136 70 Proposed change per Revenue Summary \$337,970,232 \$345,738,747 \$346,896,368 74 Overall Revenue \$337	55		All kWh - WINTER	0.08719	0.08719	0.08748
57 Factor RESA - Winter 3.013% 3.337% 58 Factor RESB 1.679% 2.018% 59 Factor RESB 2.017% 2.265% 60 Factor RESC 1.781% 2.121% 61 Factor RESC 1.781% 2.121% 61 Factor RESC 1.781% 2.226% 62 Factor RESC - Winter 0.000% 0.334% 63 Factor Other Use 0.000% 0.334% 64 Overall Change (*) 28.451% 28.451% 28.451% 65 Winter Price Below Summer (SUM-WIN)/SUM 28.451% 28.451% 28.451% 66 Change in Revenue ⁽¹⁾ \$337,970,232 \$345,738,747 \$346,896,368 67 Revenue ⁽¹⁾ \$337,970,232 \$345,738,747 \$346,896,368 70 Proposed change per Revenue Summary \$345,738,747 \$346,896,368 71 Table \$337,970,232 \$345,738,747 \$346,896,368 74 Overall Revenue \$337,970,232 \$345,738,747 \$346,8	56	Factor RESA			2.340%	2.682%
58 Factor RESB 1.679% 2.018% 59 Factor RESC 2.607% 2.955% 61 Factor RESC - Winter 1.781% 2.121% 61 Factor RESC - Winter 2.226% 2.572% 62 Factor RESC - Winter 0.000% 2.324% 63 Factor T-O-U 2.226% 2.229% 2.641% 64 Overall Change (*) 28.451% 28.451% 28.49% 65 Winter Price Below Summer (SUM-WINJ/SUM 28.451% 28.451% 28.451% 66 Change in Revenue ⁽¹⁾ \$337,970,232 \$345,738,747 \$346,896,368 68 Change in Revenue \$3337,970,232 \$345,738,747 \$346,896,368 69 Proposed change per Revenue Summary \$\$337,970,232 \$345,738,747 \$346,896,368 73 Manual Bill \$\$0 \$\$0 \$\$0 \$\$0 \$\$0 74 Overall Revenue \$\$337,970,232 \$345,738,747 \$346,896,368 \$\$0 74 Overall Revenue \$\$0 \$\$0 <td>57</td> <td>Factor RESA -</td> <td>Winter</td> <td></td> <td>3.013%</td> <td>3.357%</td>	57	Factor RESA -	Winter		3.013%	3.357%
59 Factor RESB - Winter 2.607% 2.955% 60 Factor RESC 1.781% 2.121% 61 Factor RESC - Winter 2.265% 2.226% 62 Factor RESC - Winter 0.000% 0.334% 63 Factor Other Use 0.000% 0.334% 64 Overall Change (*) 28.451% 28.451% 2.2641% 65 Vinter Price Below Summer (SUM-WIN/SUM 28.451% 28.451% 28.449% 66 Revenue ⁽¹⁾ 28.451% 28.451% 28.458, 368 67 Revenue ⁽¹⁾ \$337,970,232 \$345,738,747 \$346,896,368 68 Change in Revenue \$337,970,232 \$345,738,747 \$346,896,368 68 Change in Revenue \$337,970,232 \$345,738,747 \$346,896,368 70 Proposed change per Revenue Summary \$\$8,927,744 \$\$8,927,744 \$\$1,608 71 Manual Bill \$\$337,970,232 \$\$345,738,747 \$346,896,368 \$\$37,970,232 \$\$345,738,747 \$346,896,368 \$\$37,970,232 \$345,738,747	58	Factor RESB			1.679%	2.018%
60 Factor RESC 1.781% 2.121% 61 Factor RESC - Winter 2.226% 2.572% 62 Factor T-O-U 0.000% 0.034% 63 Factor Other Use 3.676% 4.024% 64 Overall Change (*) 28.451% 28.451% 28.451% 65 Vinter Price Below Summer (SUM-WIN)/SUM 28.451% 28.451% 28.451% 66 \$337,970,232 \$345,738,747 \$346,896,368 68 Change in Revenue ⁽¹⁾ \$337,970,232 \$345,738,747 \$346,896,368 69 Proposed change per Revenue Summary \$337,970,232 \$345,738,747 \$346,896,368 71 Manual Bil \$0 \$0 \$0 \$0 72 Manual Bil \$0 \$0 \$0 \$0 73 Manual Bil \$0 \$0 \$0 \$0 74 Overall Revenue \$337,970,232 \$345,738,747 \$346,896,368 74 Overall Revenue \$337,970,232 \$345,738,747 \$346,896,368	59	Factor RESB -	Winter		2.607%	2.955%
61 Factor RESC - Winter 0.000% 2.5226% 62 Factor T-O-U 0.000% 0.0347% 63 Factor Other Use 0.000% 0.0347% 64 Overail Change (*) 28.451% 28.525,136 37.576,14% 33.576% 33.576% 33.576% 33.576% 33.576% 33.576% 33.576% 33.576% 33.576% 33.576% 33.577% 33.576%	60	Factor RESC			1.781%	2.121%
62 Factor T-0-U 0.000% 0.334% 63 Factor Other Use 3.676% 4.024% 3.676% 4.024% 3.676% 4.024% 2.299% 2.641% 2.299% 2.641% 2.294% 2.8451% 28.451% 28.449% 28.451% 28.449% 28.451% 28.451% 28.456,636 66 67 67 67 67 67 67 6337,970,232 \$345,738,747 \$346,896,368 \$8,927,744 \$8,926,368 \$8,927,744 \$8,926,368 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,	61	Factor RESC -	Winter		2.226%	2.572%
63 Factor Other Use 3.676% 4.024% 64 Overall Change (*) 2.8451% 2.299% 2.641% 65 Winter Price Below Summer (SUM-WINJ/SUM 28.451% 28	62	Factor T-O-U			0.000%	0.334%
64 Overall Change (*) 2.299% 2.641% 65 Winter Price Below Summer (SUM-WIN)/SUM 28.451% <t< td=""><td>63</td><td>Factor Other U</td><td>Se la la</td><td></td><td>3.676%</td><td>4.024%</td></t<>	63	Factor Other U	Se la		3.676%	4.024%
65 Winter Price Below Summer (SUM-WiN)/SUM 28.451% 28.451% 28.449% 66	64	Overall Change	9 (*)		2.299%	2.641%
66 67 Revenue ⁽¹⁾ \$337,970,232 \$345,738,747 \$346,896,368 \$8,926,136 68 Change in Revenue \$8,926,136 \$8,926,136 \$8,926,136 70 Proposed change per Revenue Summary \$8,927,744 \$(\$1,608) 72 ************************************	65	Winter Price B	elow Summer (SUM-WIN)/SUM	28.451%	28.451%	28.449%
67 Revenue ⁽¹⁾ \$337,970,232 \$345,738,747 \$346,896,368 \$8,926,136 \$8,927,744 \$8,927,744 \$8,927,744 \$(\$1,608) \$8,927,744 \$(\$1,608) \$8,927,744 \$8,927,745 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,744 \$8,927,74	66					
68 Change in Revenue \$8,926,136 69	67		Revenue ⁽¹⁾	\$337,970,232	\$345,738,747	\$346,896,368
69 70 Proposed change per Revenue Summary \$8,927,744 71 (\$1,608) 72 (\$1,608) 73 Manual Bill \$0 \$0 \$0 74 Overall Revenue \$337,970,232 \$345,738,747 \$346,896,368 75 Net Metering credit (\$118) \$337,970,114 \$337,970,114	68		Change in Revenue			\$8,926,136
70 Proposed change per Revenue Summary \$8,927,744 71 (\$1,608) 73 Manual Bill \$0 \$0 74 Overall Revenue \$337,970,232 \$345,738,747 \$346,896,368 75 Net Metering credit (\$118) \$337,970,114 \$337,970,114	69					
71 (\$1,608) 72 1 73 Manual Bill \$0 \$0 74 Overall Revenue \$337,970,232 \$345,738,747 \$346,896,368 75 Net Metering credit (\$118) \$337,970,14 \$337,970,14	70		Proposed change per Revenue Summary			\$8,927,744
72 Manual Bill \$0 \$0 73 Manual Bill \$0 \$0 74 Overall Revenue \$337,970,232 \$345,738,747 \$346,896,368 75 Net Metering credit (\$118) 76 \$337,970,114 \$337,970,114	71					(\$1,608)
T3 Manual Bill \$0 \$0 \$0 74 Overall Revenue \$337,970,232 \$345,738,747 \$346,896,368 75 Net Metering credit (\$118) \$337,970,114	72					
74 Overall Revenue \$337,970,232 \$345,738,747 \$346,896,368 75 Net Metering credit	73		Manual Bill	\$0	\$0	\$0
75 Net Metering credit (\$118) 76 \$337,970,114	74		Overall Revenue	\$337,970,232	\$345,738,747	\$346,896,368
76 \$337,970,114	75		Net Metering credit	(\$118)		
	76			\$337,970,114		

	A	В	С	D	E	F	G	Н
1	Kansas Cit	y Power & Li	ght - Misso	ouri				
2	Private Unm	netered Lightir	ng Service					
3		Ũ	0					
4	Case No:	ER-201	8-0145	Juris Increase (%) =	0.939%			
5	Status:	Direct						
6		J		-				
7	Rate Schedule	Rate Code	Tariff Sheet	Description	Current Rate	Proposed Rate	%^	MRU Codes
8			No.					
9	AL	1ALDA, 1ALDE	33	5800 Lumen High Pressure Sodium Unit	\$23.93	\$24.15	0.919%	S058
10				8600 Lumen Mercury Vapor Unit	\$25.17	\$25.41	0.954%	M086
11				16000 Lumen High Pressure Sodium Unit	\$27.40	\$27.66	0.949%	H160
12				22500 Lumen Mercury Vapor Unit	\$30.81	\$31.10	0.941%	M225
13				22500 Lumen Mercury Vapor Unit	\$30.81	\$31.10	0.941%	V225
14				27500 Lumen High Pressure Sodium Unit	\$29.14	\$29.41	0.927%	H275
15				50000 Lumen High Pressure Sodium Unit	\$31.79	\$32.09	0.944%	H500
16				63000 Lumen Mercury Vapor Unit	\$40.04	\$40.42	0.949%	V630
17								
18		Optional Charge	s				_	
19		1ALDA, 1ALDE	33	Each 30-foot ornamental steel pole installed	\$7.35	\$7.42	0.952%	SP30
20				Each 35-foot ornamental steel pole installed	\$8.39	\$8.47	0.954%	SP35
21				Each 30-foot wood pole installed	\$5.63	\$5.68	0.888%	WP30
22				Each 35-foot wood pole installed	\$6.15	\$6.21	0.976%	WP35
23	1			Each overhead span of circuit installed	\$4.12	\$4.16	0.971%	SPAN
24	1			Underground lighting unit	\$3.15	\$3.18	0.952%	U300
25				5 5 5				
26	NOTE: All Current an	nd Proposed rates are by	/ month.					

	A	В	С	D	E	F	G H	I	J	K	L
1	Kansas Cit	v Power & Liah	nt - Missou	ıri							
-	Municipal S	troot Lighting Sc									
2	iviunicipal S	treet Lighting Se	ervice								
3							-				
4	Case No.	ER-2018-0145			Juris Increase (%) =	= <mark>0.939%</mark>					
-	Statue [.]	Direct					_				
5	Status.	Direct									
6	Data Oakadala	Data Orala	T =		Description	0		Dura contra	. 4 .	-	
/	Rate Schedule	Rate Code		Data Na	Description	Current Rate	Manthali	Proposed R	ite Manthlu	- %∆	MRU Codes
8	N 41		Sheet No.	Rate No.	5000 Lunner LED (Oleve A) Ture V wetter	Annual	Monthly	Annual	Monthly	0.000%	1010
9	MIL	IMLLL	35	1.1	5000 Lumen LED (Class A) Type V pattern	\$249.36	\$20.78	\$251.76	\$20.98	0.962%	LOAS
10	-			4.0	5000 Lumen LED (Class A) Type V pattern - Twin	\$498.72	\$41.56	\$503.52	\$41.96	0.962%	LOAT
11	-			1.2	5000 Lumen LED (Class B) Type II pattern	\$249.36	\$20.78	\$251.76	\$20.98	0.962%	LOBS
12	-			0.0	5000 Lumen LED (Class B) Type II pattern - Twin	\$498.72	\$41.50	\$503.52	\$41.96	0.962%	LOBI
13	-			2.3	7500 Lumen LED (Class C) Type III pattern	\$280.44		\$283.08	\$23.59	0.941%	LOCS
14	-			2.4	12500 Lumen LED (Class C) Type III pattern	\$000.66	\$40.74 \$24.02	\$306.16	\$47.10	0.941%	LOCI
10	-			2.4	12500 Lumen LED (Class D) Type III pattern	\$299.10 ¢509.22		\$301.92	\$25.10	0.923%	LODS
16	-			0.5	12500 Lumen LED (Class D) Type III pattern - Twin	\$598.32	\$49.86	\$603.84	\$50.32	0.923%	LODI
17	-			2.5	24500 Lumen LED (Class E) Type III pattern	\$324.12 ©C40.04	\$27.01	\$327.12	\$27.26	0.926%	LOES
10	-			0.4	24500 Lumen LED (Class E) Type III pattern - Twin	\$048.24	\$54.02	\$654.24	\$04.5Z	0.926%	LOET
19	-			2.1	5000 Lumen LED (Class B) Type II pattern	\$137.16	\$11.43	\$138.48	\$11.54	0.962%	LOBE
20	-			2.3	7500 Lumen LED (Class C) Type III pattern	\$168.24	\$14.02	\$169.80	\$14.15	0.927%	LOCE
21	4			2.4	12500 Lumen LED (Class D) Type III pattern	\$186.96	\$13.58 \$17.66	\$188.76	\$15.73	0.963%	LODE
22	4			2.5	24500 Lumen LED (Class E) Type III pattern	\$211.92	ງ ຈຳ7.66	\$213.96	\$17.83	0.963%	LOEE
23	4	1111.01	254	1 1	0500 Lumon High Droppuro Sadium	¢150 04	¢10 17	\$150.40	\$42.00	0.0440/	800F
24	4	IIVILƏL	JOA	1.1	16000 Lumen High Pressure Sodium	φ100.04 ¢261.72	ອາວ.1/ ¢ວາ.01	\$159.48 \$264.40	ຈ13.∠9 ¢22.04	0.911%	SUSE
25	-			1.2	16000 Lumen High Pressure Sodium	\$261.72	\$21.81	\$264.12	\$22.01	0.917%	SIDE
26	-	TMLSL, TMLML		8.1	8600 Lumen Mercury Vapor	\$274.92	\$22.91	\$277.56	\$23.13	0.960%	MO8S
27	-				ACTION TO A STATE AND A STATE	\$549.84	\$45.82	\$555.12	\$46.26	0.960%	M081
28	-			8.2	12100 Lumen Mercury Vapor	\$308.28	\$25.69	\$311.16	\$25.93	0.934%	M125
29	-			0.0	12100 Lumen Mercury Vapor - Twin	\$616.56	\$51.38	\$622.32	\$51.86	0.934%	MOOT
30	-			0.3	22500 Lumen Mercury Vapor	\$330.12 \$670.04	_\$20.01	\$339.24	\$28.27	0.928%	MOOT
31	-			0.4	22500 Lumen Mercury Vapor - Twin	\$072.24	\$00.02	\$0/0.40 \$070.04	\$00.04 \$00.57	0.928%	IVIZZ I
32	-			8.4	9500 Lumen High Pressure Sodium	\$268.32	\$22.36	\$270.84	\$22.57	0.939%	S095
33	-			0.5	9500 Lumen High Pressure Sodium - Twin	\$536.64	\$44.72	\$541.68	\$45.14	0.939%	5091
34	-			8.5	16000 Lumen High Pressure Sodium	\$298.92	\$24.91	\$301.68	\$25.14	0.923%	5165
35	-				16000 Lumen High Pressure Sodium - Twin	\$597.84	\$49.82	\$603.36	\$50.28	0.923%	S161
30	-			8.6	27500 Lumen High Pressure Sodium	\$317.76	\$26.48	\$320.76	\$26.73	0.944%	S27S
37	-			0.7	27500 Lumen High Pressure Sodium - Twin	\$635.52	\$52.96	\$641.52	\$53.46	0.944%	5271
38	-			8.7	50000 Lumen High Pressure Sodium	\$346.56	\$28.88	\$349.80	\$29.15	0.935%	5505
39	-				50000 Lumen High Pressure Sodium - Twin	\$693.12	\$57.76	\$699.60	\$58.30	0.935%	S501
40	-										
41	4	Optional Equipment	t	0.4	Ohard Dala	* 40.70	M 4 F0	\$40.0÷	A4 ==	0.0110/	005
42	4	IMLML, IMLSL,	35A	9.1	Steel Pole	\$18.72 #46.00	\$1.56	\$18.84	\$1.57	0.641%	OSPL
43	4	TIVILLL	35B	9.2	Aluminum Pole	\$46.92	\$3.91	\$47.40	\$3.95	1.023%	OAPL
44	4			9.3	Underground Service extension under sod	\$78.96	\$0.58 005 40	\$79.68	\$6.64	0.912%	OEUS
45	4			9.4	Underground Service extension under concrete	\$301.44 ¢42.00	⇒∠⊃.1∠ ¢2.50	\$304.32	\$25.36	0.955%	OEUC
46	4			9.5	Dreakaway Base	φ43.08	_ ຈວ.59	\$43.44	\$3.62	0.836%	OBAB
4/	N 41	4141-01	250	[40.0.40.4](***)		<u>¢0.000</u>		¢0.002		_	
48	IVIL	INILUL	358	[10.0,10.1](iii)	Annual Energy Unarge	φ0.082 ¢65.92	¢5 40	\$U.U83	¢E EA	0.0440/	C160
49	4			10.0(1)		€121 €4	ູ ອຸວ.4ອ ¢10.07	900.44 \$422.00	φ0.04 ¢11.00	1.0029/	CIGU
50	4			10.0(2)		φ131.04	φ10.9 <i>1</i>	φ13 ∠. 00	φ11.00	1.003%	0101
51	4	2011 81	26	11	0500 Lumon High Droppuro Sadium	¢150.04	¢10.17	¢450.40	\$42.20	0.0440/	800F
52	4	JIVILOL	30	1.1	16000 Lumen High Pressure Sodium	φ100.04 ¢061.70	φι3.1/ ¢21.01	\$159.48 \$264.40	ຈ13.∠9 ¢22.04	0.911%	509E
53	4			1.2	TOUUU LUMEN HIGN Pressure Soaium	φ <u>201.72</u>	_\$∠1.01	⊋264.12	ə22.01	0.917%	510E
54	4	2MIMI 2MICI	264	4.1	9600 Luman Maraun Manar	¢074 00	¢22.01	\$077 FC	¢02.42	0.0000/	MORE
55	4	SIVILIVIL, SIVILSL	JOA	4.1	0000 Lumen Mercury Vapor	\$E40.94	_ק∠∠.७। ¢45.00	¢∠//.50	\$∠3.13 ¢46.20	0.960%	IVIU85
20	4				0000 Lumen Link Pressure Cadium	φ049.04	φ 4 0.0∠ ¢00.00	\$000.12	ቅ40.∠0	0.960%	
5/	4			4.4	9500 Lumen High Pressure Sodium	\$208.32 \$500.04	_ ⊅∠∠.30 © 4.4.70	ቅ ∠/U.84	\$22.57 \$45.44	0.939%	5095
58	4			4.5	SOULLUMEN HIGH Pressure Sodium - I Win	3530.04		\$541.68	\$45.14	0.939%	5091
59	4			4.5	10000 Lumen High Pressure Sodium	\$298.92 ¢507.04	_⊋∠4.91 ©40.02	\$301.68	\$25.14	0.923%	5165
00	4			4.6	10000 Lumen High Pressure Sodium - Twin	3097.84	\$49.0Z	\$0U3.30	a50.28	0.923%	5101
01	4			4.0	27500 Lumen High Pressure Sodium	\$317.70 \$625.50	_ຈ∠0.4ŏ ¢52.06	\$320.76	\$26.73	0.944%	52/5
62	4			47	27000 Lumen High Pressure Sodium	Φ030.02	φυ∠.ઝ0 ¢⊃o oo	₽041.5∠ ¢240.90	903.40 \$20.45	0.944%	52/1
03	4			4./	50000 Lumen High Pressure Sodium	φ340.30 ¢602.12	_9∠0.00 ¢E7.76	\$349.8U	\$29.15 \$59.20	0.935%	3003
04	4				Source Lamen High Pressure Sodium - Twin	9093. IZ	φ01.10	\$033.00	\$30.3U	0.935%	5001
00	1										

A	В	С	D	E	F	GI	1 1	J	К	L
66				•						
67	Optional Equipment									
68	3MLML, 3MLSL	36A	5.1	Steel Pole	<mark>\$18.72</mark>	\$1.56	\$18.84	\$1.57	0.641%	OSPL
69			5.2	Aluminum Pole	<mark>\$46.92</mark>	\$3.91	\$47.40	\$3.95	1.023%	OAPL
70			5.3	Underground Service extension under sod	<mark>\$78.96</mark>	\$6.58	\$79.68	\$6.64	0.912%	OEUS
71			5.4	Underground Service extension under concrete	<mark>\$301.44</mark>	\$25.12	\$304.32	\$25.36	0.955%	OEUC
72			5.5	Breakaway Base	<mark>\$43.08</mark>	\$3.59	\$43.44	\$3.62	0.836%	OBAB
73										
74 ML	3MLCL	36B	6.2	8600 Lumen - Limited Maintenance	<mark>\$133.68</mark>	\$11.14	\$134.88	\$11.24	0.898%	C08L
75			6.3	22500 Lumen - Limited Maintenance	<mark>\$290.76</mark>	\$24.23	\$293.52	\$24.46	0.949%	C22L
76			6.4	9500 Lumen - Limited Maintenance	<mark>\$133.68</mark>	\$11.14	\$134.88	\$11.24	0.898%	C09L
77			6.5	27500 Lumen - Limited Maintenance	\$290.76	\$24.23	\$293.52	\$24.46	0.949%	C27L
78										
79 ML-LED	1MLLL (LED)	48A	11.1	Small LED (≤ 7000 lumens)	<mark>\$268.32</mark>	\$22.36	\$270.84	\$22.57	0.939%	L03S
80				Small LED (≤ 7000 lumens) - Twin	\$536.64	\$44.72	\$541.68	\$45.14	0.939%	L03T
81			11.2	Large LED (> 7000 lumens)	<mark>\$298.92</mark>	\$24.91	\$301.68	\$25.14	0.923%	L07S
82				Large LED (> 7000 lumens) - Twin	\$597.84	\$49.82	\$603.36	\$50.28	0.923%	L03T
83										
84	Optional Equipment									
85	1MLLL (LED)	48A	12.1	Ornamental steel pole	<mark>\$18.72</mark>	\$1.56	\$18.84	\$1.57	0.641%	OSPL
86			12.2	Aluminum pole	<mark>\$46.92</mark>	\$3.91	\$47.40	\$3.95	1.023%	OAPL
87			12.3	Underground service extension under sod	<mark>\$78.96</mark>	\$6.58	\$79.68	\$6.64	0.912%	OEUS
88			12.4	Underground service extension under concrete	\$301.44	\$25.12	\$304.32	\$25.36	0.955%	OEUC
89			12.5	Breakaway base	<mark>\$43.08</mark>	\$3.59	\$43.44	\$3.62	0.836%	OBAB
90										
91									-	

	А	В	С	D	E	F	G	Н	I	J
1	Kansas Cit	y Powe	r & Ligh	t - Missour	i					
2	Off-Peak Lig	ghting S	Service							
3										
4	Case No.	ER-20	18-0145		Juris Increase (%) =	= <mark>0.939%</mark>				
5	Status:	Direct								
5	olalas.	Direct			_					
7	Rate Schedule	Rate Tariff			Description	Current Rate		Proposed Rate		0/ 4
8		Code	Sheet No.	Rate No.				•		%Δ
9	OLS	10LSL	45	1.1	Total Watts X MBH X BLF ÷ 1000	\$0.08302		\$0.08380		0.940%
10				1.2	First 100 Watts X MBH X BLF ÷ 1000	\$0.08302		\$0.08380		0.940%
11					Excess over 100 Watts X MBH X BLF ÷ 1000	\$0.07767		\$0.07840		0.940%
12				1.3	First 100 Watts X MBH X BLF ÷ 1000	\$0.08302		\$0.08380		0.940%
13					Next 50 Watts X MBH X BLF ÷ 1000	\$0.07767		\$0.07840		0.940%
14					Excess over 150 Watts X MBH X BLF ÷ 1000	\$0.07498		\$0.07568		0.934%
15				1.4	First 100 Watts X MBH X BLF ÷ 1000	\$0.08302		\$0.08380		0.940%
16					Next 150 Watts X MBH X BLF ÷ 1000	\$0.07498		\$0.07568		0.934%
17					Excess over 250 Watts X MBH X BLF ÷ 1000	\$0.06828		\$0.06892		0.937%
18				1.5	First 100 Watts X MBH X BLF ÷ 1000	\$0.08302		\$0.08380		0.940%
19					Next 300 Watts X MBH X BLF ÷ 1001	\$0.06828		\$0.06892		0.937%
20					Excess over 400 Watts X MBH X BLF ÷ 1000	\$0.06828		\$0.06892		0.937%
21	1		45A	2.1	Total Watts X MBH X BLF ÷ 1000	\$0.08302		\$0.08380		0.940%
22										_
23	NOTE: All customers	under this ra	ate code (10LS	L) are billed through	PeopleSoft. Rates are not in CIS.					
24	1									

	A	В	С	D	E	F	G	Н	1
1	Kansas Cit	y Powe	r & Light	- Missouri					
2	Municipal T	- raffic Co	ontol Signa	al Service					
2			onder origine						
5	Casa Na		10.0445		$\left \right\rangle$	0.020%	1		
4	Case NO.	ER-20	10-0145		Julis increase (%) –	0.93978			
5	Status:	Direct							
6					_			_	
7	Rate Schedule	Rate	T;	ariff	Description	Current Rate	Proposed Rate	%^	MRII Codes
8		Code	Sheet No.	Rate No.				/04	
9	TR	1TSLM	37	1	Individual Control	\$202.74	\$204.64	0.937%	1CTL
10				3A	1-Way, 1-Light Signal Unit	\$47.75	\$48.20	0.942%	1W1L
11				3B	4-Way, 1-Light Signal Unit - Suspension	<u>\$56.53</u>	\$57.06	0.938%	4W1L
12				4	Pedestrian Push Button Control	<u>\$169.69</u>	\$171.28	0.937%	BUTN
13			37A	6	Multi-Phase Electronic Control	\$489.62	\$494.22	0.940%	4PEC
14									
15			Optional Eq	uipment				-	
16			37A	4	3-Light Signal Unit	\$28.85	\$29.12	0.936%	3LTU
17				5	2-Light Signal Unit	<u>\$27.76</u>	\$28.02	0.937%	2LTU
18				6	1-Light Signal Unit	\$8.69	\$8.77	0.921%	1LTU
19				7	Pedestrian Control Equipment	\$3.87	\$3.91	1.034%	PBPR
20			37B	8	12-Inch Round Lens	\$7.04	\$7.11	0.994%	12RD
21				9	9-Inch Square Lens	\$7.97	\$8.04	0.878%	09IN
22				11a	Vehicle - Actuation Unit - Loop Detector - Single	\$36.09	\$36.43	0.942%	LP01
23				11b	Vehicle - Actuation Unit - Loop Detector - Double	<u>\$57.26</u>	\$57.80	0.943%	LP02
24				12	Flasher Equipment	<u>\$10.24</u>	\$10.34	0.977%	FLEQ
25				13a	Mast Arm - Style 2	\$47.95	\$48.40	0.938%	ARM2
26				13b	Mast Arm - Style 3	\$47.53	\$47.98	0.947%	ARM3
27			37C	14	Back Plate	<u>\$2.19</u>	\$2.21	0.913%	PLTE
28	1			15	Wood Pole Suspension	\$22.22	\$22.43	0.945%	WPSU
29	1			18	Traffic Signal Pole	\$12.19	\$12.30	0.902%	POLE
30								-	
31	NOTE: All Current a	nd Proposed r	rates are by month	۱.				_	
32									

	A	В	С	D	E	F	G
1	Kansas Cit	v Power	& Light - Mis	souri			
		. .		Soull			
2	Two-Part -	Time of Us	se Pricing (Fro	ozen)			
3							
4	Case No	ER-2	018-0145	Juris Increase (%) =	0.939%		
<u> </u>	Status:	Direct				3	
5	Status.	Direct					
6		-					1
-	Rate Schedule	Tariff Sheet	Voltage or	Description	Current Rate	Proposed Rate	%Δ
/	TOD	NO.	Charge	Winter On Back		-	
0	1155	200	Secondary	SGS SGA	\$0.05655	\$0.05708	0.037%
10	1			MGS MGA	\$0.03033	\$0.03700	0.037%
11	•				\$0.04701	\$0.04350	1 042%
12	1			LPS	\$0.04119	\$0.04158	0.947%
13	1			Winter Off-Peak			
14	1			SGS, SGA	\$0.04880	\$0.04926	0.943%
15	1			MGS, MGA	\$0.03946	\$0.03983	0.938%
16				LGS, LGA	\$0.03791	\$0.03831	1.055%
17				LPS	\$0.03460	\$0.03493	0.954%
18				Summer On-Peak			
19				SGS, SGA	\$0.14606	\$0.14743	0.938%
20				MGS, MGA	\$0.13196	\$0.13320	0.940%
21				LGS, LGA	\$0.12770	\$0.12904	1.049%
22				LPS	\$0.11972	\$0.12084	0.936%
23				Summer Off-Peak	***	******	0.0440/
24				SGS, SGA	\$0.06268	\$0.06327	0.941%
25	1				\$0.05229 \$0.05000	\$0.05276 \$0.05052	1.040%
20	•			LOG, LOA	\$0.03000 \$0.04447	\$0.03032	0.944%
28	•			Elo	φ0.04441	0.04400	0.04470
29	1	Primary		Winter On-Peak			-
30	1			SGS. SGA	\$0.05486	\$0.05538	0.948%
31	1			MGS, MGA	\$0.04762	\$0.04807	0.945%
32	1			LGS, LGA	\$0.04561	\$0.04609	1.052%
33]			LPS	\$0.03995	\$0.04033	0.951%
34				Ninter Off-Peak			
35]			SGS, SGA \$0.04736		\$0.04780	0.929%
36				MGS, MGA	\$0.03829	\$0.03865	0.940%
37				LGS, LGA	\$0.03678	\$0.03717	1.060%
38				LPS	\$0.03360	\$0.03392	0.952%
39	4			Summer On-Peak	60 40 40 4	00 40044	0.0409/
40	•			SGS, SGA	\$0.13464 \$0.12190	\$0.13011 \$0.13204	0.942%
41	•				\$0.12180 \$0.11788	\$0.12294 \$0.11012	1.052%
42	•			LGS, LGA	\$0.11766 \$0.11050	\$0.11912	0.941%
44	1			Summer Off-Peak		40.1110 4	0.04170
45	1			SGS. SGA	\$0.05922	\$0.05978	0.946%
46	1			MGS, MGA	\$0.04943	\$0.04989	0.931%
47	1			LGS, LGA	\$0.04725	\$0.04775	1.058%
48]			LPS	\$0.04204	\$0.04243	0.928%
49							_
50]		Substation	LPS			
51				Winter On-Peak	\$0.03946	\$0.03983	0.938%
52	4			Winter Off-Peak	\$0.03313	\$0.03344	0.936%
53				Summer On-Peak	\$0.10343	\$0.10440	0.938%
54	4			Summer Off-Peak	\$0.04148	\$0.04187	0.940%
55	ł		Transmission	1.00			-
50	ł		riansmission	LFO Winter On Book	¢0.02020	\$0.02057	0.04494
52	7			Winter Off Peak	\$0.03920 \$0.03201	\$0.03957 \$0.03957	0.344%
50				Summer On-Peak	\$0.10307	\$0 10404	0.941%
60	1			Summer Off-Peak	\$0.04121	\$0.04160	0.946%
61	1						2.21070
62	1	20D	Program Charge	SGS and SGA Customers	\$11.60	\$11.71	0.948%
63	1			All other Customers	\$34.81	\$35.14	0.948%
64	1					•	_
65	NOTE: All Current a	nd Proposed Pro	gram Charge rates are t	by month. The rate design for all Secondary and Prin	nary TPP customers within the	e SGS and	-
66	LGS rate classes are	e adjusted sepera	ately through the rate de	sign of their respective rate classification.			
67	1						

	A	В	С	D	E	F	G				
1	Kansas Cit	y Power &	& Light - Missouri								
2	Standby Se	rvice for S	elf-Generating Customer (Fr	ozen)							
3	Standby or Breakdown Service										
4											
5	Case No.		ER-2018-0145	Juris Inci	rease (%) =	<mark>0.939%</mark>					
6	Status:	Direct									
7											
8	Rate Schedule	Tariff Sheet No.	Description	Current Rat	e	Proposed Rate	%Δ				
9	SGC	28B	11:00 a.m 2:00 p.m.	<mark>\$0.03294</mark>		\$0.03325	0.941%				
10			2:00 p.m 6:00 p.m.	<mark>\$0.08048</mark>		\$0.08124	0.944%				
11			6:00 p.m 7:00 p.m.	<mark>\$0.03294</mark>		\$0.03325	0.941%				
12											
13	SA	30	Demand Charge (per kW of demand)	<mark>\$15.963</mark>		\$16.113	0.940%				
14			Energy Charge (per kWh)	<mark>\$0.1977</mark> 1		\$0.19957	0.941%				
15											
16											

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
Rates	TOC-(1,2)	Table of Contents	Adjust language to no longer reference tariff sheet nos. identifying the Real Time Pricing program and Two-Part Time-of-Use schedule.	The Company is proposing to eliminate both its Real-Time Pricing Program and Two-Part Time-of-Use schedule. There are no customers served on these frozen rates. Additionally, the administrative effort to continue to offer this unused product and maintain the tariff is overly burdensome.
			Include the proposed Schedule RTOU, Schedule RD, and Schdule RDTOU.	The Company is proposing to add three Residential pilot programs to its Rate Book 7: (1) Residential Time of Use Pilot; (2) Residential Demand Pilot; and (3) the Residential Demand plus Time of Use Pilot based on findings from multiple rate design studies conducted in the Company's GMO jurisdiction.
			Include the proposed Schedule CCN	The Company is proposing to add a Public Electric Vehicle Charging Station Service to its Rate Book 7 for both residential and non-residential customers.
			Include the proposed Schedule RER.	The Company is proposing to add a Renewable Energy Rider Program to its Rate Book 7 to provide its non-residential customers with a voluntary opportunity to purchase renewable energy.
			Include the proposed Schedule SSP	The Company is proposing to add a Solar Subscription Pilot Rider to its Rate Book 7 for all customer classes.
			Include the proposed Schedule SSR and retire Schedule SGC	The Company is proposing to eliminate its current Standby Service for Self-Generating Customers and replace it with its proposed Standby Service Rider in an effort to maintain consistency among jurisdictions.
			Retire Schedule SA	The Company is proposing to eliminate its Standby or Breakdown Service. There are no customers served on this rate. Additionally, the administrative effort to continue to offer this unused product and maintain the tariff is overly burdensome.
			Adjust language to mark Schedule AL as Frozen.	The Company is proposing to freeze its Private Unmetered Lighting Service and implement an original Private Unmetered LED Lighting Service for new customers.
			Retire MEEIA Cycle 1 Schedule MP	The Company is proposing to eliminate its MEEIA Cycle I MPower program because this program is not available after April 1, 2016.
			Include proposed Schedule PL	The Company is proposing to add a Private Unmetered LED Lighting Service to its Rate Book 7 to phase out its current Private Area Lighting rate schedules.

k	Tariff Sheet No.	Name of Schedule	Proposed Change	Support				
	7-7A	Residential Time of Use Pilot (New)	Create original Schedule RTOU.	The Company is proposing to add a Residential Time of Use pilot program to its Rate Book 7 based on findings from multiple rate design studies conducted in the Company's GMO jurisdiction.				
	7(B-C)	Residential Demand Pilot (New)	Create original Schedule RD.	The Company is proposing to add a Residential Demand pilot program to its Rate Book 7 based on findings from multiple rate design studies conducted in the Company's GMO jurisdiction.				
	7(D-E)	Residential Demand plus Time of Use Pilot (New)	Create original Schedule RDTOU.	The Company is proposing to add a Residential Demand plus Time of Use pilot program to its Rate Book 7 based on findings from multiple rate design studies conducted in the Company's GMO jurisdiction.				
	9A, 10A, 11A	Misc. schedules	Adjusted language to add rate codes reflected by rate design.	The Company is proposing to add language identifying Space Heating rate codes along with Secondary General Use rate codes as both share the same charges not including a space heat energy charge.				
	9B	Small General Service	Remove Unmetered Service	The SGS Primary rate design does not include an Unmetered Service charge.				
	((9-11),14E, 18,49))E, (17,19)D, 49O	Misc. schedules	Adjust language referencing Non-MEEIA Opt Out Provisions location in tariff.	t The Company's proposal to add a Restoration charge will requre an adjustment to the Rule Nos. of Section 8 in the Rules and Regulation Book 2, thereby, adjusting Rule No. 8.09 to 8.10.				
	16, 16(A-B)	Clean Charge Network (New)	Create original Schedule CCN.	The Company is proposing to add a Clean Charge Network to its Rate Book 7 for both residential and non-residential customers.				
	21, 21(A-D)	Mpower Rider	Retire Schedule MP	The Company is proposing to eliminate its MEEIA Cycle I MPower program because this program is not available after April 1, 2016.				
	20, 20(A-E)	Two-Part Time-of-Use	Retire Schedule TPP	The Company is proposing to eliminate its Two-Part Time-of-Use schedule. There are no customers served on these frozen rates. Additionally, the administrative effort to continue to offer this unused product and maintain the tariff is overly burdensome.				
	22	Thermal Storage Rider	Delete reference to the Real-Time Pricing and Real-Time Pricing Plus Programs.	The Company is proposing to eliminate the Real-Time Pricing Program and Two-Part Time-of-Use schedule from its Rate Book 7.				
	25-25(A-D)	Real-Time Pricing	Retire Schedule RTP	The Company is proposing to eliminate both its Real-Time Pricing Program schedule. There are no customers served on these frozen rates. Additionally, the administrative effort to continue to offer this unused product and maintain the tariff is overly burdensome. Schedul				

ariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
	26-26(A-D)	Real-Time Pricing Plus	Retire Schedule RTP-Plus	The Company is proposing to eliminate both its Real-Time Pricing Program schedule. There are no customers served on these frozen rates. Additionally, the administrative effort to continue to offer this unused product and maintain the tariff is overly burdensome.
	28-28(A-E)	Standby Service Rider (New)	Retire Schedule SGC and propose new Schedule SSR.	The Company is proposing to retire it's current Standby Service for Self-Generating Customers and propose a Standby Service Rider in its place.
	29-29(A-D)	Special Contract Service	Adjust language and retire Sheet Nos. 29(C-D)	The Company is proposing to adjust the language within its Special Contract Service to reflect the proposed elimination of both the Real- Time Pricing program and the Two-Part Time-of-Use schedule.
	30, 30A	Standby or Breakdown Service	Retire Schedule SA	The Company is proposing to eliminate its Standby or Breakdown Service as it is frozen and there are no contracted customers. Additionally, the tariff is not available to customers after January 10, 1966.
	33, 33(A-B)	Private Unmetered Lighting Service	Mark sheets as frozen.	The Company is proposing to freeze its Private Unmetered Lighting Service and propose an original Private Unmetered LED Lighting Service to be made available to future customers.
	35, 35(A-B)	Municipal Street Lighting Service	(1) Adjust the language to re-define the availability of Schedule ML; (2) adjust language in Section 9.1 to reflect a Metal pole and not a steel pole; (3) eliminate Section 9.2 of Schedule ML and adjust successive Section Nos; (4) to grant customers the opportunity to us light types other than High Pressure Sodium Vapor; and (5) add an LED option not available at time of LED rollout.	The Company is proposing to adjust the language of its Municipal Street Lighting Service to closer align it across jurisdictions with that of the Company's GMO territory.
	39, 39(A-E)	Solar Subscription Pilot Rider (New)	Create original Schedule SSP.	The Company is proposing to add a a Solar Subscription Pilot Rider to its Rate Book 2 for all customers.
	40, 40(A-G) Renewable Ene (New)		Create original Schedule RER.	The Company is proposing to add a Renewable Energy Rider.
	44, 44(A-B)	Private Unmetered LED Lighting Service	Create original Schedule PL.	The Company is proposing to add an original Private Unmetered LED Lighting Service for both residential and non-residential custmers to its Rate Book 7 in an effort to replace its current Private Area Lighting rate schedules.
	45	Off-Peak Lighting Service	Adjust the language to re-define the availability of Schedule OLS to include both metered and unmetered customers.	The Company is proposing to adjust the language of its Off-Peak Lighting Service that allow for flexibility in the metering approach and to better coordinate service across jurisdictions.

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
	50.(11-19), 50.(21-31)	Fuel Adjustment Clause	Adjust language to account for operational changes.	The Company is proposing: (1) to resubmit the current FAC tariffs identified on Sheet Nos. $50.11 - 50.19$ with an update to the language within the subtitle of each making them applicable for service provided from June 8, 2017 through the effective date of the proposed ER-2018-0145 rate case, as these are the FAC rules and rates currently in effect; and (2) to submit a new set of Original Tariff Sheets $50.21 - 50.31$ as part of our ER-2018-0145 Rate Case that will update language for operational changes as well as update the allowable SPP transmission percentage recoverable through the FAC to 2016 FERC Form 1 data, update the base rate to reflect current net fuel costs and net system input, add language to establish additional voltage levels with regard to the FAC tariff rate recovery, and to add language related to the Renewable Energy Rider tariff.

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
Rules and Regulations	1(.02, .03)	Table of Contents	Adjust language to reflect proposed changes in Rule Nos.	The Company's proposal to add a Restoration Charge will require adjusting the Rule Nos. for Sections (3,8).
	1.04	Table of Contents	Adjust Language to reflect Rule 9.07 on Sheet 1.30F.	The Company's proposal to add Rule 9.04(D) requires movement of Rule 9.07 to Sheet No. 1.30F.
	1.04C	Table of Contents	Adjust language to delete Item #17 Home Appliance Recycling Rebate and make it Reserve For Future Use	The Table of Contents does not reflect the prior removal of the Home Appliance Recycling Rebate.
	1.14	Supplying Electric Service	 Adjust language in Rule 3.14; Add Rule 3.15 Restoration of Electric Service; Reorder Rule Nos. 	The Company is proposing to add a rule Rule 3.15 to its Rules and Regulations Book 2, thereby adjusting the Rule Nos. of successive rules within Section 3, that states if any customer were to terminate their electric service and request the Company to reconnect service within one years time, they must pay a Restoration Charge on top of any unpaid balance before electric service may be connected again. Furthermore, the Company is also proposing to adjust the language of Rule 3.14 so that the Customer may not become confused between a Reconnection and Restoration Charge. This proposed language will maintain consistency of Rules and Regulations books across jurisdictions.
	1.24 B-C	Metering	Place a space between the header and the first bullet.	To maintain format consistency throughout the Rules and Regulations Book 2.
	1.27	Billing and Payment	Add Rule 8.06 and adjust successive Rule Nos.	The Company is proposing to add a Rule 8.06 to its Rules and Regulations Book 2 defining the Restoration Charge applicable through the Company's proposed Rule 3.15.
	1.28	Billing and Payment	Adjust Rule Nos. to incorporate the addition of Rule 8.06.	The Company's proposal to add a Rule 8.06 require adjusting successive Rule Nos. throughout Section 8 of the Rules and Regulations Book 2.
	1.30 D-E	Extension of Electric Facilities	Adjust language to add Rule 9.04(D)	The Company is proposing to add Rule 9.04(D) to its Rules and Regulations Book 2 identifying construction charge reduction amounts specific for Residential and Non-Residential customers who locate Distribution Extensions on underutilized circuits.
	1.30F	Extension Upgrade	Remove language from Sheet 1.30E and place on Sheet 1.30F.	The Company's proposal to add Rule 9.04(D) requires expansion of Rule 9.07 to Sheet No. 1.30F.
	1.42	Private, Unmetered Protective Lighting Service	Remove Application for Private Area Lighting Service as it is no longer applicable	The Company is proposing to adjust the language of Rule 12.03 to remove the Application for Private Area Lighting Service and identify through Rule 12.03 that the Company may enter into agreements with customers or prospective customers as needed to complete requests for service that are relative to private or unmetered protective lighting.

Kansas City Power and Light Missouri Proposed Non-Rate Tariff RevisionsCase No. ER-2018-0145Tariff BookTariff SheetName of ScheduleProposed Ch

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support		
	2	Business Demand Side Management	Remove references to RTP and fix the format of the footer.	To maintain format consistency throughout the Rules and Regulations Book 2.		
	2.24	Residential Demand Side Management	Fix the format of the footer.	To maintain format consistency throughout the Rules and Regulations Book 2.		

	КС	P&L - Missouri Jurisdiction	Class REVENUE SUMMARY	/ - For Direct filing - ER-	2018-0145				
	(A)	(B)	(C)	(D)	(E)	F=B-(C+D)	H=F*(%) 1.88%		
MISSOURI RATE GROUP	Weather Normalized CG kWh	Revenue from Existing Rates (Including FAC, DSIM, EDR)(1)	FAC Rider/Adjustments	DSIM Rider/Adjustments	EDR credits**	Revenue from Existing Rates less FAC & DSIM adjustments (1)*	Requested Increase- from Rev Model excluding EDR gross- up (Equal increase)	Adj Request-FAC Impact (Lighting Spread to other classes)	Proposed Revenue - Full Increase
LARGE POWER TOTAL	1,945,646,593	\$ 154,588,113	\$ 5,902,200	\$ 6,547,602	\$ (1,884,376) \$ 141,588,547	\$ 2,660,038	-\$349,147	\$142,968,366
LARGE GEN SVC TOTAL	2,051,190,274	\$ 211,259,269	\$ 6,307,429	\$ 14,949,613	\$ (1,038,756) \$ 190,002,227	\$ 3,569,590	\$11,654	\$191,853,849
MEDIUM GEN SVC TOTAL	1,209,196,315	\$ 144,932,920	\$ 3,553,546	\$ 9,073,815	\$ (68,604) \$ 132,305,559	\$ 2,485,638	\$188,159	\$133,594,912
SMALL GEN SVC TOTAL	418,577,203	\$ 62,840,412	\$ 1,256,299	\$ 3,198,129	\$ (3,984) \$ 58,385,983	\$ 1,096,903	\$177,590	\$58,954,970
RESIDENTIAL TOTAL	2,591,713,540	\$ 353,723,045	\$ 6,878,525	\$ 8,874,407	(\$118) \$ 337,970,114	\$ 6,349,478	\$8,927,744	\$349,243,691
MO Metered TOTALS	8,216,323,925	\$ 927,343,759	\$ 23,898,000	\$ 42,643,566	\$ (2,995,838) \$ 860,252,430	\$ 16,161,647	\$ 8,956,000	\$ 876,615,788
MO Lighting TOTAL:	83,584,174	\$ 10,999,456	\$ 262,762	\$ -	\$-	\$ 10,736,694	\$ 201,711		\$10,736,694
MO TOTAL	8,299,908,098	\$ 938,343,216	\$ 24,160,762	\$ 42,643,566	\$ (2,995,838) \$ 870,989,124	\$ 16,363,358	\$ 8,956,000	\$ 887,352,482

⁽¹⁾ All classes' revenues reflect both EDR/Mpower(DRI) credits and Manual Bill revenue.

*Across all classes, consistent with the MEEIA S&A, adjustment of test year retail base sales are made to reflect MEEIA kw/kWh savings. A DSIM LPS non-customer specific adjustment was made of \$549,763.85. Note: All other adjustments were made at the customer level consistent with all other LPS adjustment/revenues. ** Includes Mpower Credits and net metering credits.

		KCP&L - Missou	ri Jurisdiction Class REVEN	IUE SU	MMARY - For Direc	rt fili:	ing - ER-2018-0145					
	(A)	(B)	(C)		(D)		(E)	F=B-(C+D)	H=F*(%) 1.88%			
MISSOURI RATE GROUP	Weather Normalized CG kWh	Revenue from Existing Rates (Including FAC, DSIM, EDR)(1)	FAC Rider/Adjustments	³ Rie	DSIM der/Adjustments		EDR credits**	Revenue from Existing Rates less FAC & DSIM adjustments (1)*	Requested Increase- from Rev Model excluding EDR gross- up (Equal increase)	Requested Increase- Revenue Shifts with EDR gross up	Proposed Revenue (1)	
LARGE POWER TOTAL	1,945,646,593	\$ 154,588,11	3 \$ 5,902,200	0 \$	6,547,602	\$	(1,884,376)	\$ 141,588,547	\$ 2,660,038	\$1,415,662	\$ 142,968,366	
LARGE GEN SVC TOTAL	2,051,190,274	\$ 211,259,26	9 \$ 6,307,429	9\$	14,949,613	\$	(1,038,756)	\$ 190,002,227	\$ 3,569,590	\$1,871,381	\$ 191,853,849	
MEDIUM GEN SVC TOTAL	1,209,196,315	\$ 144,932,92	0 \$ 3,553,546	6\$	9,073,815	\$	(68,604)	\$ 132,305,559	\$ 2,485,638	\$1,290,658	\$ \$ 133,594,912	
SMALL GEN SVC TOTAL	418,577,203	\$ 62,840,41	2 \$ 1,256,299	9\$	3,198,129	\$	(3,984)	\$ 58,385,983	\$ 1,096,903	\$569,063	\$ \$ 58,954,970	
RESIDENTIAL TOTAL	2,591,713,540	\$ 353,723,04	5 \$ 6,878,525	5\$	8,874,407		(\$118)	\$ 337,970,114	\$ 6,349,478	\$11,273,580	\$ 349,243,691	
MO Metered TOTALS	8,216,323,925	\$ 927,343,75	9 \$ 23,898,000	0\$	42,643,566	\$	(2,995,838)	\$ 860,252,430	\$ 16,161,647	\$ 16,420,344	\$ 876,615,788	
MO Lighting TOTAL:	83,584,174	\$ 10,999,45	6 \$ 262,762	2 \$	-	\$	-	\$ 10,736,694	\$ 201,711		\$10,736,694	
MO TOTAL	8,299,908,098	\$ 938,343,21	6 \$ 24,160,762	2\$	42,643,566	\$	(2,995,838)	\$ 870,989,124	\$ 16,363,358	\$ 16,420,344	\$ 887,352,482	

⁽¹⁾ All classes' revenues reflect both EDR/Mpower(DRI) credits and Manual Bill revenue.

*Across all classes, consistent with the MEEIA S&A, adjustment of test year retail base sales are made to reflect MEEIA kw/kWh savings. A DSIM LPS non-customer specific adjustment was made of \$549,763.85. Note: All other adjustments were made at the customer level consistent with all other LPS adjustment/revenues. ** Includes Mpower Credits and net metering credits.