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:	KCP&L Greater Missouri Operations Company
Case No.:	ER-2018-0146
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2018-0146

DIRECT TESTIMONY

OF

MARISOL E. MILLER

ON BEHALF OF

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Kansas City, Missouri
January 2018

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DIRECT TESTIMONY

OF

MARISOL E. MILLER

Case No. ER-2018-0146

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.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L" or "Company") as Supervisor – Regulatory Affairs.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L Greater Missouri Operations Company ("GMO").

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.

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.

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

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

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to:

I. Explain how the Company satisfied the MPSC's minimum filing requirements ("MFR") under 4 CSR 240-3.030 for this rate case filing;

II. Explain and support the Company's annualized/normalized revenues;

III. Provide an update on MPSC ordered Rate Design Studies

IV. Explain the Electric Class Cost of Service ("CCOS") Study; and

V. Explain and support the Company's Electric Rate Design.

I. MINIMUM FILING REQUIREMENTS

Q: What is the purpose of this part of your testimony?

A: The purpose of this part of my testimony is to confirm that GMO has satisfied the MPSC's MFR, as set forth in 4 CSR 240-3.030.

Q: How did GMO satisfy the MFR?

A: The following information was prepared and attached to the Company's Application filed concurrently with this testimony, to address the specific requirements of the MFR as outlined in 4 CSR 240-3.030(3):

A. Letter of transmittal;

B. General information, including:

1. The dollar amount of the aggregate annual increase and percentage over current revenues;
2. Names of counties and communities affected;
3. The number of customers to be affected;

4. The average change requested in dollars and percentage change from current rates;

5. The proposed annual aggregate change by general categories of service and by rate classification;

6. Press releases relative to the filing; and

7. A summary of reasons for the proposed changes.

II. ANNUALIZED/NORMALIZED REVENUES

Q: Were the retail revenues included in this filing prepared by you or under your supervision?

A: Yes, they were.

Q: Will you describe the method used in developing the revenues for this case?

A: Both the weather-normalized kilowatt-hour ("kWh") sales and customer growth levels by rate class were developed by Company witness Albert R. Bass, Jr. Mr. Bass explains those figures in his Direct Testimony. The test year used by the Company in this case was the 12 months ending June 30, 2017, which we expect will be updated through June 30, 2018. The monthly bill frequencies for the 12 months ending June 30, 2017, that contain the billing units for each of the billing blocks for the various rate components, were developed under my supervision. GMO's test year spanned a period where billed revenues included rate classes/rate structures that were pre-consolidated (July 2016-February 2017), as well as, consolidated (February 2017-June 2017). As such, consolidated bill frequencies were developed by collecting the actual usage and customer counts billed in each month of the test period and applying them to the existing rate structures. The pre-consolidated actual revenues were weather normalized and adjusted for customer growth. The pre-consolidated revenues were then multiplied by the rate increase that took effect on February 22, 2017 to obtain the weather normalized and customer growth adjusted monthly revenues available. Finally, these monthly revenues by class were moved to the equivalent consolidated rate class (e.g. pre-consolidated small general service class revenues were moved to the equivalent consolidated small general service class). The sum of these monthly revenues was compared to the actual revenues for the test year ending June 30, 2017 to determine the revenue adjustment contained in the Summary of Adjustments attached to the Direct Testimony of Company witness Ronald A. Klote as Schedule RAK-4 (adjustment no. R-20).

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.

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

A: The Demand-Side Investment Mechanism ("DSIM") and the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") Rider is separate from the revenue requirement requested in this case and thus the associated DSIM/RESRAM 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 testimony on the FAC, please see the Direct Testimony of Tim M. Rush for the primary details concerning the FAC in this case.

III. RATE DESIGN-STUDIES-UPDATE

Q: Rate Design studies were ordered in GMO's last rate case. Can you explain what was ordered and the status of the studies?

A: In GMO's last rate case ("ER-2016-0156"), a Stipulation & Agreement ("S&A") was filed on September 20, 2016 outlining several studies to be completed by GMO's next rate case or rate design case. The specific S&A language included the following:

> *"Agree to study 1) modifying GMO's seasonal rates in a future rate proceeding to establish rates for Peak months and Shoulder months, as opposed to GMO's current Summer/Non-Summer seasonal split, including applicable determinants; and 2) responsible energy use as related to residential block rates. The Company will work with the Signatories to define the scope of study. GMO will file the results of this study as part of its direct testimony in GMO's next general rate case or rate design case, whichever occurs first."*

> *"GMO will include in its direct filing in its next rate case or rate design case a study of TOU rates for GMO including TOU residential and SGS rates, critical peak rates, Electric Vehicle TOU rates for stand-alone charging stations, TOU rates applicable to Electric Vehicle charging associated with an existing account, Real Time Pricing, Peak Time Rebates, and other rate types which could encourage load shifting/efficiency. GMO will propose rates based on this study no later than its next rate case or rate design case."*

Q: Are these studies included/filed in this rate case filing?

A: Yes. They are attached as Schedules MEM-1, MEM-2, and MEM-3.

Q: What were the overall results of the studies?

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

Based on the overall analysis, this study does not support modifying the current seasons used by GMO. The cost analysis documents higher average costs in the summer months supporting the current two season rate structure, and the review of regional utility rates indicates that the GMO summer/winter seasons is consistent with the seasonal structure used by other utilities. Furthermore, introducing additional seasons would lead to greater complexity and create potentially confusing price signals for customers due to the cyclical nature of the billing process.

Residential Block Study - The purpose of this study was to evaluate the role of residential energy blocks in promoting responsible energy use. This analysis was not intended to determine which rate structures should be offered, but rather to identify 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.

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

Time of Use Study - 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.

The TOU Rate Study ("Study") consisted of collecting information and conducting qualitative and quantitative analyses of the existing GMO Residential and Small General Service rates and analyzing new Residential and Small General Service TOU rate designs.

The development and design of rates for the Residential and Small General Service classes was based upon consideration of Company goals, application of good rate making principles, consideration of the qualitative ratings, comparison to common practice, and the experience of BMcD in this area. Further, the designs were evaluated using load research and CCOS analysis, designed to be revenue neutral to the existing rates in each class, reflect the utility's CCOS by season and time-period, and to meet GMO and KCP&L's rate design objectives described in the report.

The Study recommendations include offering three new Residential rate options: (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.

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

A: The Company is including a proposal to offer to Residential Customers a Demand Rate Pilot, a TOU Energy Pilot, and a pilot that includes a TOU Energy Rate and a Demand Rate in this rate case filing.

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

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

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

A: The Company's plan to ensure pilot success is to track and analyze pilot program results/progress over time to inform 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 on a smaller scale. This information will take some time to analyze, as well as, require further consideration and modification to determine that a broader implementation will be beneficial to most customers in the Residential class. Ultimately, 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.

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

A: No, the TOU study utilized dated (latest available at the time the study was performed) Class Cost of Service Studies and Load Research. 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.

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

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

IV. ELECTRIC CLASS COST OF SERVICE STUDY

Q: Please give an overview of the Company's testimony supporting the electric Class Cost of Service study.

A: The CCOS study is supported by the following Company witnesses:

- Brad Lutz's direct testimony includes a summary of past CCOS studies and production allocation methodologies used and provides an explanation of the process resulting in a recommended change in the production allocation method.

- Tom Sullivan's direct testimony provides a discussion and support for utilization of the Average & Excess production allocation method ("A&E").
- This testimony includes discussion of the preparation of the CCOS study filed in this proceeding.

Q: Has the Company performed a CCOS study for this case?

A: Yes, the Company performed a CCOS study representative of the GMO jurisdiction. A summary of the results of the Company's CCOS studies are attached and marked as Schedule MEM-4.

Q: Was the study prepared by you or under your direct supervision?

A: Yes, it was. Consistent with prior filings, the Company retained the services of Management Applications Consulting who performed the primary CCOS modeling using their proprietary software and data provided by the Company.

Q: Has the Company filed a CCOS in previous rate cases?

A: Yes. In all rate cases filed since 2008, the Company has filed a CCOS study.

Q: What is the purpose of the CCOS study?

A: The purpose of the CCOS study is to directly assign or allocate each relevant component of cost on an appropriate basis in order to determine the contribution that each customer class and rate makes toward the Company's overall rate of return. The CCOS analysis strives to attribute costs in relationship to the cost-causing factors of demand, energy and customers.

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

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 exploring the distribution of costs to the respective classes.

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

A: The primary classes the Company used in its analysis are Residential, Small General Service, Large General Service, Large Power Service, and Lighting. Additionally, the study includes details at the rate level.

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

A: Generally, they do. The Residential class has several rate classifications available to it that include general use, one-meter general use and heat, and a two-meter rate with general use on one meter and a separate meter for space heating. The Small General Service and Large General Service classes also have general usage rates and all electric rates, plus they can be specific to the voltage level at which the customer receives service. The Large Power Service class is distinguished by the specific voltage at which the customer receives service. In total, the Company has four classes of service (plus Lighting), but has approximately 27 rates to meet the specific needs of the customer and reporting and billing requirements.

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, with known and measurable changes projected through June 30, 2018.

Q: What general categories of costs 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.

Q: 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.

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.

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.

Q: After the above classification of plant investment and operating costs into customer- energy- and demand-related components, what was the next step in the CCOS study?

A: The next step was to allocate each of the three categories of cost to each customer class utilizing allocation factors appropriate for each of the above categories of cost.

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. Customer-related 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 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.

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.

Q: Was GMO's load research data used to develop any other allocators?

A: Yes, it was used to develop distribution plant allocators based on customer's non-coincident loads within each class.

Q: Are any costs assigned directly to classes?

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

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

A: Production plant is the single, largest component cost to allocate to the classes within the study. As such, the production allocator has the most impact on the outcome of the CCOS study. After considering all allocation theories and ensuring that the selected method aligned with the principles of reflecting actual planning and operating characteristics, cost causation, recognizing the broad set of customer class characteristics and their usage, and producing stable results on a year to year basis, the Company selected the utilization of the Energy Weighted approach, specifically the Average & Excess Production Plant Allocation method, incorporating a four (4) Coincident Peak (CP) component. An Energy Weighted approach was viewed to be cost effective, balanced through its incorporation of energy, and less subjective than other methods. Utilization of the Average & Excess method is an energy-weighted method of production plant allocation that gives classes a reasonable balance between the energy and capacity function of generating facilities.

Q: Has this allocation method been proposed before?

A: Yes. Company witness Tom Sullivan identifies in his direct testimony other companies in the region that have proposed this method. In addition, other parties have proposed variations of the A&E in testimony of other GMO rate case dockets.

Q: How were the fuel costs associated with the production plant allocated in the CCOS study?

A: Fuel costs were allocated using a monthly kWh allocator. Based on monthly fuel costs from the Company for the 12 months ended June 30, 2017, each month's fuel costs were allocated to each customer class's corresponding calendar month kWh sales adjusted for losses. These allocated results were summed by rate and major customer class to identify a proxy fuel allocator which was then used to allocate the actual fuel costs shown in the CCOS study.

Q: How were the off system sales margins that GMO receives from its external sales of energy allocated?

A: They were allocated using the Energy allocator.

Q: What method did you use to allocate transmission plant costs?

A: Transmission plant costs were allocated using Average & Excess -4 four coincident peaks ("4CP").

Q: What method did you use to allocate Distribution Plant?

A: Distribution Plant was primarily allocated using a Non-Coincident Peak ("NCP") demand allocator based on the use of NCP class demands for Primary Plant in Accounts 360 through 367, with the exception of Account 363, which used a 12-CP demand allocation. Also, Accounts 364, 365, 366 and 367 included methods to recognize primary and secondary voltage cost separation.

Q: What method did you use to allocate Line Transformers and secondary plant?

A: Line Transformers and secondary plant costs were allocated to customers receiving secondary service based on the weighted average of the diversified class demands (NCP) and undiversified individual customer maximum demands.

Q: What method did you use to allocate Services?

A: Since we consider services customer-related, these costs were allocated based on the customers total diversified maximum customer demands.

Q: What method did you use to allocate Meters?

A: Meter costs, recorded to Account 370, are also customer-related and were allocated using an assignment of all meters and metering devices to customer rates.

Q: Did you include any other rate base elements in the study?

A: Yes, multiple rate base elements have been included. The following details their allocation:

- Additions to net plant included cash working capital, materials and supplies, prepayments, fuel inventory, and various regulatory assets.
- The cash working capital component of rate base was developed and allocated on related expenses or plant in the CCOS study.
- Materials and supplies were allocated on total plant .
- Prepayment items were allocated on total plant.
- Fuel inventory was allocated on energy.

- The regulatory assets were allocated on labor, energy, or demand allocation factors depending on the costs tracked.
- The accumulated deferred taxes were allocated on total plant.
- Customer advances for construction were allocated on total distribution plant.
- Customer deposits were developed using the data analysis by customer group available from the Company.

Q: What revenues did you use for this study?

A: The class and rate revenues were developed under my supervision and were discussed earlier in this testimony. Other sources of revenues such as Miscellaneous Revenues were allocated consistent with the revenue source.

Q: How were Operation and Maintenance ("O&M") Expenses allocated?

A: O&M Expenses were allocated using various methods dependent of the cost causation. O&M for production, transmission and distribution plant were allocated to customer classes following plant. Customer Accounts Expenses, Customer Services and Information Expenses, Sales Expenses, and Administrative and General Expenses were allocated based on the results of individual allocation studies. Administrative & General expenses were primarily allocated on the labor allocator with the exception of the following:

- Account 930.1, General Advertising, which was allocated based on the number of customers
- Account 928, Regulatory Commission expenses, which was primarily allocated to classes on revenues at the uniform claimed rate of return
- Account 935 Maintenance of General Plant, which was allocated on general plant.

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

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

Q: What were the results of the CCOS study?

A: The jurisdictional rate of return was calculated to be 6.9%. Individual classes' rates of return at current rates vary, and based on the current costs, are shown in the following table.

Residential	Small General Service	Large General Service	Large Power Service	General Time of Day Service	Thermal Service	Other Lighting
5.3%	13.2%	7.4%	8.2%	11.5%	4.5%	6.2%

Q: If rates were changed so that GMO earned the same rate of return from each customer class, how much would each class's rates need to change?

A: To achieve the jurisdictional revenue increase of 2.6%, the classes should be adjusted by the percentages in the table below.

Residential	Small General Service	Large General Service	Large Power Service	General TOD Service	Thermal Service	Other Lighting
9.1%	-15.5%	0.8%	-1.5%	-11.2%	11.2%	6.7%

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, Thermal, and Lighting classes revenues are below the Total Missouri ("MO") Retail rate of return level, the Large Power and Large General class revenues are above the Total MO Retail rate of return, while the Small General and General Time of Day ("TOD") Service class revenues are well above.

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

A: Yes, another element of the study was to explore costs at the rate level. This data provides additional information to aid the Company in preparing its rate design. Schedule MEM-5 is attached and contains this rate level information.

Q: Is seasonality still reflected in the study?

A: No. Seasonality has been removed from the study because it more closely relates to rate design and is discussed in the rate design section of this testimony.

Q: Are you proposing changes to the class revenues based on the results of the study?

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 a 3.85% increase to the Residential class, and
- Apply a 1.31% increase equally to the remaining classes

Application of these proposals to the electric rates is discussed further in the rate design section of this testimony.

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

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

V. ELECTRIC RATE DESIGN

Q: Are you sponsoring the electric tariffs filed in this case?

A: Yes, I am.

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 decrease over current revenues reflecting impacts before the rebasing of fuel for the fuel adjustment clause, in the amount of $2.4 million (-0.32%). The aggregate annual increase over current revenues including the rebasing of fuel for the fuel adjustment clause is $19.3 million (2.61%).

Utilizing the results of the CCOS, the Company is proposing that an increase of 3.85% be applied to Residential class revenues with a customer charge of $14.50. The $14.50 proposed customer charge is based on the results of the CCOS and is consistent with prior Commission approved customer charges. The remaining revenue shortfall/increase was then applied equally to remaining Residential bill components. 1.31% increase would be applied to all remaining classes on an equal percentage basis, including Lighting, but excluding the recently approved Light Emitting Diode ("LED") Municipal Street Lighting rates. Company witness Brad Lutz provides additional support for how the increase will be applied to the LED Lighting rates. The Large General Service and Large Power classes would have 75% of the increase applied to the second energy block with the remainder of the increase applied equally to the remaining components. The summary of revenues and proposed increase by class may be found in Schedules MEM-6 and MEM-6A.

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 Rider, a Solar Subscription Pilot Rider, as well as proposal of a new Standby tariff. Company Witness Brad Lutz explains this in detail in his Direct Testimony, as well as, and update on the latest lighting initiatives.

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

A: The specific, proposed changes to rules and regulations and non-base rate tariffs may be found in Schedule MEM-7. Changes are proposed to better align the rules & regulations with current costs or planned business practices and are generally minimal in impact. The most significant changes included elimination to of the frozen Real-Time

Pricing tariffs and modifications of the Special Contracts tariffs. The special contract tariffs were streamlined to better align with business practices and the frozen RTP tariffs are being proposed to be eliminated given the administratively burdensome nature to maintain these frozen tariffs.

Q: Does the Company propose any changes to the GMO Lighting class?

A: Yes**.** As mentioned previously, the CCOS studies indicated the unmetered Lighting class should be increased. However, based on the introduction of LED in GMO's jurisdiction in tariff filing JE-2016-0344 on June 1, 2016, the application of this increase will impact specific lighting rates only. Please see the Direct Testimony of Company witness Brad Lutz for more detail on how this increase will be applied within the Lighting class.

Q: Are you proposing any additional tariff changes?

A: Yes, there have also been changes to the FAC tariffs that are explained in detail in the Direct Testimony of Company witness Tim. M. Rush.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

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 KCP&L Greater Missouri Operations Company consisting of twenty-four (24) 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 29th day of January 2018.

Notary Public

My commission expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

KCP&L Greater Missouri Operations Company

Seasonal Rate Structure Study

December 12, 2017

KCP&L Greater Missouri Operations Company
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I. Executive Summary

Under the terms of settlement[1] for its most recent rate case (ER-2016-0156), Kansas City Power & Light (KCP&L) Greater Missouri Operations Company (GMO) conducted this study to evaluate the reasonableness of modifying the seasonal rate structure for residential customers. The purpose was to consider alternate methods for representing the seasons within the residential rates, specifically a peak and shoulder month seasonal rate structure, as opposed to the current summer/winter seasons, if the change would better reflect the current drivers of system capacity needs, the market energy price variation, and any other relevant drivers.

The results of this analysis support the current summer/winter seasons when evaluated on an allocated cost basis. To help in the evaluation of monthly capacity and energy costs, a residential revenue requirements model was constructed using allocated rate base costs and actual operating cost data from 2015 and 2016, which represent the first two full years of GMO's participation in the Southwest Power Pool (SPP) Integrated Marketplace[2]. These costs were applied to weather-normalized, customer growth-adjusted (WN/CG) billing frequency data[3] to estimate an average cost per kWh. The analysis shows the monthly average cost ($/kWh) for residential customers is distinctly higher in the summer months of June through September. The model estimates the average cost for the summer months of $0.15/kWh in both 2015 and 2016, while all other non-summer months averaged about 5 cents per kWh lower, or $0.10/kWh. Figure 11 on page 19 shows the difference in summer and non-summer prices based on the residential revenue requirements model and provides support for the current summer/winter seasons.

From the scope of work developed with the rate case settlement Signatories, cost alignment was established as a critical consideration and therefore the primary driver of the analysis. Rate base costs were allocated based on a review of customer usage data[4] that documented higher average and peak usage in the summer months. This peak component of the allocation methodology is reflective of the utility planning process and is consistent with the approach employed in filing for the recent GMO rate case. The resulting allocation produced rate base costs[5] that were higher in the summer months, driven primarily by the combined average and peak method applied to production assets[6]. Operating costs were assigned based on a review of historical data. The review documented somewhat higher SPP market costs in the summer months on a $/kWh basis. However, the variability from month to month

[1] ER-2016-0156 Non-Unanimous Stipulation and Agreement, filed September 20, 2016 ("ER-2016-0156 Stipulation")

[2] https://www.spp.org/markets-operations/integrated-marketplace/

[3] CCOS Consolidated Allocator file from ER-2016-0156

[4] Average usage history for 2015 and 2016 taken from Report 1A Comparative Total Electric Revenues, which reports sales on an accrued basis; peak usage from WN/CG data used for production rate base allocation.

[5] Rate base costs were allocated using WN/CG sales volumes and following the method used in CCOS model for ER-2016-0156.

[6] Consistent with the scope defined for this study, GMO utilized class cost of service data that was readily available to understand costs. This class cost of service data was created for the ER-2016-0156 rate case and utilized an average and peak allocation methodology for production costs. GMO is in the process of performing new class cost of service studies and is evaluating allocations used within that process. Allocations used in these new studies may not match those used in the past and any change could affect the conclusions offered in this report.

within the year was relatively small, indicating a degree of price stability in the SPP market during the period analyzed.

As an additional element of the study scope, this study reviewed seasonal rate structures at other utilities in the region. The findings here demonstrated that the summer/winter seasons employed by GMO is consistent with the seasonal rate structures used by other utilities. The review included residential rates for twenty-eight utilities (excluding KCP&L) and found that twenty employ summer/winter seasons and eight offer the same rates year around. When the review is restricted to the eleven states including Missouri and its neighboring states, ten use summer/winter seasons and one offers the same rates year around.

As a final element, this study considered the impact that additional seasons could have on customer billing. Due to the current cyclical billing of customers, there are differences between the timing of usage and the billing rate in the transition months between seasons. This effect is especially pronounced for customers who are billed on or shortly after the first of the month, where the rate for the billing month is applied to usage that largely corresponds to the previous month. While this creates some complexity with the current two seasonal rate periods (summer/winter), introducing additional rate seasons would bring even greater complexity, with each extra season producing two additional cross-over months. Implementing many cross-over months would result in a larger disconnect between the usage and the billing, confusing any price signals associated with the rates.

Based on the overall analysis, this study does not support modifying the current seasons used by GMO. The cost analysis documents higher average costs in the summer months supporting the current two season rate structure, and the review of regional utility rates indicates that the GMO summer/winter seasons is consistent with the seasonal structure used by other utilities. Furthermore, introducing additional seasons would lead to greater complexity and create potentially confusing price signals for customers due to the cyclical nature of the billing process.

II. Background and Purpose

In its most recent rate case (ER-2016-0156), KCP&L Greater Missouri Operations Company (GMO) agreed to conduct a study considering a revised seasonal approach for residential energy pricing that modifies the current summer/non-summer seasons to include shoulder months.

In the case, a non-unanimous stipulation and agreement was established, and the Signatories agreed in part "***to study 1) modifying GMO's seasonal rates in a future rate proceeding to establish rates for Peak months and Shoulder months, as opposed to GMO's current Summer/Non-Summer seasonal split, including applicable determinants*** *(emphasis added)*; and 2) responsible energy use as related to residential block rates. The Company will work with the Signatories[7] to define the scope of study. GMO will file the results of this study as part of its direct testimony in GMO's next general rate case or rate design case, whichever occurs first."[8]

The agreement was developed in response to recommendations from the Missouri Public Service Commission (PSC) offered in the Staff Report on Rate Design and the Rebuttal Testimony of staff witness Sarah L. Kliethermes. The Staff Report recommended in part that GMO *"consider moving to Peak and Shoulder month seasonal rates that better reflect the current drivers of system capacity needs and the market energy price variation."*[9] In her subsequent rebuttal testimony, PSC witness Kliethermes recommended that the Commission order GMO to file a rate design case upon the completion of one year's worth of load research data that includes, among other items, *"a study of the reasonableness of modifying GMO's seasonal rates to establish rates for Peak months and Shoulder months, as opposed to GMO's current Summer / Non-Summer seasonal split, including applicable determinants."*[10]

This effort is being performed in conjunction with other studies concerning rate design. Resulting from the same Commission order, the Company is also examining its block rate structure. Additionally, as a result of an order in the KCP&L-Missouri jurisdiction, the Company is also reviewing the feasibility of dynamic rates such as real-time pricing. All of these efforts will continue to influence rate design strategy going forward.

[7] The Signatories are KCP&L Greater Missouri Operations Company, Staff of the Missouri Public Service Commission, Missouri Department of Economic Development – Division of Energy, Midwest Energy Consumers Group, and Missouri Industrial Energy Consumers.
[8] ER-2016-0156 Stipulation, page 9 and 10.
[9] Staff Report – Rate Design, ER-2016-0156, filed July 29, 2016, page 28, line 11.
[10] Rebuttal Testimony of Sarah L. Kliethermes, ER-2016-0156, filed August 15, 2016, page 16, line 19.

III. Seasonal Split Study Scope

In accordance with the previously mentioned stipulation and agreement, GMO worked with the Signatories to define the scope of the seasonal and block rate studies. For purposes of this report, which focuses on the seasonal rate study, the scope was defined as follows:

> *The Company will review and evaluate the appropriateness of modifying the current summer and winter seasonal split used for pricing in its residential retail rates. Utilizing cost and usage data that is readily available, the Company will determine if any alternative monthly splits can provide better cost alignment. Specifically, the Company will review costs related to energy supply, transmission, distribution, and customer service to determine the influence on monthly cost variation. Consideration will be made for applicability with: other rate design alternatives that might be proposed, the influence of customer billing cycles, and impact on revenue recovery. The Company will also investigate the seasonal splits utilized by other electric utilities to determine if any alternative might be appropriate for the Company. At a minimum, utilities considered will be located in Missouri and neighboring states.*[11]

It is important to note here that the scope is limited to residential rates using cost and usage data that are readily available[12]. The focus on residential rates recognizes the monthly variability and consequent impact this customer class has on overall system demand for capacity and energy. Furthermore, the use of readily available data should be sufficient to review and evaluate the appropriateness of modifying the seasons based on cost alignment; the goal of this study is not to develop a detailed rate design, which could require additional data and more extensive analysis.

[11] The scope was defined by the Company and no objections offered by the Signatories on January 23, 2017 following two earlier conference calls to discuss.

[12] Examples of readily available data include historical financial statements (income statement and balance sheet), SPP market reports, and existing Class Cost of Service studies.

IV. Methodology

The analytical approach for this study was geared toward determining if there is a seasonal split that better reflects the current drivers of system capacity needs and the market energy price variation.

To assess the reasonableness and appropriateness of modifying the existing seasonal rate structure, this study assembled and reviewed cost data on a monthly basis for 2015 and 2016, which represent the first two full calendar years of GMO's participation in the SPP Integrated Marketplace. In the current business model, the SPP market exerts a strong influence on utility revenue requirements, since under this new market construct GMO purchases its entire customer load from SPP and sells its generator output to SPP, a change from when GMO managed its own load requirements. The seasonality of customer demand and resource availability influence the market price for energy and the cost to serve customers.

This study incorporated the following elements: 1) Seasonal Rates at Other Utilities Review, 2) GMO Customer Usage Review, 3) GMO Cost Review, and 4) GMO Residential Revenue Requirements Modeling.

> *Seasonal Rates at Other Utilities*. Prior to beginning the GMO analysis, a review of seasonal rates at other utilities was conducted to determine how other electric providers address seasonality and assess if there may be appropriate alternatives for GMO to consider.[13]
>
> *Customer Usage Review*. The customer usage review is important to the study, since customer demand and usage patterns can influence asset allocation and monthly operating costs. In fact, the observed seasonality of residential customer usage has been offered to support the recommendation for conducting this study.[14]
>
> *GMO Cost Review*. Following the customer usage review, a review of costs was conducted, beginning with an examination of income statements for 2015 and 2016. While the income statements present information from an accounting perspective rather than a cost-allocated view, the cost information contained therein is a key input to the development of a residential revenue requirements model.[15]
>
> *GMO Residential Revenue Requirements Modeling*. Following the cost review, a residential revenue requirements model was constructed to produce a monthly projection of revenue requirements using allocated cost assignments for rate base and cost of service elements. These allocations included considerations of maintenance scheduling and operational practices utilized by GMO. A review of the monthly revenue requirements was then used to evaluate variations in cost and assess the potential for modifying the existing summer/non-summer seasonal design.[16]

[13] Refer to Section V for detailed analysis.
[14] Refer to Section VI for detailed analysis.
[15] Refer to Section VII for detailed analysis.
[16] Refer to Section VIII for detailed analysis.

V. Seasonal Rates at Other Utilities

Prior to beginning the GMO analysis, a review of residential seasonal structures used at other utilities was conducted. The purpose of this review was to determine if any alternative might be appropriate for GMO to consider. Twenty-eight utilities (not including KCP&L) in Missouri and other regional states were reviewed. The complete list is included in following table.

TABLE 1. RESIDENTIAL RATES SUMMER SEASON SUMMARY

Residential Rates - Summer Season Summary

	Utility	State	Summer Period (if applicable)	Summer Peak (MW)	Winter Peak (MW)	W/S	EIA-861 State
Bordering States	Empire District Electric Company	MO	First four monthly billing periods on and after June 16	1,094	1,149	1.05	MO
	Union Electric	MO	Jun - Sep billing periods	7,661	6,843	0.89	MO
	Entergy Arkansas	AR	Jun - Sep	4,665	4,035	0.86	AR
	Oklahoma Gas and Electric	AR	Jun - Oct revenue months	5,808	4,772	0.82	OK
	Interstate Power & Light	IA	Jun 16 - Sep 15	3,005	2,531	0.84	IA
	MidAmerican Energy	IA	Jun - Sep billing periods	4,624	3,755	0.81	IA
	MidAmerican Energy	IL	Jun - Sep billing periods	4,624	3,755	0.81	IA
	Empire District Electric Company	KS	Year Around	1,094	1,149	1.05	MO
	Westar	KS	Jun - Sep billing months	2,637	1,801	0.68	KS
	Oklahoma Gas and Electric	OK	Jun - Oct revenue months	5,808	4,772	0.82	OK
	Public Service Company of Oklahoma	OK	Jun - Oct billing months	4,164	2,974	0.71	OK
Regional States	Montana-Dakota Utilities Co.	ND	Jun - Sep	664	606	0.91	ND
	Otter Tail Power	ND	Jun - Sep	716	897	1.25	MN
	Black Hills Power	SD	Year Around	424	308	0.73	SD
	NorthWestern Energy	SD	Year Around	309	301	0.97	SD
	MidAmerican Energy	SD	Jun - Sep billing periods	4,624	3,755	0.81	IA
	Montana-Dakota Utilities Co.	SD	Jun - Sep	664	606	0.91	ND
	Otter Tail Power	SD	Jun - Sep	716	897	1.25	MN
	Minnesota Power	MN	Year Around	1,442	1,637	1.14	MN
	Northern States Power	MN	Jun - Sep	7,298	5,578	0.76	MN
	Otter Tail Power	MN	Jun - Sep	716	897	1.25	MN
	Consolidated Water Power Company	WI	Year Around	154	152	0.99	WI
	Superior Water, Light and Power Company	WI	Year Around	122	123	1.01	WI
	Wisconsin Electric Power	WI	Year Around	5,314	4,318	0.81	WI
	Wisconsin Public Service	WI	Year Around	2,117	1,797	0.85	WI
	Madison Gas & Electric	WI	Jun 1 - Sep 30	651	505	0.78	WI
	Northern States Power	WI	Jun - Sep	7,298	5,578	0.76	MN
	Wisconsin Power & Light	WI	Jun - Sep	2,564	2,153	0.84	WI

Note: Peak demand data taken from 2015 EIA-861 Form. Some utiliities with multiple locations report under one state; refer to EIA-861 State column for reporting state.

The initial review found only one utility, Oklahoma Gas & Electric (OG&E), utilizing a shoulder season for residential customers. In addition to summer and winter seasons, OG&E's Oklahoma utility identified the months of May and October as a shoulder season. However, GMO later discovered that OG&E has eliminated the shoulder season in their latest rate case to make the season definitions consistent with other OG&E tariffs.[17] With the results of this change reflected in the table above, twenty of the twenty-eight utilities reviewed have summer and non-summer seasons and eight do not recognize different seasons.

For the utilities offering the same rates year around, seven of the eight are located in states to the north of Missouri. While a dual (summer/winter) peaking nature may help to explain this rate structure for some of the utilities in this grouping, this is not a consistent finding. A review of 2015 peak demand data from EIA-861 shows that three of the seven utilities (NorthWestern Energy, Consolidated Water Power Company, and Superior Water, Light and Power Company) had summer and winter peaks that differed by less than 3%, indicating summer and winter peaks that were relatively close in magnitude. However, one of the seven (Minnesota Power) had a significant winter peak that was nearly 14% higher than the

[17] Oklahoma Gas & Electric Company, Cause No. PUD 201500273: Direct Testimony of William Wai, OG&E, Page 7, December 18, 2015 and Order 662059, Effective May 1, 2017

summer, and the two largest utilities (Wisconsin Electric Power and Wisconsin Public Service) had summer peaks that were significantly higher than winter.

For the utilities with summer seasons, fifteen of the twenty define summer as the months of June through September, two define it as June 16 through September 15, and three define it as June through October.

If the review is restricted to Missouri and neighboring states, the results show that ten of the eleven utilities studied offer a summer/winter season rate structure and only one has the same rate year around.

The results of the seasonal rate structure review are summarized in the chart below.

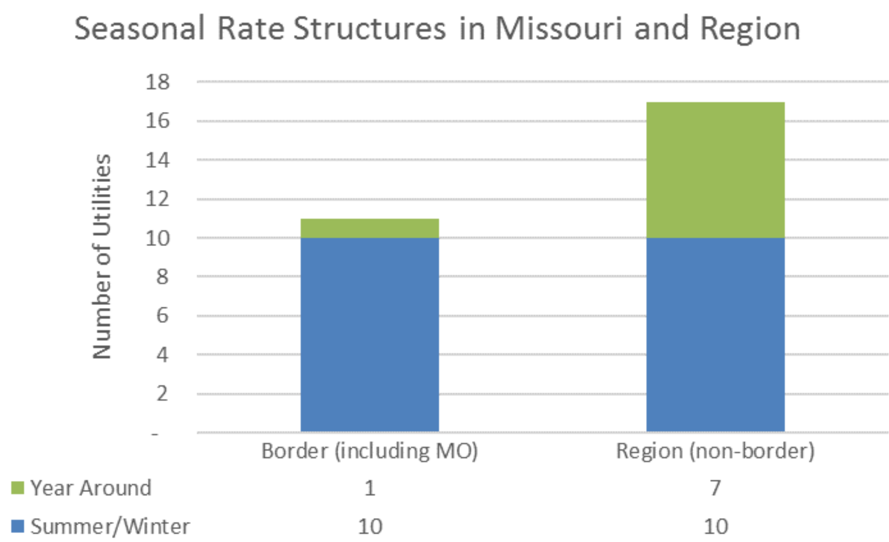


FIGURE 1. SEASONAL RATE STRUCTURES IN MISSOURI AND REGION

Based on this review, GMO's use of a summer/winter season structure is consistent with the common approach in the region. In the following section, the quantitative evaluation of GMO's seasonal structure begins with a review of customer usage patterns.

VI. GMO Customer Usage Review

A review of customer usage history clearly indicates a seasonal pattern. In the charts below, GMO retail sales[18] exhibit the largest peak in the summer with a secondary peak in the winter months of December and January.

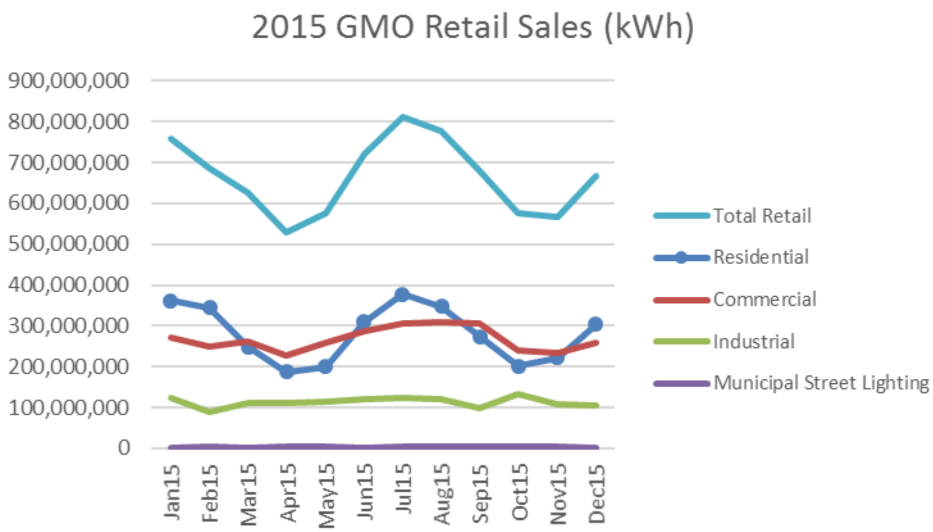


FIGURE 2. 2015 GMO RETAIL SALES (KWH)

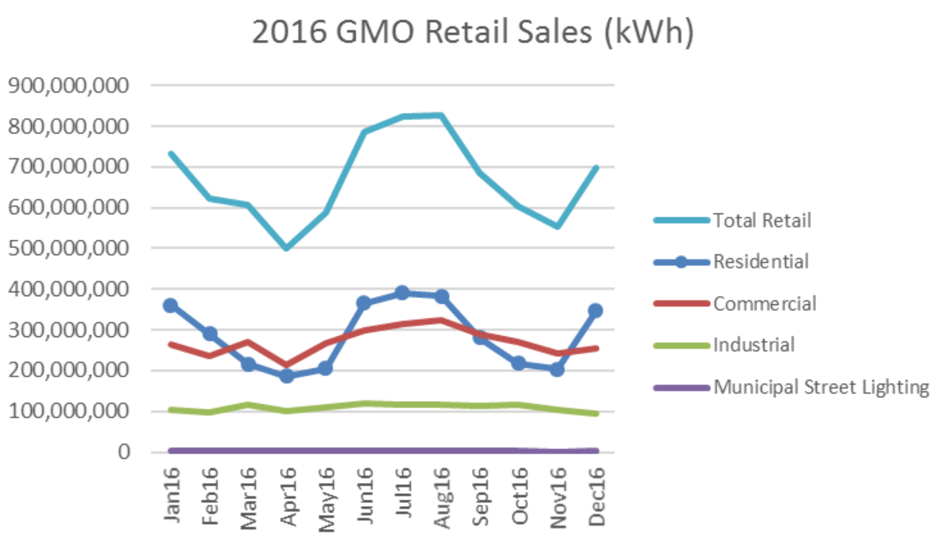


FIGURE 3. 2016 GMO RETAIL SALES (KWH)

Considering usage by customer classification, the charts show that residential sales exhibit the largest variation from month to month and therefore exert the most influence on the monthly changes in total

[18] Retail sales analyzed here are from Report 1A Comparative Total Electric Revenues, which reports sales on an accrued (rather than billing) basis. Use of accrued sales data is important to match the timing of customer usage with production and SPP market costs.

retail sales. The other customer classifications have less variation in sales from month to month. Industrial and municipal street lighting customer volume does not change much on a monthly basis, while commercial customers do show an increase in summer volume, but to a lesser degree than residential.

While changes in monthly sales will influence variable operating expenses, it is also important to consider the impact of peak demand on the cost to provide service. Since planning decisions must account for serving the highest hourly demand within the year, the timing of peak demand influences the need for system resources and the allocation of associated costs.

To assess the seasonality of peak hourly demand, the chart below presents the monthly coincident peaks for GMO using weather-normalized, customer growth-adjusted billing frequency data[19]. Here the data clearly show the summer peaking nature of GMO, with the highest monthly peaks in the four summer months of June through September. Additionally, the data demonstrate the significant variation of residential peak demands and the influence of the class contribution on the GMO total.

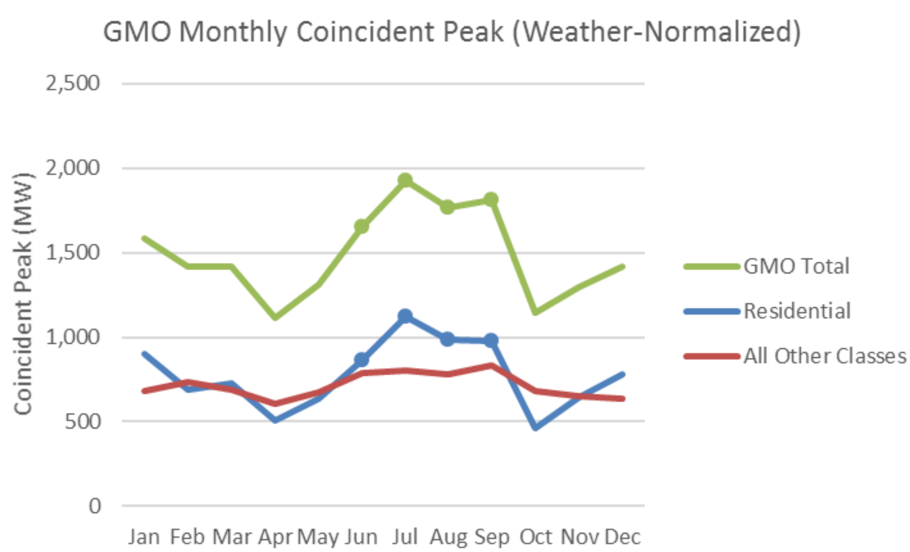


FIGURE 4. GMO MONTHLY COINCIDENT PEAKS

In summary, the customer usage review documents seasonality in both energy usage and peak demand, with the residential customer classification exerting a significant influence on both. In the following section, the study examines cost data to determine how these customer usage patterns affect monthly variations in operating expenses.

[19] CCOS Consolidated Allocator file from ER-2016-0156

VII. GMO Cost Review

The cost review for GMO began with an examination of the income statement from the general ledger on an accrued revenue basis. On an annual basis, the income statements for 2015 and 2016 used in this study show the following:

TABLE 2. GMO INCOME STATEMENT 2015-2016

GMO Income Statement ($)	2015	2016
Retail Electric Revenues	**745,003,483**	**755,717,408**
Fuel	116,909,628	92,569,357
SPP Net Expense	82,110,439	108,252,661
Fuel & SPP Net	**199,020,067**	**200,822,018**
Margin	**545,983,416**	**554,895,390**
Non-Fuel O&M	230,500,233	232,206,632
General Taxes	49,378,335	49,084,302
Depreciation	94,682,314	97,293,592
Other Regulated Accounts	1,642,752	1,620,537
Non-Fuel O&M / General Taxes / Depreciation	**376,203,634**	**380,205,063**
Operating Income (Loss)	**169,779,782**	**174,690,327**
Non Operating Expense	(632,886)	7,914,353
Interest	55,485,838	57,307,245
Income (Loss) Before Taxes	**114,926,830**	**109,468,729**
Income Taxes	**43,863,803**	**42,376,585**
Net Income (Loss)	**71,063,027**	**67,092,144**

A quick review of the line items in the income statement provides an introduction to support the cost analysis in the remainder of this study.

> *Retail Electric Revenues*: The retail electric revenues represent the sales to all customer classes, including residential.
>
> *Fuel & SPP Net Expense*: The fuel and SPP net expense captures the cost of fuel and fuel handling and the net SPP expense. The net SPP expense is comprised of expenses for purchased power and transmission of electricity by others netted against wholesale electric revenue and other electric revenue. The combined fuel & SPP expense captures the effect of market price variations on GMO customers.
>
> *Non-Fuel Operation & Maintenance (O&M) / General Taxes / Depreciation*: These expenses represent the remaining operating expenses (labor for example) that are not tied directly to the SPP energy market. Non-fuel O&M is the largest expense of these categories followed by depreciation, general taxes (mostly property tax), and other regulated accounts.
>
> *Operating Income*: The operating income is simply the retail electric revenues minus the operating expenses identified above.
>
> *Non-Operating Expense*: The non-operating expense captures the netting of various non-operating revenues and expenses. These expenses are not included in retail rates.
>
> *Interest*: Interest expense includes interest from all forms of borrowing used to finance the company.
>
> *Income Taxes*: Income taxes represent taxes paid on the income before tax.

Net Income: Net income represents revenue minus operating and non-operating expenses, interest, and income taxes. Net income is also commonly referred to as earnings.

While the annual income statement helps to identify the relative magnitude of cost categories, a monthly view is required to determine seasonal variations. From the charts below, it is clear that operating expenses follow retail sales volumes, with the fuel and SPP net expense driving the variability. This is understandable, since the other cost categories (non-fuel O&M, general taxes, and depreciation) are relatively flat from month to month on an accounting basis.

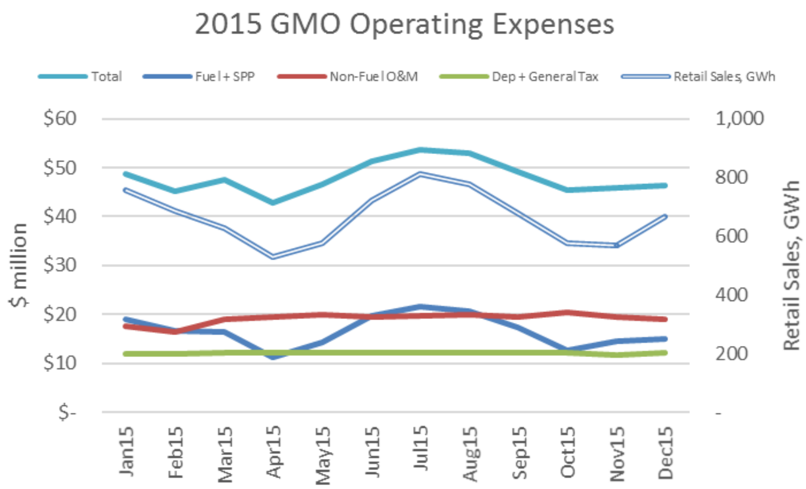


FIGURE 5. 2015 GMO MONTHLY OPERATING EXPENSES

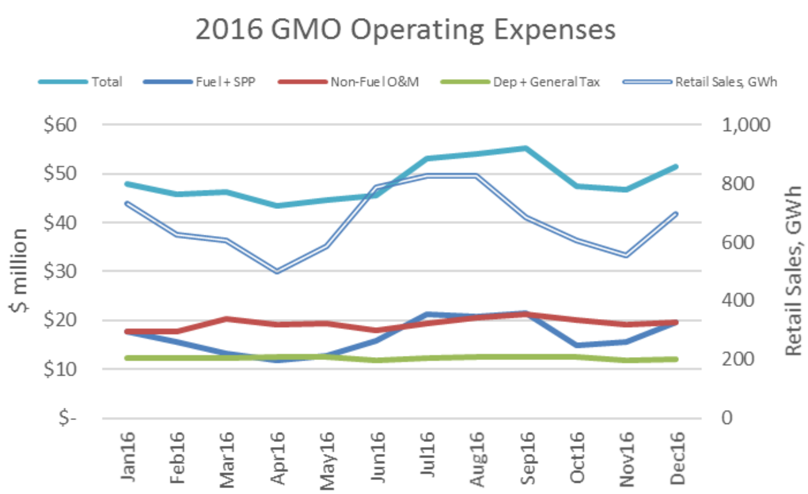


FIGURE 6. 2016 GMO MONTHLY OPERATING EXPENSES

Since fuel and SPP net expense is the largest contributor to the variation in monthly operating expenses, it may be instructive to consider how this category varies on a per kWh unit basis. The charts below present both the gross dollar amount and the average per kWh for 2015 and 2016.

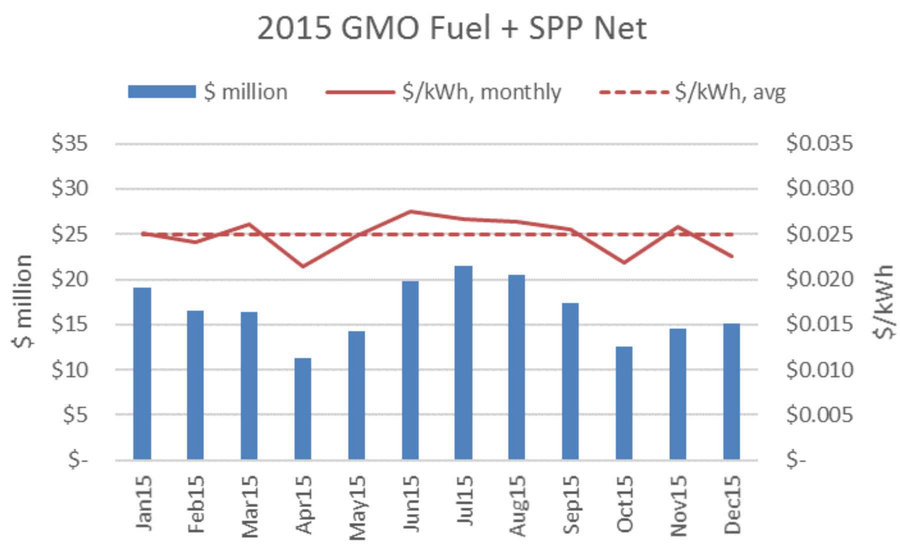


FIGURE 7. 2015 GMO FUEL AND SPP NET EXPENSES

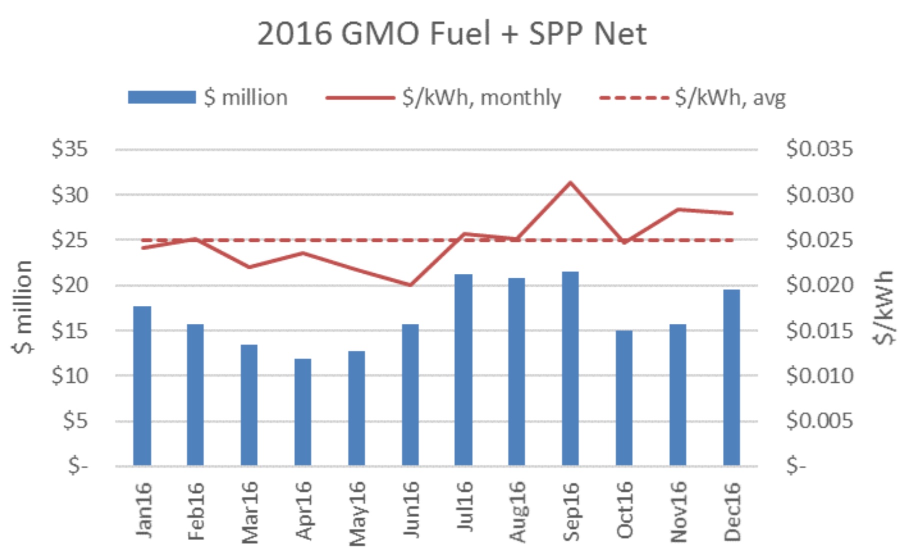


FIGURE 8. 2016 GMO FUEL AND SPP NET EXPENSES

In 2015, the annual average was $0.0250/kWh with a range from a low of $0.0214/kWh in April to a high of $0.0274 in June. The summer months of June through September were all somewhat above average. In 2016, the annual average was also $0.0250 per kWh, indicating a degree of price stability in the SPP market. The summer results for 2016 are skewed by non-recurring settlements that produced a net credit for transmission of electricity by others in June[20] and a larger than normal expense in September[21]. This lowers the monthly cost in June and raises the amount in September. Removing these non-recurring items from the analysis provides a more accurate representation of the seasonal variation due to monthly SPP market differences.

When the non-recurring settlements are removed from the 2016 analysis, the results for the summer months of June, July, and September are higher than the revised annual average of $0.255/kWh. The result for the remaining summer month of August is somewhat below the annual average. However, at $0.02515/kWh, the August expense is higher than six of the eight non-summer months. The chart below presents the fuel and SPP expense results for 2016 with the non-recurring items excluded. With these adjustments, the monthly average expense still falls in a narrow range from a low of $0.0217/kWh in May to a high of $0.0291/kWh in September.

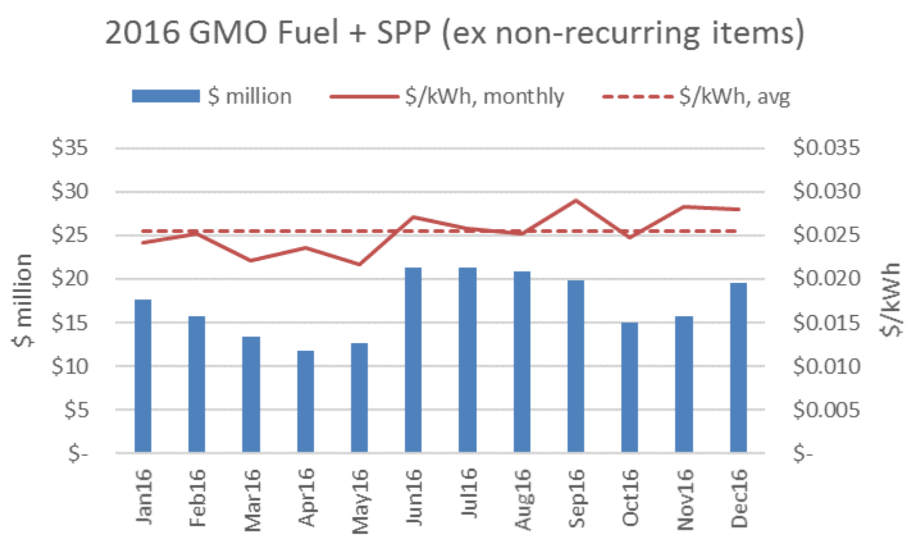


FIGURE 9. 2016 GMO FUEL AND SPP EXPENSES (EXCLUDING NON-RECURRING ITEMS)

In summary, the income statement review shows that there is some seasonality in expenses driven by changes in retail sales. Specifically, the income statement review produces the following findings:

1) Total operating expenses vary from month to month in response to changes in retail sales volume and show higher levels of cost during the four summer months of June through September,
2) Expenses for fuel and the SPP market follow changes in monthly sales volume, while most other operating expenses are relatively constant from an accounting perspective, and

[20] In June 2016, a credit to transmission of $5,565,621.29 was booked due to a MISO RTOR (Regional Through and Out Rates) resettlement. RTOR are separate transmission rates for transactions where electricity originated in one transmission control area is transmitted to a point outside that control area.
[21] In September 2016, the first round of SPP Z2 resettlements produced an increase of $2,182,914 in transmission expense. This increase in total monthly expense was somewhat offset by a credit of $575,433 for the Crossroads Base ROE settlement. The SPP Z2 process is ongoing, however, since the September expense was an historical true up, the monthly amount will be smaller going forward.

3) As demonstrated in the customer usage review, residential customers exert the strongest influence on the monthly variation in retail sales volume.

With the importance of residential customers' influence on monthly expense variation established, the next section turns to answering the question of whether there is a seasonal split that better reflects the current drivers of system capacity needs and the market energy price variation. To address this question, a Residential Revenue Requirements model was developed to consider residential customer impact on capacity and energy needs.

VIII. GMO Residential Revenue Requirements

The development of revenue requirements is the first step in determining rates that allow a utility to recover operating expenses and earn a return on investment. In its simplest form, the equation for revenue requirements can be expressed as RR = COS + RB x ROR, where RR is revenue requirements, COS is cost of service, RB is rate base, and ROR is rate of return.

Related to this evaluation, the effects of market energy price variation are captured in the cost of service, while the financial requirements for system capacity are accounted for in the rate base investment.

In this section, an estimate of revenue requirements for residential customers was developed to address the potential to modify the existing seasonal rate structure. Historical, actual cost information was reviewed and applied to weather-normalized sales data to produce a monthly estimate of the average cost to serve GMO residential customers.

GMO Rate Base

In the following table, a residential rate base estimate was developed for GMO relying on the consolidated Class Cost of Service Study (CCOS) methodology included in the Company's direct filing for the ER-2016-0156 rate case. Based on the allocation methodology explained below, residential customers are assigned 55.7% of the total rate base for GMO, which equates to roughly $1.1 billion.

TABLE 3. GMO RESIDENTIAL RATE BASE

GMO Rate Base ($000)	2015	2016
Production	1,022,061	1,067,388
Transmission	251,328	256,815
Distribution	730,316	768,220
General Plant	116,273	114,333
Non-Plant	(272,999)	(320,442)
Total	1,846,980	1,886,315
Residential Allocation (% of total asset functional class)		
Production	49.2%	49.2%
Transmission	52.1%	52.1%
Distribution	65.9%	65.9%
General Plant	55.6%	55.7%
Non-Plant	55.6%	55.7%
Residential Rate Base ($000)		
Production	502,463	524,747
Transmission	131,023	133,884
Distribution	481,129	506,100
General Plant	64,680	63,601
Non-Plant	(151,863)	(178,255)
Total Residential RB	1,027,433	1,050,077
% of Total GMO RB	55.6%	55.7%

For simplification, the rate base used above reflects the net balance at year end of the previous year (December 31, 2014 for the 2015 model and December 31, 2015 for the 2016 model). The general categories included in rate base are production, transmission, distribution, and general plant, and non-plant. The first three categories capture investments in plant by function, while the general plant is not assigned to a specific use. The non-plant category captures various items including inventories and the liability for accumulated deferred income taxes. Deferred tax is the single largest item in the non-plant category, which is an offset to rate base.

The allocation of rate base to residential customers was made for each of these categories following the methods employed in the GMO CCOS study. Specifically, production was allocated using a combination of the average energy and the four highest monthly coincident peaks (CP), transmission was allocated on the average of the twelve monthly CPs, distribution was allocated on the annual non-coincident peak (NCP), and the general plant and non-plant categories were allocated using the weighted average percentage of the first three plant investment categories.

The following chart shows the rate base allocation used in this study to produce monthly revenue requirements for return on equity, interest, and depreciation.

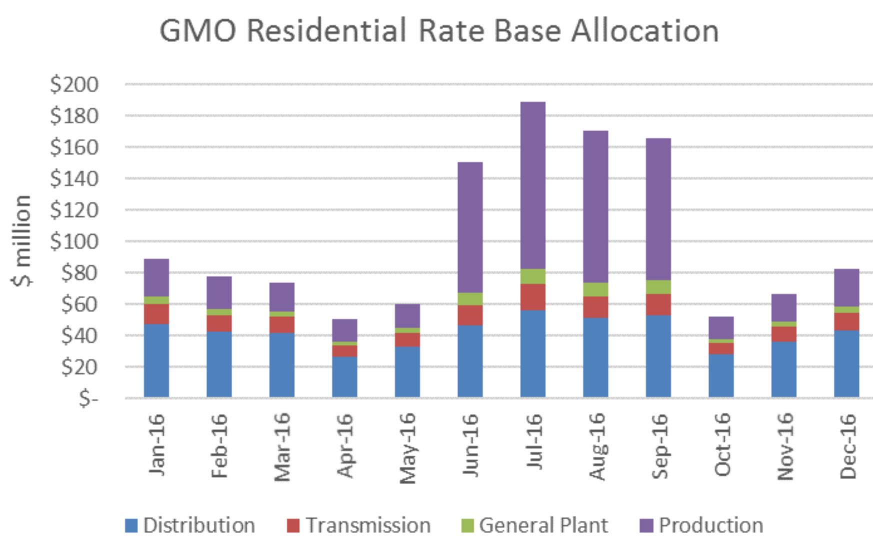


FIGURE 10. GMO RESIDENTIAL RATE BASE ALLOCATION (2016)

This graphical presentation highlights the significance of the rate base allocation in the summer months of June through September. This result is mainly driven by the allocation of the production rate base using the combined average and peak methodology.[22] The peak element of the method recognizes the importance of the four summer month peaks in planning for capacity additions and GMO's practice of scheduling plant maintenance outages in other months with lower demand to ensure capacity availability in the summer. (See Figure 4: GMO Monthly Coincident Peaks on page 9 for monthly CP data.)

[22] The Average & Peak allocation methodology is a blended allocation that combines energy use (the average) with a coincident peak demand (the peak). The relationship between the two factors is established based on the system load factor. This allocation methodology is consistent with methods proposed by the Company in the ER-2016-0156 rate case.

Rate of Return

The rate of return represents the utility's authorized return on investment based on the overall cost of capital. For GMO, the capital structure includes common equity, preferred stock, and long-term debt. The following table presents the GMO capital structure used in the revenue requirements model for this study. For estimating purposes, the structure uses balance sheet information from December of the preceding year, consistent with the approach employed for rate base development.

TABLE 4. GMO CAPITAL STRUCTURE

GMO Capital Structure	2015	2016
Residential Rate Base ($ million)	$ 1,027	$ 1,050
Debt (%)	49.14%	50.34%
Preferred Stock (%)	0.55%	0.52%
Common Equity (%)	50.31%	49.13%
Interest (%)	5.55%	5.44%
Return on Preferred (%)	4.29%	4.29%
Return on Common (%)	9.70%	9.70%
Weighted-Average Cost of Capital (%)	7.63%	7.53%
Tax Rate (%)	38.39%	38.39%

The rate base and rate of return information can be used to determine revenue requirements for return on equity. Additionally, an estimate of total residential revenue requirements can be developed using an effective income tax rate of 38.39% and an estimate for operating expenses that will be explained in further detail below.

TABLE 5. GMO ANNUAL RESIDENTIAL REVENUE REQUIREMENTS

Residential RR ($ million)	2015	2016
Return on Equity	$ 50	$ 50
Income Taxes	$ 31	$ 31
Profit Before Tax	$ 82	$ 82
Interest	$ 31	$ 32
Profit Before Int + Tax	$ 113	$ 114
Operating Expenses	$ 300	$ 302
Revenue Requirement	$ 412	$ 416

Based on the above, residential revenue requirements were estimated at $412 million in 2015 and $416 million in 2016. As a point of reference, the residential revenue requirements in the ER-2016-0156 model prior to settlement were $402 million. The differences between the calculations are reasonable considering the simplifying assumptions for rate base, capital structure, and operating costs used in the study model. The following section on cost of service explains the cost assumptions in the study revenue requirement model.

Cost of Service

For this study, cost of service expenses were grouped into the following categories: fuel and SPP, non-fuel O&M, general taxes, interest, and depreciation.

Fuel and SPP - The fuel and SPP expense, which does vary by month, was calculated by multiplying the average cost from the income statement by the weather-normalized sales volume. This estimate could be refined by running an hourly production cost model to account for the higher proportion of peak price energy used by residential customers, but an approximation using historical monthly averages is sufficient for initial screening, especially considering the relatively small variation in the average monthly expense ($/kWh) demonstrated in the previous section.

Non-Fuel O&M - Based on the weather-normalized sales forecast used in ER-2016-0156, residential customers account for 43.2% of energy sales. Therefore, residential customers were assigned 43.2% of the annual non-fuel O&M, which was then allocated by month according to residential sales volume.

General Taxes – Property tax accounts for almost 90% of this expense category, so the allocation was based on an allocation of gross plant investment for production, transmission, and distribution.

Interest – Interest expense is associated with debt taken on to support capital investment and working capital requirements. Therefore, a proportion of the annual interest expense from the income statement was assigned to residential customers using the total rate base allocator.

Depreciation – Depreciation expense applies to plant investments to recognize their decline in value as they are used over time. Therefore, depreciation was allocated to residential customers according to their share of net plant investment.

In the tables below, the residential revenue requirement estimate is presented on a monthly basis using the historical cost data applied to weather-normalized sales. The results show the monthly average cost ($/kWh) is distinctly higher in the summer months of June through September. The model estimates the average cost for the summer months is $0.149/kWh in both 2015 and 2016, while all other months average about 4.5 cents per kWh lower at $0.103/kWh in 2015 and $0.104 in 2016.

TABLE 6. GMO MONTHLY RESIDENTIAL REVENUE REQUIREMENTS (2015)

Residential RR ($million)	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Tot-15	Sum-15	Win-15
Return on Equity	3.7	3.2	3.0	2.1	2.5	6.2	7.8	7.0	6.8	2.1	2.7	3.4	50.4	27.7	22.6
Income Taxes	2.3	2.0	1.9	1.3	1.5	3.8	4.8	4.4	4.2	1.3	1.7	2.1	31.4	17.3	14.1
Profit Before Tax	5.9	5.2	4.9	3.4	4.0	10.0	12.6	11.3	11.0	3.4	4.4	5.5	81.8	45.0	36.8
Interest	2.2	2.0	1.9	1.3	1.5	3.8	4.8	4.3	4.2	1.3	1.7	2.1	30.9	17.0	13.9
Profit Before Int + Tax	8.2	7.2	6.8	4.7	5.5	13.8	17.4	15.6	15.2	4.7	6.1	7.5	112.6	62.0	50.6
Operating Expenses	28.4	24.8	22.1	16.0	17.6	29.4	35.9	34.0	28.4	15.9	20.7	26.6	299.7	127.7	172.0
Revenue Requirement	**$ 36.5**	**$ 31.9**	**$ 28.9**	**$ 20.6**	**$ 23.0**	**$ 43.2**	**$ 53.2**	**$ 49.7**	**$ 43.7**	**$ 20.6**	**$ 26.8**	**$ 34.1**	**$ 412.3**	**$ 189.7**	**$ 222.6**
$/kWh	**$ 0.10**	**$ 0.10**	**$ 0.11**	**$ 0.10**	**$ 0.11**	**$ 0.15**	**$ 0.15**	**$ 0.14**	**$ 0.16**	**$ 0.10**	**$ 0.11**	**$ 0.10**	**$ 0.120**	**$ 0.149**	**$ 0.103**

TABLE 7. GMO MONTHLY RESIDENTIAL REVENUE REQUIREMENTS (2016)

Residential RR ($million)	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Tot-16	Sum-16	Win-16
Return on Equity	3.6	3.2	3.0	2.1	2.4	6.2	7.7	7.0	6.8	2.1	2.7	3.4	50.3	27.7	22.6
Income Taxes	2.3	2.0	1.9	1.3	1.5	3.8	4.8	4.3	4.2	1.3	1.7	2.1	31.3	17.2	14.1
Profit Before Tax	5.9	5.2	4.9	3.4	4.0	10.0	12.6	11.3	11.0	3.4	4.4	5.5	81.6	44.9	36.7
Interest	2.3	2.0	1.9	1.3	1.6	3.9	4.9	4.4	4.3	1.3	1.7	2.1	31.9	17.6	14.3
Profit Before Int + Tax	8.2	7.2	6.8	4.7	5.5	13.9	17.5	15.7	15.3	4.8	6.1	7.6	113.5	62.5	51.0
Operating Expenses	28.2	25.3	21.2	16.5	17.0	27.5	35.9	33.9	30.3	16.6	21.5	28.7	302.5	127.5	175.0
Revenue Requirement	**$ 36.4**	**$ 32.5**	**$ 28.1**	**$ 21.3**	**$ 22.5**	**$ 41.4**	**$ 53.4**	**$ 49.6**	**$ 45.6**	**$ 21.4**	**$ 27.6**	**$ 36.3**	**$ 416.0**	**$ 190.0**	**$ 226.0**
$/kWh	**$ 0.10**	**$ 0.10**	**$ 0.10**	**$ 0.10**	**$ 0.10**	**$ 0.14**	**$ 0.15**	**$ 0.14**	**$ 0.17**	**$ 0.10**	**$ 0.11**	**$ 0.10**	**$ 0.121**	**$ 0.149**	**$ 0.104**

In the following chart, the monthly average cost ($/kWh) from the revenue requirement model is plotted against the ER-2016-0156 rate case CCOS results. The results for both the model and rate case indicate the same general pattern of higher costs in the summer months.

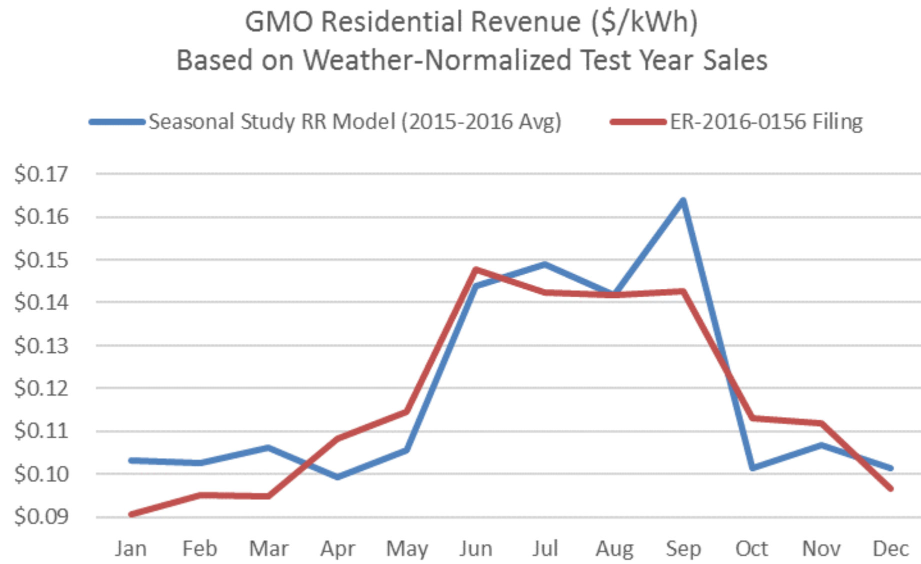


FIGURE 11. GMO RESIDENTIAL REVENUE REQUIREMENTS ($/KWH)

While the revenue requirement model produces generally similar results to the rate case filing, the following differences are worth noting.

1) The revenue requirement model results for the summer months of June, July, and August are very similar to the rate case model. However, the revenue requirement model shows a very sharp increase for the month of September. This is due to the nature of residential customer usage in the month. Residential demand exhibits a large coincident peak, in line with the other summer months, and thus receives a significant demand-based cost allocation for production assets. However, total residential usage for the month is lower than for the other summer months. As a result, the production allocation is spread over fewer kWh and the average cost per kWh is higher.
2) The revenue requirement model average costs are higher than the rate case model for the winter months of January, February, March, and December. This result is produced by the use of a more detailed revenue calculation in the GMO rate case model which employs declining block rates[23] for heating customers. Since heating customer usage is higher in these months, a higher proportionate of overall usage is billed at a lower rate, and thus, the overall customer class average is lower. In the revenue requirement model, there is no distinction between customers within the residential class.
3) The revenue requirement model average costs are lower than the rate case model for the winter months of April, May, October, and November. This result can be explained by the decreased usage by heating customers and therefore lower proportion of billing at the declining rates in the rate case. As a result, the overall customer class average rate increases in the rate case filing.

[23] A declining block rate is a rate design technique where increasing levels of use are priced at reduced costs. For GMO, under its currently approved Residential rates, the blocks are 0 to 600 kWh, 601 to 1000 kWh, and over 1000 kWh. The winter rates heating customers served by those blocks are $0.10625, $0.06035, and $0.04991 per kWh, respectively.

In summary, both the rate case filing and the revenue requirements modeling for this study support the current seasonal split for residential customers. The analysis produces an average cost that is significantly higher in the summer months of June through September and lower in all other months.

IX. Customer Billing Consideration

In evaluating seasonal rates, consideration of customer billing processes presents additional concerns beyond the cost and consistency considerations discussed previously. Introducing a shoulder season (or seasons) could produce additional timing differences between sales and billing and create customer confusion due to the added billing complexity associated with the cross-over between multiple seasons.

Under current operations, it is not practical to read and bill all residential customers on the same day. Therefore, customers are divided into groups, and each group of customers is billed on a cyclical basis, whereby those customer's meters are read and a bill subsequently produced around the same day each month. Consequently, at the extreme ends of the billing cycle timeline, some customers may have meters read on the first of the month, while other customers may have meters read at the end of the month. For GMO, each bill is produced based on the rate for the billing month, meaning the customer with a meter reading on the first of the month is billed at the current month rate for usage corresponding to the prior month period. At the other extreme, the customer with a meter reading at the end of the month would be billed for usage corresponding to the current month.

An example of a customer with billing at the first of the month can help to illustrate the issue with seasonal cross-over. Under the current two season rate structure, a customer who is billed on June 1, a summer billing month and represented by "Month B" in the chart below, would be billed at the June summer rate for usage that occurred in May, which is a winter rate month and represented by "Month A". In October, the transition month from summer to winter, this customer would encounter the same effect of billing at a seasonal rate different than the usage month.

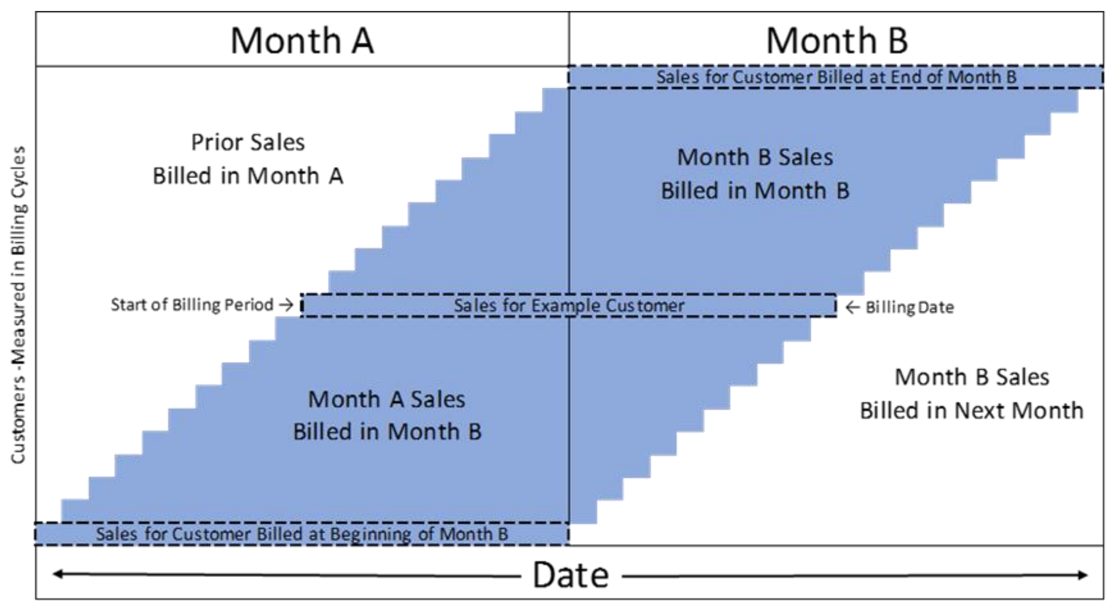


FIGURE 12. GMO TIMING OF SALES VS BILLING

In summary, due to the cyclical billing of customers, a number of customers will receive bills where the usage does not correspond with the seasonal rate. While this currently creates some complexity with two seasonal rate periods (summer/winter), introducing additional rate seasons would bring even greater complexity, with each extra season producing two additional cross-over months. Implementing many cross-over months would result in a larger disconnect between the usage and the billing, confusing any price signals associated with the rates.

X. Conclusion

Based on the monthly revenue requirements modeling, this study does not support modifying the current seasonal split for GMO residential customers. When capacity and energy costs are assigned to residential customers using allocation methods consistent with past Company approaches, the average cost of a unit of energy is significantly higher in the summer months of June through September and lower in the other months. Additionally, the summer/winter seasonal rate structure employed by GMO is consistent with the approach taken by other utilities in the region.

The results of this analysis also support the current summer/winter seasons when evaluated on an allocated cost basis. To address capacity and energy costs on a monthly basis, a residential revenue requirements model was constructed using allocated rate base costs and actual operating cost data from 2015 and 2016, which represent the first two full years of GMO's participation in the SPP Integrated Marketplace. These costs were applied to weather-normalized usage data to estimate an average cost per kWh. The analysis shows the monthly average cost ($/kWh) for residential customers is distinctly higher in the summer months of June through September. The model estimates the average cost for the summer months is $0.149/kWh in both 2015 and 2016, while all other months average about 4.5 cents per kWh lower at $0.103/kWh in 2015 and $0.104 in 2016.

From the scope of work developed with the rate case settlement Signatories, cost alignment was a critical consideration and therefore the primary driver of the analysis. Rate base costs were allocated based on a review of customer usage data that documented higher average and peak usage in the summer months. This allocation methodology recognizes the utility planning process and is consistent with the approach employed in filing for the recent GMO rate case. The resulting allocation produced rate base costs that were higher in the summer months, driven primarily by the combined average and peak method applied to production assets. Operating costs were assigned based on a review of historical data. The review documented somewhat higher SPP market costs in the summer months on a $/kWh basis. However, the variability from month to month within the year was relatively small, indicating a degree of price stability in the SPP market.

As an additional element of the study scope, this study reviewed seasonal rate structures at other utilities in the region. The findings here demonstrate that the summer/winter seasons employed by GMO is consistent with the seasonal rate structures used by other utilities. The review included residential rates for twenty-eight utilities (excluding KCP&L) and found that twenty employ a summer/winter season and eight offer the same rates year around. When the review is restricted to the eleven states including Missouri and neighboring states, ten use a summer/winter season and one offers the same rates year around.

As a final element, this study considered the impact that additional seasons could have on customer billing. Due to the current cyclical billing of customers, there are differences between the timing of usage and the billing rate in the transition months between seasons. This effect is especially pronounced for customers who are billed on or shortly after the first of the month, where the rate for the billing month is applied to usage that largely corresponds to the previous month. While this creates some complexity with current two seasonal rate periods (summer/winter), introducing additional rate seasons would bring even greater complexity, with each extra season producing two additional cross-over months. Implementing many cross-over months would result in a larger disconnect between the usage and the billing, confusing any price signals associated with the rates.

In conclusion, this study supports the current summer/winter seasons currently used for GMO residential customers based on monthly revenue requirements modeling, consistency with other regional utilities, and customer billing and price signal considerations.

BLOCK RATE STUDY

December 8, 2017

This Block Rate Study is intended to evaluate the role of residential energy blocks in promoting responsible energy use and is provided in response to a provision of the Commission Report and Order in Case No. ER-2014-0370.

Residential Block Rate Study

This report reflects the Residential Block Rate analysis KCP&L-Greater Missouri Operations Company ("GMO" or "Company") performed to evaluate the role of residential energy blocks in promoting responsible energy use. This analysis is not intended to determine which rate structures should be offered, but rather to identify 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. Definition of a rate design requires consideration of a broad set of issues, most beyond the quantitative analysis completed here.

In completing this work, efforts were made to ensure GMO perspectives were emphasized, however, in some cases details of this report may focus on, or incorporate elements from the Kansas City Power & Light ("KCP&L") in its Missouri ("KCP&L-MO") or Kansas ("KCP&L-KS") jurisdictions. The results of this analysis will be considered in future analysis of residential rates in both KCP&L and GMO jurisdictions.

1 BLOCK RATE STUDY OVERVIEW & EXECUTIVE SUMMARY

1.1 Block Rate Study Background

In Missouri Public Service Commission ("Commission") case ER-2016-0156, a non-unanimous stipulation[1] was established and in part, GMO agreed to study responsible energy use as related to residential block rates. For the purpose of this document, this Study will be referred to as the "Block Rate" study and will be filed as part of the Company's direct testimony in its next general rate case or rate design case, whichever occurs first.

1.2 Block Rate Study Scope

In accordance with the previously mentioned stipulation and agreement, GMO worked with the Signatories[2] to define the scope of the Block Rate study. The scope was defined as follows:

> *The Company will review and evaluate the role of residential energy blocks in promoting responsible energy use*, with consideration of existing or any proposed season splits. In evaluating the blocks, consideration will be made for the number, size, and price of the individual blocks. The Company will also investigate residential block rates utilized by other electric utilities to determine if any alternative might be appropriate for the Company. At a minimum, utilities considered will be located in Missouri and neighboring states. Consideration will be made for alternatives that could achieve responsible energy use.*

* *Responsible energy use: For the purpose of this study responsible energy use occurs when a customers are given the opportunity to respond consistently to cost-based energy prices, while minimizing the variations from costs observed on both an individual basis and on an "average per-customer" or other averaging basis while also supporting and accommodating the principles of a good rate design (efficient, equitable, stable, and understandable with*

[1] ER-2016-0156 Non-Unanimous Stipulation and Agreement, filed September 20, 2016 ("ER-2016-0156 Stipulation")

[2] The Signatories are KCP&L Greater Missouri Operations Company, Staff of the Missouri Public Service Commission, Missouri Department of Economic Development – Division of Energy, Midwest Energy Consumers Group, and Missouri Industrial Energy Consumers.

consideration for gradualism and ensuring revenue sufficiency). In this study, particular consideration will be given to the efficiency promoting effects of consistent price signals in consideration of the study parameters for seasonal and blocked rates.

1.3 Relationship to other Rate Studies

This report reflects the Residential Block Rate analysis the Company has performed to evaluate the role of usage blocks to promote responsible energy use by residential customers. This study is one of several rate studies undertaken by the Company in response to recent rate case orders issued by the Commission, in all Company jurisdictions. While this study ultimately identifies a rate block for multiple rate options in each jurisdiction, it does not analyze or recommend other rate design parameters of a particular block rate implementation necessary to propose a rate. GMO plans to use these study results in conjunction with the other studies and rate design analysis to develop proposed enhancements to the existing residential rate structures.

1.3.1 *Specific Commission Ordered Rate Studies*

In Commission case ER-2016-0156, GMO agreed to study: 1) modifying GMO's seasonal rates in a future rate proceeding to establish rates for Peak months and Shoulder months, as opposed to GMO's current Summer/Non-Summer seasonal split, including applicable determinants; 2) responsible energy use as related to residential block rates.[3]

In the same case, GMO agreed to include in its direct filing in its next rate case or rate design case a study of Time of Use ("TOU") rates for GMO including TOU residential and SGS rates, critical peak rates, Electric Vehicle TOU rates for stand-alone charging stations, TOU rates applicable to Electric Vehicle charging associated with an existing account, Real Time Pricing, Peak Time Rebates, and other rate types which could encourage load shifting/efficiency.[4] That report is in progress and will be addressed separately.

Similarly, in ER-2014-0370 the Commission also ordered KCP&L-MO to complete a study regarding the redesign of its time-of-use rates within two years of the effective date of that order.[5] That report was submitted on September 15, 2017 and provided a summary of results compiled from various time variant studies completed by KCP&L and GMO.[6]

Additionally, in Docket 16-GIME-576-GIE, the Kansas Corporation Commission ("KCC") issued a procedural order directing KCP&L-KS and other interested parties to file written reports which analyze alternative methodologies for determining what the benefit residential all-electric space heating customers provide to the KCP&L-KS system and KCP&L-KS's residential non-all-electric space heating customers.[7] That report was submitted on July 5, 2017 and established that all customers benefited from the existence of electric space heating load and supported that current rates are reflective of that benefit.[8]

[3] ER-2016-0156 Stipulation, page 9 and 10.

[4] ER-2016-0156 Stipulation, page 10 and 11.

[5] ER-2014-0370 Report and Order, Issued September 2, 2015, page 92.

[6] EO-2018-0070 Kansas City Power & Light Company's Standby Tariff Review Report and Time of Use Study, Filed September 15, 2017.

[7] 16-GIME-576-GIE Procedural Order, Issued September 22,2016.

[8] 16-GIME-576-GIE Responsive Comments and Report of Kansas City Power & Light Company Concerning Its All-Electric Residential Rates, Filed July 5, 2017.

1.3.2 *Company Time of Use Rate Studies*

Multiple studies have been undertaken by the KCP&L and GMO companies in recent years to explore TOU and other time variant rates to gain a better understanding of the role of time variant rates and help determine an appropriate path forward for these rates.

KCP&L completed a series of progressive studies in partnership with the Electric Power Research Institute (EPRI) that investigated TOU and other Time Variant Rates ("TVR"). This body of work was undertaken in preparation of implementing newly designed, modern, TOU rates that provide proper pricing signals and incentives for customers to modify their electric usage patterns to the benefit of both themselves and all KCP&L and GMO customers. The four studies include:

- EPRI-Matching Electric Service Plans to KCP&L's Strategic Objectives (EPRI-ESP)–EPRI Supplemental Research Project, 2012-2014,
- KCP&L SmartGrid Residential Time-of-Use Pilot (SGDP-TOU)– a component of the KCP&L DOE SmartGrid Demonstration Project, 2010-2015,
- EPRI-KCP&L Residential Time-of-Use Impact Study (EPRI-TOU)– EPRI Smart Grid Demonstration Project Analysis, 2010-2015, and
- EPRI-Measuring Customer Preferences for Alternative Electricity Service Plans (EPRI-ESP) – EPRI Supplemental Research Project, 2014-2015.

More recently, the Company engaged Burns & McDonnell (BMcD) to perform a residential rate design strategy study and targeted rate design studies to meet specific Commission and KCC requirements. For the rate strategy engagement, BMcD conducted the study and prepared a general long term plan for implementing Residential rate designs that align with the utility's internal goals and objectives, reflect good rate making principles, and align with future technologies being implemented. This BMcD study will also serve as an input to subsequent rate designs being prepared by KCP&L and KCP&L-GMO.

1.3.3 *Company 2017 DSM Potential Study*

GMO performed further rate analysis as part of the Demand-Side Management (DSM) Potential Study performed for the Integrated Resource Planning (IRP) process.[9] The Potential Study evaluated peak demand savings potential of several alternative residential rate options to identify rate designs that could be used by the Company to achieve additional energy efficiency and peak load management goals.

The DSM Potential Study found that, for residential customers, TOU and Demand rates have the ability to provide significant long term potential peak demand savings impact.[10] These study results have been incorporated into the BMcD Residential Rate Design Strategy Study and will serve as another input to subsequent rate designs being prepared by KCP&L and GMO.

1.4 Block Rate Study Summary

<u>The primary focus of this Block Rate analysis is not to determine what pricing should be offered, but rather to identify appropriate rate block thresholds to promote responsible energy use for a variety of rate</u>

[9] '*Kansas City Power & Light 2016 DSM Potential Study*', Applied Energy Group, 2016
Filed June 1, 2017 in docket EO-2017-0230 as Appendix 5A-F of the KCP&L Greater Missouri Operations Company (GMO) Integrated Resource Plan-2017 Annual Update.

[10] IBID, Volume 1:Executive Summary (Appendix 5A), page 15

structures that will be considered in future Company rate design analysis. Definition of a rate design requires consideration of a broad set of issues, most beyond the quantitative analysis completed here. The goal of this study is to provide an input to that larger process.

Since the first commercial generation of electricity, rate design has been a challenge for customers and utilities alike. The high levels of cost associated with electricity production and distribution, and the fact that what is produced, must be consumed has led to a multitude of rate designs to attempt to best match the rates paid by customers with the cost and operational characteristics of the service provided. Block pricing, long a method for pricing goods in a way to reflect the decreasing marginal cost of production, was first applied to address increasing demand for electric service. Building on work began by Thomas Edison and John Hopkinson, Arthur Wright proposed the first block rate designs in the late 1800's. The block designs worked well and served the needs of a growing electric industry. Quickly institutionalized over the following years, multi-part rates utilizing block rate elements became the norm. Additionally, as the Electric Industry grew and Electric Utility Regulation became the common structure, the block rate again proved useful to help recover costs allowed under traditional ratemaking. The high fixed costs associated with electric service could be recovered, in part by a service or customer charge, with the remainder recovered through the blocked energy charge. Placing higher amounts of cost in the early blocks would better ensure recovery for the utility and better ensure all users contributed to that fixed cost. This two-part design provided a cost efficient method to equitably recover costs from residential customers in proportion to the costs they cause. In application, block rates are applied in three main forms, explored in Section 2, each defined by the relationship of the prices of the respective blocks;

- Flat Block Rates – prices remain constant across the various usage blocks,
- Declining Block Rates ("DBR") – prices decrease as you progress through the usage blocks, and
- Inclining Block Rates ("IBR") – prices increase as you progress through the usage blocks.

Review of electric block rate history in Section 3 examine the progression of block rate designs at KCP&L. Further, review of the structures deployed in the region in Section 4, show that many of the neighboring summer peaking utilities, like GMO continue to use a block rate during the winter season to provide segmentation that will allow pricing reflective the benefits of improved load factor and reduced costs. Further, review of the fixed charges (customer charges or service charges) associated with these rates imply general under recovery of fixed costs, meaning some portion of those costs are being recovered within the energy charges. This transference of cost recovery commonly contributes to DBR application.

The industry guidance found by the research and discussed in Section 4, suggests that block designs should be based on a 'baseline' or average usage levels for each type of customer type.[11,12] Multi-family housing has been a growing percentage of residential housing in the Kansas City area and regional planners expect this trend to continue for the foreseeable future. Therefore, in determining the proper blocks, the impact of housing 'premise type' (apartment vs single family) was evaluated in addition to end-use (general use vs space heating) and seasons (cooling, heating, and off).

[11] '*Residential Electric Rates Revisited-Part 1: A Historical Perspective*', The EPIC Energy Blog, 2013
Available at: https://epicenergyblog.com/2013/06/05/128/

[12] '*Electricity Pricing-Engineering Principles and Methodologies'*, Lawrence J. Vogt, P.E., 2009, page 289.

The 'baseline' monthly usage, as the typical non-weather influenced usage for all residential customers, was determined to be 600 kWh. Variations were also identified by premise-type and by end-use that were further considered in the analysis. When distinguishing by end-use, baseline usage for General Use and Electric Space Heat customers was determined to be 600 kWh and 750 kWh respectively. When distinguishing by premise-type, baseline usage for multi-family and single family residences were determined to be 400 kWh and 700 kWh respectively.

To understand the applicability to the Company and documented in Section 5, three potential constructs for a Summer Season blocks similar to other regional rate implementations were developed and analyzed for each jurisdiction:

- 2-tier Baseline Use blocks using the ALL-RES baseline usage as the transition
- 2-Tier Average Use blocks using the ALL-RES July-Aug. average use as the transition
- 3-Tier Premise Differentiated blocks using July-Aug. average use for APT (Apartment) and SGL (Single Family) as the transitions.

Within these alternatives, the Summer Season block structure that could provide the best segmentation would be the 2-tier Baseline Usage blocks with a single step at 600 kWh. This is the current block structure that is implemented in the KCP&L-MO General Use rate and it is consistent with the block structure analyzed in the 2017 DSM Potential Study.

Similarly, three potential constructs for a Winter Season block design, inspired by regional applications, were analyzed for each jurisdiction and documented in Section 5:

- 3-Tier Baseline Use blocks with baseline and GEN-SGL Jan.-Feb. average use as price transition
- 3-Tier Premise Differentiated blocks using GEN-APT April-May and GEN-SGL Jan.-Feb. average usages as price transitions at 400 kWh Tier 1 and 1,000 kWh Tier 2 transitions.

The analysis found that the combination of the 3-Tier Premise Differentiated blocks supports consistent block segmentation across all jurisdictions.

Within these alternatives, an appropriate Winter Season block structure for the Company to implement in all jurisdictions is the 3-Tier Premise Differentiated block structure with a first block cap at 400 kWh and a second block cap at 1,000 kWh.

The study, in Section 6, also investigated industry opinion or guidance for on use of block designs and other rates for responsible energy use. Block rates remain a significant part of most utility rate designs. Elements of the Flat, DBR, and IBR designs can be found in place at most regional utilities. The role of these rates in supporting responsible energy use is less clear. In some jurisdictions, the IBR has been deployed in an effort to influence energy use. Often limited by the available metering technology, IBR has served as an alternative, however, its effectiveness has been questioned. While it is generally recognized that an IBR provides a blunt incentive for a customer to conserve electricity use over time, recent studies are showing that price response to an IBR is not as significant as was achieved by some of the early IBR responsiveness testing conducted in the 1980s and early 1990's.[13,14] Additionally, IBR rate design would violate the principal of rate design based on cost, but instead would move more to a subsidization rate,

[13] '*The Paradox of Inclining Block Rates*', Brattle, Public Utility Fortnightly Magazine, 2015. Available at: https://www.fortnightly.com/fortnightly/2015/04/paradox-inclining-block-rates?authkey=6eb0815f18fd8ea697a9268ee673dc115525cd339a489c7062cb6646ba442f5e

[14] '*Trends in Regional U.S. Electricity and Natural Gas Price Elasticity*', EPRI, 2010, pg. 1.4. Available at: https://www.epri.com/#/pages/product/000000000001022196/

where customers would fall in the later inverted portion of the rate are subsidizing customers whose usage does not fall into the inverted portion of the rate.

Additionally, investigation efforts identified that policy goals are shifting from a simple energy conservation focus toward achieving greenhouse gas (GHG) reductions. Many are recognizing the need to assess the GHG emissions associated with various ways to power end uses, as opposed to simply the number of kilowatt-hours consumed. To that end, “emissions efficiency” is becoming as or more important than “energy efficiency” moving forward and ultimately may be the best measure of responsible energy use.[15] Some rate designs create an economic disincentive to pursue “emissions efficiency” through beneficial electrification.

Two types of alternative residential rate designs are often proposed to meet rapidly evolving customer needs; time based rates and demand based rates. Combining both rate mechanisms into a Demand-TOU rate provides pricing signals for customers to manage their consumption patterns to limit their peak usage levels and when to use energy based on the time varying prices. The Potential Study found that, for residential customers, TOU and Demand rates have significant, long term potential DR impact.[16]

1.5 Block Rate Study Conclusion and Recommendation

Company quantitative review of the block rates would support that a summer season, 2-tier Baseline Usage block with a single step at 600 kWh and a winter season, 3-Tier Premise Differentiated block structure with a first block cap at 400 kWh and a second block cap at 1,000 kW. In a future rate design, it would be appropriate to consider a block price applied consistent across jurisdictions and, to the extent possible, have the winter first block based on similar percentages of the summer season block prices. This relationship is suggested to reflect the generally common types of usage, lighting for example, that would be expected to occur in the initial usage blocks. However, this approach does not reflect an appropriate long term solution. It is the opinion and recommendation of the Company that TOU and Demand rate options are better rate designs for GMO to pursue to meet the objectives of responsible energy use, demand-side management, and beneficial electrification.

2 BLOCK RATES DEFINED

Since the first commercial generation of electricity, rate design has been a challenge for customers and utilities alike. The high levels of cost associated with electric production and the fact that what is produced, must be consumed, has led to a multitude of rate designs to attempt to best match the rates paid by customers with the cost and operational characteristics of the service provided. Early rate designs were focused on end use, such as pricing per light bulb, while later converted to measured use based on watt and watt-hours. During this same timeframe, rate structures were constrained by the capabilities of the residential meter which had only registered total energy (kWh) consumed and the frequency with which the utility periodically reads the meter. It is under these conditions that the block rate mechanism was deployed. Block pricing, long a method for pricing goods in a way to reflect the decreasing marginal cost of production, was first applied to address increasing demand for electric service. Building on work

[15] ‘*Environmentally Beneficial Electrification: The dawn of ‘emissions efficiency’*, The Electricity Journal, 29 (2016) pg. 52-58. Available at: http://www.sciencedirect.com/science/article/pii/S1040619016301075

[16] ‘*Kansas City Power & Light 2016 DSM Potential Study, Applied Energy Group, 2016, Volume 1: Executive Summary*’, Page 15

began by Thomas Edison and John Hopkinson, Arthur Wright proposed the first block rate designs for pricing demand in the late 1800's. The block designs worked well and served the needs of a growing electric industry. Quickly institutionalized over the following years, multi-part rates utilizing block rate elements became the norm. Additionally, as the electric industry grew and electric utility regulation became the common structure, the block rate again proved useful to help recover costs allowed under traditional ratemaking. When applied to Residential rates, the high fixed costs associated with providing electric service could be recovered, in part by service or customer charge, with the remainder recovered through the blocked energy charge. Placing higher amounts of cost in the early blocks would better ensure recovery for the utility and better ensure all users contributed to that fixed cost. This two-part design provided a cost-efficient method to equitably recover costs from residential customers in proportion to the costs they cause.[17] In application, block rates are applied in three main forms, each defined by the relationship of the prices of the respective blocks; flat, declining, and inclining. Other variations, such as U-shaped, exist but are not common.

2.1 Flat Block Rates

Flat block energy rates are volumetric rates by the fact that they charge for the amount of energy consumed but, they are constant and do not vary by time of day or level of consumption.

The National Association of Regulatory Utility Commissioners ("NARUC") describes flat block rates in the following way:

> *A flat rate design charges customers per unit of consumption, at the same rate for all units of consumption. The total costs (or some subset) allocated to a class are divided by the usage of that class to produce a rate. This rate is then uniformly applied to any usage by a customer within that class. This rate structure (in combination with a monthly customer charge) is commonly used in designing rates for residential electric customers. Indeed, this is the most common form of residential rate design used across the country today. A flat rate can meet certain objectives, such as affordability, identified by the jurisdiction. On the other hand, recognizing that the cost of electricity varies throughout the day and by location, a flat rate may not reflect the actual costs to serve a customer in a given time period.*[18]

Flat block rates are a common pricing mechanism used by some utilities, but historically they were not as prevalent as declining block rates. As the emphasis toward conservation increased following the 1970's energy crisis and the subsequent effort by the U.S. Congress to pass the Public Utility Regulatory Act (PURPA) of 1978. A portion of PURPA established Federal Public Utility Ratemaking standards, one of which discouraged the use of declining block rates and limited their use to the extent utilities could demonstrate that costs reduced with increased usage. Following PURPA, most utilities implemented seasonal rates that were flat during the peak season and retained the declining block structure in the non-peak seasons where they were cost justified, reflecting the benefits of increased grid utilization.

2.1.1 *Pros and Cons of Flat Block Rates*

The following points outline the arguments typically presented for and against Flat Block Rates.

[17] '*Electrical Rates*', G.P.Watkins PHD, D. Van Nostrand Co., New York, 1921, p. 47.

[18] '*Distributed Energy Resources Rate Design and Compensation*', NARUC, Washington, D.C. 2016, p. 23.

2.1.1.1 Arguments for Flat Block Rates:

- Simple for customer to understand.
- Efficient residential pricing mechanism with low metering and meter reading costs.
- Equitable method of cost allocation for customer with similar usage patterns and load profiles.

2.1.1.2 Arguments against Flat Block Rates

- Does not adequately track the utility costs to serve.
- Does not provide pricing signals reflective of variations in cost.
- Does not have any association with the time of the energy use (peak, off-peak, etc.) to provide feedback for responsible use.
- Tends to benefit low use customers.

2.2 Declining Block Rates

Declining block rate ("DBR") mechanisms, applied during the initial growth of the electric industry, have served as a simple and equitable means to recover costs from customers. Electricity was first utilized for lighting in buildings, and thus the first rate block designs were based on the area or number of rooms that were illuminated. As electrification of homes progressed, introducing new uses for electric energy, the declining block rate provided a means for incrementally targeting various domestic electric end uses with reduced rates reflective of the reduced average prices resulting from increased use. In early rate designs, the kWh blocks were very small in size and several in number as the goal was to provide pricing reflective of the marginal cost of adding load through new devices as electric refrigeration, cooking, water heating, and other basic appliances to their homes.[19]

Over time, as utility costs increased, increases in cost were generally assigned to the early block of the rate instead of increasing customer or service charges. Placement in the early blocks served to better ensure recovery from all customers, serving to increase the differential between the early blocks and the later blocks. Today, the declining block rate structure is still used to support beneficial electric load additions. Declining block rates are often used to provide prices reflective of the average cost for the installation of electric heating equipment, especially by summer peaking utilities that have extra capacity available in the winter period. However, contemporary block rate design tends to be more simplistic with fewer and larger kWh blocks compared to the predecessors.[20]

The NARUC describes declining block rates in the following way:

> *A decreasing or declining block rate (DBR) structure is designed to charge customers a lower per unit rate as their usage increases within a billing cycle. DBRs are still sometimes used to reflect decreasing fixed costs per unit as output increases; a higher initial rate would recover the initial fixed costs, and rates would decrease over the blocks as the rate reflects more variable costs. There is some disagreement that by lowering the savings potential, DBRs discourage conservation, energy efficiency, and customer adoption of technologies that may reduce consumption or otherwise reflect costs. These types of block rates do not require advanced metering technology to implement.*[21]

[19] '*Electricity Pricing-Engineering Principles and Methodologies*', Lawrence J. Vogt, P.E., 2009, p. 288.

[20] '*Electricity Pricing-Engineering Principles and Methodologies*', Lawrence J. Vogt, P.E., 2009, p. 289.

[21] '*Distributed Energy Resources Rate Design and Compensation*', NARUC, Washington, D.C. 2016, p. 26.

Declining block rates were the mainstay of the utility industry, through the 1970's, during decades in which the marginal energy costs declined with the construction of each new generation unit. With the increased focus on conservation and increasing cost of new generation, many utilities discontinued use of DBRs during the peak capacity (summer) seasons. But most summer peaking utilities, like KCP&L and GMO, continue to use DBRs during the winter season to reflect the benefits of improved load factor and the reduced costs of supplying electric heating and other responsible end uses of electricity.

2.2.1 *Pros and Cons of Declining Block Rates*

The following points outline the arguments typically presented for and against DBRs.

2.2.1.1 Arguments for DBR:

- Efficient residential pricing mechanism that easily understood by consumers.
- Equitable method of cost allocation for customer with similar usage patterns and load profiles.
- Provides revenue stability for the utility,
  - More fixed costs recovered in lower blocks
  - Less fluctuation in revenue due to abnormal weather (hotter or cooler).
- Provides bill stability for Consumer,
  - Less energy cost volatility due to abnormal weather.
- Tracks traditional costs of providing services.
- Can promote increased grid utilization from beneficial electrification.

2.2.1.2 Arguments against DBR:

- Pricing is established based on cost and does not provide support or subsidy for energy efficiency or conservation efforts that benefit from a higher cost in the later blocks.
- Is based only on monthly usage.
- Lacks any association with the time of the energy use (peak, off-peak, etc.) to provide feedback for responsible use.
- Provides a lower average cost under higher levels of use.

2.3 Inclining Block Rate

The inclining block rate structure ("IBR") is used to provide customers with a price that escalates with increasing levels of energy usage. With this type of structure, energy can be priced in a punitive way to deter higher levels of consumption and thus encourage customers to conserve energy. The performance of this price signal is determined by how sensitive customers are to price for their energy purchases. In economic terms, this price elasticity determines customer response. The IBR is commonly used for pricing when costs are high and capacity may be more constrained than at other times, particularly during the peak season. IBR is often used when more advanced rate design options such as TOU, are not feasible, usually due to metering limitations. As structured, the inclining block rate places a preponderance of the cost recovery responsibility on the higher use customers that are served under the rate schedule.

NARUC describes inclining block rates in the following way.

> *An increasing, inverted, or inclining block rate (IBR) structure is designed to charge customers a higher per unit rate as their usage increases over certain "blocks" within a billing cycle. For example, a three-tier IBR would identify three blocks of usage. For each block, there is a price for all electricity used within it, with the price increasing as a customer moves through the blocks over a billing period. One of the main purposes of an IBR is to send a conservation signal to customers*

and to incentivize energy efficiency and reduce consumption on the system. In other words, as the price increases with each block, customers may be encouraged to conserve to avoid having to pay the higher block price. In designing an IBR, some considerations must be made, such as the price differentials between the various consumption blocks and the availability of timely consumption information to customers. If customers do not possess the ability to access their consumption data throughout the billing cycle, they will not know when their consumption reaches the higher block rate. Another consideration is that IBRs impose higher per unit costs on high-use customers even though delivering additional volumes may not increase the costs of providing delivery service. Although the incentive to conserve electricity over time is considered greater with an IBR design through avoiding higher prices during the month, this rate does not reflect the hourly or daily changes to the cost of electricity. A customer may pay more for electricity over a given month, even though a majority of its usage may be entirely off-peak; since an IBR does not reflect the day-to-day considerations of peak and off-peak, a customer may overpay for electricity as compared with its otherwise basic cost of service.[22]

As the emphasis toward conservation increased through the 1980's, IBRs were introduced as a conservation inducement that could be implemented within the legacy metering constraints. While studies have shown that IBRs do result in some level of conservation, most conclude that customers are in fact responding to their higher overall electric bill and not the individual pricing steps.[23] More recent studies of other time variant rates, such as TOU rates, show greater customer response as they send pricing signals better aligned with the utilities cost of providing energy services.[24,25] Beyond conservation, IBRs are often viewed as providing a form of 'life-line' or 'subsistence level' usage in the first block to protect low income and elderly from the full impact of increasing costs.[26]

2.3.1 *Pros and Cons of Inclining Block Rates*

The following points outline the arguments typically presented for and against IBRs.

2.3.1.1 Arguments for IBR

- Blunt promotion of Conservation by sending a non-cost based price signal that higher levels of energy use is more expensive. (higher usage customers often have higher price elasticity relative to other customers and therefore higher prices for higher usage results in conservation).
- The non-cost based design can be used to compel conservation, by supporting energy efficiency policies and mandates.
- Can be structured to provide a form of 'life-line' or 'subsistence level' rate.
- Reflects view that long-term or social marginal costs are increasing.
- Depending on implementation method, an IBR rate can be used in conjunction with energy efficiency measures to provide more realized savings to the participating customer. This can result in more customer participation and more response than the optional energy efficiency measures alone.

[22] '*Distributed Energy Resources Rate Design and Compensation*', NARUC, Washington, D.C. 2016, p. 24

[23] *'Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing*', ITO*,* American Economic Review, Vol. 104 No. 2, 2014, pg. 537-563. Available at*:* http://dx.doi.org/10.1257/aer.104.2.537

[24] '*The Paradox of Inclining Block Rates'*, Brattle, Public Utility Fortnightly Magazine, 2015.

[25] '*Trends in Regional U.S. Electricity and Natural Gas Price Elasticity'*, EPRI, 2010, pg. 1.4**.**

[26] '*Electricity Pricing-Engineering Principles and Methodologies'*, Lawrence J. Vogt, P.E., 2009, p. 289.

2.3.1.2 Arguments against IBR

- Support for energy efficiency is not cost based and results in a subsidy for energy efficiency participants at the expense of non-participants.
- Increased revenue instability for utility,
  - less fixed costs recovered in lower blocks. Revenue recovery dependent on higher blocks.
  - fluctuations due to abnormal weather (hotter or cooler).
- Increased price instability for Consumer,
  - Increased energy cost volatility due to abnormal weather.
- Provides a weak pricing signal,
  - not based on when or how efficiently energy is used,
  - not reflective of costs, and
  - customer response based on total electric bill increase, not block price.
- Disproportionate economic impact to larger use customers.
- Negative impact on high users not associated with excess (medical use, window unit air conditioning cooling systems, specialized equipment, etc.).
- Promotes grid defection as larger use customers look to other sources of electricity, generally solar. Grid defection can increase the cost for customers unable to similarly defect.
- Discourages beneficial electrification (Space heating, EV adoption, etc.).
- Can serve as a poor transition point to for time variant pricing. If time based rates are expected in the future, an IBR will create artificially low rates for some customers, making the impact of a transition to a time variant rate more impactful and difficult to implement.

3 EVOLUTION OF RESIDENTIAL BLOCK RATES AT KCP&L

The construct of residential block rates at KCP&L has evolved over the past century as the characteristics of customer use and metering technology have evolved and provide valuable insight as to how block rates also evolved for GMO. The foundation of block rate structures in Missouri was established by a few decisions by the Public Service Commission (PSC) in the years shortly after being established in 1913.

> ***Block rates: Hours-use rates***, A schedule of block rates is more understood and in general more satisfactory in application to residence than an hours-use rate. Charleston Comm Club v Mo Pub Util. Co, 2 Mo PSC 311.[27]
>
> ***Unreasonable blocks***, Electric block rate schedules based upon blocks of 100 kWh militate against the purpose of block rates in that they unduly limit the proper effect and minimize the encouragement of long hours use. Re Ft Scott & Nevada L Co, 2 Mo PSC 581.[28]
>
> ***Reasonable blocks:*** Upon consumers' data showing an average consumption by resident consumers of 17 kWh and business consumers 41.2 kWh and taking into consideration active and connected load etc. a block schedule based upon blocks of 20 kWh for residence and 40 kWh for consumers is held reasonable. Re Ft Scott & Nevada L Co, 2 Mo PSC 581.[29]

The KCP&L residential block rates evolved with a focus on end-use applications. In addition, KCP&L had variations in block rates based on jurisdiction and the customer density (urban, suburban, or rural) of the

[27] '*Missouri Public Service Commission Digest*', 1922, p.212. Available at: https://books.google.li/books?id=wC4wAAAAYAAJ

[28] Ibid

[29] Ibid

service territory. The following summaries, prepared from a review of the KCP&L tariff archives, illustrate how the of the KCP&L Missouri urban residential rate structures have evolved over time.

1920-1945 – Basic residential service based on lighting as the main end-use.

Residential-Lighting - rate without cooking or water heating, usage per block based on number of rooms.

Optional Water Heating & Cooking only riders with separately metered usage.

Residential-Combined Lighting Cooking – Optional rate for customers with cooking and/or water heating and required throw-over switch between stove and water heater.

Customers without throw-over switch were required to be on Residential Demand Rate.

Residential Demand – 'hours-use' rate for residential lighting combined water heating and cooking without throw-over switch. Three 'hours-use' declining cost rate blocks (30, +40, and >70 kWh/kW). Demand individually calculated, 100 watts per room plus 50% of range and 100% water heater ratings.

1945-1950 – Block rates introduced. Incorporated cooking as an end-use in residential service with a usage block adjustment

Residential Service–rate for lighting, cooking, refrigeration and household appliances.

Two blocks (<30 and >30 kWh) and demand adjustment increased size of first block for usage > 1,500 kWh.

Optional, Controlled Water Heating only rider with separately metered usage and Company time clock and bypass switch.

1951-1963, - Usage of Block expanded to incorporate additional end-uses. Introduced excess capacity demand charges and 'hours use' all-purpose rate for residential customers.

Residential Service – established ordinary domestic use as lighting, cooking, refrigeration and household appliances.

Three blocks (<30, +50, and >80 kWh) expanded to four blocks (<30, +50, +50, and >130 kWh).

Excess capacity of $1.25 per kW in excess of 10kW.

Optional Space Heating only riders with separately metered usage.

Residential-Water Heating – rate for ordinary domestic use and water heating.

Four blocks (<30, +50, +40, and >120 kWh) expanded to (<30, +50, +50, and >130 kWh).

Excess capacity of $1.25 per kW in excess of 10kW.

Company time clock or double-throw switch controlled water heater until 1959.
Optional Air Conditioning & Space Heating riders with separately metered usage.

Residential-All Purpose – 'hours-use' block rate for all domestic use.

Four declining cost 'hours-use' rate blocks (<100, +100, +100, and >300 kWh) based on 30-minute kW demand.

Residential All Electric - rate for all electric residence with electric space heating – *frozen in 1963.*

Three blocks (<250, +750, and >1000 kWh) with seasonally differentiated prices, third block declining in winter and inclining in summer.

Company time clock controlled water heater or double-throw switch with electric range.

1963 -1966 – **Blocks further expanded.** Removed excess demand charges, froze separate meter water heating riders.

Residential Service – ordinary domestic use

Six declining blocks (<22, +28, +80 +370, +500, and >1,000 kWh).

Optional Space Heating rider with separately metered usage.

Residential-Water Heating – ordinary domestic use with water heating.
Six declining blocks (<22, +28, +80 +370, +500, and >1,000 kWh).

Optional Space Heating rider with separately metered usage.

Residential-Three-phase Air Conditioning – rate for ordinary domestic use with three-phase air conditioning.
Six declining blocks (<22, +28, +80, +370, +500, and >1,000 kWh).
Additional charge ($/HP or $/kW) during six summer months (April-Oct.).

Residential-Water Heating & Three-phase Air Conditioning – rate for ordinary domestic use with water heating and three-phase air conditioning. Six declining rate blocks (<22, +28, +80 +370, +500, and >1,000kWh).
Additional charge ($/HP or $/kW) during 6 summer months. (April-Oct.).

1966 – 1977 – **Block consolidation begins.** Consolidated Tariff structure

Residential Service – All existing general use, water heating, and three-phase Air Condition single and two-meter constructs continue under consolidated tariff.
Five declining blocks (<30, +100, +370, +500, and >1,000 kWh).

Residential-All Electric – rate for all electric residence with electric space heating. (*Frozen 1971*).
Summer, four declining blocks (250, +750, +500, and >1,500).
Heating, three declining blocks (250, +750, and >1000 kWh).

1976 – 1984 - Introduced seasonal distinction in all rates.

Residential Service – All existing residential configurations continue.
Five declining blocks (<30, +100, +370, +500, and >1,000 kWh) last block pricing varied by season.

1984 – 1986 – **Continued Block consolidation.** Introduced Residential Demand Rate.

Residential Service – All existing residential configurations continue with summer tail block either flat or inclining.

Residential Demand Service (RDS) – Three-part demand rate with a $4 Customer Charge instead of a minimum bill.
Energy in declining blocks: Summer (<200, +500, +400, and >1100); Winter (<200, +400, +100, and >700).
Demand Charges ($0, 1, 2, and 3/kW) were inclining based on four demand blocks (<1, +3, +3, and >7 kW).

1986 -mid 1996 – Block Price Variations Explored. Major redesign of all rates – PURPA considerations

- Service Charge replaced minimum bill based on cost of first usage block.
- Service Charges differentiated by; without space heating, with space heating, and rural.
- Introduced different winter and summer usage blocks, declining with some inclining tail blocks.
- Introduced two time variant rates (RTDD, RTDE).

Residential Service - rate for all domestic residential use with multiple schedules.

General Use – 1 Meter – Summer (<500 and >500); Winter (<1000 and >1000) declining priced blocks.

G.U. & Water Heat – 1 Meter – Summer (<130, +130, +740, +200, and >1200) "W" priced[30] blocks; Winter (<130, +130, +940, +400 and >1600) "U" priced blocks[31].

G.U. & Space Heat - 1 Meter – Summer (<500 and >500); Winter (<1080 and >1080) declining priced blocks.

G.U. Water & Space Heat – 1 Meter - Summer (<500 and >500) declining priced blocks;
Winter (<285, +130, +1155, +775, and >2345) "W" priced blocks.

Space Heat 2nd Meter – Summer (<500 and >500) declining priced blocks; Winter – Flat.

Space & Water Heat 2nd Meter – Summer (<500 and >500) declining priced blocks; Winter-Five generally declining blocks (<155, +130, +795, +665, and >1745).

Residential Demand (RTDD) – Three-part demand rate *(Discontinued in 1996).*
Energy in declining blocks: Summer (<700, +400, and >1100); Winter (<400 and >400).
Demand Charges ($0, 3, 4, and 5/kW) were inclining based on four demand blocks (<1, +3, +3, and >7 kW).

Residential Time of Day (RTDE) – Two period summer only Time of Day rate *(Discontinued in 1996).*
Summer: On-Peak (2 - 8 p.m. Monday-Friday)-2 inclining blocks (<300 and >300); Off-Peak – Flat;
Winter: Two declining blocks (<700 and >700).

Mid 1996 – Present – **Continued Block consolidation.** Part of general simplification and consolidation of rates.

- Service Charges simplified to 1-meter and 2-meter
- Urban/rural rate distinctions eliminated
- Legacy 2-meter water heating special use rates collapsed into Electric Space Heating
- Rate blocks simplified: Summer-FLAT; Winter-declining based on varying constructs of three standard blocks (<600, +400, and >1,000 kWh).

Residential Service - rate for all domestic residential use with multiple schedules.

General Use – 1 Meter – Winter - three declining blocks (<600, +400, and >1000).

Gen. Use and Space Heat – 1 Meter – Winter - two declining blocks (<1,000 and >1000).

Gen. Use w/ Space Heat 2nd Meter – Winter - three declining blocks (<600, +400, and >1000)
- *Frozen in 2007*.

Gen. Use w/ Space & Water Heat 2nd Meter – Winter - three declining blocks (<600, +400, and >1000)
- *Frozen in 1996.*

Residential Time of Day (RTOD) – Two period summer only TOD rate - *Frozen 2015.*
Summer: On-Peak (1 - 7 p.m. Monday-Friday) - Flat; Off-Peak – Flat. Winter: Flat.
Replaced legacy RDS, RTDD, and RTDE rates.

[30] 'W' priced blocks have alternating declining and inclining block prices (2nd block price declines, 3rd block price inclines, 4th block price declines, 5th block price inclines.

[31] 'U' priced blocks have declining price in the second (and third) block and inclining prices in subsequent blocks.

4 DETERMINING THE STUDY METHODOLOGY

The following sections provide a summary of the preparatory analysis the Company performed to determine the methodology to be used in performing the block rate analysis.

4.1 Review Regional Utility Electric Block Rates

Table 4-1 on the following page provides a comparison of the residential block rate structures for KCP&L, GMO, and other utilities in the states surrounding Missouri. Based on a review of the utility web sites and their respective rate sheets, several generalized observations can be made regarding residential rates in our region:

- Customer charges or Service charges are generally below $20. Based on past Company cost studies, these charges cannot be reflective of true fixed cost and are likely set at a price driven by policy considerations.
- Summer rates are either Flat or IBR, generally Flat to the North of the KCP&L/GMO area and generally IBR to the South.
- Winter rates are typically DBR. If General Use is flat, there is typically a DBR heating rate
- Several of the utilities have a kWh cap on the block rate tariff which requires the customer be placed on another, more suitable rate, typically TOU or three-part demand, when the usage level is exceeded.
- The Company observes that utilities reviewed are not utilizing specific end-use rates in their current designs but instead represent the heating cost differential through the pricing of the winter block rates.

4.2 Review Industry Guidelines

The Company performed an on-line search for industry opinions, guidelines, or other informative resources on block rate designs and responsible energy use.

4.2.1 *Published Guidelines for Defining Rate Blocks*

Literature searches found few guidelines on how to establish the appropriate block levels. As previously mentioned, a very early Commission ruling found that appropriate blocks should be set based on the average use of different types of customers.[32] The few guidelines found in industry references follow.

The average consumption of electricity for basic, non-weather sensitive end-uses, based on the U.S. residential sector is generally in the range of 500-600 kWh per month. Thus, the first step of the block rate is often set at a kWh level which captures the expected average base use energy for the specific class of customers.

Most of the utilities in the surrounding jurisdictions have block designs for their winter, i.e. non-summer, season and are evenly split between two or three tier structures. Few design generalizations can be observed based on a simple inspection of the rates themselves. The tiers appear to be based on a mix of baseline usages, average usages, and maximum usages.

In the 2013 Residential Rate Study for the KCC, Christensen and Associates developed three block prices for each season. "We attempted to set the thresholds such that approximately one-third of the customers

[32] '*Missouri Public Service Commission Digest*', 1922, p.212.

fall into each category (e.g., one-third of the customers have monthly usage that reaches into the second block). The summer tiers developed for the study were set at <900, +600, and >1,500 kWh."[33]

Table 4-1: Regional Residential Electric Block Rates

Company	State	Rate	Limits	Summer				Winter			
					Block 1	Block 2 (%Blk 1)	Block 3 (%Blk 1)		Block 1	Block 2 (%Blk 1)	Block 3 (%Blk 1)
KCP&L-MO	MO	Gen		IBR	ALL			DBR	<600	+400 (60%)	>1000 (50%)
KCP&L-MO	MO	Heat		FLAT	ALL			DBR	<1,000	>1,000 (63%)	
KCP&L-GMO	MO	Gen		FLAT	ALL			DBR	<600	>600 (73%)	
KCP&L-GMO	MO	Heat		FLAT	ALL			DBR	<1,000	+400 (57%)	>1,000 (47%)
Ameren-MO	MO	ALL		FLAT	ALL			DBR	< 750	>750 (68%)	
Empire	MO	ALL		FLAT	ALL			DBR	<600	>600 (81%)	
KCP&L-KS	KS	Gen		FLAT	ALL			FLAT	ALL		
KCP&L-KS	KS	Heat		FLAT	ALL			DBR	<1,000	>1,000 (87%)	
Westar	KS	ALL		IBR	<900	>900 (+10%)		DBR	<900	>900 (82%)	
OPPD	NE	Gen		FLAT	ALL			DBR	<100	+ 900 (86%)	>1,000 (61%)
OPPD	NE	Heat	Low Use Credit	FLAT	ALL			DBR	<100	+780 (86%)	>880 (50%)
Lincoln Elec	NE	ALL	3 lvl Fac Chg	FLAT	ALL			FLAT	ALL		
MidA-IA Pwr	IA	ALL	>50k kWh GSvc	FLAT	ALL			DBR	<1,000	>1,000 (55%)	
Alliant-IPL	IA	ALL		FLAT	ALL			DBR	<500	+ 700 (73%)	>1,200 (28%)
OGE	OK	ALL		IBR	<1,400	>1,400 (+19%)		DBR	<600	>600 (30%)	
PSO	OK	ALL		IBR	<1,350	>1,350 (+29%)		DBR	<475	+900 (66%)	>1,350 (44%)
Entergy-AR	AR	ALL	<6kWh /yr ~-5%	IBR	<1,500	>1500 (+30%)		DBR	<1,000	>1,000 (74%)	
Ameren-IL	IL	Del		FLAT	ALL			DBR	<800	>800 (53%)	
MW Energy	KS	Gen	>25k Dmd Rate	IBR	<500	+600 (+16%)	>1,100 (+32%)	FLAT	ALL		
MW Energy	KS	Heat	>25k Dmd Rate	IBR	<500	+600 (+16%)	>1,100 (+32%)	DBR	<1,100	>1,100 (71%)	
Springfld CU	MO	ALL		IBR	<500	>500 (+12%)		DBR	<900	>900 (89%)	

From 1976 until 2001, each California utility had two-tier block rates with the first tier based on 'baseline' usage which the California legislature established at 50 to 60% of average residential consumption and 60 to 70% of average all electric residential consumption during the winter heating season. Typical baseline

[33] *'Residential Rate Study for the Kansas Corporation Commission Final Report'*, Christensen Associates Energy Consulting, LLC, 2012. Available at: http://www.kcc.state.ks.us/electric/residential_rate_study_final_20120411.pdf

usage varied from 300kWh to 500kWh based on company and climate zone. In 2001, the California legislature froze the rates on the first two tiers, established a cap for the second tier at 130% of baseline, and the California Public Utilities Commission (CPUC) ordered utilities to create three additional uncapped block tiers.[34]

Of the few utilities in the surrounding jurisdictions that have summer season blocks with varied pricing, they are all either two or three-tier inclining structures. Of the two-tier block structures, those with lower tier-one levels (500-900 kW) have a smaller step percentage price increase (10-12%) and those that set the tier-one level at a higher level (1,350-1,500 kWh) have a larger step percentage price increase (20-30%). The three tier structures have step levels at (500 and 1,100kWh) with step percentage price increases (30%) nearly equally split between the step levels.

4.2.2 *Published Guidelines for Rates that Promote Responsible Energy Use*

Following the 1973 Arab Oil Embargo, Congress enacted PURPA in 1978 as part of the National Energy Act. PURPA and subsequent amendments were designed to promote energy conservation, promote greater use of domestic and renewable energy, and established PURPA standards.[35] The Federal ratemaking standards promoted energy conservation through improvements in rate design (cost of service, seasonal rates, discouraged DBR unless cost justified, and TOD rates) and energy efficiency and other demand-side management programs.

Responding to PURPA and the increasing marginal cost of electricity production resulting from the second oil crisis and Three Mile Island Nuclear Generating Station accident (both which occurred in 1979), utilities began implementing numerous energy conservation and DSM initiatives to reduce the increasing demand for electricity. Within the residential sector, most utility sponsored DSM initiatives could be classified in three categories:

- Pricing Signals through Rates – GMO, like most utilities, eliminated the DBRs during the summer season and offered optional TOD and Demand Rates. The cost of TOD metering prohibited wide scale implementation of TOD rates, so some utilities implemented the IBR rates for their conservation effect.
- Energy Efficiency ("EE") Programs – Most utilities, including GMO, provided education materials on EE, some offered home energy audits, and others provided rebate and incentive programs for customer adoption of EE measures. These utility programs focused on energy efficiency and the overall reduction in energy usage.
- Demand Response Programs – These programs provided incentives to customers to allow the utility to directly control air conditioners, water heaters, and similar end-used devices during critical peak usage periods. Demand response programs focused on the reduction in electrical usage during peak system loading periods to manage the need for future generation capacity.

Congress last amended the PURPA standards with American Recovery and Reinvestment Act (ARRA) of 2009 by adding consideration for Smart Grid investments and SmartGrid information. Under ARRA, the

[34] '*Residential Electric Rates Revisited-Part 1: A Historical Perspective*', The EPIC Energy Blog, 2013

[35] 16 U.S. Code-Title 16-Chapter 46-Public Utility Regulatory Policies.
Available at: https://www.law.cornell.edu/uscode/text/16/chapter-46

U.S. Department of Energy's (DOE) Smart Grid Investment Grant Program (SGIG) funded substantial deployment of Automated Metering Infrastructure (AMI) by numerous utilities.

Ten utility programs took part in the DOE Consumer Behavior Study (CBS) "to produce more robust and credible analysis of impacts, costs, benefits, and lessons learned and assist utility and regulatory decision makers in evaluating investment opportunities involving time-based rates."[36] The study concluded that customers' response to TOU rates was greater, with larger on- to off-peak response than with smaller ratios and that the use of a programmable communicating thermostats (PCT) significantly increased the customers' level of demand response.[37] The CBS study demonstrates that TOU and other TVRs can be an effective tool to reduce peak demand and enable customers to better manage their electric consumption and costs.

> *"DOE hopes the experiences and results from the CBS effort which have been published to date, as well as those yet to come, can help other utilities and regulators more aggressively pursue the application of time-based rates for residential customers."*[38]

Additionally, the electric industry is in the beginning stages of a transformation and grid modernization in response to the influence of renewable resources, distributed generation, energy storage, electric vehicles, home energy management, and new more efficient and grid-interactive loads. Across the industry, utilities, regulatory agencies, and legislative bodies are grappling with a wide range of grid modernization policy and regulatory issues including sweeping changes business models, investments in non-traditional utility assets, and significant changes to cost recovery and rate design.[39]

The following sections highlight some of the key observations regarding this grid transformation and the evolution of retail rates that will be required to facilitate the evolving definition of 'responsible energy use'. The Company contends these observations are important and applicable to this study. These observations support the goal of this study and provide a longer-term view to potential rate design approaches.

4.2.2.1 The Evolving Landscape of Mass Market Rate Designs

The following excerpts from a recently published review of alternative rate designs for residential 'mass market' customers by the Rocky Mountain Institute ("RMI") identify TOU and Demand Rates as next steps in the evolution in residential rates.

> *There is a serious conversation unfolding around electricity rate design for mass-market (residential and small commercial) customers—both in the U.S. and internationally. New proposals are appearing for how to improve rates to meet emerging challenges (and opportunities) around environmental impact, customer engagement, bill management, reliability,*

[36] '*Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*', U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, 2016, page iv. Available at: https://www.smartgrid.gov/document/CBS_Results_Time_Based_Rate_Studies.html

[37] IBID, page x.

[38] IBID, page 71.

[39] '*The Top Utility Regulation Trends of 2017—So Far',* C. Girouard, Greentech Media, July 2017. Available at: https://www.greentechmedia.com/articles/read/top-10-utility-trends-regulation-of-2017-aee#gs.RIHG1B4

and cost recovery. These proposals frequently generate debate and conflicting opinions between stakeholders.[40]

Recent trends are forcing stakeholders across the industry to take stock of how customer needs are evolving and how that affects the electricity system. Customer load profiles are becoming more diverse while new technology is increasing potential customer capabilities [41]

Existing default rates in the U.S. are simple—typically pairing a flat, volumetric energy rate with a customer charge. These rates have worked well enough but are proving inadequate in the face of recent trends, as they fail to provide price signals that reflect system costs and enable customer response. An expanded rate design toolkit is needed, but it is critical that solutions do not reduce signals for energy efficiency or be difficult for customers to understand and respond to.[42]

Two types of alternative mass-market rate designs are often proposed to meet rapidly evolving customer needs in the near-term:

- ***Time-based rates** can provide more accurate price signals to customers, better reflecting the marginal cost of supplying and delivering electricity. These price signals may lead customers to change their consumption patterns to reduce both peak and total consumption.*
- ***Demand charge rates** can provide a price signal to reduce peak demand and can potentially allocate peak driven costs more fairly. Customers may respond by changing their consumption patterns to reduce peak demand, flattening their load profile.43*

These solutions can be important near-term steps in the ongoing evolution of rate design.[44]

Utility customers can derive additional financial benefits when time variant rates correspond more closely to the actual electrical production costs and benefits:

"Furthermore, a myriad of financial benefits inure to utilities and their ratepayers when customers take service under and respond to time-based rates. The value associated with lowering peak demands is often at its highest when reductions in consumption coincide with times that the local or regional power system is experiencing its highest level of demand (i.e., the coincident system peak demand). Such reductions in electricity demand at these times can lead to future deferrals of new investments or upgrades in electric generation, distribution and possibly transmission facilities, and/or avoidance of higher prices or demand charges from wholesale power suppliers. These results can lead to reductions in the utility's overall cost of service, which can benefit all customers when the reductions are passed on through retail rates."[45]

4.2.2.2 Integration of Distributed Energy Resources

The electric grid is beginning to change with the rise of distributed generation from distributed energy resources (DER), electricity storage, and solar photovoltaics (PV). Additionally, smart appliances, home

[40] '*A Review of Alternative Rate Designs-Industry Experience with Time-Based and Demand Charges for Mass Market Customers*', Rocky Mountain Institute, Boulder, CO, 2016, Page 5.
Available at: https://www.rmi.org/insights/reports/review-alternative-rate-designs/

[41] IBID.

[42] IBID.

[43] IBID.

[44] IBID.

[45] '*Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*', U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, 2016, pg. 2.

energy management systems, and electric vehicles are providing new capabilities for consumers to manage energy use. To achieve the full value of DER, they must be fully included in the planning and operation of the grid, to create what EPRI terms 'The Integrated Grid'. The following excerpts highlight some of the rate transformations that will be required to promote and compensate DER for their participation in the evolving grid (emphasis added).

> *A policy and regulatory framework will be needed to encourage the effective, efficient, and equitable allocation and recovery of costs incurred to transform to an integrated grid. New market frameworks will have to evolve in assessing potential contributions of distributed and central resources to system capacity and energy costs. Such innovations will need to be anchored in principles of equitable cost allocation, cost-effective and socially beneficial investment, and service that provides universal access and avoidance of bypass.*[46]
>
> *Rates are generally considered equitable if customers pay an appropriate share of total utility costs, in proportion to the costs they cause, along with a percentage of common costs. Rates encourage efficient consumption decisions if they reward or penalize these decisions in proportion to their resulting costs or savings. In either case, such cost causation is an important principle for both allocating costs and designing rates that guide consumptive decisions.* [47]
>
> *A customer's load profile can generally be characterized by two quantities: total energy consumption (in kWh) and the contribution to peak demand (in kW). The resulting costs they create are a function of both quantities. … While these two variables may have been linked more strongly in the past, new technologies and consumer behaviors are changing that relationship. A customer with electric vehicles, PV, or storage operating behind the meter will likely have a net load profile much different from a residence with only electric HVAC and other common appliances. …* ***Creating a more balanced emphasis between total energy consumption and contributions to peak demand provides incentives for both energy efficiency and demand management, as well as the technologies that address each.***[48]

In a recent 'Utility of the Future' study, the Massachusetts Institute of Technology Energy Initiative examined how the provision and consumption of electric services is likely to evolve and developed a framework of proactive regulatory, policy, and market reforms needed to enable the evolution of the electrical power grid with the goal of integrating all resources distributed or centralized. The framework included the following points:

- *Flat, volumetric tariffs are no longer adequate for today's power systems and are already responsible for inefficient investment, consumption, and operational decisions.*
- *Peak-coincident capacity charges that reflect users' contributions to incremental network costs incurred to meet peak demand and injection, as well as scarcity - coincident generating capacity charges, can unlock flexible demand and distributed resources and enable significant cost savings.*
- *Granularity matters. The value or cost of electricity services can vary significantly at different times and at different locations in electricity networks. Progressively improving the temporal and locational granularity of prices and charges for these services can deliver increased social welfare.*

[46] '*The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*', EPRI. Palo Alto, CA: 2014, Page 24
Available at: https://www.epri.com/#/pages/product/000000003002002733/

[47] '*The Integrated Grid: Capacity and Energy in the Integrated Grid*', EPRI. Palo Alto, CA: 2015, Page 27.
Available at: https://www.epri.com/#/pages/product/000000003002004878/.

[48] '*The Integrated Grid: Capacity and Energy in the Integrated Grid*', EPRI. Palo Alto, CA: 2015, Page 28. emphasis added.
Available at: https://www.epri.com/#/pages/product/000000003002006692/

However, these benefits must be balanced against the costs, complexity, and potential equity concerns of implementation

- *To establish a level playing field for all resources, cost-reflective electricity prices and regulated charges should be based only on what is metered at the point of connection to the power system — that is, the profile of injections and withdrawals of electric power at a given time and place, rather than the specific devices behind the meter. In addition, cost-reflective prices and regulated charges should be symmetrical, with injection at a given time and place compensated at the same rate that is charged for withdrawal at the same time and place.*[49]

Similarly, a recent RMI eLab report highlights the need to change electricity pricing to be more reflective of the costs and benefits of grid services exchanged between the customer and utility. The report presents a pathway for deliberately and incrementally increasing rate sophistication along three continuums for residential and small commercial customers:

- ***Attribute unbundling*** *— shifting from fully bundled pricing to rate structures that break apart energy, capacity, ancillary services, and other components*
- ***Temporal granularity*** *— shifting from flat or block rates to pricing structures that differentiate the time-based value of electricity generation and consumption (e.g., peak vs. off-peak, hourly pricing)*
- ***Locational granularity*** *— shifting from pricing that treats all customers equally regardless of their location on the distribution system to pricing that provides geographically differentiated incentives for DERs.* [50]

4.2.2.3 Growing Consensus for Environmentally Beneficial Electrification

While PURPA focused on promoting energy conservation through EE and reduced consumption along with increased use of renewable, there is a growing industry discussion regarding the 'beneficial' or 'efficient' electrification. The benefits of increasing electricity's portion of overall energy to reduce environment emissions, improve efficiency, and enhance grid flexibility are discussed in a recent Electricity Journal article:

Consensus is growing that meeting aggressive GHG reduction goals will require electrification of end uses such as space heating, water heating, and transportation. A recent report by Environmental and Energy Economics (E3) states that "critical to the success of long-term GHG goals" is "fuel-switching away from fossil fuels in buildings and vehicles."[51] *Lawrence Berkeley National Laboratory similarly concludes that "widespread electrification of passenger vehicles, building heating, and industry heating" is essential for meeting California's GHG reduction goals.*[52] *Work at Stanford University also indicates that "one potential way to combat ongoing climate change, eliminate air pollution mortality, create jobs and stabilize energy prices involves*

[49] '*Utility of the Future: Executive Summary*', MIT Energy Initiative, 2016, Pages 5-6

Available at: https://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Executive-Summary.pdf

[50] '*Rate Design for the Distribution Edge-Electricity Pricing for a Distributed Resource Future*', Rocky Mountain Institute, eLAB, 2014, page 7. Available at: https://d231jw5ce53gcq.cloudfront.net/wp-content/uploads/2017/04/2014-25_eLab-RateDesignfortheDistributionEdge-Full-highres-1.pdf

[51] *'California PATHWAYS: GHG Scenario Results*', Energy + Environmental Economics, 2015.

[52] '*California's Carbon Challenge Phase II Volume I: Non- Electricity Sectors and Overall Scenario*', LBNL. 2013.

converting the world's entire energy infrastructure to run on clean, renewable energy."[53] … Many other researchers around the globe are echoing the same conclusions. … The consensus on environmentally beneficial electrification, it seems, is in. [54]

The article summarizes trends in the electric power industry that are enhancing the opportunity to electrify end-uses as a means to reduce GHG emissions.

- First is the adoption and implementation of public policy goals to achieve GHG emissions reductions.
- The second trend is the lowering of GHG emissions rates of the U.S. electric sector overall due to technology advances and cost reductions of cleaner electric generation, as well as policy goals.
- The third trend generating abundant opportunity for environmentally beneficial electrification is the significantly increased efficiency of end-use equipment itself.
- The fourth electrification trend is the growing need for "flexiwatts" to enable greater integration of renewable energy into the electric grid. [55]

The Brattle Group, suggests that utilities should explore modifications to rate designs to remove disincentives for beneficial electrification

Some existing rate designs may create an economically inefficient disincentive to pursue electric end-uses. For instance, an inclining-block rate (IBR) structure charges customers an escalating price as their consumption increases over the course of the month. This rate design has largely been used as a policy tool to promote electricity conservation, but, given that both electric heating with heat pumps and home charging of [Battery Electric Vehicles] BEVs would significantly increase total electricity consumption, customers under IBR have a financial disincentive to adopt a heat pump water heater, heat pump space heater or BEV charging at home.[56]

In addition to reforming existing rate designs, there may also be a practical need to create a new rate design for a subset of customers who own certain end-uses.[57] *For instance, many utilities have created a rate designed specifically for customers with electric vehicles. By offering a lower price during off-peak hours to reflect the lower cost of generating and supplying electricity in those hours, the rate provides BEV owners with an opportunity to manage their charging patterns to save money on their electricity bill while also providing a benefit to the power system.*[58]

4.3 Consideration of the Company Energy Efficiency Program

When considering the goal of this study and its focus on responsible energy use, the contribution of energy efficiency cannot be overlooked. When applied, energy efficiency measures provide direct and impactful

[53] '*Stanford Engineers develop state-by-state plan to convert U.S. to 100% clean, renewable energy by 2050*'. Stanford News, 2015.

[54] '*Environmentally Beneficial Electrification: The dawn of 'emissions efficiency'*, The Electricity Journal, 29 (2016), Pages 52-53.

[55] IBID, Pages 53-54.

[56] Electrification, Emerging Opportunities for Utility Growth', Brattle, 2017, pg. 17. Available at: http://www.brattle.com/system/news/pdfs/000/001/174/original/Electrification_Whitepaper_Final Single_Pages.pdf?1485532518

[57] While such rates should be cost-based and therefore could be applicable to any customer – with or without a particular end-use – in some cases there may be advantages to designing a rate that is specifically aligned with the operational characteristics of the target end-use technology, in order to incentivize the optimal utilization of that technology.

[58] IBID

results, reflecting a high level of responsible energy use. Customers are utilizing energy to perform the work they want but are increasing the efficiency associated with that work. Through the Missouri Energy Efficiency Investment Act (MEEIA), the Company has endeavored to deploy a suite of programs that will provide Customers with opportunities to use their energy more efficiently and to save money.

Currently in the second “cycle” of program offerings, the Company offers a broad suite of programs for Residential, Commercial, and Industrial customers. Those designed to benefit Residential customers include:

- Whole House Efficiency
- Home Lighting Rebate
- Residential Programmable Thermostat
- Online Home Energy Audit

These programs provide a practical means for customers to influence their energy use. Whether through the utilization of LED lighting, high efficiency heating and cooling equipment, or a programmable thermostat, a customer can reduce or influence the timing of their usage to the benefit of the customer and the Company.

Beyond the existing programs, there is potential in deploying rates as a program within the MEEIA structures. Time variant rates and demand rates in particular provide the best complement to the other programs and the goal of supporting responsible energy use. Pilot programs examining these designs are being considered by the Company and may be offered as part of a future program cycle.

4.4 Review Regional Utility Time Variant Rates

Table 4-2 below provides a summary of the residential TOU and other TVR structures available utilities in Missouri and the surrounding States. Based on a review of the utility web sites and their respective rate sheets, several generalized observations can be made regarding residential rates in our region:

- Many of the TOU rates appear to be legacy designs first implemented in the 1980’s in response to PURPA requirements.
- All of the TOU programs are implemented as optional rates.
- Half of the TOU rates are summer only with Flat or DBR prices in the winter period.
- Most of the TOU rates have longer (six plus hours) on-peak time periods.
- Most of the summer On-Peak to Off/Super-Off peak price differentials are modest (2-4x).
- Public Service of Oklahoma & Oklahoma Gas & Electric have shorter On-Peak periods with more aggressive On- to Off-peak price ratios.
- Critical Peak Pricing (“CPP”) is only offered as an optional TOU rate by PSO & OGE, which were first implemented as part of a DOE SmartGrid Demonstration Project.

Table 4-2: Regional Residential Time Variant Rates

Company	State	Rate	Limits	Availability	Summer				Winter			
					Periods	On-Peak	Off / Inter.	Super Off Pk.	Periods	On-Peak	Off / Inter.	Super Off Pk
KCP&L-MO	MO	TOD	500 cust	FROZEN	2	1-7 pm 21.2¢	Other 1.8x		FLAT			
KCP&L-KS	KS	TOD	500 cust	FROZEN	2	1-7 pm 17.6¢	Other 2.4x		FLAT			
KCP&L-GMO	MO	TOD		FROZEN	3	1-8 pm 20.4¢	Other 1.8x	10p-6a 3.0x	2	7am-10 pm 13.1¢		10p-7a 2.5x
Ameren	MO	TOU	Pilot 5k cust	Optional no NetMtr	2	2-7 pm 30.5¢	Other 4x	10p-8a 4x	DBR	<750	>750	
Westar	KS	TOU	Pilot 1k cust	Optional	3	1-8 pm 15.231¢	10am-1pm 1.4x	Other 2.25x	2	10am-8pm 8.979¢	10a-1pm 1.6x	Other 1.6x
Empire	MO	TOU Rider	50 cust	Optional	3	12-7 pm std +2.75¢	Other std -0.42¢	10pm-9am std -1.04¢	2	6am-10pm std +0.15¢	Other std -0.11¢	10pm-9am std -0.11¢
IA Pwr	IA	TOU		Optional	3	1-6 pm 20.925¢	Other 2.3x	10p-8a 3.2x	2	1-6 pm 7.809¢	Other 1x	10p-8a 1.2x
IPL	IA	TOU Rider		Optional	3	7am-8pm 140% std	Other 50% std		2	7am-8pm 140% std	Other 50% std	
OGE	OK	TOU	Summer Only	Optional	2	2-7 pm 20.925¢	Other 5.2x		DBR	<600	>600	
OGE	OK	TOUw CPP	Summer Only	Optional	2	2-7 pm 5-42¢	Other 1-8.4x		DBR	<600	>600	
PSO	OK	TOU	Summer Only	Optional	2	2-7 pm 10.2¢	Other 5.x		DBR	<475	>475 <1350	>1350
PSO	OK	TOUw CPP	Summer Only	Optional	3	2-7 pm 10.2¢ (65¢)	Other 3.6x	11p-10a 5.9x	DBR	<475	>475 <1350	>1350
Entergy	AR	TOU	Time Period Variations	Optional	3	1-7 pm 13.88¢	Other 2.1x	10p-6a 2.4x	2	1-6 pm 6.7¢	Other 1x	10p-6a 1.2x

4.5 Basis for Study Methodology

During KCP&L-MO's last significant rate redesign effort in the mid 1990's, the number of residential rate blocks was reduced from as many as five blocks, to three standard blocks (<600, +400, and >1000). These three blocks applied to all KCP&L jurisdictions. Until the Commission ordered KCP&L-MO to implement an IBR design for the Residential General Use rate in the summer season, all summer rates were flat across all jurisdictions. In the winter season, the General Use rates are either flat or declining and space heating rates are declining. The primary focus of this rate block analysis is not to determine which rate structures should be offered, but rather in determining the most appropriate rate block thresholds for consideration in future rate design analysis.

Many neighboring utilities, who have summer peaks like GMO continue to use block designs during the winter season to structure pricing to reflect the benefits of improved load factor and the reduced costs of supplying off season uses. Further, review of the fixed charges (customer charges or service charges) associated with these rates imply general under recovery of those costs in the fixed charge, meaning some portion of those costs are being recovered within the energy charges. This transference of cost recovery commonly contributes to DBR application.

Since the late 1990's, the residential housing market in the Kansas City area has experienced a significant change with an increasing percentage of new construction occurring as multi-family housing. Mid-

American Regional Council and other regional planning groups expect this trend to continue for the foreseeable future as the "Baby Boomer" generation continues to age and downsize and they better align to the lifestyle preferences of the post "Baby Boomer" populations.[59] [60] Therefore, the impact of housing 'premise type' (apartment vs single family) was evaluated to determine appropriate rate blocks.

Industry sources suggests that blocks should be based on a 'baseline' or average usage levels for each type of customer type.[61,62] Baseline usage can be established in two ways, a "ground up" baseline based on a defined set of appliances and typical kWh consumption which may represent more of a representative minimal usage level. The second, which was chosen for this analysis, is to look at actual average customer usage levels during low usage, off-season months to establish a typical non-weather influenced usage level.

[59] Kansas City Metro Market Trends, Preferences and Opportunities to 2040, Mid America Regional Planning Commission, 2012. Available at: http://www.marc.org/Regional-Planning/Creating-Sustainable-Places/assets/Nelson_MarketTrends Presentation11-8-12.aspx

[60] National Trends & Demand for Smart Growth in Kansas City, Mid America Regional Planning Commission, 2012., 2012. Available at: http://www.marc.org/Regional-Planning/Creating-Sustainable-Places/assets/DRAFT_RCLCO_PPT.aspx

[61] '*Residential Electric Rates Revisited-Part 1: A Historical Perspective*', The EPIC Energy Blog, 2013 Available at: https://epicenergyblog.com/2013/06/05/128/

[62] '*Electricity Pricing-Engineering Principles and Methodologies'*, Lawrence J. Vogt, P.E., 2009, page 289.

5 BLOCK RATE THRESHOLD ANALYSIS

The following sections summarize the comprehensive analysis of customer usage the Company undertook to evaluate the role of residential energy blocks in promoting responsible energy use.

5.1 Customer Usage Data Preparation

To create the customer usage dataset for each jurisdiction on which to perform the block usage analysis, 2016 monthly actual residential customer usage data by premise was extracted from Company databases and loaded it into Excel for analysis. Below is a count of the records extracted:

- KCP&L-KS – 216,107 records
- KCP&L-MO – 219,894 records
- GMO – 263,744 records

To improve the usage analysis for 'typical' customers and minimize the impact of outliers, each dataset was reviewed and edited to:

- Remove premises with annual usage below 101 kWh as they are uncharacteristically low and are not representative of a normal residential class customer. These are likely vacant premises, garages, or outbuildings.
  - KCP&L-KS – 2,886 records
  - KCP&L-MO - 575 records
  - GMO - 3,219 records
- Remove premises with partial year usage,
  - KCP&L-KS – 74,384 records
  - KCP&L-MO – 67,068 records
  - GMO – 76,545 records
- Remove premises with annual usage greater than 30,000 kWh, as they are uncharacteristically high and are not representative of a normal residential class customer. There was concern that these high data points would skew the analysis results.
  - KCP&L-KS - 4,943 records
  - KCP&L-MO - 2,690 records
  - GMO - 6,350 records

This left each jurisdiction dataset with the following number of record with complete annual usage:

- KCP&L-KS - 133,894 records
- KCP&L-MO - 149,561 records
- GMO –177,630 records

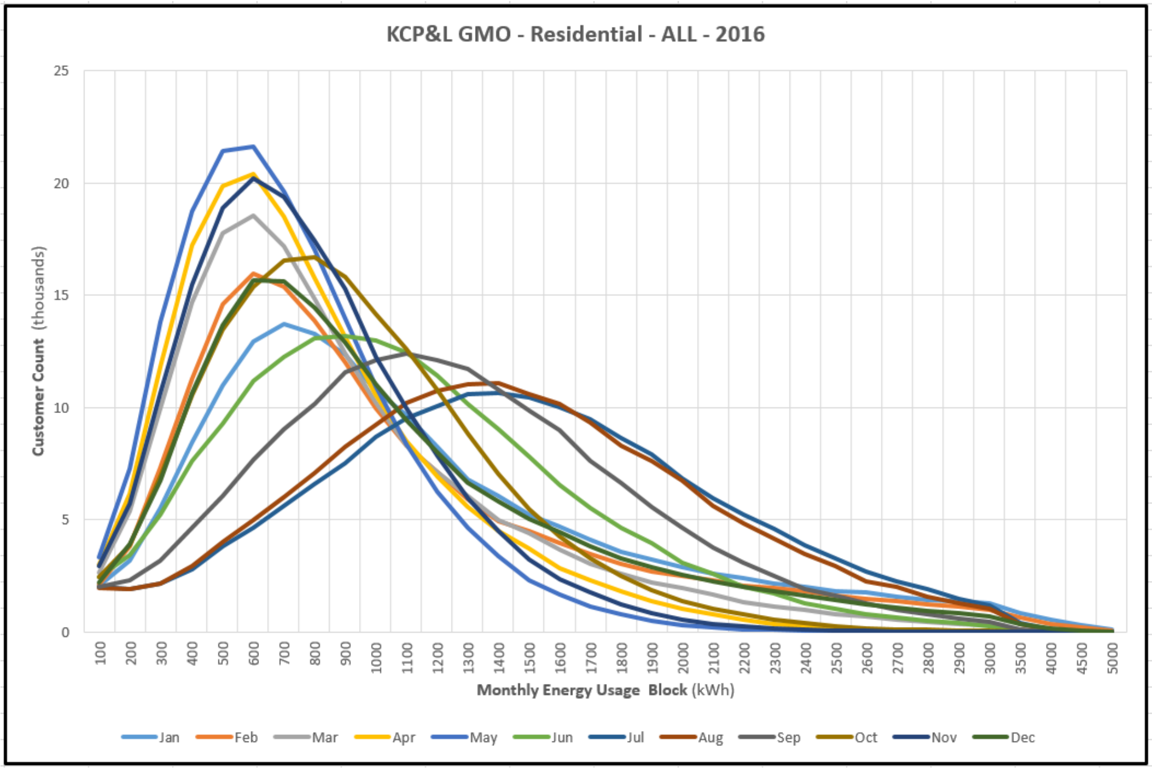
To further improve the analysis, the premise addresses were analyzed to improve the consistency of the premise use attribution for single family and apartment premises. Typical corrections to the premise type attribute included:

- Premise with APT in the address reset to APT as the Premise Type.
- Premise with UNIT in the address were inspected and Premise Type set to APT or DPLX as appropriate.
- Premise with # in the address were inspected and Premise Type set to APT or DPLX as appropriate.
- Premise with LOT in the address were inspected and Premise Type set to MOBL as appropriate.
- Premise with GARAGE in address set to AUXL as the Premise Type.

- Premise with BARN in address set to AGRI as the Premise Type.

Tables of customer count distributions were then compiled for 100 kWh usage block by month and combinations of Usage Type (General Use and Heating) and Premise Type (ALL, APT, SGL) for further analysis. Figure 5-1 illustrates a typical customer count distribution in graphical form.

Figure 5-1: Typical Customer Count Distribution by Usage Block



5.2 Preliminary Usage Data Segmentation

As a preliminary segmentation of usage data, the average usage by 'season' was calculated for each of the premise and usage combinations and tabulated in Table 5-1 following. In this analysis, the 'seasons' were defined as:

- Annual – all 12 months Jan.-Dec.
- Summer – 4 summer months, June-Sept.
- COOL2 – 2 predominate peak cooling months, July-Aug.
- Winter – 8 non-summer months
- OFF – 4 months, April, May, Oct., Nov.
- OFF2 – 2 predominate low usage months, April-May
- HEAT4 – 4 heating months, Dec.-March
- HEAT2 – 2 predominate heating months, Jan-Feb

With the following premise-usage combinations:

- ALL-RES – all uses with all premise types
- ALL-APT – all uses with premise type=APT (multi-family)
- ALL-SGL - all uses with premise type=SNGL (single family)
- GEN-ALL - all general use rate codes with all premise types

- GEN-APT – all general use rate codes with premise type = APT
- GEN-SGL - all general use rate codes with premise type = SNGL
- HEAT-ALL - all heating rate codes with all premise types (single and two meter rates)
- HEAT-APT – all heating use rate codes with premise type = APT
- HEAT-SGL - all heating use rate codes with premise type = SNGL

Table 5-1: Jurisdictional Average Usages by Usage Group and Season

GMO	Average Usages by Usage Group and Season (kWh)								
	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	177,630	18,671	146,314	113,614	7,964	96,846	64,016	10,707	49,468
Annual	1,041	684	1,096	926	547	967	1,243	786	1,345
Summer	1,298	755	1,384	1,275	788	1,333	1,339	730	1,485
COOL2	1,453	818	1,554	1,440	873	1,506	1,478	777	1,646
Winter	912	649	951	752	426	785	1,196	814	1,276
OFF	757	500	796	684	414	714	885	563	958
OFF2	707	476	742	618	364	645	863	559	931
HEAT 4	1,067	798	1,105	819	438	856	1,507	1,065	1,593
HEAT 2	1,178	895	1,218	882	462	921	1,704	1,218	1,797
KCPL-MO	Averages Usage by Usage Group and Season (kWh)								
	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	149,562	37,612	101,642	117,226	2,316	87,069	32,334	14,597	14,574
Annual	880	630	967	837	519	922	1,033	805	1,234
Summer	1,154	749	1,299	1,156	742	1,267	1,150	760	1,490
COOL2	1,325	850	1,496	1,337	859	1,466	1,286	837	1,680
Winter	742	570	801	678	407	750	975	827	1,106
OFF	630	452	692	603	384	661	727	558	876
OFF2	578	419	632	541	328	598	709	562	838
HEAT 4	855	688	910	753	429	838	1,222	1,096	1,335
HEAT 2	931	773	983	807	453	900	1,382	1,279	1,475
KCPL-KS	Average Usages by Usage Group and Season (kWh)								
	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	133,894	21,701	101,395	99,685	8,782	82,298	34,209	12,919	19,097
Annual	1,057	726	1,134	1,024	563	1,080	1,155	836	1,364
Summer	1,445	830	1,581	1,499	863	1,577	1,288	808	1,596
COOL2	1,597	905	1,745	1,659	951	1,745	1,417	873	1,763
Winter	863	673	911	786	414	832	1,088	850	1,248
OFF	755	512	810	736	412	776	809	580	958
OFF2	704	502	752	674	375	711	792	589	927
HEAT 4	972	835	1,011	836	416	889	1,367	1,119	1,538
HEAT 2	1,059	968	1,090	885	435	942	1,564	1,331	1,728

5.3 Baseline Usage Analysis

The first step in establishing any block rate structure is to understand the baseline usage for each Usage Group. The 'baseline' usage was defined as the typical (by either average use or median) non-weather influenced usage. The baseline usage should also represent the usage of approximately 50% of the customers. While not specifically a 'life-line' usage amount, it represents a typical non-weather related use amount of energy consumption for a customer.

For all KCP&L and GMO jurisdictions, the non-weather related usage is best represented by the usage in April and May (OFF2) which are the predominately lowest two usage months and are least influenced by weather. In 2016, these OFF2 months had 12.5% fewer heating degree days and 46.5% fewer cooling degree days than normal, so the 2016 usage data should contain less weather-related usage than normal.

Table 5-2 thru Table 5-4 following, summarize the following OFF2 season statistics for each Usage Group by jurisdiction:

- Customer count
- Average monthly kWh usage
- Median monthly kWh usage
- Rate block with highest customer count
- Percent customers by usage threshold

These tables show similar baseline usage patterns across Usage Groups for all jurisdictions. The average OFF2 season usage varies as expected based on premise-type and end-use. In general, the average use by electric heating customer, both APT and SGL, is approximately 200 kWh more per month. This is largely due to the additional consumption caused by electric water heating and cooking in homes on the electric heating rates. The tables also show that for each Usage Group, the KCP&L-MO jurisdiction has an average usage 50-100 kWh less per month than the other KCP&L and GMO rate jurisdictions. This usage differential may be caused be several factors including; generally smaller dwelling sizes and a higher incidence of premises on legacy 2-meter water heating rates which are included under the electric space heating tariff.

Table 5-2: GMO OFF2 Season Usage Distribution Summary

GMO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	177,630	18,671	146,314	113,614	7,964	96,846	64,016	10,707	49,468
Average Usage	707	476	742	618	364	645	863	559	931
Median Usage	632	414	668	557	303	582	798	503	868
Largest Block	5-600	3-400	5-600	4-500	2-300	4-500	6-700	3-400	7-800
Usage Block									
< 400 kWh	22.9%	47.9%	18.9%	28.6%	66.3%	24.6%	12.8%	34.2%	7.8%
< 500 kWh	34.5%	61.8%	30.2%	42.2%	78.4%	38.3%	20.9%	49.4%	14.3%
< 600 kWh	46.4%	73.0%	42.2%	55.3%	86.3%	52.0%	30.4%	63.0%	23.0%
< 700 kWh	57.1%	81.0%	53.4%	66.5%	91.2%	63.8%	40.4%	73.4%	32.8%
< 750 kWh	62.0%	84.1%	58.5%	71.3%	92.8%	69.0%	45.3%	77.6%	38.0%
< 800 kWh	66.3%	86.9%	63.2%	75.4%	94.2%	73.4%	50.1%	81.5%	43.1%

Table 5-3: KCP&L-MO OFF2 Season Usage Distribution Summary

KCP&L-MO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	149,561	37,612	101,642	117,226	23,016	87,069	32,334	14,596	14,573
Average Usage	578	419	632	541	328	598	709	562	838
Median Usage	504	345	559	473	269	530	633	495	768
Largest Block	3-400	2-300	4-500	3-400	1-200	4-500	4-500	3-400	6-700
Usage Block									
< 400 kWh	21.7%	42.3%	14.4%	24.5%	56.6%	16.0%	11.6%	19.8%	4.4%
< 400 kWh	35.8%	58.3%	27.7%	39.5%	72.9%	30.5%	22.4%	35.3%	10.7%
< 500 kWh	49.4%	70.5%	42.0%	53.6%	83.1%	45.7%	34.4%	50.7%	20.0%
< 600 kWh	61.4%	79.4%	55.1%	65.5%	89.4%	59.1%	46.3%	63.7%	30.8%
< 700 kWh	71.1%	85.7%	66.1%	75.0%	93.4%	70.1%	57.0%	73.6%	42.2%
< 750 kWh	75.1%	88.0%	70.8%	78.8%	94.7%	74.6%	61.9%	77.5%	48.1%
< 800 kWh	78.6%	90.1%	74.8%	82.0%	95.8%	78.4%	66.4%	81.1%	53.3%

Table 5-4: KCP&L-KS OFF2 Season Usage Distribution Summary

KCP&L-KS	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	133,894	21,701	101,395	99,685	8,782	82,298	34,209	12,919	19,097
Average Usage	704	502	752	674	375	711	792	589	927
Median Usage	636	438	684	609	318	647	724	533	869
Largest Block	5-600	3-400	5-600	5-600	2-300	5-600	5-600	4-500	7-800
Usage Block									
< 400 kWh	21.6%	58.3%	27.7%	23.4%	72.9%	30.5%	16.3%	35.3%	10.7%
< 500 kWh	33.5%	70.5%	42.0%	35.9%	83.1%	45.7%	26.4%	50.7%	20.0%
< 600 kWh	45.8%	79.4%	55.1%	48.8%	89.4%	59.1%	37.0%	63.7%	30.8%
< 700 kWh	57.0%	78.7%	51.8%	60.2%	91.5%	56.3%	47.5%	70.0%	32.5%
< 750 kWh	62.0%	82.1%	57.2%	65.2%	93.0%	61.7%	52.5%	74.6%	37.6%
< 800 kWh	66.6%	85.2%	62.2%	69.8%	94.6%	66.7%	57.3%	78.9%	42.8%

5.3.1 *Baseline Usage for the Average Residential Customer*

Developing reference baseline usages by end-use and premise-type may be beneficial in the development of usage blocks. But for the first element of the baseline analysis, focus was maintained on defining the baseline usage for the average residential customer. The question then arises, should the baseline usage be based on: 1) the average customer usage; 2) the median of customer usages; or 3) the upper threshold of rate block representing the highest number of customers. As the previous tables illustrate, the median usage is lower than the average usage and the threshold of the highest populated rate block is below the median.

The median was chosen, rounded to the nearest 100. This value often coincided with the rate block representing the largest number of customers within the Usage Group and generally provided a threshold representing approximately 50% of the customers. Using this criterion, the baseline usage levels for all residential (ALL-RES) customers without an end-use or premise-type distinction within each jurisdiction are:

- GMO - 600 kWh with 46.4% of customers below this level
- KCP&L-MO - 500 kWh with 49.4% of customers below this level
  (or 600 kWh with 61.4% of customers below this level for consistency)
- KCP&L-KS - 600 kWh with 45.8% of customers below this level

These baseline usage levels are highlighted in in yellow in the respective jurisdiction tables noted previously and are depicted graphically in Table 5-2 thru 5.4 following, with the OFF Season monthly customer counts by usage block distribution.

If a baseline usage were to be set for residential customers, independent of end-use or premise type, the 600 kWh threshold would serve as the most appropriate usage amount.

Figure 5-2: GMO Baseline Usage Block Threshold

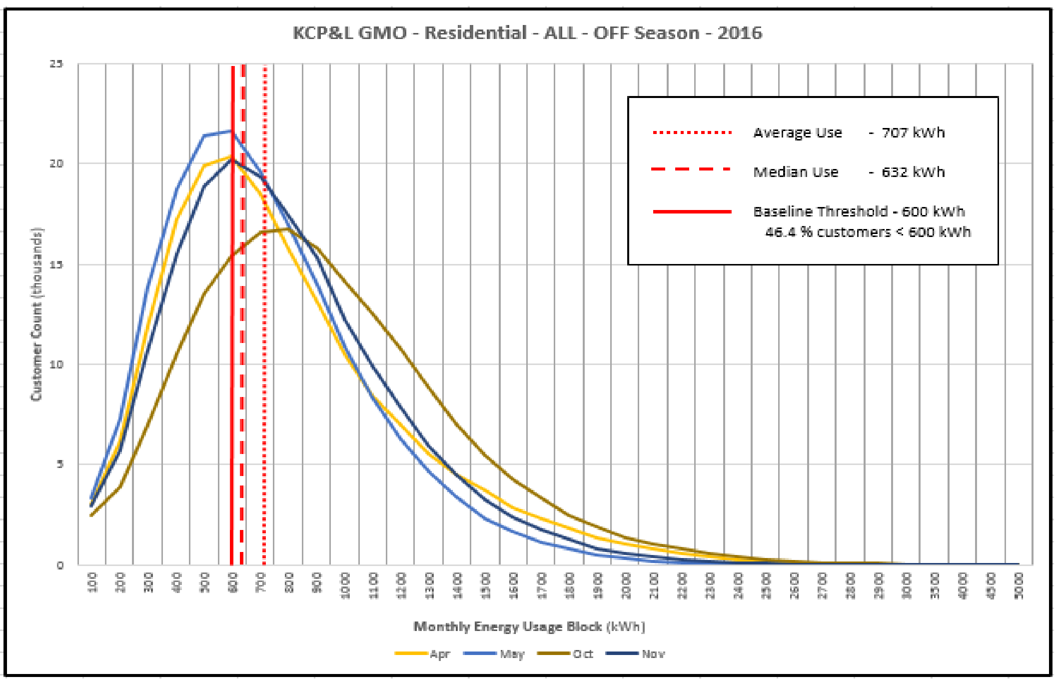


Figure 5-3: KCP&L-MO Baseline Usage Block Threshold

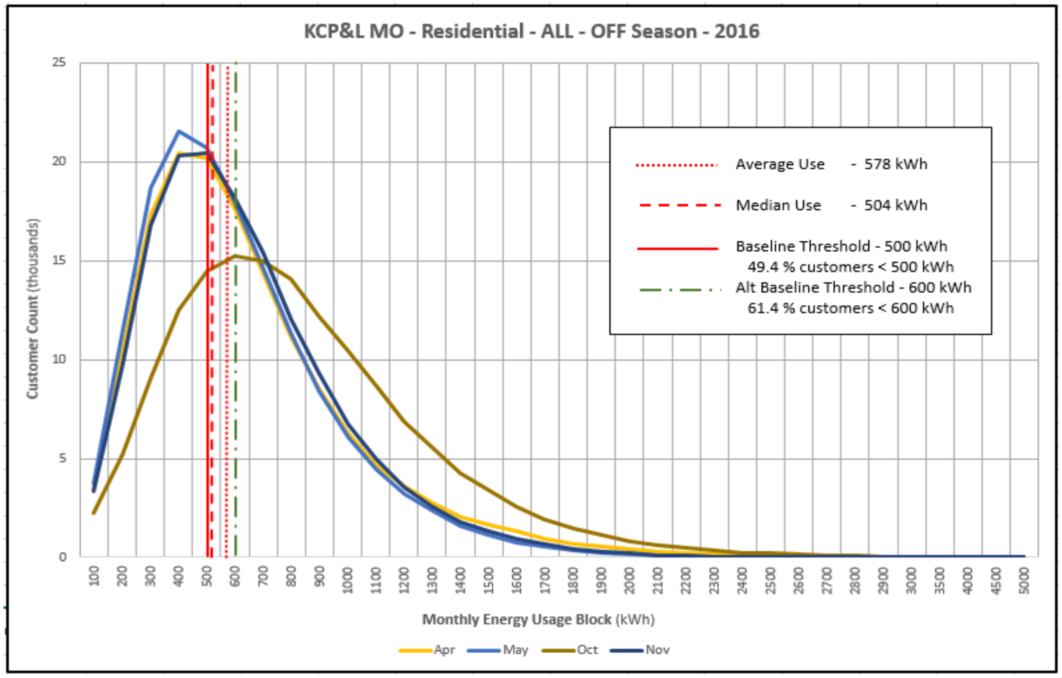
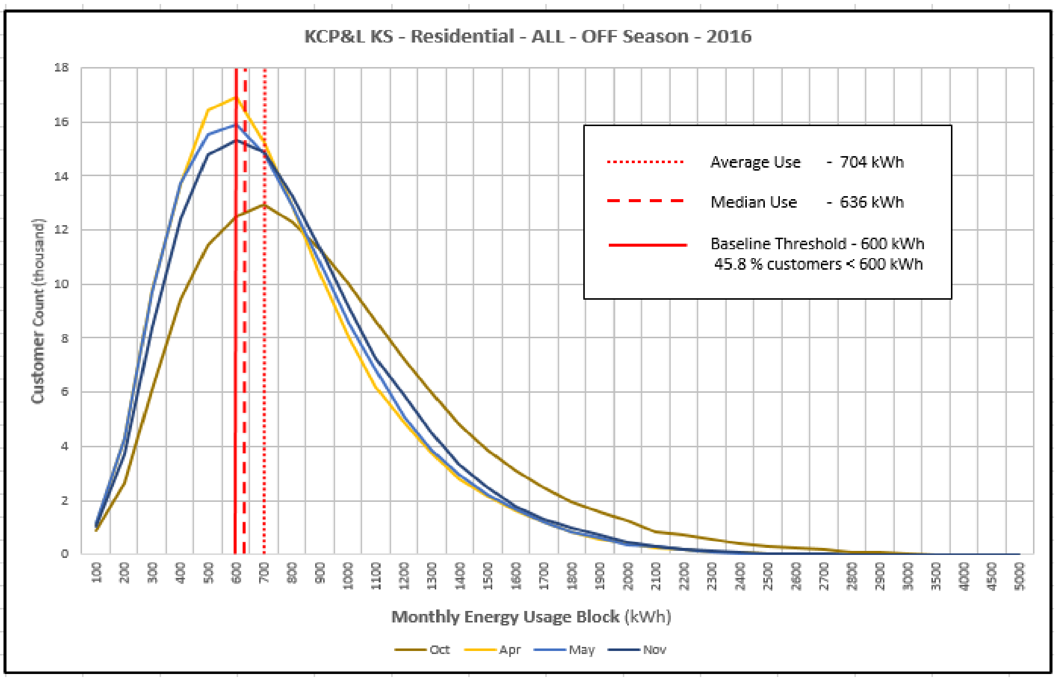


Figure 5-4: KCP&L-KS Baseline Usage Block Threshold



5.3.2 *Baseline Usage for the Average Customer by End-Use*

Considering the Company's historical water heating and space heating rates, it is important to understand the differences in baseline usage with these end-use distinctions. Using the same baseline criteria, baseline usage levels for all General Use (GEN-ALL) and Electric Space Heating (HEAT-ALL) customers without premise-type considerations for each jurisdiction are:

General Use (GEN-ALL):

- GMO - 600 kWh with 55.3% of customers below this level
- KCP&L-MO - 500 kWh with 53.6% of customers below this level
  (or 600 kWh with 65.5% of customers below this level for consistency)
- KCP&L-KS - 600 kWh with 48.8% of customers below this level

Electric Space Heating (HEAT-ALL):

- GMO - 800 kWh with 50.1% of customers below this level
  (or 750 kWh with 45.3% of customers below this level for consistency)
- KCP&L-MO - 600 kWh with 46.3% of customers below this level
  (or 750 kWh with 61.9% of customers below this level for consistency)
- KCP&L-KS - 700 kWh with 47.5% of customers below this level
  (or 750 kWh with 52.5% of customers below this level for consistency)

This end-use review identified the same 600 kWh OFF-Season baseline usage level for General Use (GEN-ALL) customers as RES-ALL customers. A slightly higher percentage of GEN-ALL customers fall below the 600 kWh baseline compared to RES-ALL customers. For the Electric Space Heating (HEAT-ALL) usage group, the review identified a significantly higher baseline usage level with greater variability by jurisdiction. The increased baseline usage is largely due to the additional consumption caused by electric water heating and cooking in homes on the electric heating rates.

For consistency across all jurisdictions, when distinguishing by end-use, baseline usage thresholds of 600 kWh for General Use and 750 kWh for Electric Space Heating customers should be considered.

5.3.3 *Baseline Usage for the Average Customer by Premise Type-Use*

Considering the expectation of continued growth in multi-family housing, it is important to understand the differences in baseline usage with these premise-type distinctions. Using the same baseline criteria, baseline usage levels for all Apartment (APT-ALL) and all Single Family (SGL-ALL) customers are:

Apartment (APT-ALL):

- GMO - 400 kWh with 47.9% of customers below this level
- KCP&L-MO - 300 kWh with 42.3% of customers below this level
  (or 400 kWh with 58.3% of customers below this level for consistency
- KCP&L-KS - 400 kWh with 58.3% of customers below this level

Single Family (SGL-ALL):

- GMO - 700 kWh with 53.4% of customers below this level
- KCP&L-MO - 600 kWh with 55.1% of customers below this level
  (or 700 kWh with 66.1% of customers below this level for consistency)
- KCP&L-KS - 700 kWh with 51.8% of customers below this level

This premise based review identified that for both premise types, the baseline usage of KCP&L-MO customers is lower than the other jurisdictions. This usage differential may be caused be several factors, one being generally smaller dwelling sizes.

For consistency across all jurisdictions, when distinguishing by premise-type, baseline usage thresholds of 600 kWh for multi-family and 700 kWh for single family customers should be considered.

5.4 Summer Block Analysis

Using the results of the literature search for opinions and guidelines on how to establish the appropriate block levels for block rates and the review of blocks in place at surrounding utilities, the Company considered several alternative constructs. The block analysis focused on the ALL-RES, ALL-APT, ALL-SGL premise usage groups. The analysis of three potential block constructs are presented in the following subsections.

5.4.1 *2-tier- Baseline Use Blocks*

The 2-tier Baseline Use Block construct set the first-tier usage block cap based on the residential (ALL-RES) baseline usage level established in the previous analysis. This structure would be implemented such that nearly all customers would have some level of second tier usage. The advantage of this structure is that the majority of customers experience some level of exposure to the second block.

Using this construct, the baseline usage block levels all residential customers within each jurisdiction would be:

- GMO - 600 kWh with 46.4% of customers below this level during COOL2 season
- KCP&L-MO - 500 kWh with 49.4% of customers below this level during COOL2 season (or 600 kWh with 61.4% of customers below this level for consistency)
- KCP&L-KS - 600 kWh with 45.8% of customers below this level during COOL2 season

This construct happens to be similar to the block structure modeled in the DSM Potential Study and the structure used at KCP&L-MO. The DSM Potential Study evaluated a 500 kWh first block. The current blocks implemented in the Residential General Use rate has a 600 kWh first block. As noted in the baseline analysis, it is recommended that a baseline usage of 600 kWh be used across all jurisdictions for consistency.

Table 5-5 to Table 5-7 following, present the average usage for the Summer and COOL2 season along with the percentage of customers by usage block for each Usage Group by jurisdiction. They also show that 7-15 % of ALL-RES customers COOL2 season usage would fall within the first tier and would not see exposure to the second pricing block. A small percentage, 26-37%, of all apartments also fall within this group.

Table 5-5: GMO Usage Distribution Summary for 2-tier Baseline Blocks

GMO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	177,630	18,671	146,314	113,614	7,964	96,846	64,016	10,707	49,468
Summer	1,298	755	1,385	1,275	788	1,333	1,339	730	1,487
COOL2	1,453	818	1,554	1,440	873	1,507	1,478	777	1,648
Usage Block									
< 600 kWh	9.9%	37.0%	6.0%	9.6%	33.2%	7.0%	10.6%	39.8%	4.0%

Table 5-6: KCP&L-MO Usage Distribution Summary for 2-tier Baseline Blocks

KCPL-MO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	149,562	37,612	101,642	117,226	2,316	87,069	32,334	14,597	14,574
Summer	1,154	749	1,299	1,156	742	1,267	1,150	760	1,490
COOL2	1,325	850	1,496	1,337	859	1,466	1,286	837	1,680
Usage Block									
< 500 kWh	10.7%	26.3%	5.9%	10.3%	27.7%	5.4%	12.2%	24.0%	2.3%
< 600 kWh	14.5%	35.2%	8.0%	13.7%	35.7%	7.4%	17.6%	34.4%	3.5%

Table 5-7: KCP&L-KS Usage Distribution Summary for 2-tier Baseline Blocks

KCPL-KS	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	133,894	21,701	101,395	99,685	8,782	82,298	34,209	12,919	19,097
Summer	1,445	830	1,581	1,499	863	1,577	1,288	808	1,596
COOL2	1,597	905	1,745	1,659	951	1,745	1,417	873	1,763
Usage Block									
< 600 kWh	7.5%	27.6%	3.3%	5.6%	25.3%	3.4%	13.0%	29.1%	2.9%

5.4.2 *2-tier – Average Usage Block*

The 2-tier Average Usage Block construct sets the first-tier block usage based on the average summer season usage for all residential customers. This structure is similar to the summer block structure at several regional utilities[63]. Table 5-8 to Table 5-10 following, present the average usage for the Summer and COOL2 season along with the percentage of customers by usage block for each Usage Group by jurisdiction. Using this construct, the baseline block levels for all residential customers are highlighted in yellow within the table for each jurisdiction and are:

- GMO - 1,300 kWh with 44.1% of customers below this level during COOL2 season
- KCP&L-MO - 1,200 kWh with 46.8% of customers below this level during COOL2 season
- KCP&L-KS - 1,500 kWh with 49.1% of customers below this level during COOL2 season

With this block construct, nearly half of all residential customer's monthly summer usage would fall within the first-tier energy and therefore would not see exposure to the second block.

[63] Oklahoma Gas & Electric, Public Service of Oklahoma, and Entergy Arkansas

Table 5-8: GMO Usage Distribution Summary for 2-tier Average Usage Blocks

GMO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	177,630	18,671	146,314	113,614	7,964	96,846	64,016	10,707	49,468
Summer	1,298	755	1,385	1,275	788	1,333	1,339	730	1,487
COOL2	1,453	818	1,554	1,440	873	1,507	1,478	777	1,648
Usage Block									
< 1200 kWh	38.0%	81.8%	31.2%	38.6%	77.7%	34.2%	36.8%	84.9%	25.3%
< 1300 kWh	44.1%	85.9%	37.5%	45.0%	82.3%	40.8%	42.4%	88.6%	31.2%
<1400 kWh	50.2%	89.1%	44.0%	51.3%	85.8%	47.3%	48.2%	91.5%	37.5%

Table 5-9: KCP&L-MO Usage Distribution Summary for 2-tier Average Usage Blocks

KCPL-MO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	149,562	37,612	101,642	117,226	2,316	87,069	32,334	14,597	14,574
Summer	1,154	749	1,299	1,156	742	1,267	1,150	760	1,490
COOL2	1,325	850	1,496	1,337	859	1,466	1,286	837	1,680
Usage Block									
< 1200 kWh	46.8%	79.0%	35.3%	45.6%	77.2%	37.1%	51.2%	81.8%	24.5%
< 1300 kWh	52.8%	83.3%	41.8%	51.8%	81.5%	43.7%	56.4%	86.0%	30.3%
<1400 kWh	58.5%	86.7%	48.3%	57.8%	85.3%	50.2%	61.2%	88.9%	36.6%

Table 5-10: KCP&L-KS Usage Distribution Summary for 2-tier Average Usage Blocks

KCPL-KS	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	133,894	21,701	101,395	99,685	8,782	82,298	34,209	12,919	19,097
Summer	1,445	830	1,581	1,499	863	1,577	1,288	808	1,596
COOL2	1,597	905	1,745	1,659	951	1,745	1,417	873	1,763
Usage Block									
<1200 kWh	32.7%	77.8%	22.9%	29.2%	74.2%	23.8%	43.1%	80.1%	19.4%
<1300 kWh	38.1%	82.3%	28.4%	34.7%	79.0%	29.3%	48.1%	84.6%	24.6%
<1400 kWh	43.6%	86.2%	34.2%	40.4%	83.3%	35.1%	53.1%	88.2%	30.4%
< 1500 kWh	49.1%	89.4%	40.1%	46.0%	86.8%	41.0%	58.0%	91.2%	36.4%

5.4.3 *3-Tier – Premise Differentiated Block*

The 3-Tier Premise Differentiated Block construct set the first-tier block usage based on the average summer season usage for all multi-family customers (yellow table highlights). The second-tier block usage was based on the average summer season usage of all single-family customers (blue table highlights). This structure is similar to the summer block structure at other regional utilities[64]. Using this construct, the 3-Tier Premise Differentiated block levels for all residential customers by each jurisdiction would be:

- GMO - Tier1 - 800 kWh with 17.1% of customers below this level during COOL2 season
  Tier2 – 1,400 kWh with 50% of customers below this level during COOL2 season
- KCP&L-MO - Tier1 - 700 kWh with 19.0% of customers below this level during COOL2 season

[64] Midwest Energy

Tier2 – 1,300 kWh with 52.8% of customers below this level during COOL2 season

- KCP&L-KS - Tier1 - 800 kWh with 14.2% of customers below this level during COOL2 season
  Tier2 – 1,500 kWh with 46.8% of customers below this level during COOL2 season

Table 5-11 through

Table 5-13 following, present the average usage for the Summer and COOL2 season along with the percentage of customers by usage block for each Usage Group by jurisdiction. With this block construct, 80-85% of all residential customers would receive some exposure to the later blocks.

Table 5-11: GMO Usage Distribution Summary for 3-Tier Blocks

GMO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	177,630	18,671	146,314	113,614	7,964	96,846	64,016	10,707	49,468
Summer	1,298	755	1,385	1,275	788	1,333	1,339	730	1,487
COOL2	1,453	818	1,554	1,440	873	1,507	1,478	777	1,648
Usage Block									
< 700 kWh	13.2%	46.8%	8.3%	12.8%	41.9%	9.6%	14.0%	50.4%	5.8%
< 800 kWh	17.1%	55.7%	11.5%	16.7%	50.3%	13.1%	17.7%	59.7%	8.2%
< 900 kWh	21.5%	63.6%	15.3%	21.3%	58.1%	17.4%	21.8%	67.7%	11.3%
< 1300 kWh	44.1%	85.9%	37.5%	45.0%	82.3%	40.8%	42.4%	88.6%	31.2%
< 1400 kWh	50.2%	89.1%	44.0%	51.3%	85.8%	47.3%	48.2%	91.5%	37.5%

Table 5-12: KCP&L-MO Usage Distribution Summary for 3-Tier Blocks

KCPL-MO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	149,562	37,612	101,642	117,226	2,316	87,069	32,334	14,597	14,574
Summer	1,154	749	1,299	1,156	742	1,267	1,150	760	1,490
COOL2	1,325	850	1,496	1,337	859	1,466	1,286	837	1,680
Usage Block									
< 700 kWh	19.0%	44.3%	10.1%	17.8%	44.0%	11.0%	23.4%	44.7%	5.2%
< 800 kWh	24.0%	53.0%	13.8%	22.5%	51.9%	14.8%	29.4%	54.7%	7.6%
< 1300 kWh	52.8%	83.3%	41.8%	51.8%	81.5%	43.7%	56.4%	86.0%	30.3%
< 1400 kWh	58.5%	86.7%	48.3%	57.8%	85.3%	50.2%	61.2%	88.9%	36.6%

Table 5-13: KCP&L-KS Usage Distribution Summary for 3-Tier Blocks

KCPL-KS	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	133,894	21,701	101,395	99,685	8,782	82,298	34,209	12,919	19,097
Summer	1,445	830	1,581	1,499	863	1,577	1,288	808	1,596
COOL2	1,597	905	1,745	1,659	951	1,745	1,417	873	1,763
Usage Block									
< 700 kWh	10.6%	37.6%	5.0%	8.1%	34.7%	5.2%	17.7%	39.7%	4.0%
< 800 kWh	14.2%	47.7%	7.2%	11.3%	44.3%	7.6%	22.8%	50.1%	5.8%
< 1400 kWh	43.6%	86.2%	34.2%	40.4%	83.3%	35.1%	53.1%	88.2%	30.4%
< 1500 kWh	49.1%	89.4%	40.1%	46.0%	86.8%	41.0%	58.0%	91.2%	36.4%

5.4.4 *Block Summary and Recommendation*

Based on this analysis, the Summer Season block structure that could provide the best distribution among the blocks would be the 2-tier Baseline Usage blocks with a single break at 600 kWh. This block structure was chosen based on the following rational:

- It is consistent with the block structure analyzed in the latest DSM Potential Study.
- Nearly all customers would have some second-tier usage.
- It provides minimal usage level pricing for customers.

Figure 5-5 to Figure 5-7 following, depict the three block structure thresholds on the ALL-RES (without end-use distinction) on the summer season customer distribution by usage block graphs for each jurisdiction.

Figure 5-5: GMO Summer Thresholds

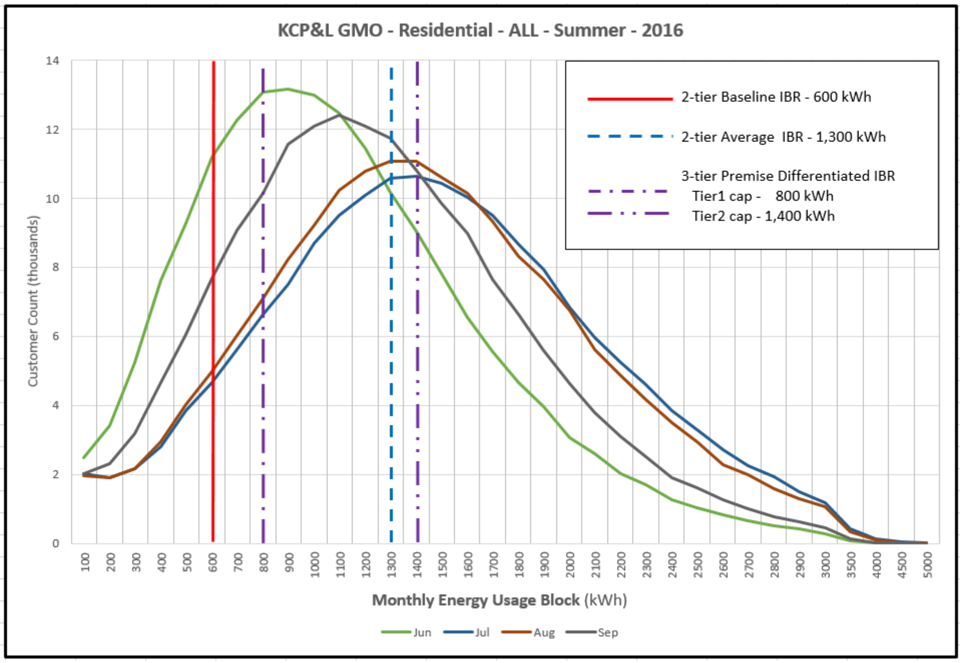


Figure 5-6: KCP&L-MO Summer Thresholds

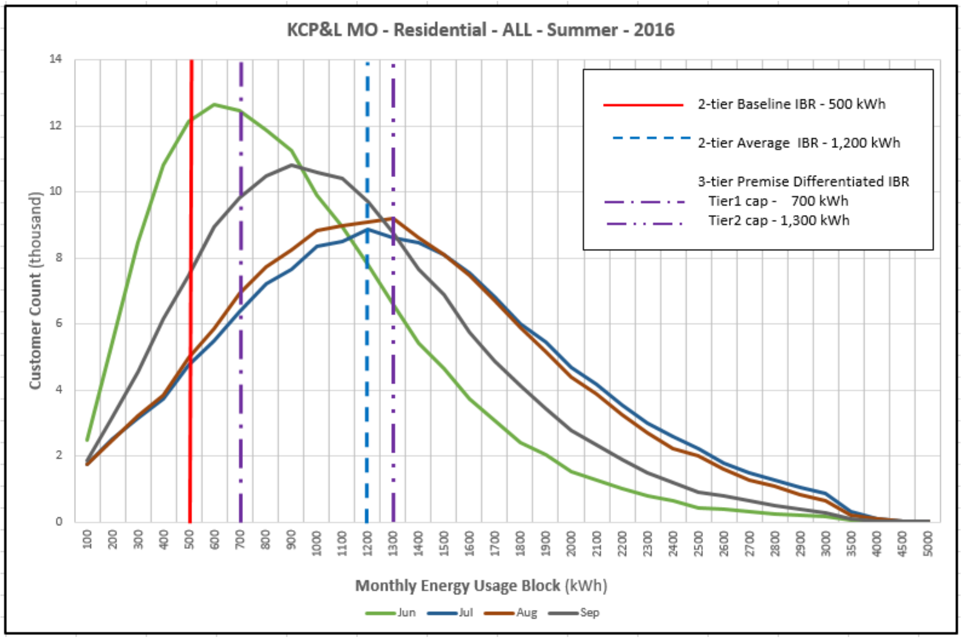
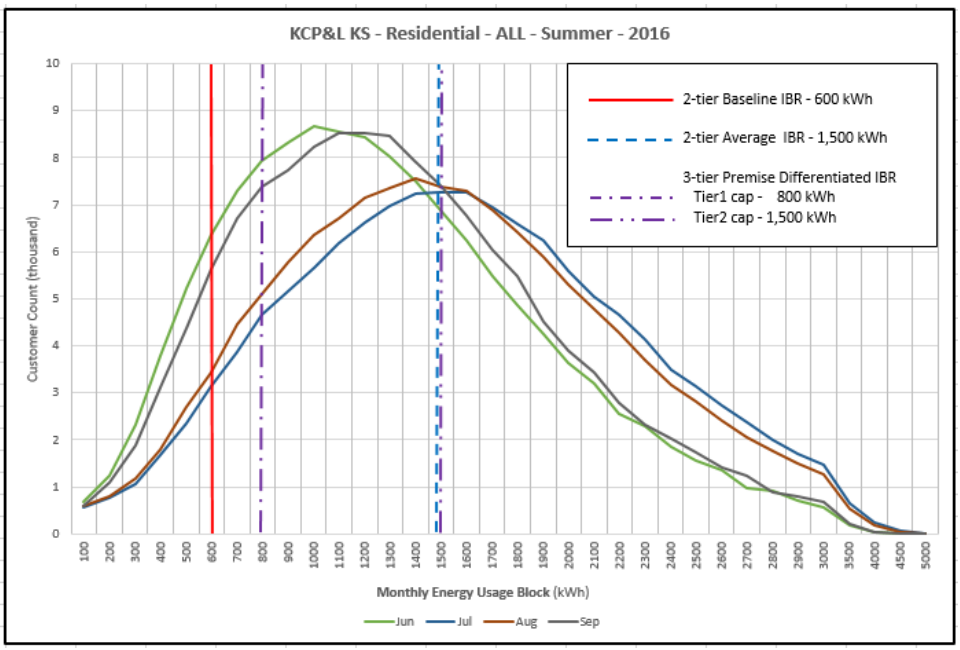


Figure 5-7: KCP&L-KS Summer Thresholds



5.5 Winter Block Analysis

The current winter block rate structures vary across the GMO and KCP&L rate jurisdictions. They are all generally based on the same three standard blocks (<600, +400, and >1000), but differ slightly simply because of the rate process. The following table illustrates these differences by expressing the block prices as a percentage of the jurisdictions General Use first block price. In comparing these blocks, it is important to note that Kansas rates do not include fuel cost, transmission costs, or property taxes, as they are recovered through separate riders that are not included in these base rates.

Table 5-14: Summary of Existing GMO and KCP&L Winter Block Rates

Rate	Character	< 600 kWh	< 600 kWh	+ 400 kWh	>1,000 kWh
General Use		**% GU Summer**	**% GU W 1st Blk**	**% GU 1st Blk**	**% GU 1st Blk**
GMO	2-tier-2nd blk	85% (0.12050)	100% (0.10625)	73.41% (0.07800)	73.41% (0.07800)
KCP&L-MO	3 tier	88.6% (0.13806*)	100% (0.12231)	60.5% (0.07396)	53.6% (0.06561)
KCP&L-KS	FLAT	77.2% (0.10751)	100% (0.08300)	100% (0.08300)	100% (0.08300)
Heating					
GMO	3-tier	85% (0.12050)	100% (0.10625)	56.8% (0.06035)	46. 9% (0.04991)
KCP&L-MO	2-tier-3rd blk	70.3% (0.13806*)	79.3% (0.09703)	79.3% (0.09703)	49.9% (0.06098)
KCP&L-KS	2-tier-3rd blk	69.5% (0.10751)	90.0% (0.07474)	90.0% (0.07474)	78.6% (0.06575)

* General Use summer rate equal to space heating summer rate based on pre IBR implementation.

The Company established a series of design points to guide the design of a new winter season block structure that would be appropriate for all GMO and KCP&L jurisdictions. In developing the block design points, the Company included consideration of rate structures of other regional utilities, average customer usage by end-use, and premise type.

The key design points are:

- The Heating first block cap should be based on the OFF2-season usages to reflect non-weather related usage.
- The second block cap should be based on the average usage of a General Use single family premise during the heating season.
- During rate design, it would be appropriate if the Heating first block would be priced similarly to the General Use first block rate and the pricing differential of the second block be modest as it will largely be comprised of HEATING customer general use, but will include some multi-family electric space heating use.

Based on these design points we focused our winter block analysis on two block structures, the 3-Tier Baseline and 3-Tier Premise. These two potential constructs are presented in the following sections.

5.5.1 *3-Tier Baseline Use Block*

The 3-Tier Baseline Use Block construct would establish the first-tier usage block cap based on the OFF2 season baseline usage level (600 kWh) established in the baseline analysis. The second-tier usage block cap would be based on the average GEN-SGL's monthly usage during the HEAT2 season. Using this construct, the 3-Tier Baseline Use Winter block levels for all residential customers within each jurisdiction would be based on the following thresholds:

- GMO - Tier2 - 600 kWh with 79% GEN-APT, 33% GEN-SGL below during HEAT2 season.
Tier3 - 900 kWh with 62% GEN-SGL, 36% HEAT-APT below during HEAT2 season.
Tier3 Alt – 1,000 kWh w/68% GEN-SGL, 43% HEAT-APT below during HEAT2.
- KCP&L-MO - Tier2 - 600 kWh with 80% GEN-APT, 37% GEN-SGL below during HEAT2 season.
Tier3 - 900 kWh with 65% GEN-SGL, 37% HEAT-APT below during HEAT2 season.
Tier3 Alt – 1,000 kWh w/71% GEN-SGL, 43% HEAT-APT below during HEAT2.
- KCP&L-KS - Tier2 - 600 kWh with 81% GEN-APT, 25% GEN-SGL below during HEAT2 season.
Tier3 - 900 kWh with 56% GEN-SGL, 30% HEAT-APT below during HEAT2 season.
Tier3 Alt – 1,000 kWh w/65% GEN-SGL, 35% HEAT-APT below during HEAT2.

The resulting Baseline block structure is very close to the existing KCP&L usage blocks, so an alternative 1,000 kWh Tier 3 threshold was evaluated for consistency with the current usage blocks and ease of implementation. Table 5-15 to Table 5-17 following, present the average usage for the OFF2 (yellow highlights), HEAT4 and HEAT2 (blue highlights) seasons along with the percentage of customers by usage block for each Usage Group by jurisdiction.

Table 5-15: GMO Usage Distribution Summary for 3-Tier Baseline Use Blocks

GMO	**ALL RES**	**ALL APT**	**ALL SGL**	**GEN ALL**	**GEN APT**	**GEN SGL**	**HEAT ALL**	**HEAT APT**	**HEAT SGL**
Cust. Count	177,630	18,671	146,314	113,614	7,964	96,846	64,016	10,707	49,468
OFF 2	707	476	742	618	364	645	863	559	931
HEAT 4	1,067	798	1,107	819	438	856	1,507	1,065	1,597
HEAT 2	1,178	895	1,218	882	462	**921**	1,704	1,218	1,800
Usage Block									
< 600 kWh	27.7%	42.3%	24.9%	37.6%	78.6%	33.1%	10.1%	15.3%	8.7%
< 700 kWh	35.9%	48.1%	33.4%	47.8%	84.3%	43.8%	14.7%	21.2%	13.1%
< 800 kWh	43.5%	53.9%	41.5%	56.8%	88.1%	53.4%	19.9%	28.4%	18.0%
< 900 kWh	50.4%	59.4%	48.7%	64.5%	91.0%	61.7%	25.3%	**35.8%**	23.2%
< 1000 kWh	56.2%	64.3%	54.8%	70.6%	92.8%	68.3%	30.7%	43.1%	28.3%

Table 5-16: KCP&L-MO Usage Distribution Summary for 3-Tier Baseline Use Blocks

KCPL-MO	**ALL RES**	**ALL APT**	**ALL SGL**	**GEN ALL**	**GEN APT**	**GEN SGL**	**HEAT ALL**	**HEAT APT**	**HEAT SGL**
Cust. Count	149,562	37,612	101,642	117,226	2,316	87,069	32,334	14,597	14,574
OFF 2	578	419	632	541	328	598	709	562	838
HEAT 4	855	688	910	753	429	838	1,222	1,096	1,335
HEAT 2	931	773	983	807	453	**900**	1,382	1,279	1,475
Usage Block									
< 600 kWh	39.6%	56.2%	33.5%	46.2%	80.4%	37.0%	15.6%	18.0%	12.6%
< 700 kWh	48.5%	61.5%	43.7%	55.9%	85.4%	47.8%	21.7%	23.9%	18.8%
< 800 kWh	56.2%	66.0%	52.7%	63.9%	88.8%	57.2%	28.4%	30.0%	26.2%
< 900 kWh	62.8%	69.9%	60.3%	70.4%	91.1%	**64.9%**	35.1%	**36.5%**	33.1%
< 1000 kWh	68.3%	73.4%	66.7%	75.7%	92.8%	71.1%	41.6%	42.8%	40.0%

Table 5-17: KCP&L-KS Usage Distribution Summary for 3-Tier Baseline Use Blocks

KCPL-KS	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	133,894	21,701	101,395	99,685	8,782	82,298	34,209	12,919	19,097
OFF 2	704	502	752	674	375	711	792	589	927
HEAT 4	972	835	1,011	836	416	889	1,367	1,119	1,538
HEAT 2	1,059	968	1,090	885	435	**942**	1,564	1,331	1,728
Usage Block									
< 600 kWh	26.3%	40.8%	22.1%	31.6%	81.2%	25.4%	10.6%	13.4%	8.1%
< 700 kWh	35.2%	46.1%	31.7%	42.0%	87.4%	36.2%	15.3%	18.1%	12.6%
< 800 kWh	43.9%	50.9%	41.3%	51.9%	91.7%	46.7%	20.7%	23.1%	18.1%
< 900 kWh	51.9%	55.4%	50.2%	60.6%	94.3%	**56.3%**	26.6%	**28.9%**	23.9%
< 1000 kWh	59.0%	59.6%	58.0%	68.1%	95.8%	64.5%	32.5%	35.0%	29.8%

With the Baseline block construct, 25-40% of all residential customer's winter usage would consistently be within the first block and 50-60% of customer's usage (55-68% for the 1,000 kWh alternate) would consistently fall below the second block cap.

As noted in the baseline analysis, the average use by electric heat customer, both APT and SGL, is approximately 200 kWh more per month. This is largely due to the increased consumption of energy associated with electric water heating and cooking in homes on the electric heating rates. This was not a detriment when using the baseline in the summer block construct because it provides lower-use general use and apartment dwellers additional price protection, as they typically have fewer options for conserving electricity. But, using the 600 kWh baseline as the first block cap during the winter does not provide electric heating customers with the proper segmentation for the additional electric water heating and cooking usage.

The focus for determining second block cap is to identify a threshold that will distinguish the beneficial electric heating usage and other general usage in single family dwellings. The 900 kWh threshold provides a good break point for the third tier for the following reasons:

- It correlates with the average usage of the GEN-SGL premise group during the HEAT2 season.
- It correlates with the average OFF2 season usage of the HEAT-SGL premise group.
- 90-95% of all GEN-APT customer's usage falls below this during the HEAT2 season.
- And 65-70% of HEAT-APT customers will have usage in the third block during the HEAT2 season.

The alternative 1,000 kWh is a less natural break point with respect to the data, but provides a safeguard against excess use by requiring more above average use in the second block before receiving the third-tier discount and matches the current break point for some of the jurisdictions. With this alternative:

- 28-40% of HEAT-SGL customers would have all winter usage below the 3rd tier.
- 35-43% of HEAT APT customers would have all winter usage below the 3rd tier.
- 65-71% of GEN-SGL customers would have all winter usage below the 3rd tier.
- 93-96% of GEN-APT customers would have all winter usage below the 3rd tier.

It is recommended to use 1,000 kWh as the block Tier-3 threshold across all jurisdictions for consistency. Figure 5-8 to

Figure 5-10 following, depict the two thresholds for the 3-Tier Baseline block structure for the on the ALL-RES on the winter season customer distribution by usage block graphs for each jurisdiction.

Figure 5-8: GMO - Winter Season Baseline Block Thresholds

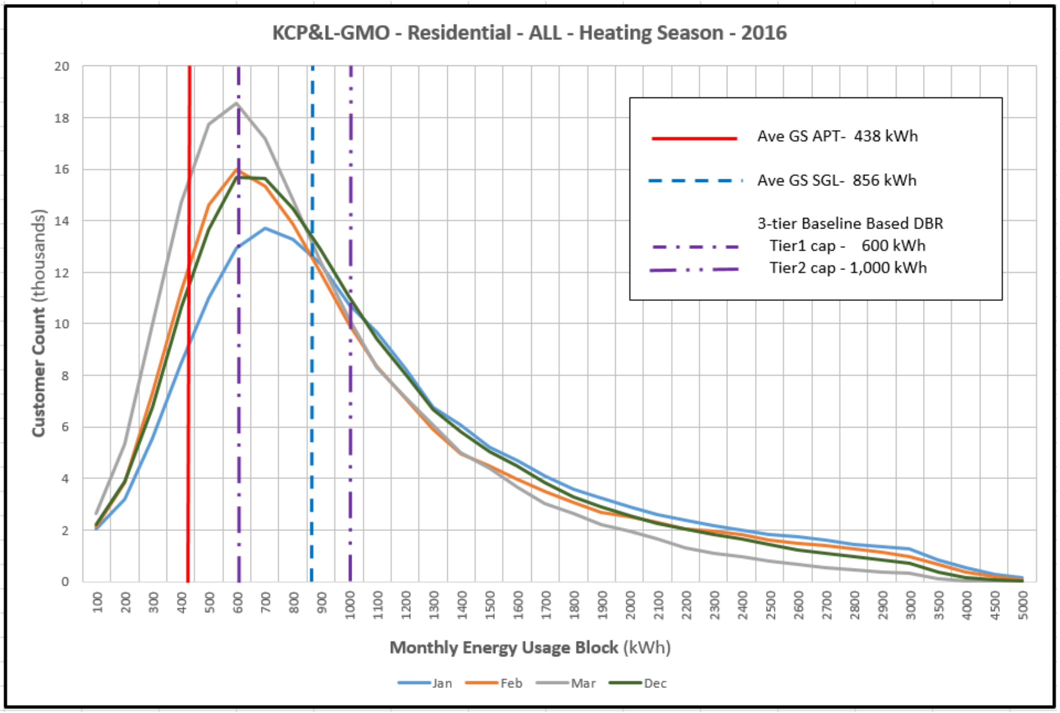


Figure 5-9: KCP&L-MO - Winter Season Baseline Block Thresholds

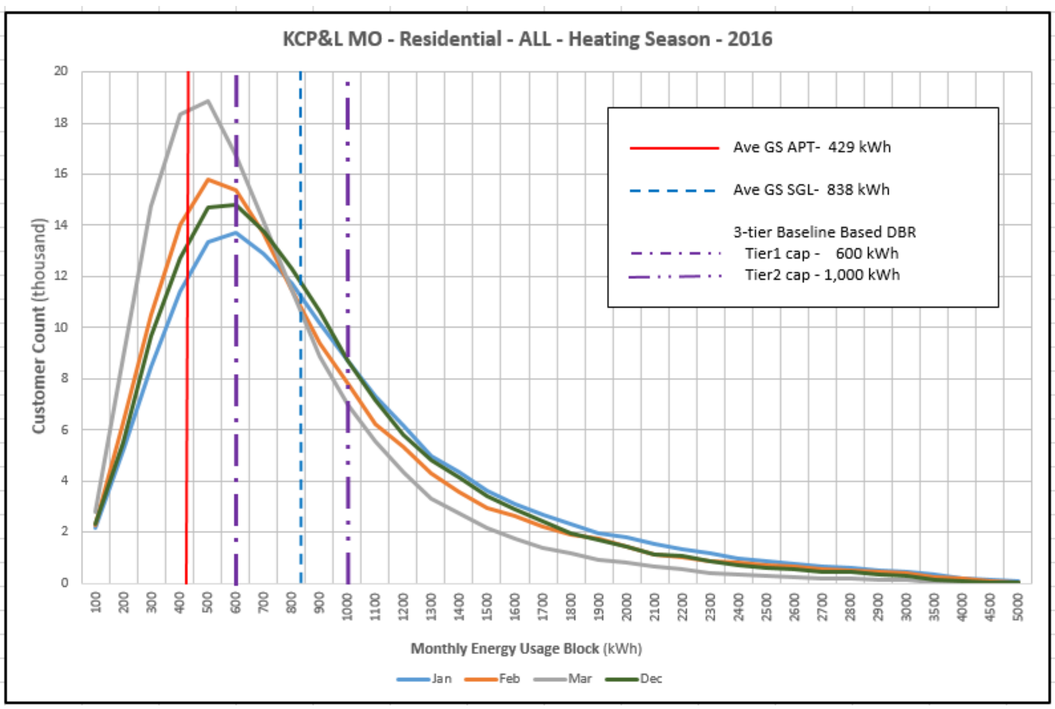
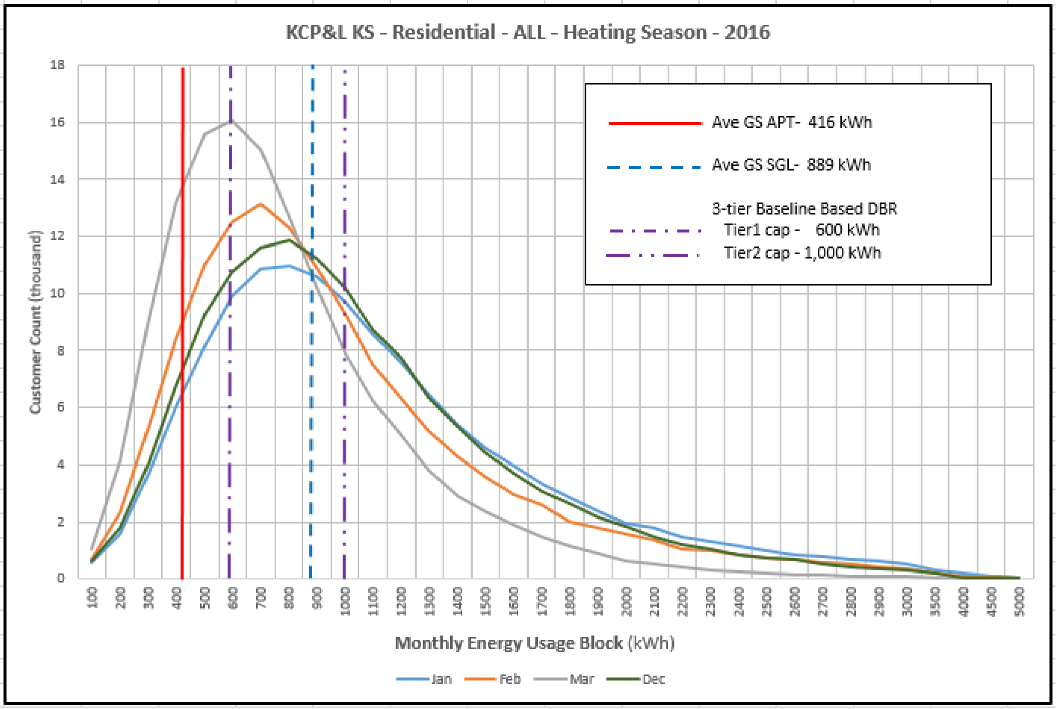


Figure 5-10: KCP&L-KS - Winter Season Baseline Block Thresholds



5.5.2 *3-Tier Premise Differentiated Block*

The 3-Tier Premise Differentiated block construct would establish the first-tier usage block cap based on the GEN-APT average winter (HEAT4) usage and the differences in OFF2 season usage between GEN-APT and HEAT-APT premises. The second-tier usage block cap would be based on the average GEN-SGLs monthly usage during the HEAT2 season. Using this construct, the 3-Tier Premise Differentiated Winter usage block levels for all residential customers within each jurisdiction would be based on the following thresholds:

- GMO - Tier2 - 400 kWh with 58% GEN-APT, 13% GEN-SGL below during HEAT2 season
  Tier3 - 900 kWh with 62% GEN-SGL, 36% HEAT-APT below during HEAT2 season
  Tier3 Alt – 1,000 kWh w/68% GEN-SGL, 43% HEAT-APT below during HEAT2
- KCP&L-MO - Tier2 - 400 kWh with 61% GEN-APT, 14% GEN-SGL below during HEAT2 season
  Tier3 - 900 kWh with 65% GEN-SGL, 37% HEAT-APT below during HEAT2 season
  Tier3 Alt – 1,000 kWh w/71% GEN-SGL, 43% HEAT-APT below during HEAT2
- KCP&L-KS - Tier2 - 400 kWh with 57% GEN-APT, 8% GEN-SGL below during HEAT2 season
  Tier3 - 900 kWh with 56% GEN-SGL, 29% HEAT-APT below during HEAT2 season
  Tier3 Alt – 1,000 kWh w/65% GEN-SGL, 35% HEAT-APT below during HEAT2

The resulting block tier 3 threshold is very close to the existing KCP&L-MO tier-3 usage level, so an alternative 1,000 kWh Tier-3 threshold was evaluated for consistency with the current usage blocks. Table 5-18 to Table 5-20 following, present the average usage for the OFF2 (yellow highlights), HEAT4 and HEAT2 (blue highlights) seasons along with the percentage of customers by usage block for each Usage Group by jurisdiction.

Table 5-18: GMO - Usage Distribution Summary for 3-Tier Premise Differentiated Blocks

GMO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	177,630	18,671	146,314	113,614	7,964	96,846	64,016	10,707	49,468
OFF 2	707	476	742	618	364	645	863	559	931
HEAT 4	1,067	798	1,107	819	438	856	1,507	1,065	1,597
HEAT 2	1,178	895	1,218	882	462	921	1,704	1,218	1,800
Usage Block									
< 400 kWh	12.3%	28.6%	9.5%	17.2%	57.9%	13.0%	3.7%	6.7%	2.7%
< 500 kWh	19.5%	35.8%	16.5%	27.0%	70.3%	22.3%	6.4%	10.1%	5.2%
< 600 kWh	27.7%	42.3%	24.9%	37.6%	78.6%	33.1%	10.1%	15.3%	8.7%
< 800 kWh	43.5%	53.9%	41.5%	56.8%	88.1%	53.4%	19.9%	28.4%	18.0%
< 900 kWh	50.4%	59.4%	48.7%	64.5%	91.0%	61.7%	25.3%	35.8%	23.2%
< 1000 kWh	56.2%	64.3%	54.8%	70.6%	92.8%	68.3%	30.7%	43.1%	28.3%

Table 5-19: KCP&L-MO Usage Distribution Summary for 3-Tier Premise Differentiated Blocks

KCPL-MO	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	149,562	37,612	101,642	117,226	2,316	87,069	32,334	14,597	14,574
OFF 2	578	419	632	541	328	598	709	562	838
HEAT 4	855	688	910	753	429	838	1,222	1,096	1,335
HEAT 2	931	773	983	807	453	900	1,382	1,279	1,475
Usage Block									
< 400 kWh	20.1%	40.2%	12.8%	24.2%	60.9%	14.4%	5.5%	7.6%	3.2%
< 500 kWh	29.9%	49.3%	22.7%	35.4%	72.6%	25.3%	10.0%	12.5%	7.1%
< 600 kWh	39.6%	56.2%	33.5%	46.2%	80.4%	37.0%	15.6%	18.0%	12.6%
< 800 kWh	56.2%	66.0%	52.7%	63.9%	88.8%	57.2%	28.4%	30.0%	26.2%
< 900 kWh	62.8%	69.9%	60.3%	70.4%	91.1%	64.9%	35.1%	36.5%	33.1%
< 1000 kWh	68.3%	73.4%	66.7%	75.7%	92.8%	71.1%	41.6%	42.8%	40.0%

Table 5-20: KCP&L-KS Usage Distribution Summary for 3-Tier Premise Differentiated Blocks

KCPL-KS	ALL RES	ALL APT	ALL SGL	GEN ALL	GEN APT	GEN SGL	HEAT ALL	HEAT APT	HEAT SGL
Cust. Count	133,894	21,701	101,395	99,685	8,782	82,298	34,209	12,919	19,097
OFF2	704	502	752	674	375	711	792	589	**927**
HEAT 4	972	835	1,011	836	416	889	1,367	1,119	1,538
HEAT 2	1,059	968	1,090	885	435	**942**	1,564	1,331	1,728
Usage Block									
< 400 kWh	10.7%	26.3%	6.9%	13.1%	56.7%	8.0%	3.7%	5.6%	2.3%
< 500 kWh	17.9%	34.2%	13.6%	21.7%	71.1%	15.7%	6.7%	9.1%	4.6%
< 600 kWh	26.3%	40.8%	22.1%	31.6%	81.2%	25.4%	10.6%	13.4%	8.1%
< 800 kWh	43.9%	50.9%	41.3%	51.9%	91.7%	46.7%	20.7%	23.1%	18.1%
< 900 kWh	51.9%	55.4%	50.2%	60.6%	**94.3%**	**56.3%**	26.6%	28.9%	23.9%
< 1000 kWh	59.0%	59.6%	58.0%	68.1%	95.8%	64.5%	32.5%	35.0%	29.8%

With the 3-Tier Premise Differentiated block construct, 10-20% of all residential customer's winter usage would consistently be within the first block and 50-60% of customer's usage (55-68% for the 1,000 kWh alternate) would consistently fall below the second block cap.

As previously noted, the primary purpose of the winter blocks is to support rate segmentation that can be used to price energy reflective of the benefit electric heating provides all customers by spreading fixed capacity and infrastructure costs over greater energy sales volumes. In this block structure, the second-tier threshold was established at 400 kWh to recognize the lower baseline usage of multi-family residences and to recognize the 200 kWh difference in baseline usage between general use and electric heating customers. This difference is largely due to the increased consumption of energy associated with electric water heating and cooking in homes on the electric heating rates. Using the 400 kWh threshold as the first block cap provides better pricing for the electric heating customers in response to the additional electric water heating and cooking usage during the entire winter season.

The 400 kWh first block provides a good break point for the second tier for the following reasons:

- It correlates with the average usage of the GEN-APT premise group during the OFF2 season.
- It correlates with the average usage of the GEN-APT premise group during the HEAT3/4 seasons.
- 57-61% of all GEN-APT customer's usage falls below this during the HEAT2 season.
- HEAT-APT customers will have some usage in the second block during the OFF season.
- Only 6-8% of HEAT-APT customers have usage levels below this during the HEAT2 season.
- Only 10-20% of all residential customers would have all winter usage in the first block.

The focus for determining second block cap is to identify a threshold that will distinguish the beneficial electric heating usage and other general usage in single family dwellings. The 900 kWh threshold provides a good break point for the third-tier for the following reasons:

- It correlates with the average usage of the GEN-SGL premise group during the HEAT2 season.
- It correlates with the average OFF2 season usage of the HEAT-SGL premise group.
- 90-95% of all GEN-APT customer's usage falls below this during the HEAT2 season.
- 65-70% of HEAT-APT customers will have usage in the third block during the HEAT2 season.

The alternative 1,000 kWh is a less natural break point, but provides a safeguard against non-efficient use by requiring more above average use in the second block before receiving the third-tier differential. With this alternative:

- 28-40% of HEAT-SGL customers would have all winter usage below the 3rd tier
- 35-43% of HEAT APT customers would have all winter usage below the 3rd tier
- 65-71% of GEN-SGL customers would have all winter usage below the 3rd tier
- 93-96% of GEN-APT customers would have all winter usage below the 3rd tier.

It is recommended to use 1,000 kWh as the block tier 3 threshold across all jurisdictions for consistency. Figure 5-11 to Figure 5-13 following, depict the two thresholds for the 3-Tier Premise Differentiated block structure on the ALL-RES on the winter season customer distribution by usage block graphs for each jurisdiction.

Figure 5-11: GMO Winter Season Premise Differentiated Block Thresholds

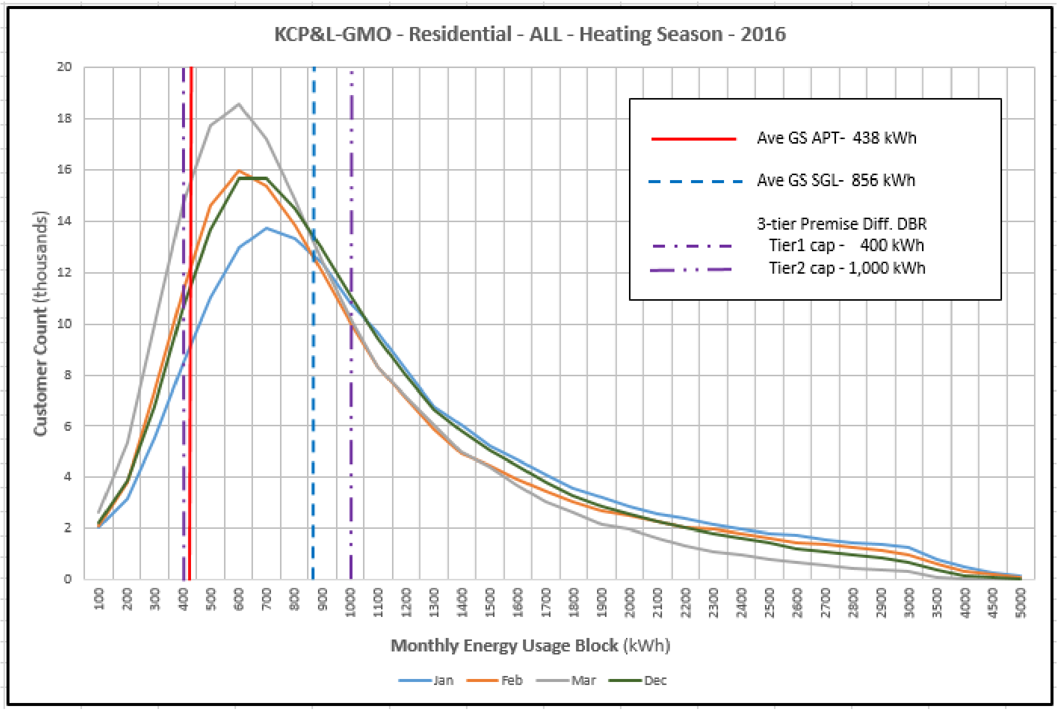


Figure 5-12: KCP&L-MO Winter Season Premise Differentiated Block Thresholds

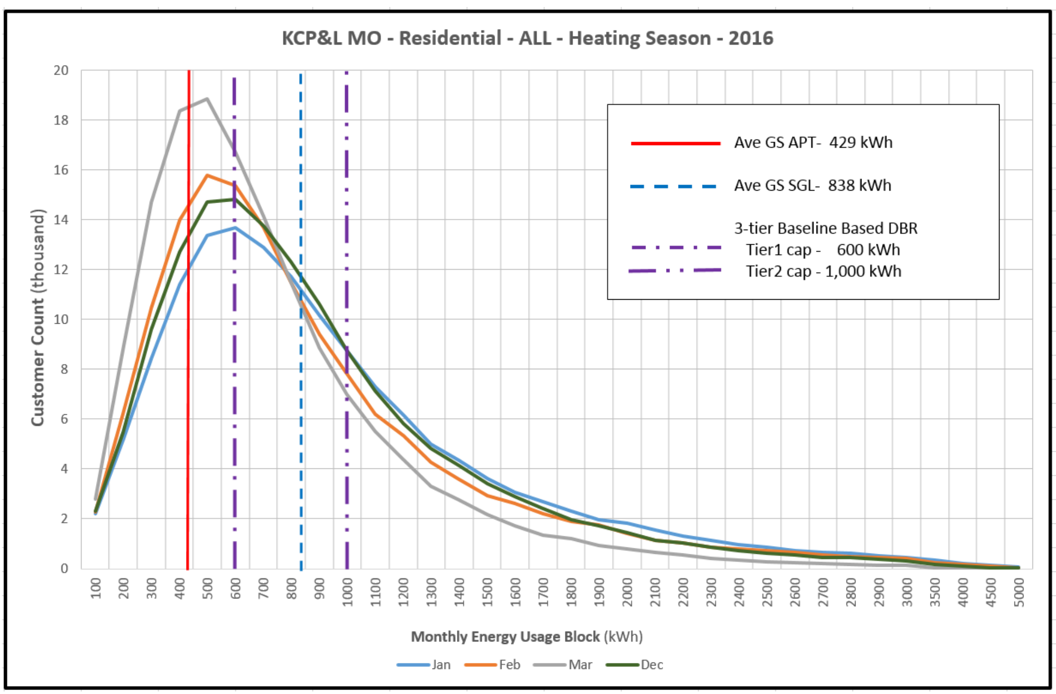


Figure 5-13: KCP&L-KS - Winter Season Premise Differentiated Block Thresholds

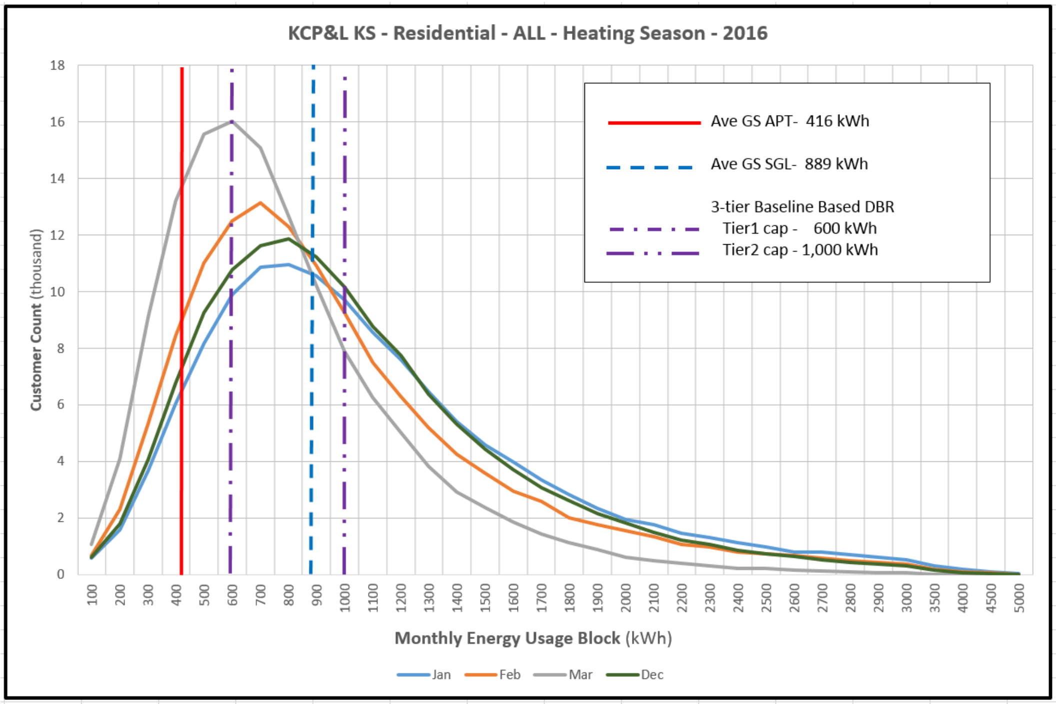


Figure 5-14 and Figure 5-15 following, depict the two block structure thresholds on APT-GEN and APT-HEAT winter season customer distribution graphs for GMO which are representative of all jurisdictions.

Figure 5-14: GMO - Premise Differentiated Block Thresholds APT-GEN

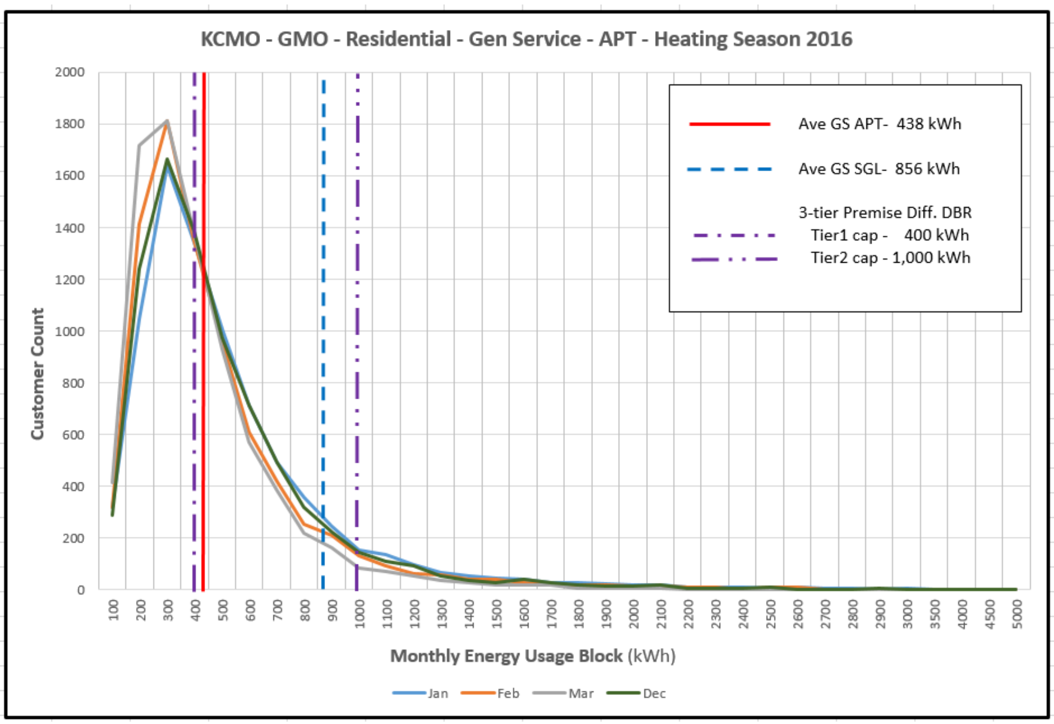


Figure 5-15: GMO - Premise Differentiated Block Thresholds APT-HEAT

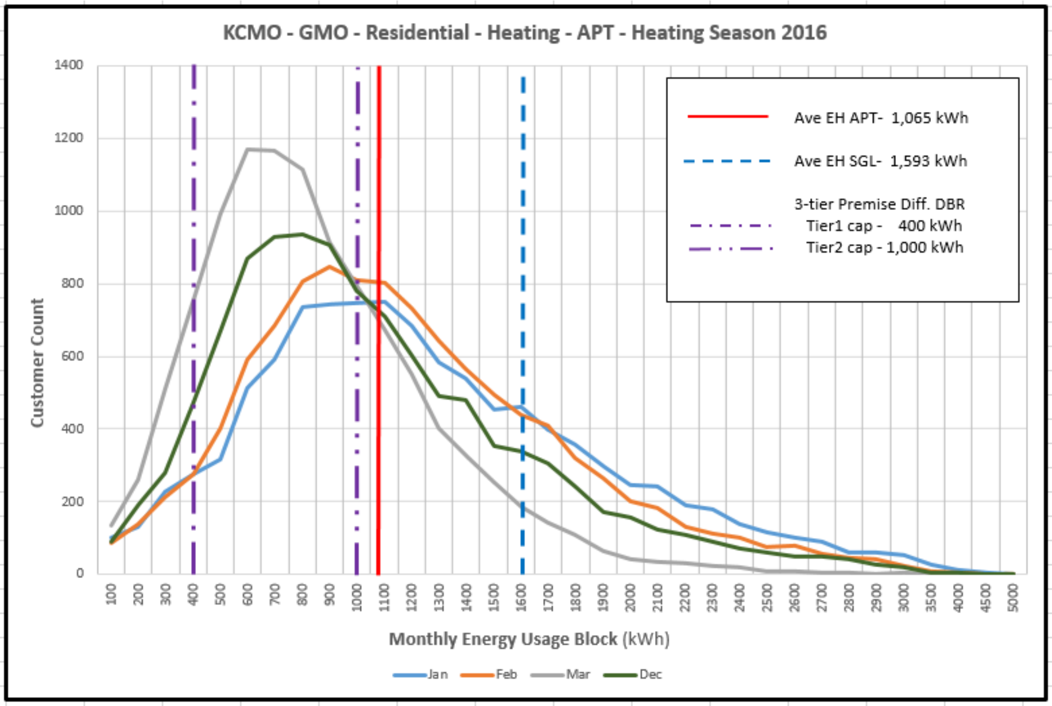


Figure 5-16 and Figure 5-17 following, depict the two block structure thresholds on SGL-GEN and SGL-HEAT winter season customer distribution graphs for GMO which are representative of all jurisdictions.

Figure 5-16: GMO Premise Differentiated Block Thresholds SGL-GEN

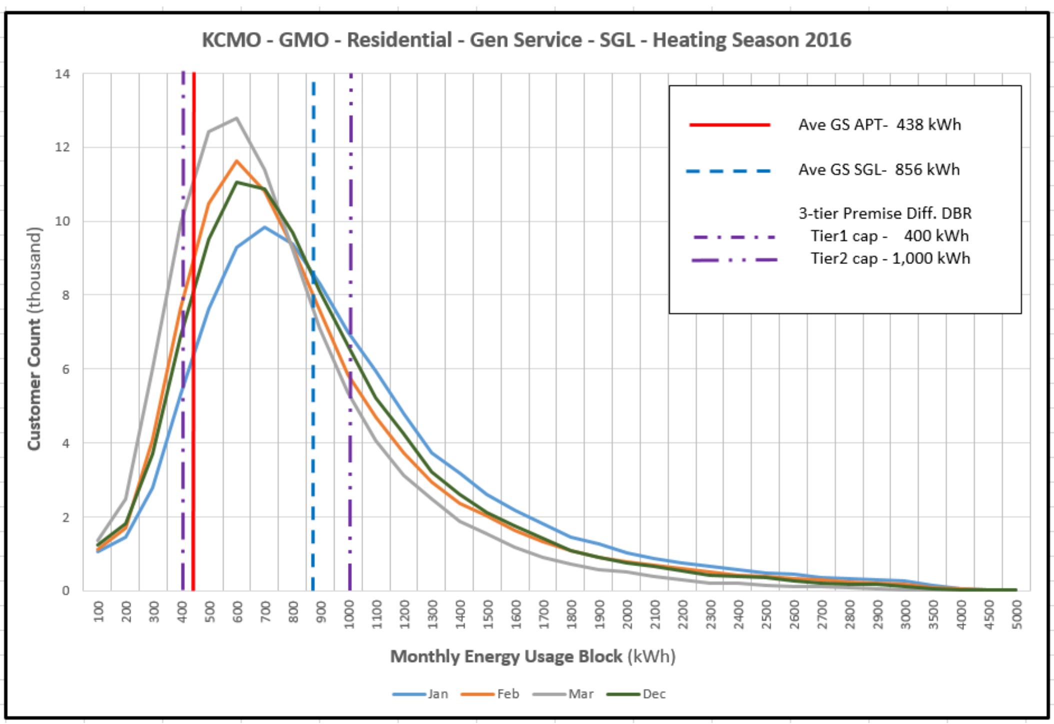
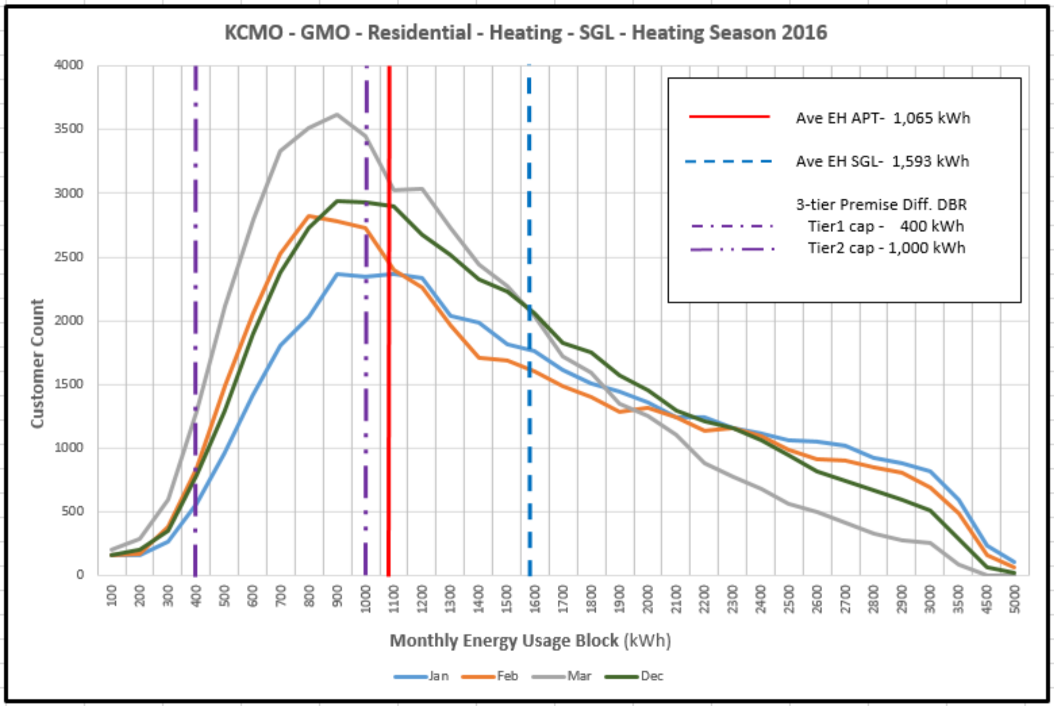


Figure 5-17: GMO Premise Differentiated Block Thresholds SGL-HEAT



5.5.3 *Block Summary and Recommendation*

Based on the analysis an appropriate Winter Season block structure for the Company to consider implementing in all jurisdictions is the 3-Tier Premise Differentiated block with a first block cap at 400 kWh and a second block cap at 1,000 kWh. This block structure was selected based on the following rational:

- Majority of regional utilities utilize Winter block structures to reflect electric heating benefits.
- First Block cap at 400 kWh best aligns with General Use multifamily, ~60% fall within the block.
- Second Block cap at 1,000 kWh aligns with single family General Use during heating season and provides price differential for multi-family electric heating.
- Best accommodates transition to uniform block pricing differential across jurisdictions.

It is appropriate that the block price differentials should be consistent across jurisdictions and, to the extent possible based on the differences in cost of service analysis, the winter first block should be based on similar percentages of the summer season first block prices.

6 RATES FOR RESPONSIBLE ENERGY USE

The following discussion explores alternatives to traditional block rates that may perform better at achieving responsible energy use.

6.1 Block Rates and Responsible Energy Use

For most of the utility industry history block rates have been a cost effective and equitable method of cost allocation for residential customers with similar usage patterns and load profiles. Under block rates in a two-part rate structure, utility costs to serve residential customers are recovered based on the amount of energy they consume. On the other hand, recognizing that the cost of electricity varies throughout the day and by location, block rates do not reflect the actual costs to serve a customer in a given time period.

As customer usages have changed and industry and societal needs have evolved, energy usage blocks have been used to serve a variety of often conflicting goals in attempts to influence customer consumption, resulting in similarly conflicting pricing signals.

More recently, greater energy utilization in the non-summer seasons has served to reduce the average cost paid by all customers through increased off peak sales and greater system utilizations. DBR rates have been argued as promoting inefficient use of electricity and discouraging conservation, and energy efficiency. As noted in our literature search, DBR may conversely be a mechanism to promote responsible use of electricity through environmentally beneficial electrification.

For the last couple of decades, IBR rate designs have been used to send a non-cost based, conservation pricing signal to customers, linking higher costs of energy with higher levels of consumption, providing a blunt incentive for energy efficiency measures and reduced consumption on the system. Under an IBR, customers with average and greater than average use often pay more for electricity over a given month for electricity with no distinction to when or how efficiently they are using electricity.

While it is generally recognized that an IBR provides an incentive for a customer to conserve electricity use over time, the level of reduced consumption by customers attributable to the IBR is widely debated. It is generally recognized that a customer's price response is more often based on their overall monthly electric bill and not the step prices of the IBR[65]. Recent IBR studies are showing that the price response from a recently deployed IBR is not as significant as were achieved by some of the early testing conducted in the 1980s and early 1990's.[66,67] Some of the reasons for this decline in IBR effectiveness are attributed to:

- IBR price impact overshadowed by more frequent general electric rate increases.
- EnergyStar and other standards have largely eliminated very inefficient devices off the market, minimizing the usage impact achievable through customer choice.
- EnergyStar standards are continuing to drive increased efficiency, so the next appliance purchased will be more efficient than the last, without consideration of price signals by the customer.

[65] *"Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing*", ITO*,* American Economic *Review, Vol. 104 No. 2, 2014, pg. 537-563.*

[66] "The Paradox of Inclining Block Rates", Brattle, Public Utility Fortnightly Magazine, 2015.

[67] "Trends in Regional U.S. Electricity and Natural Gas Price Elasticity", EPRI, 2010, pg. 1.4**.**

- Customers have become more environmental/energy conscience and have a greater propensity to purchase the green/efficient devices for reasons other than energy bill savings.

Policy goals are shifting from the simple energy conservation focus of yesteryear, toward achieving GHG reductions. Many are recognizing the need to assess the GHG emissions associated with various ways to power end-uses, as opposed to simply managing the number of kilowatt-hours consumed. To that end, "emissions efficiency" may be as, or more important than "energy efficiency" moving forward and ultimately may be the best measure of responsible energy use.[68] Some rate designs, like the IBR which charge customers an escalated, non-cost based price as their consumption increases over the course of the month, creates an economic disincentive to pursue beneficial electrification and achieve emissions efficiency.

6.2 Time Variant Rates for Responsible Energy Use

There is serious conversation across the entire utility industry around electricity rate design for residential customers.[69] New proposals are appearing for how to improve rates to meet emerging challenges (and opportunities) around environmental impact, customer engagement, bill management, reliability, and cost recovery.[70,71,72,73,74] Recent trends are requiring the industry to take stock of how customer needs are evolving and how that affects the electric grid.

Customer load profiles are becoming more diverse, while new technology is increasing potential customer capabilities.[75] Existing, default residential energy rates are simple and have worked well enough in the past, but are proving inadequate in the face of recent trends, as they fail to provide price signals that reflect system costs and enable meaningful customer response. An expanded set of rate designs are needed, but they must not limit signals for energy efficiency or be difficult for customers to understand and respond to.

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. Each structure will be important in the ongoing evolution of residential rate design.

TOU based rates provide more accurate price signals to customers, better reflecting the marginal cost of supplying and delivering electricity. Well-designed TOU rates better allocate time-varying costs to prices for consumption to time intervals that drive those costs. These more precise price signals lead customers

[68] '*Environmentally Beneficial Electrification: The dawn of 'emissions efficiency'*', The Electricity Journal, 29 (2016) pg. 52. Available at: http://www.sciencedirect.com/science/article/pii/S1040619016301075

[69] '*A Review of Alternative Rate Designs-Industry Experience with Time-Based and Demand Charges for Mass Market Customers'*, Rocky Mountain Institute, Boulder, CO, 2016, Page 5.

[70] '*Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies'*, U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, 2016,

[71] '*The Top Utility Regulation Trends of 2017—So Far',* C. Girouard, Greentech Media, July 2017.

[72] *A Review of Alternative Rate Designs-Industry Experience with Time-Based and Demand Charges for Mass Market Customers'*, Rocky Mountain Institute, Boulder, CO, 2016

[73] '*Rate Design for the Distribution Edge-Electricity Pricing for a Distributed Resource Future*', Rocky Mountain Institute, eLAB, 2014.

[74] 'Residential Consumers and the Electric Utility of the Future', American Public Power Association, 2016. Available at: https://www.publicpower.org/system/files/documents/ppf_residential_utility_of_the_future_final.pdf

[75] '*The Integrated Grid: Capacity and Energy in the Integrated Grid'*, EPRI. Palo Alto, CA: 2015, Page 28.

to change their consumption patterns during periods meaningful to the utility and help reduce both peak and total consumption.

Demand based rates provide a price signal to reduce peak demand and can potentially allocate peak or capacity driven costs more fairly. Customers respond by changing their consumption patterns to reduce peak demand, flattening their load profile and thereby improving overall grid utilization and deferring or potentially deferring capacity additions.

Combining both rate mechanisms into a Demand-TOU rate provides the pricing signals for customers to manage their consumption patterns to limit their peak usage levels and when to use energy based on the time varying prices. The Demand-TOU rate structure provides the utility to better pricing mechanism to allocate both fixed and variable costs based on cost causation and provide the customer effective price signals by which to manage their energy usage and ultimately to control their costs.

Individually, and when used in combination, the TOU and Demand rates provide effective pricing mechanisms to promote beneficial electrification and other efficient uses of electricity by increasing grid utilization and minimizing cost impacts to other customers. For example, offering a lower price during off-peak hours to reflect the lower cost of generating and supplying electricity in those hours provides EV owners with an opportunity to delay charging to the off-peak hours, saving them money on their electricity bill while also providing a benefit to the energy grid.

The GMO DSM Potential Study performed for the IRP process evaluated the DR potential of several alternative residential rate options, including residential IBR, TOU, and Demand rates. The Potential Study found that, for residential customers, TOU and Demand rates have significantly greater potential DR impact compared to block rates, and in particular, IBR.[76]

6.3 Conclusion of Rate Structures for Responsible Energy Use

Based on our literature review and considerations discussed above, GMO should pursue TOU and Demand rate options as the best rate designs to purse to meet the objectives of responsible energy use, demand-side management, and beneficial electrification. TOU and Demand rate options provides improved demand response potential, limits impacts to higher energy users that may already be using energy efficiently, and promotes cost efficient forms of electrification such as electric vehicles.

6.4 Additional Considerations to Improve Performance of Existing Block Rates

Through the course of this Block Rate study, the Company has identified several additional actions that the Company should consider that could improve the performance of the existing Residential rates, support new rate design efforts, and provide more customers the ability to elect future optional TOU and/or Demand based rates. The following points highlight these actions:

- <u>Investigate Proactive application of the Residential Other Use rate</u> - During the preparation of the customer usage data for analysis, the Company observed a number of accounts (garages, wells, barns, etc.) served by the Residential Rate that would be appropriate to serve under the Residential Other Use Rate as these accounts do not exhibit usage patterns consistent with a traditional residence. In the past, it was normal to serve these accounts under the Residential Rate. Recently, a Residential Other Use rate has been made available in all jurisdictions

[76] '*Kansas City Power & Light 2016 DSM Potential Study-Volume 1:Executive Summary*', Applied Energy Group, 2016, Page 15.

providing a more appropriate rate for these premises. The Company should consider investigating the impact of moving these Customers. Moving these accounts proactively would insure the application matches the rate.

- Examine the impact of transitioning the 2-meter rates to a single meter rate – Looking forward, eliminating the 2-meter usages would be an appropriate action to allow for customers to elect TOU or Demand based rates which would be based on whole-house consumption. Combining the 2-meter usages could be achieved in the Meter Data Management system without requiring modifications to the customer electrical wiring.
- Retain Block Rates for Lower Use Residential Customers - In the future, as the Company considers implementing alternative residential rate designs to meet evolving customer needs, GMO should consider reserving the simple block rate for lower-use residential customers. Many lower-use customers, especially multi-family residences, have similar usage patterns and have limited ability to adopt more energy efficient appliances or implement load management technologies. In these situations, the simple, block rate design is appropriate.

7 BLOCK RATE STUDY FINDINGS AND RECOMMENDATIONS

The primary focus of this Block Rate study is not to determine a rate structures that should be offered, but rather to determine the most 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.

A plausible design would have baseline usage for General Use and Electric Space Heat customers set at 600 kWh and 750 kWh respectively. The Summer Season block structure would be the 2-tier Baseline Usage with a single step at 600 kWh and the Winter Season block structure is the 3-Tier Premise Differentiated block structure with a first block cap at 400 kWh and a second block cap at 1,000 kWh.

Policy goals are shifting from the simple energy conservation focus of yesteryear toward achieving GHG reductions. Many are recognizing the need to assess the GHG emissions associated with various ways to power end-uses, as opposed to simply managing the number of kilowatt-hours consumed. To that end, “emissions efficiency” may be as or more important than “energy efficiency” moving forward and ultimately may be the best measure of responsible energy use. Some rate designs that can deviate from a cost basis, like the IBR, create an 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. Combining both rate mechanisms into a Demand-TOU rate provides pricing signals for customers to manage their consumption patterns to limit their peak usage levels and when to use energy based on the time varying prices. The Potential Study found that, for residential customers, TOU and Demand rates have significantly greater potential DR impact compared to block rates, and in particular, IBR.

Based on our literature review and considerations discussed above, TOU and Demand rate options are the best rate designs for the Company to purse to meet the objectives of responsible energy use, demand-side management, and beneficial electrification. TOU and Demand rate options provide improved demand response potential, limit impacts to higher energy users that may already be using energy efficiently, and promotes cost efficient forms of electrification such as electric vehicles.

KCP&L - Greater Missouri Operations Time of Use Rate Study

KCP&L – Greater Missouri Operations Company

Time of Use Rate Study
Project No. 97119

Final Report
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prepared for

KCP&L – Greater Missouri Operations Company
Time of Use Rate Study
Kansas City, Missouri

Project No. 97119

Final Report
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prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CCOS	Class Cost of Service
CIS	Computer Information Systems
CPP	Critical Peak Pricing
DBR	Declining Block Rate
DCFC	Direct Current Fast Charge
DG	Distributed Generation
DR	Demand Response
EV	Electric Vehicle
GMO	Greater Missouri Operation
GU	General Use
IBR	Inclining Block Rate
KCP&L	Kansas City Power & Light
LMP	Locational Marginal Price
MPSC	Missouri Public Service Commission
NPC	Non-Coincident Peak
PTR	Peak Time Rebates
RTP	Real-Time Pricing
SDS	Small General Service with Demand
SDS TOU	Small General Service with Demand Time-of-Use
SGS	Small General Service without Demand

Abbreviation	Term/Phrase/Name
SGS TOU	Small General Service without Demand Time-of-Use
SH	Electric Space Heat
TOU	Time-of-Use
TOU-D	Time-of-Use Energy with Demand
TOU-E	Time of Use Energy
VPP	Variable Peak Pricing

1.0 EXECUTIVE SUMMARY

1.1 Introduction

The Missouri Public Service Commission (MPSC or Commission) issued an order for KCP&L – Greater Missouri Operations Company (GMO or Company) to study time of use (TOU) rates. As described in the non-unanimous stipulation and agreement filed September 20, 2016 in MPSC Docket No. ER-2016-0156, GMO was ordered to include in its next rate case or rate design case, a study of TOU rates including TOU Residential and Small General Service rates, critical peak rates, electric vehicle TOU rates for stand-alone charging stations, TOU rates applicable to electric vehicle charging associated with an existing account, real time pricing, peak time rebates, and other rate types which could encourage load shifting/efficiency. GMO will propose rates based on this study no later than its next rate case, or rate design case.

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. This report has been prepared to summarize the TOU Rate Study for the GMO jurisdiction. Where applicable, the report may reference the related company, Kansas City Power & Light Company (KCP&L) or its regulated jurisdictions in Missouri (KCP&L-MO) and Kansas (KCP&L-KS).

The TOU Rate Study (Study) consisted of collecting information and conducting qualitative and quantitative analyses of the existing GMO Residential and Small General Service rates. The Study also extended to analyzing new Residential and Small General Service TOU rate designs. The following sections summarize the contents of the report, as well as, the Study recommendations.

1.2 Time of Use Rates Background

Section 2.0 of this report provides a summary of existing TOU rates offered by GMO and previous studies prepared by KCP&L that are referenced in this Study. GMO and KCP&L have offered TOU rates to their Residential and Small General Service customer classes in portions of the three existing jurisdictions. KCP&L has also conducted various internal studies, pilots, and analyses over the past several years that provide valuable input and assumptions into this Study. As described in Section 2.0, the existing TOU rates have recently been frozen and should be eliminated and replaced with new TOU rates that incorporate the findings within this Study and other studies prepared by KCP&L.

1.3 Internal Stakeholder Input

Section 3.0 of this report provides a summary of relevant regulatory requirements in Missouri, Company business goals and objectives, and general input on rate design. BMcD met with stakeholders throughout

KCP&L, who work on behalf of GMO, which included individuals in Regulatory Affairs, Energy Resource Management, Energy Solutions, Customer Service, Market Insights, Information Technology, Measurement Technologies and Revenue Management. There are several overarching themes that resulted from the internal stakeholder interviews that were generally consistent across all groups. The most prominent themes that impacted rate design are provided in Section 3.0 of this Study.

1.4 Rate Qualitative Evaluation and Selection

Section 4.0 of this report provides a summary of the qualitative analysis of various rate design options specific to GMO and rates recommended for further investigation in this Study. This Study considered each rate option in the context of the qualitative evaluation of rate options summarized below in Table 1-1 and detailed in Section 4.0 of this Study, to identify the rate design options that best aligned with GMO's criteria.

Table 1-1: KCP&L and GMO Residential and Small General Service Qualitative Summary

KCP&L & GMO Rate Design Goals	Flat Energy Rate	Declining Block Rate	Inclining Block Rate	Demand Rate	TOU - Energy Rates	TOU - Energy + Demand Rates	Dynamic Rates VPP / CPP / PTR	Real Time Pricing
Provide Revenue Stability and Sufficiency	NEUTRAL	POSITIVE	NEGATIVE	POSITIVE	NEUTRAL	POSITIVE	NEUTRAL	NEUTRAL
Promote Economic Efficiency in Rate Design	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE
Promote Peak Load Reduction and Load Shifting	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE
Support Efficient Use of Energy	NEUTRAL	NEGATIVE	NEUTRAL	POSITIVE	NEUTRAL	POSITIVE	NEUTRAL	NEUTRAL
Provide Customer Value & Satisfaction	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE
Provide Rate & Bill Simplicity	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	NEGATIVE	NEGATIVE

KCP&L & GMO Other Goals	Flat Energy Rate	Declining Block Rate	Inclining Block Rate	Demand Rate	TOU - Energy Rates	TOU - Energy + Demand Rates	Dynamic Rates VPP / CPP / PTR	Real Time Pricing
Support Cost Effective Electric Space Heating and Other Non-Summer Use	NEGATIVE	POSITIVE	NEUTRAL	POSITIVE	NEUTRAL	POSITIVE	NEUTRAL	NEUTRAL
Support Cost Effective Electric Vehicle Charging and Other Off-Peak Use	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	POSITIVE	POSITIVE	NEUTRAL	NEUTRAL
Support Equitable Cost Recovery From Distributed Generation and Other Low Use	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	NEGATIVE	POSITIVE	NEGATIVE	NEGATIVE
Metering and Billing Capablility	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	NEGATIVE	NEGATIVE
Recommended	Limited	Limited	No	Yes	Yes	Yes	No	No

Table 1-12 and Table 1-23 present the Residential and Small General Service rate options evaluated in the Study, the rates that are recommended for future implementation, and those that were designed and analyzed in the Study. As presented, dynamic pricing rates were considered, but not designed or analyzed in this Study. Specific TOU rates' applicability to EV charging were examined, however, end use rates specifically for Residential customers with EV were not designed or analyzed in this Study, but rather EV charging was evaluated within an overall TOU rate rather than as a specific end use rate.

Table 1-2: GMO TOU Rate Study Residential Rate Options

Residential TOU Rate Options	Status	Evaluated	Recommended	Recommended Availablity	Designed	Analyzed	Note
General Use	Existing	Yes	Yes	Standard Offer	Yes	Yes	Optional for all customers. Minimize availability to low use customers.
Space Heat	Existing	Yes	Yes	Frozen	Yes	Yes	Minimize and eventually limit SH availability over time.
Demand Rate	New	Yes	Yes	Optional	Yes	Yes	Optional for all customers. Marketed to SH customers.
TOU Energy Rate	New	Yes	Yes	Optional	Yes	Yes	Optional for all customers. Marketed to EV. Minimize availability.
TOU Energy + Demand Rate	New	Yes	Yes	Optional	Yes	Yes	Optional for all customers. Marketed to customers with EV and SH.
TOU - EV Single Meter	New	Yes	No	No	No	Yes	Customers will use a TOU rate. End use rates not available.
TOU - EV Separate Meter	New	Yes	No	No	No	Yes	Customers will use a TOU rate. Submetered EV not available.
Critical Peak Pricing	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.
Peak Time Rebate	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.
Real Time Pricing	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.

Table 1-3: GMO TOU Rate Study Small General Service Rate Options

Small General Service TOU Rate Options	Status	Evaluated	Recommended	Recommended Availablity	Designed	Analyzed	Note
SGS	Existing	Yes	Yes	Standard Offer	Yes	Yes	Default under 25 kW. Optional for all. Minimize availability.
SDS	Existing	Yes	Yes	Standard Offer	Yes	Yes	Default over 25 kW. Optional for all.
SGS TOU	New	Yes	Yes	Optional	Yes	Yes	Optional for all. Minimize availability over time.
SDS TOU	New	Yes	Yes	Optional	Yes	Yes	Optional for all.
TOU - EV Single Meter	New	Yes	No	No	No	Yes	Customers will use a TOU rate. End use rates not available.
TOU - EV Separate Meter	New	Yes	No	No	No	Yes	Customers will use a TOU rate. Submetered EV not available.
Critical Peak Pricing	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.
Peak Time Rebate	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.
Real Time Pricing	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.

1.5 Rate Implementation Plan

Section 5.0 of this report provides conceptual long-term rate transition plans for the GMO Residential and Small General Service customer classes based on the internal stakeholder input and qualitative evaluations. GMO and KCP&L intend to offer rates that support their long-term rate design and business objectives. These rates may reflect changes from existing rates, and where practical, should be offered as optional rates initially, while existing rates that are not consistent with the utility's long-term rate design strategy should be phased out gradually. This makes way for new rates to be marketed and implemented, initially through a pilot program, for existing and future customers. This may include freezing and then eliminating rates or otherwise limiting rate availability. The timing of new rate implementations will vary based on GMO and KCP&L's meter deployment, regulatory filings, IT capabilities, and other external considerations such as statutory limitations around net metering. The basic components of the recommended long-term GMO rate transition plan are derived from interviews with internal stakeholders and working groups, and is provided in Table 1-34 and Table 1-45 with additional details regarding each step provided in Section 5.0 of this Study.

Table 1-4: GMO Residential Rate Transition Plan

Rate Option	Current	Step 1	Step 2 *Pending Pilot Results*	Step 3 *Pending Pilot Results*	Notes
General Use Rate	Available	Available	Available and Cap	Available and Cap	Step 2 - Optional for all customers under a threshold. Step 2 - Cap rate to users under a threshold (<30,000 kWh/year, 25 kW cap).* Sept 3 - Reduce cap to smaller usage customers (<9,000 kWh/year, 7.5 kW cap).
Electric Space Heating Rate	Available	Available	Freeze	Unavailable	Step 2 - Freeze SH rate short term. Step 2 - Give all customers option for Demand Rate. Step 3 - Eliminate SH class long term.
Optional Demand Rate (Optimal Rate for Space Heating)	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited number of customers. Step 2 - Optional for all customers. Step 2 - Demand Rate offered to new SH customers (revenue neutral). Step 3 - Move all existing SH customers to this rate long term.
Optional TOU Energy Rate (Optimal Rate for Electric Vehicle)	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited number of customers. Step 2 - TOU Energy marketed to EV customers. Step 2 - Cap rate to users under a threshold (<30,000 kWh/year, 25 kW cap). Step 3 - Reduce cap to smaller usage customers (<9,000 kWh/year, 7.5 kW cap).
Optional TOU Energy and Demand Rate (Optimal Rate for Space Heating and Electric	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited amount of customers. Step 2 - Optional for all customers. Step 2 - TOU Energy and Demand Rate marketed to EV + SH customers. Step 3 - Offer as the default TOU rate for all new customers.

[1] All existing and future rates will have seasonality.
[2] Steps 1, 2, and 3 will depend on regulatory support and technical capabilities in each jurisdiction.
[3] Step 1 (Pilot Study) results will validate and refine future steps in each utility jurisdiction.
[4] New demand + energy rate plan is revenue neutral to electric space heating customers and general use customers.
[5] These caps were selected as a reasonable initial design as they are similar to those used within the GMO SGS class to distinguish the transition between non-demand and demand rates. The 25kW limit also has relevance within the distribution network where the 25kW size is perceived to match the common size for distribution transformation for these customers. The additional terms (9,000 kWh and 7.5kW) were established to support further reduction of the limits and were derived from a review of load factors for Residential customers.

Table 1-5: GMO Small General Service Rate Transition Plan

Rate Option	Current	Step 1	Step 2 *Pending Pilot Results*	Step 3 *Pending Pilot Results*	Notes
Small General Service Rate (SGS)	Available	Available	Available	Available	Step 2 - Cap rate to users under a threshold (<30,000 kWh/year, 25 kW cap). Step 3 - Reduce cap to smaller usage customers (<9,000 kWh/year, 7.5 kW cap).
Small General Service Demand Rate (SDS)	Available	Available	Available	Available	Step 3 - Eliminate minimum facilities demand provision.
Optional Small General Service TOU Rate (SGS TOU)	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited number of customers. Step 2 - TOU Energy marketed to all SGS customers. Step 2 - Cap rate to users under a threshold (<30,000 kWh/year, 25 kW cap). Step 3 - Reduce cap to smaller usage customers (<9,000 kWh/year, 7.5 kW cap).
Optional Small General Service Demand TOU Rate (SDS TOU)	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited number of customers. Step 2 - TOU Energy + Demand marketed to all SDS customers. Step 3 - Eliminate minimum facilities demand provision.

[1] All existing and future rates will have seasonality.
[2] Steps 1, 2, and 3 will depend on regulatory support and technical capabilities.
[3] Step 1 (Pilot Study) results will validate and refine future steps in each utility jurisdiction.
[4] SGS TOU and SDS TOU availability to existing and new customers will depend on meter deployment.
[5] These caps were selected as a reasonable initial design as the 25 kW is currently used within the GMO SGS class to distinguish the transition between non-demand and demand rates. The 25kW limit also has relevance within the distribution network where the 25kW size is perceived to match the common size for distribution transformation for these customers. The additional terms (9,000 kWh and 7.5kW) were established to support further reduction of the limits and were derived to maintain consistentency with the Residential class.

1.6 Rate Design Approach

Section 6.0 of this report provides the underlying methodology used by BMcD to prepare the Residential and Small General Service TOU rates developed in this Study. Each task within the rate design approach is explained with additional details provided in subsequent sections of this report.

1.7 Utility Rate Design Peer Review

Section 7.0 of this report includes a peer review of TOU rates and demand rates currently being offered across the United States along with a summary of the common practices employed in various TOU rate and demand rates. The TOU and demand rates developed within this Study reflect common rate design practices employed by other utilities including, but not limited to, seasonality, time periods, and prices.

1.8 Load Analysis and Time of Use Periods

Section 8.0 of this report provides an analysis of system and customer class load profiles and the development of TOU pricing periods. Based on the load analysis review, time of use periods were defined for Residential and Small General Service classes which aligned with GMO's system and customer class load shapes and other common practices for time of use period time definition.

1.9 Cost of Service Analysis

Section 9.0 of this report provides the development of the seasonal class cost of service based TOU rates for Residential and Small General Service classes. The optional rate structures developed are designed to be cost based by component and season and reflect industry excepted rate designs for Residential and Small General Service TOU and demand rates. Each cost component in the class cost of service was assigned to either a TOU period or billing demand determinant to determine a cost based charge for each of the optional rate designs developed.

1.10 Time of Use Rate Designs

Section 10.0 of this report provides a description of the rate designs developed and the basis for their designs. Optional rates for Residential and Small General Service were developed and designed based on the general principles documented in this Study. Rates were designed and tested with calendar year 2015 load research data sets with the goal of generating revenue neutral rates for both Residential and Small General Service customers. Not all the rates generate revenue neutral bills for each customer load profile and type. Modifications were made where appropriate to limit the potential increase or decrease to Residential and Small General Service customers. For consistency between rates, certain provisions such as consistent customer charges were applied across rate plans. All new optional rates were designed to maintain seasonality in the rate structure and remove declining block structures in the winter months. The optional rates would initially be offered to a limited number of customers through a pilot program. Analysis would then be performed to determine program performance and possibly revise optional new rates for GMO. Optional new rates are presented in the following tables 1-6 and 1-7 with details provided in Section 10.0.

Table 1-6: GMO - Residential Optional Rate Designs

Existing		Existing		New		New		New	
General use Rate		Space Heating Rate		Optional Demand Rate		Optional TOU Energy Rate		Optional TOU Energy + Demand Rate	
	Price		Price		Price		Price		Price
Customer Charge ($/mo)	$10.43	Customer Charge ($/mo)	$10.43	Customer Charge ($/mo)	$10.43	Customer Charge ($/mo)	$10.43	Customer Charge ($/mo)	$10.43
Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)	
Summer	$0.121	Summer	$0.121	Summer	$0.037	Summer Peak	$0.302	Summer Peak	$0.101
						Summer Off Peak	$0.107	Summer Off Peak	$0.031
						Summer Super Off Peak	$0.046	Summer Super Off Peak	$0.017
Winter, up to 600	$0.106	Winter, up to 600	$0.106	Winter	$0.034	Winter Peak	$0.211	Winter Peak	$0.100
Winter 601 - 1000	$0.078	Winter 601 - 1000	$0.060			Winter Off Peak	$0.090	Winter Off Peak	$0.025
Winter, 1001 +	$0.078	Winter, 1001 +	$0.050			Winter Super Off Peak	$0.033	Winter Super Off Peak	$0.019
Tier 1 Max kWh	600	Tier 1 Max kWh	600	Tier 1 Max kWh	N/A	Tier 1 Max kWh	N/A	Tier 1 Max kWh	N/A
Tier 2 Max kWh	1,000	Tier 2 Max kWh	1,000	Tier 2 Max kWh	N/A	Tier 2 Max kWh	N/A	Tier 2 Max kWh	N/A
Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)	
Summer Demand	N/A	Summer Demand	N/A	Summer Demand	$15.25	Summer Demand	N/A	Summer Demand	$15.25
Winter Demand	N/A	Winter Demand	N/A	Winter Demand	$7.75	Winter Demand	N/A	Winter Demand	$7.75
Summer Demand	N/A	Summer Demand	N/A	Summer Demand	On Peak	Summer Demand	N/A	Summer Demand	On Peak
Winter Demand	N/A	Winter Demand	N/A	Winter Demand	On Peak	Winter Demand	N/A	Winter Demand	On Peak
Current Default General Use Rate Small Use Customers		Current Default Space Heat Rate Frozen Space Heat Rate		Optimal Space Heat Rate Default for High Use Customers Revenue neutral to GU and SH classes		Optimal EV Rate Available for all customers Revenue neutral for GU class		Optimal Space Heat + EV Rate Default for High Use Customers Revenue neutral for GU and SH classes	

1. For this analysis, summer months are assumed from June 1 to September 30 for optional rates.
2. TOU Peak from 4 - 8 pm. Off Peak from 6 am to 4 pm and 8 pm to 12 am. Super Off Peak from 12 am to 6 am.
3. Max monthly on-peak demand is billed based on 15 min maximum measured demand from 4 - 8 pm.
4. Existing rates are based on Residential rates effective February 22, 2017.
5. New optional rates are set to recover the same revenues as the existing GU and SH rates.

Table 1-7: GMO Small General Service – Optional Rate Designs

SGS Rate		Optional SDS Rate		Optional SGS TOU Rate		Optional SDS TOU Rate	
	Price		Price		Price		Price
Customer Charge	$23.91	Customer Charge	$23.91	Customer Charge	$23.91	Customer Charge	$23.91
Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)	
Summer	$0.140	Summer, up to 180	$0.098	Summer Peak	$0.278	Summer Peak	$0.074
				Summer Off Peak	$0.121	Summer Off Peak	$0.026
				Summer Super Off Peak	$0.061	Summer Super Off Peak	$0.015
Winter	$0.088	Winter, up to 180	$0.071	Winter Peak	$0.157	Winter Peak	$0.070
		Winter, over 180hrs	$0.064	Winter Off Peak	$0.082	Winter Off Peak	$0.024
				Winter Super Off Peak	$0.048	Winter Super Off Peak	$0.017
Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)	
Distribution Demand	N/A	Distribution Demand	$1.45	Distribution Demand	N/A	Distribution Demand	$1.07
NCP, Ratchet, Peak	N/A	NCP, Ratchet, Peak	Ratchet NCP	NCP, Ratchet or CP	N/A	NCP, Ratchet or CP	Ratchet NCP
NCP Ratchet (%)	N/A	NCP Ratchet (%)	100%	NCP Ratchet (%)	N/A	NCP Ratchet (%)	100%
Summer Demand	N/A	Summer Demand	$1.27	Summer Demand	N/A	Summer Demand	$19.00
Winter Demand	N/A	Winter Demand	$1.24	Winter Demand	N/A	Winter Demand	$11.50
Summer Demand	N/A	Summer Demand	NCP	Summer Demand	N/A	Summer Demand	On Peak
Winter Demand	N/A	Winter Demand	NCP	Winter Demand	N/A	Winter Demand	On Peak
Standard Rate (<25kW)		Standard Rate (>25kW)		Proposed SGS TOU Energy		Proposed SDS TOU Energy + Demand	

1. Summer months from June 1 to September 30 for proposed rates.
2. TOU Peak from 1 - 6 pm. Off Peak from 6 am to 1 pm and 6 pm to 12 am. Super Off Peak from 12 am to 6 am.
3. Max monthly on-peak demand is billed based on 15 minute maximum measured demand from 4 - 8 pm.
4. Ratcheted NCP demand is billed based on 15 minute maximum monthly demand and ratcheted for 12 months
5. Existing rates are based on GMO SGS and SDS rates effective February 22, 2017.
6. New optional SGS TOU Energy Rates are set to recover the same revenues as the existing SGS Rates based on load research profiles.
7. New optional SDS TOU Energy Rates are set to recover the same revenues as the existing SDS Rates based on load research profiles.

1.11 Revenue and Bill Analysis

Section 11.0 of the report provides estimates of the revenue impacts due to offering new TOU rates including the impacts from self-selection and the associated potential revenue losses. Implementing optional rates for the Residential and Small General Service classes may result in revenue loss due to customers self-selecting the optional rates that save them money without changes in behavior.

1.12 Demand Response Analysis

Section 12.0 of this report summarizes previous KCP&L Study assumptions regarding expected demand response from TOU rates and the estimated GMO revenue and cost impacts from the rates developed in this Study. Implementing options rates for the Residential and Small General Service classes may result in customers shifting loads in response to the TOU and Demand rates. Demand response may reduce revenues and avoid costs for GMO as described in this Study.

1.13 Customer Bill Analysis

Section 13.0 of this report provides an analysis of the typical bills at varying levels and load factors under the existing and optional rates developed in this Study. Each of the optional rates developed in this Study were assessed across a range of load factors and usage levels to quantify the potential impact for various types of customers. The overall impact to each customer would range based on their usage, load factor, profile, and end use equipment as described in this Study.

1.14 Electric Vehicle Rate Analysis

Section 14.0 provides an assessment of TOU rates and Demand rates developed in this Study and their application to Residential customers with electric vehicles. Each of the optional rates developed in this Study can be used by EV customers to cost effectively shift their EV charging loads and achieve savings that reflect the utility's cost of service.

1.15 Study Recommendations

BMcD recommends several actions be taken by GMO based on the investigations, findings, and analyses conducted in this Study and previous studies referenced in this report. The Study recommendations are presented herein.

- GMO should remove the existing frozen Residential and Small General Service TOU rates described in Section 2.0 of this Study from its rate manual and move the few remaining customers on those rates to one of the new optional rates in this Study or place them onto the appropriate default rate.
- GMO should make modifications to its existing Residential rates and offer new optional rates that are consistent with internal stakeholder input summarized in Section 3.0 of this Study. If expected impacts warrant, modifications to existing rates, such as Residential General Use or Small General Service, should be made gradually.
- GMO should explore the possibility of offering the rate design options, as programs in a future 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 (Integrated Resource Planning or "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 type program or like mechanism 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.
- GMO should implement new optional rates for both the Residential and Small General Service classes that best meet GMO goals and objectives and are consistent with trends geographically and

nationally as outlined in Section 4.0 of this Study. GMO should continue to monitor state, regional, and national regulatory and rate trends as new rates are implemented.

- GMO should follow the Rate Transition Plan in Section 5.0 of this Study. This plan initially includes offering three new Residential rate options as part of a pilot in 2018 that include (1) a Demand Rate, (2) a TOU Energy rate, and (3) a TOU Energy and Demand Rate. Results of the pilot will 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.
- GMO should update the new optional Residential and Small General Service rates developed in this Study following the rate design approach described in Section 6.0 in the future as needed. Future updates to optional rates should reflect GMO's CCOS model described in Section 9.0 and provide rate revenues similar to the GU rates and SH rates described in Section 10.0.
- The optional rates should be marketed to Residential customers and initially made available to a limited number of GMO's Residential GU and SH customers balanced in proportionate to the number of GU and SH customers.
- GMO will need to measure and verify the impacts of the new optional rates implemented in the pilot. Several key results that will need to be quantified prior to offering rates to all Residential and Small General Service customers will include revenue loss from self-selection as described in Section 11.0 and customer demand response and revenue impacts as described in Section 12.0.
- Longer term and once the Company has performed analysis on the pilots implemented and measured their impact as positive, GMO should expand its offering to all Residential customers and promote them as the rates to use for Residential in home EV charging as described in Section 14.0 of this Study. These new optional rates will support cost effective EV charging and other off-peak use.

2.0 TIME OF USE RATES BACKGROUND

GMO and KCP&L have offered TOU rates to their Residential and Small General Service customer classes in portions of the three existing jurisdictions. KCP&L has also conducted various internal studies, pilots, and analyses over the past several years that provide valuable input and assumptions into this Study. This section provides a summary background of the historical TOU rates available in GMO, as well as a summary of the related TOU studies and analyses prepared on behalf of, or by, KCP&L.

2.1 Existing Frozen GMO TOU Rates

GMO has offered TOU rates to its Residential and Small General Service Customers through the former Missouri Public Service (MPS) rate jurisdiction. The TOU rates for these classes have recently been frozen[1] and are no longer available to new customers. Table 2-1 presents the existing TOU rates and peak, shoulder, off-peak hours for each season for the GMO Residential and Small General Service classes.

Table 2-1: GMO Residential and Small General Service TOU Rates (FROZEN)

Existing - FROZEN KCP&L GMO Residential Service Time-of-Day		
Seasons	**Summer**	**Winter**
	1-Jun	1-Oct
Weekdays	**Summer**	**Winter**
Peak	1:00 PM - 8:00 PM	7:00 AM - 10:00 PM
Shoulder	6:00 AM - 1:00 PM	
Shoulder	8:00 PM - 10:00 PM	
Off-Peak	10:00 PM - 6:00 AM	10:00 PM - 7:00 AM
Weekends	**Summer**	**Winter**
Shoulder	6:00 AM - 10:00 PM	
Off-Peak	10:00 PM - 6:00 AM	All Hours
Customer Charge	**Summer**	**Winter**
	$18.46	$18.46
Energy Charges ($/kWh)		
Peak	$0.20449	$0.13122
Shoulder	$0.11362	
Off-Peak	$0.06823	$0.05238
Demand Charges ($/kW)		
Peak	N/A	N/A

Existing - FROZEN KCP&L GMO General Service Time-of-Day (Single Phase Service)		
Seasons	**Summer**	**Winter**
	1-Jun	1-Oct
Weekdays	**Summer**	**Winter**
Peak	1:00 PM - 8:00 PM	7:00 AM - 10:00 PM
Shoulder	6:00 AM - 1:00 PM	
Shoulder	8:00 PM - 10:00 PM	
Off-Peak	10:00 PM - 6:00 AM	10:00 PM - 6:00 AM
Weekends	**Summer**	**Winter**
Shoulder	6:00 AM - 10:00 PM	
Off-Peak	10:00 PM - 6:00 AM	All Hours
Customer Charge	**Summer**	**Winter**
	$24.86	$24.86
Energy Charges ($/kWh)		
Peak	$0.20906	$0.13556
Shoulder	$0.11618	
Off-Peak	$0.06969	$0.05412
Demand Charges ($/kW)		
Peak	N/A	N/A

Existing - FROZEN KCP&L GMO General Service Time-of-Day (Single Phase Service with Demand)		
Seasons	**Summer**	**Winter**
	1-Jun	1-Oct
Weekdays	**Summer**	**Winter**
Peak	1:00 PM - 8:00 PM	7:00 AM - 10:00 PM
Shoulder	6:00 AM - 1:00 PM	
Shoulder	8:00 PM - 10:00 PM	
Off-Peak	10:00 PM - 6:00 AM	10:00 PM - 6:00 AM
Weekends	**Summer**	**Winter**
Shoulder	6:00 AM - 10:00 PM	
Off-Peak	10:00 PM - 6:00 AM	All Hours
Customer Charge	**Summer**	**Winter**
	$24.86	$24.86
Energy Charges ($/kWh)		
Peak	$0.12783	$0.10634
Shoulder	$0.07099	
Off-Peak	$0.04278	$0.04278
Demand Charges ($/kW)		
Peak	$10.694	$0.000

[1] TOU rates were frozen as part of Commission order in Case No. ER-2016-0156. In its direct testimony, the Company asserted the rates were not working as intended and had little customer adoption. The Company chose to freeze these rates, making the rates unavailable to new customers, until studies related to TOU and necessary metering and billing system infrastructure was put in place to properly support these special rates.

The existing frozen TOU rates, when available, were not widely adopted by either the Residential or Small General Service classes. Based on BMcD's general review of the TOU rates, it's possible that the low level of adoption may have been attributable to one or more of the reasons below:

- **Customer Charge Differential May Be Too High -** Customers paid a higher fixed monthly customer charge, which funded the more specialized metering equipment that was required for TOU rates. With the current frozen TOU rates, the customer charge differential is nearly $8.00 more per month. Future Residential TOU rates may not require this differential since all metering will be TOU capable.[2]
- **On-Peak Period Duration May Be Too Long** – When compared to other utilities offering TOU rates and consideration of common practice, the on-peak period from 1 pm to 8 pm may be too long for most Residential customers to effectively shift their load to lower priced off-peak time periods.
- **Peak to Off Peak Price May Be Too Small** – Based on a comparison to other TOU designs, the 2 to 1 price differential between on-peak and off-peak time periods may not have provided enough economic value to those customers who made significant changes in their usage patterns.
- **Additional Marketing and Promotion May Have Been Needed** – While no comprehensive review of marketing was performed, it's possible GMO and KCP&L may not have adequately marketed TOU rates to customers.
- **Lack of Hourly Load Data/System limitations** – Due to metering and billing system limitations, GMO was not able to provide Residential customers with their hourly data or estimate the bills under the optional rates. This data could have assisted customers in understanding if TOU rates would be beneficial to the them when deciding on whether to switch. Without this information, customers did not know if TOU rates would increase or decrease their bill.

KCP&L has conducted several studies to evaluate and understand TOU rates. This Study offers additional recommendations that align with utility industry best practices and the Company's rate design goals. GMO and KCP&L are in the process of installing new metering technology that may provide access to customer hourly data in a way that was not available before and could provide insight that aids in the offering of future rate design offerings that will provide more customer rate options. These factors should enable a more successful offering of TOU rates than has been possible in the past.

[2] This assumes that the Company will be at 100% implementation of the Automated Metering Infrastructure (AMI), which may not be the case when Time of Use rates are offered to customers. Current plans estimate that the Company may not be 100% AMI until 2020.

2.2 Summary of Recent Time of Use Rate Studies

KCP&L has conducted a series of TOU and other Time Variant Rate (TVR) studies. The studies were undertaken in preparation of implementing newly designed, modern, TOU rates that provide proper pricing signals and allow for customers to modify their electric usage patterns to the benefit of both themselves and all GMO and KCP&L customers. The specific foundational TVR rate analyses that have been performed by KCP&L that provide input into this Study are listed below.

- Electric Power Research Institute (EPRI)-Matching Electric Service Plans to KCP&L's Strategic Objectives (EPRI-ESP) – EPRI Supplemental Research Project, 2012-2014.
- KCP&L SmartGrid Residential Time-of-Use Pilot (SGDP-TOU) – a component of the KCP&L Division of Energy SmartGrid Demonstration Project, 2010-2015
- EPRI-KCP&L Residential Time-of-Use Impact Study (EPRI-TOU)– EPRI Smart Grid Demonstration Project Analysis, 2010-2015
- ERPI-Measuring Customer Preferences for Alternative Electricity Service Plans (EPRI-ESP) – EPRI Supplemental Research Project, 2014-2015
- KCP&L 2016 Demand Side Management (DSM) Potential Study (DSM-TOU)– Applied Energy Group, 2016-2017
- BMcD-KCP&L and GMO Residential Rate Design Strategy Study (BMcD-TOU)- Burns & McDonnell Engineering Company, 2017

3.0 INTERNAL STAKEHOLDER RATE DESIGN INPUT

BMcD met with stakeholders throughout KCP&L, who work on behalf of GMO, which included individuals in Regulatory Affairs, Energy Resource Management, Energy Solutions, Customer Service, Market Insights, Information Technology, Measurement Technologies and Revenue Management. There are several overarching themes that resulted from the internal stakeholder interviews that were generally consistent across all groups. The most prominent of these are listed below. Additional detailed input on each of these subjects is documented in the KCP&L Residential Rate Strategy Report. [3]

- Existing Residential Rate Structure – Several elements of the current rate design are working well today. Residential seasonal rates, declining block rates (DBRs), and cost based customer charge provide a time tested, basic rate design that should continue until a new rate structure can be offered that better aligns with rate design principles and Company goals and better utilizes the new technology and systems.
- Existing Small General Service Rate Structure - Several elements of the current rate design are working well, including the use of a demand charge and ratcheted demand charge within a four-part rate design. The existing Small General Service demand rates, however, are currently low and could be adjusted to better reflect the utility's cost to provide service. Offering a simpler, kWh based rate for the smallest of the Small General Service customers provides a suitable alternative for loads not appropriate for management of demand and energy use.
- Existing TOU Rates – The existing TOU rates for the Residential and Small General Service classes, which are currently frozen, should remain frozen and/or eliminated, given their current design and limited participation.
- Future TOU Rates – A simple TOU rate that can be used to help promote efficient energy use, including EV adoption, is desired in the near term. This rate should reflect upgrades in metering technology, billing technology, the utility's costs, and new TOU periods. TOU would help achieve demand side management (DSM) goals as well as satisfy other factors such as customer choice and regulatory mandates.
- Dynamic Rates - Dynamic TOU rate options, such as real-time pricing (RTP), critical peak pricing (CPP), variable peak pricing (VPP) and peak time rebates (PTR) which are viewed as increasingly

[3] Residential Rate Design Strategy Study, Burns & McDonnell Engineering Company, 2017.

complex, are not strongly supported by internal stakeholders now. It is perceived that these dynamic rates will need to be deployed incrementally and only after TOU effectiveness can be evaluated.

- Demand Rates and Multi-Part Rates – The Residential class should move to a rate structure that includes a demand charge and provides a TOU optionality within the energy charge in the future. Small General Service rates should include a facilities charge, demand charge, and TOU optionality with more costs being recovered through the demand charges. This will facilitate customer choice and cost-based rates.
- Metering & Billing – GMO and KCP&L would like to take advantage of new Advanced Metering Infrastructure (AMI), Meter Data Management (MDM), and Customer Information System (CIS) currently being designed and implemented. These systems will better enable the deployment of demand rates and TOU rates for all KCP&L and GMO Residential and Small General Service customers by 2020.
- Customer Insights – Internal customer focus group surveys and market studies indicate that customers desire rate options including TOU rates, green rates, or other rates which they can actively use to save or promote their energy choices.
- Electric Space Heating – GMO and KCP&L would like to work towards implementing a cost-based rate structure that recognizes the value of electric space heating load and other non-summer loads while not having special end-use requirements. GMO and KCP&L do not intend to offer separate TOU rates for General Use (GU) and Space Heating (SH).
- Electric Vehicles (EV) – GMO and KCP&L would prefer to implement a rate in all jurisdictions that can be used by and marketed to EV owners to shift EV charging load off-peak in a cost-efficient manner.
- Distributed Generation (DG) – GMO and KCP&L would like to address the growth of DG and better mitigate existing cross subsidization and cost shifting through long term modifications to its existing rate design for both Residential and Small General Service.

4.0 RATE QUALITATIVE EVALUATION AND SELECTION

GMO and KCP&L provided BMcD with previously prepared documents regarding its internal rate design positions and strategic goals on rate design for the Residential and Small General Service classes. In the stakeholder interview process, BMcD solicited input on the key rate design principles listed below which align with utility industry best practices and Bonbright's Rate Design Principles[4]. Where appropriate, additional insight was collected on specific new industry issues such as EVs, DG, peak load reduction and shifting, and energy efficiency, as well as, electric space heating. GMO and KCP&L desire that any new rates align with good rate making principles.

4.1 Qualitative Evaluation Criteria

Each rate option considered was qualitatively evaluated prior to conducting rigorous in-depth modeling and analysis. Rate designs considered should reflect good rate making principles and consist of a range of potential options that exist today. Additionally, the rate evaluation should analyze if the rate structures align with future technologies being developed, are supportive of GMO and KCP&L's goals and objectives, and are consistent with regulatory trends geographically and nationally. The criteria used to evaluate each rate option for the Residential and Small General Service classes are listed below.

- Provide Revenue Sufficiency and Stability – Rates provide an opportunity to produce revenues sufficient to cover KCP&L's annual revenue requirements. Rates provide predictable revenues through changes in system load conditions and weather.
- Provide Cost of Service Based Rate Designs – Rates are cost based. Revenue is collected by class, classification, and season based on amounts derived from the GMO class cost of service.
- Promote Economic Efficiency in Rate Design – Rates reflect time-varying wholesale prices, reflect the relevant risk to providers, and offer choices that reflect diverse consumer risk preferences. Rates can encourage the adoption of technologies that can provide services to the energy grid and customers.
- Promote Peak Load Reduction and Load Shifting – Rates promote peak load reduction and the shifting of load from peak periods (months and hours), reflecting the associated cost savings and other benefits.
- Support Efficient Use of Energy – Rate designs allow for savings from energy efficiency and demand reduction measures deployed by customers.

[4] James C. Bonbright, Principles of Public Utility Rates (New York, Columbia University Press, 1951)

- Provide Customer Value and Satisfaction – Customers are provided adequate price signals to respond to the rates and can receive value, either real or perceived.
- Provide Rate and Bill Simplicity – Customers can understand the rate options offered. For the Residential classes, this criterion is measured relative to the current two-part residential rate with a DBR charge. For the Small General Service classes, this criterion is measured relative to the energy rate for Small General Service without Demand (SGS) customers; and relative to the energy plus demand rate structure for Small General Service with Demand (SDS) customers.
- Support Cost Effective Electric Space Heating and Other Non-Summer Use – Rate designs reflect the cost to provide service by time and season for customers who tend to use more energy in the non-summer periods for uses such as electric space heating.
- Support Cost Effective EV Charging and Other Off-Peak Use – Rate designs reflect the cost to provide service by time and season for customers who tend to use more energy in the off-peak periods for uses such as EV charging.
- Support Equitable Cost Recovery from DG and Other Low Use Conditions – Rate designs allow for equitable recovery of costs from customers reflective of their use of the energy grid and not the energy they consume. Provide cost-based rates to customers with DG and protecting from cost-shifting to non-DG customers.
- Metering and Billing Complexity – Rates can be billed and metered within the new metering and billing systems.

4.2 Rate Options Qualitative Evaluation Summary

The results of the qualitative evaluation of each rate option are presented in Table 4-1. The detailed qualitative evaluation of each rate option considered against GMO and KCP&L's criteria is documented in the KCP&L Residential Rate Strategy Report. [5] The criteria and relative scoring for each rate option considered in the assessment applies to all Residential and Small General Service customer classes.

[5] Residential Rate Design Strategy Study, Burns & McDonnell Engineering Company, 2017.

Table 4-1: KCP&L and GMO Residential and Small General Service Qualitative Summary

KCP&L & GMO Rate Design Goals	Flat Energy Rate	Declining Block Rate	Inclining Block Rate	Demand Rate	TOU - Energy Rates	TOU - Energy + Demand Rates	Dynamic Rates VPP / CPP / PTR	Real Time Pricing
Provide Revenue Stability and Sufficiency	NEUTRAL	POSITIVE	NEGATIVE	POSITIVE	NEUTRAL	POSITIVE	NEUTRAL	NEUTRAL
Promote Economic Efficiency in Rate Design	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE
Promote Peak Load Reduction and Load Shifting	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE
Support Efficient Use of Energy	NEUTRAL	NEGATIVE	NEUTRAL	POSITIVE	NEUTRAL	POSITIVE	NEUTRAL	NEUTRAL
Provide Customer Value & Satisfaction	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE
Provide Rate & Bill Simplicity	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	NEGATIVE	NEGATIVE

KCP&L & GMO Other Goals	Flat Energy Rate	Declining Block Rate	Inclining Block Rate	Demand Rate	TOU - Energy Rates	TOU - Energy + Demand Rates	Dynamic Rates VPP / CPP / PTR	Real Time Pricing
Support Cost Effective Electric Space Heating and Other Non-Summer Use	NEGATIVE	POSITIVE	NEUTRAL	POSITIVE	NEUTRAL	POSITIVE	NEUTRAL	NEUTRAL
Support Cost Effective Electric Vehicle Charging and Other Off-Peak Use	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	POSITIVE	POSITIVE	NEUTRAL	NEUTRAL
Support Equitable Cost Recovery From Distributed Generation and Other Low Use	NEGATIVE	NEGATIVE	NEGATIVE	POSITIVE	NEGATIVE	POSITIVE	NEGATIVE	NEGATIVE
Metering and Billing Capablility	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	POSITIVE	NEGATIVE	NEGATIVE

Recommended	Limited	Limited	No	Yes	Yes	Yes	No	No

As depicted in the table above, after review of each rate option and its alignment to Rate Design and Company goals, BMcD recommends that GMO and KCP&L should pursue the recommended rate design options and make changes to existing rates as described below. Other rate structures may be appropriate in the future while others should be limited as described. Recommendations below are a direct result of consideration of Company goals, application of good rate making principles, consideration of the qualitative ratings, comparison to common practice, and the experience of BMcD in this area.

- Flat Energy Charges – Work toward gradually limiting availability of the existing flat energy rate for customers, move toward rates that reflect the utility's costs, and provide an efficient rate design. Use of flat energy rate designs should be limited to low load customers.
- Declining Block Rates – Work toward gradually limiting the availability of winter DBR structures for existing and future customers and move toward rates that reflect the utility's cost structure which include both demand rates and TOU rates.
- Inclining Block Rates – Work toward eliminating IBR used for Residential customers in all jurisdictions. GMO and KCP&L should pursue rate designs that better align with a greater range of rate design principles. As with the flat and declining blocks, GMO and KCP&L should move towards rates that better reflect the utility's cost structure which include both demand rates and TOU rates.
- Demand and Energy Rates – Implement a new optional demand rate for Residential customers. Both Residential and Small General Service customers with higher peak demands in GMO should be transitioned to a demand rate over time. Although approaches can vary, Residential demand charges should be set to recover both production and distribution fixed costs to the extent practical.

- TOU Energy Rates – Implement a TOU energy rate to support EV advancements and other beneficial forms of off-peak electric energy usage throughout the year for all classes.
- TOU Energy + Demand Rates – Implement TOU energy and demand rates to support all forms of beneficial off-peak and non-summer energy usage including electric space heating and EV charging. A TOU energy and demand rate option should eventually become the default rate for Residential and Small General Service class customers with higher peak demand and energy use. Although approaches can vary, the demand charges within these rates should be set to recover both production and distribution fixed costs to the extent practical.
- Dynamic Pricing Rates – Do not implement other dynamic rates, such as CPP, VPP, or PTR now. Dynamic rates could be justified at a later date when the value of peak demand avoidance is greater to the utility, and when Company systems are able to meter and bill the rates.
- Real-Time Pricing – Do not implement RTP now. The realizable benefits that are achieved from a RTP rate are not believed to be significant for the Residential and Small General Service classes at this time, however, they could be in the future.

4.3 Time of Use Rates Considered

In accordance with the MPSC Order No. ER-2016-0156[6], BMcD and GMO studied various TOU rates and dynamic rate options for both the Residential and Small General Service customer classes. As part of the Order, the Commission identified several alternatives to explore. This Study considered each rate option in the context of the qualitative evaluation of rate options completed and detailed in the previous section, to identify the rate design options that best aligned with GMO's criteria. From that evaluation, the following rates were identified for consideration.

Table 4-2 presents the Residential rate options evaluated in the Study, the rates that are recommended for future implementation, and those that were designed and analyzed in the Study. As presented, dynamic pricing rates were considered, but not designed or analyzed in this Study. Specific TOU rates' applicability to EV charging were examined, however, end use rates specifically for Residential customers with EV were not designed or analyzed in this Study.

Table 4-3 presents the Small General Service rate options evaluated in the Study, the rate options that were recommended for future implementation, and those that were designed in the Study for both the existing Small General Service without Demand (SGS) and Small General Service with Demand (SDS)

[6] Missouri Public Service Commission Order No. ER-2016-0156

customer classes. As presented, dynamic pricing rates were considered, but not designed or analyzed in this Study.

Table 4-2: GMO TOU Rate Study Residential Rate Options

Residential TOU Rate Options	Status	Evaluated	Recommended	Recommended Availablity	Designed	Analyzed	Note
General Use	Existing	Yes	Yes	Standard Offer	Yes	Yes	Optional for all customers. Minimize availability to low use customers.
Space Heat	Existing	Yes	Yes	Frozen	Yes	Yes	Minimize and eventually limit SH availability over time.
Demand Rate	New	Yes	Yes	Optional	Yes	Yes	Optional for all customers. Marketed to SH customers.
TOU Energy Rate	New	Yes	Yes	Optional	Yes	Yes	Optional for all customers. Marketed to EV. Minimize availability.
TOU Energy + Demand Rate	New	Yes	Yes	Optional	Yes	Yes	Optional for all customers. Marketed to customers with EV and SH.
TOU - EV Single Meter	New	Yes	No	No	No	Yes	Customers will use a TOU rate. End use rates not available.
TOU - EV Separate Meter	New	Yes	No	No	No	Yes	Customers will use a TOU rate. Submetered EV not available.
Critical Peak Pricing	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.
Peak Time Rebate	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.
Real Time Pricing	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.

Table 4-3: GMO TOU Rate Study Small General Service Rate Options

Small General Service TOU Rate Options	Status	Evaluated	Recommended	Recommended Availablity	Designed	Analyzed	Note
SGS	Existing	Yes	Yes	Standard Offer	Yes	Yes	Default under 25 kW. Optional for all. Minimize availability.
SDS	Existing	Yes	Yes	Standard Offer	Yes	Yes	Default over 25 kW. Optional for all.
SGS TOU	New	Yes	Yes	Optional	Yes	Yes	Optional for all. Minimize availability over time.
SDS TOU	New	Yes	Yes	Optional	Yes	Yes	Optional for all.
TOU - EV Single Meter	New	Yes	No	No	No	Yes	Customers will use a TOU rate. End use rates not available.
TOU - EV Separate Meter	New	Yes	No	No	No	Yes	Customers will use a TOU rate. Submetered EV not available.
Critical Peak Pricing	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.
Peak Time Rebate	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.
Real Time Pricing	New	Yes	No	No	No	No	Metering and billing systems not technically capable at this time.

5.0 RATE IMPLEMENTATION PLAN

5.1 Conceptual Rate Designs and Rate Transition Plan

GMO and KCP&L intend to offer rates that support their long-term rate design and business objectives. These rates may reflect changes from existing rates, and where practical, should be offered as optional rates initially, while existing rates may be phased out gradually. This makes way for new rates to be marketed and implemented, initially through a pilot program, for existing and future customers. This may include freezing and then eliminating rates or otherwise limiting rate availability. The timing of new rate implementations will vary based on GMO and KCP&L's meter deployment, regulatory filings, IT capabilities, and other external considerations such as statutory limitations around net metering. The basic components of the recommended long term GMO and KCP&L rate transition plan are derived from interviews with internal stakeholders and working groups, and is provided in Table 5-1 and Table 5-2. For the purposes of this Study four planning periods were established:

- Current – The existing rate design configuration and rate options available for each jurisdiction.
- Step One (1) – Represents the actions to consider for the next general rate proceeding to establish a pilot study for GMO. The optional rates should be marketed to all Residential customers through a small rollout and initially made available to a limited number of GMO's Residential GU and SH customers.
- Step Two (2) – Represents the actions to consider in a following general rate proceedings for GMO, taking into consideration results and analysis from the pilot study and verifying the appropriateness and feasibility of proceeding to Step 3.
- Step Three (3) – Represents the actions to consider in a subsequent general rate proceeding, after the successful deployment of the rates in Step 2, and after all internal system implementations are completed and stabilized.

The plans presented are provided to outline the transition expected to implement the new rate designs and to support that the rate designs are achievable. These conceptual rate designs and transition plans will serve as only <u>one input</u> into the many considerations that must be evaluated in the design of new rates for the GMO Residential and Small General Service classes. Within GMO, and all KCP&L jurisdictions, there are specific regulatory issues, customer characteristics, and rate design challenges that will need to be addressed before a final proposal may be offered as part of general rate proceeding.

The basic tenants of the long-term Residential rate transition plan for GMO, as developed by the internal stakeholders and working groups, is provided in Table 5-1. This Study provides for the development and analysis of (1) a Demand Rate, (2) a TOU Energy Rate, and (3) a TOU Energy and Demand Rate.

The basic tenants of the long-term Small General Service rate transition plan for GMO, as developed by the internal stakeholders and working groups, is provided in Table 5-2. This Study provides for the development and analysis of a (1) Small General Service TOU Energy (SGS TOU) Rate and (2) a Small General Service Demand TOU Rate (SDS TOU).

Table 5-1: GMO Residential Rate Transition Plan

Rate Option	Current	Step 1	Step 2 *Pending Pilot Results*	Step 3 *Pending Pilot Results*	Notes
General Use Rate	Available	Available	Available and Cap	Available and Cap	Step 2 - Optional for all customers under a threshold. Step 2 - Cap rate to users under a threshold (<30,000 kWh/year, 25 kW cap). Sept 3 - Reduce cap to smaller usage customers (<9,000 kWh/year, 7.5 kW cap).
Electric Space Heating Rate	Available	Available	Freeze	Unavailable	Step 2 - Freeze SH rate short term. Step 2 - Give all customers option for Demand Rate. Step 3 - Eliminate SH class long term.
Optional Demand Rate (Optimal Rate for Space Heating)	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited number of customers. Step 2 - Optional for all customers. Step 2 - Demand Rate offered to new SH customers (revenue neutral). Step 3 - Move all existing SH customers to this rate long term.
Optional TOU Energy Rate (Optimal Rate for Electric Vehicle)	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited number of customers. Step 2 - TOU Energy marketed to EV customers. Step 2 - Cap rate to users under a threshold (<30,000 kWh/year, 25 kW cap). Step 3 - Reduce cap to smaller usage customers (<9,000 kWh/year, 7.5 kW cap).
Optional TOU Energy and Demand Rate (Optimal Rate for Space Heating and Electric	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited amount of customers. Step 2 - Optional for all customers. Step 2 - TOU Energy and Demand Rate marketed to EV + SH customers. Step 3 - Offer as the default TOU rate for all new customers.

[1] All existing and future rates will have seasonality.
[2] Steps 1, 2, and 3 will depend on regulatory support and technical capabilities in each jurisdiction.
[3] Step 1 (Pilot Study) results will validate and refine future steps in each utility jurisdiction.
[4] New demand + energy rate plan is revenue neutral to electric space heating customers and general use customers.
[5] These caps were selected as a reasonable initial design as they are similar to those used within the GMO SGS class to distinguish the transition between non-demand and demand rates. The 25kW limit also has relevance within the distribution network where the 25kW size is perceived to match the common size for distribution transformation for these customers. The additional terms (9,000 kWh and 7.5kW) were established to support further reduction of the limits and were derived from a review of load factors for Residential customers.

Table 5-2: GMO Small General Service Rate Transition Plan

Rate Option	Current	Step 1	Step 2 ***Pending Pilot Results***	Step 3 ***Pending Pilot Results***	Notes
Small General Service Rate (SGS)	Available	Available	Available	Available	Step 2 - Cap rate to users under a threshold (<30,000 kWh/year, 25 kW cap). Step 3 - Reduce cap to smaller usage customers (<9,000 kWh/year, 7.5 kW cap).
Small General Service Demand Rate (SDS)	Available	Available	Available	Available	Step 3 - Eliminate minimum facilities demand provision.
Optional Small General Service TOU Rate (SGS TOU)	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited number of customers. Step 2 - TOU Energy marketed to all SGS customers. Step 2 - Cap rate to users under a threshold (<30,000 kWh/year, 25 kW cap). Step 3 - Reduce cap to smaller usage customers (<9,000 kWh/year, 7.5 kW cap).
Optional Small General Service Demand TOU Rate (SDS TOU)	Unavailable	Available (Pilot)	Available	Available	Step 1 - Optional for a limited number of customers. Step 2 - TOU Energy + Demand marketed to all SDS customers. Step 3 - Eliminate minimum facilities demand provision.

[1] All existing and future rates will have seasonality.
[2] Steps 1, 2, and 3 will depend on regulatory support and technical capabilities.
[3] Step 1 (Pilot Study) results will validate and refine future steps in each utility jurisdiction.
[4] SGS TOU and SDS TOU availability to existing and new customers will depend on meter deployment.
[5] These caps were selected as a reasonable initial design as the 25 kW is currently used within the GMO SGS class to distinguish the transition between non-demand and demand rates. The 25kW limit also has relevance within the distribution network where the 25kW size is perceived to match the common size for distribution transformation for these customers. The additional terms (9,000 kWh and 7.5kW) were established to support further reduction of the limits and were derived to maintain consistentency with the Residential class.

6.0 RATE DESIGN APPROACH

The development and design of rates for the Residential and Small General Service classes is based upon consideration of Company goals, application of good rate making principles, consideration of the qualitative ratings, comparison to common practice, and the experience of BMcD in this area. Further, the designs were evaluated through TOU load analysis and CCOS analysis. Each of the optional rates were designed to be revenue neutral to the existing rates in each class, reflect the utility's CCOS by season and time-period, and to meet GMO and KCP&L's rate design objectives described in this report and the KCP&L Rate Strategy Report. The approach to designing the new rates for Residential and Small General Service classes identified in the rate transition plan included the following tasks which are described in more detail in subsequent sections of this report:

- Utility Rate Peer Review – Collected and summarized utility rate tariffs that include optional time of use rates, demand rates, and time of use rates with demand charges. The utility rate peer review provided valuable insight into rate design trends for the rates being considered.
- Load Research - Collected calendar year 2015 hourly load research profiles and billing demand data for each Residential and Small General Service customer class and calibrated load research profiles to match annual and seasonal average energy usages by class.
- Load Analysis - Assessed system and customer class seasonal load profiles to determine appropriate time of use periods for each customer class. Selected seasonal time of use periods for subsequent TOU rate design modeling. The time of use periods selected are based on the analysis in Section 8 of this report.
- Cost of Service Analysis - The GMO class cost of service seasonal monthly unit cost per customer for production, energy, transmission, distribution, and customer costs served as the basis for cost based demand rates and TOU energy rates. The seasonal class cost of service by cost component is summarized in Section 9 of this report.
- Utility Cost and Rate Recovery Method Selection - For each rate option identified in the rate transition plan, determined how each utility cost should be recovered from utility rates. The determination of which rate recovery method to use for each cost component is outlined in Section 9 of this report.
- Energy Cost Rate Recovery Method - For costs to be recovered on an energy basis, seasonal class cost of service components were allocated across the average class energy use profile TOU periods to develop rate components for each cost.

- Demand Cost Rate Recovery Method - For costs to be recovered on a monthly demand basis, seasonal class cost of service components were allocated across the billing demand determinants derived.
- Existing Rate Revenue Model Development - Developed hourly rate revenue models to calculate typical bills at existing rates for each load research set profile within each rate class. The sample set revenues were scaled to the system level based on number of customers.
- New Rate Revenue Model Development - Developed hourly rate revenue models to calculate bills at new rates for each load research profile within each class. The sample set was scaled to the system level based on the number of customers.
- Rate Calibration - Calibrated rate options to generate revenue neutral bills for each rate, assuming that 100 percent of all customers in the sample set for each rate class switch to the new rate option. This included adjusting either the on-peak demand rate or volumetric energy rate to generate total revenues by sample set that matched the revenues generated from existing rates.
- Industry Benchmarking and Adjustment – Reviewed resultant rates and adjusted structures to align with other utility industry demand rate and time of use rate design practices.
- Revenue and Bill Analysis – All new rate options are assumed to be offered on an opt-in basis. Each load research profile is tested to determine the potential lost revenue resulting from customers switching to new rates. The resulting lost revenue from offering new optional rates is estimated, but is not assumed to be recovered in the rates and should be recovered in a recovery mechanism established in a rate case filing . This analysis is provided in Section 11 of this report.
- Demand Response Analysis – All new rate options are expected to result in some level of demand response (DR) for those customers that select the rate. In additional to the lost revenues from switching, each load research profile was modified to reflect load shifting and response to determine the potential lost revenue resulting from customers switching and DR. This is discussed in Section 12 of this report.

7.0 UTILITY RATE DESIGN PEER REVIEW

As part of this Study, data was gathered from other utilities that are implementing Residential time of use rates and demand rates. This peer review was conducted to identify what rate designs other utilities are implementing and serve as an input into the potential rate structure options developed and refined within this Study.

Table 7-1 provides a summary of Residential TOU rates offered by utilities across the United States. Among these utilities, nearly all the TOU rates are offered on an optional basis and many are coupled with a demand charge. Several of the key characteristics from this peer review are provided below.

- Nearly all the TOU rates listed are voluntary, which is the most common method of implementation.
- Many utilities offer both TOU rate pricing, as well as, TOU energy rates and demand rates.
- Some utilities, like Oklahoma Gas & Electric, have TOU only in the summer with declining block rates in the winter.
- Most TOU rates have on-peak periods starting in the afternoon starting between 2 pm and 5 pm.
- Most of the TOU rates listed have on-peak time periods lasting anywhere from 4 to 6 hours.
- Many TOU rates have two periods while some have implemented three period TOU rates.
- Most of the Summer On-Peak to Off/Super-Off peak price differentials is modest (multiples of 2-4).
- Generally, the shorter on-peak period the higher the price difference from on and off-peak prices.

Table 7-2 provides a summary of Residential demand rates offered by utilities across the United States. Among these utilities, nearly all of them are offered on an optional basis, however, several have recently implemented mandatory demand charges for all Residential customers. Several of the key characteristics from this peer review are provided below.

- The majority use 15-minute demand periods with 60-minute demand periods being the next, most prevalent.
- Basing the rate on the system coincident peak (CP) demand time period is more prevalent than using the non-coincident peak (NCP) demand.
- Most demand charges are based on current month only. Very few use any sort of historical demand ratchet, where they do, it is typically used to set a minimum demand threshold or facilities charge.

- Most of the on-peak periods are either 4-5 hours or considerably longer 8-12 hours.
- It is common to use different winter/summer on-peak and off-peak periods.
- Most vary the charge by season, but a significant number use the same value year-round. When the number is the same year-round, it is typically a lower charge.
- Several newer demand rates distinguish between distribution and generation demand charges. Some appear to include both demand and generation costs in their demand charges, while others may not. Some use monthly NCP for distribution while CP is used for generation.

Table 7-1: Utilities with Time of Use Rates

Utility	Utility Type	State	Res. Cust. Served	Rate ID	Fixed Charge ($/mo)	Demand Charge ($/kW-Month) Summer	Demand Charge ($/kW-Month) Winter	Measured Demand Coincidence	Min Demand	Facility Demand	Demand Interval	Summer On-Peak Period	Winter On-Peak Period	Energy Structure	Energy Charge On-Peak Summer	Energy Charge Off-Peak Summer	Energy Charge Super Off-Peak	Energy Charge On-Peak Winter	Energy Charge Off-Peak Winter	Energy Charge Super Off-Peak	Res Segment	Mandatory or Voluntary	Notes
Alabama Power	IOU	AL	1,241,998	RTA	14.50	1.50	1.50	NCP	none	none	15 min	1-7p	5-9am	TOU	$0.2552	$0.0552		$0.0752	$0.0552		Any	Voluntary	Flat in Off Season
Albemarle Electric Membership Corp	COOP	NC	11,521	RE-TOD	27.00	13.50	13.50	SCP	none	$2.25 NCP	15 min	2-7pm	6-10am	TOU	$0.2760	$0.0552		$0.2760	$0.0552		All	Voluntary	3ph has $54 Service Chg
Alliant Energy	IOU	WI	950,000	RG-5	15.00							11a-7p	5p-9p	TOU	$0.1790	$0.1366	$0.0740	$0.1790	$0.1366	$0.0740	All	Voluntary	
Alliant Energy	IOU	WI	950,000	RD-1	15.00	3.00	3.00	NCP	none	NCP ($0)	hour	10a-8p	5p-9p	TOU	$0.1600	$0.1200	$0.0650	$0.1600	$0.1200	$0.0650	<75 kW	Voluntary	3ph has $22.56 Service Chg
Arizona Public Service	IOU	AZ	1,019,292	R-2	12.99	8.40	8.40	SCP*	none	none	60 min	3-8pm	3-8pm	TOU	$0.1316	$0.0780		$0.1102	$0.0780		All	Voluntary	*Limited to 15% Load Factor
Arizona Public Service	IOU	AZ	1,019,292	R-3	12.99	17.44	12.24	SCP*	none	none	60 min	3-8pm	3-8pm	TOU	$0.0869	$0.0523		$0.0638	$0.0523		All	Voluntary	*Limited to 15% Load Factor
Arizona Public Service	IOU	AZ	1,019,292	R-Tech	12.99	20.25*	14.25*	SCP*	none	none	60 min	3-8pm	3-8pm	TOU	$0.0575	$0.0475		$0.0475	$0.0475		Tech	Requires Tech Items	Winter Off-Peak >5kW $6.5/kW
Arizona Public Service	IOU	AZ	1,019,292	TOU-E	12.99									TOU	$0.2431	$0.1087		$0.2307	$0.1087	$0.0320		Voluntary	
City of Glasgow	Muni	KY	5,315	RS	29.16	11.33	10.37	CPHr*	none	none	15 Min	1-7pm	4-10am	TOU	$0.0685	$0.0448		$0.0576	$0.0468		All	Mandatory	* Monthly Peak Hr. Three 4-month Seasons
Dakota Electric Association	COOP	MN	94,924	Sch 53	12.00							4p-11p	11p-4p	TOU	$0.1880	$0.0940		$0.1740	$0.0940			Voluntary	
Dominion	IOU	VA	2,105,500	IT	15.55							1p-9p	6-12am 5-9pm	TOU	$0.2359	$0.0558		$0.1959	$0.0507			Voluntary	
Dominion	IOU	VA	2,105,500	1S	12.00	4.07**	2.334**	G&T SCP Dist SCP	none	$1.61* SCP	30 min	11a-10p	7-11am 5-9pm	TOU	$0.0471	$0.0278		$0.0471	$0.0278		All	Voluntary	*Dist Demand **G&T Demand
Dominion	IOU	NC	101,158	1P	16.39	9.67	5.66	SCP	none	none	30 min	1p-9p	6-12am 5-9pm	TOU	$0.1496	$0.0278		$0.1496	$0.0278		All	Voluntary	
Duke Energy Progress	IOU	NC	1,608,151	R-TOUD	14.13	4.97	3.69	SCP	none	none	15 min	10a-9p	6a-1p 4-9pm	TOU	$0.0687	$0.0551		$0.0687	$0.0551		All	Voluntary	3ph has additonal servcie Chg
Duke Energy Progress	IOU	SC	460,178	R-TOUD	11.91	5,25	4.04	SCP	none	none	15 min	10a-9p	6a-1p 4-9pm	TOU	$0.0768	$0.0620		$0.0768	$0.0620		All	Voluntary	3ph has additonal servcie Chg
Georgia Power	IOU	GA	2,072,622	TOU-RD3	10.00	6.64	6.64	NCP	none	none	30 min	2-7pm	none	TOU	$0.0961	$0.0099		$0.0961	$0.0099		All	Voluntary	
Kentucky Utilities Company	IOU	KY	420,219	RTOD-D	12.25	7.87	7.87	G&T SCP Dist NCP	none	$3.44 NCP	15 min	1-5pm	7-11am	TOU	$0.0274	$0.0056		$0.0274	$0.0056		500 Cust	Voluntary	
Lakeland Electric	Muni	FL	101,971	RS STS	9.50							2-8pm	6-10am	TOU	$0.1832	$0.1169	$0.0613	$0.1832	$0.1169	$0.0613	All	Voluntary	
Louisville Gas and Electric	IOU	KY	348,048	RTOD-E	12.25							1p-5p	7a-11a	TOU	$0.2736	$0.0564		$0.2736	$0.0564			Voluntary	
Oklahoma Gas and Electric	IOU	OK	750,000	RTOU	13.00							2-7pm	none	TOU	0.1715	0.029		DBR	DBR			Voluntary	
Public Service Oklahoma	IOU	OK	547,000	RSTOD	20.00							2-7pm		TOU	0.10182	0.02064		DBR	DBR			Voluntary	
Pacific Gas & Electric	IOU	CA	5,400,000	E-6	9.86							1-7PM	5-8PM	TOU	0.35933	0.24406	0.16728	0.18845	0.18845	0.17176	All	Voluntary	Includes inclining block over 100% of baseline use
Salt River Project	Political Subd.	AZ	891,668	E-27 / E-27P	32.44/ 45.44	7.81/ 33.27	3.47/ 9.54	SCP	none	none	30 min	1-8pm	5-9am 5-9pm	TOU	$0.0629	$0.0419		$0.0426	$0.0386		DG only Res Pilot	Mandatory Optional (5k Cust.)	3 Seasons Service Chg. <=200 & >200a 3 +7 >10 Demand Block $
San Diego Gas and Electric	IOU	CA		TOU-DR								4-9pm	4-9pm	TOU	$0.2801	$0.2237	0.18141	$0.2382	$0.2231	0.20221	All	Voluntary / Mandator for DG Customers 2018	Includes inclining block over 130% of baseline use.
Smithfield	Muni	NC	3,386	RS7	17.00	5.93	5.93	SCP	none	none	15 min	2-6 pm	7-9 am	TOU	$0.1002	$0.0537		$0.1002	$0.0537		AC DLC	Voluntary	Winter is defined by Std Time
South Carolina Electric & Gas Co.	IOU	SC	500,000	5	14.00							2-7pm	7-12am	TOU	$0.3155	$0.1048		$0.2839	$0.1048			Voluntary	
South Carolina Electric & Gas Co.	IOU	SC	500,000	E-7	14.00	12.04	8.60	SCP	none	none	15 min	2-7pm	7-12am	TOU	$0.0955	$0.0844		$0.0955	$0.0844		All	Voluntary	
Tri-County Electric	COOP	FL	15,859	Rate 14	25.00							3p-7p	6a-9a	TOU	$0.1550	$0.1070		$0.1550	$0.1070			Voluntary	
Westar Energy	IOU	KS	700,000	TOU	16.50	6.91	2.13	NCP	1 kW	none	30 min	none	none	TOU	0.15231	0.105654	0.067548	0.055528	0.089793		North	Frozen	
Xcel Energy (PSCo)	IOU	CO	1,182,093	RE-TOU	8.75	9.73**	6.81**	)ist NCPG&T SCP	none	3.65NCP*	60 min	2-6pm**	2-6pm**	TOU	0.13814	0.0444		0.0888	0.0444				

Sources:
Appendix of Brattle testimony in the Westar Rate Case
Utility tariffs as of Sept 2017
Updated Sept 2017 by KCP&L and BMcD
Available online at https://www.eenews.net/assets/2017/03/24/document_ew_02.pdf

Table 7-2: Utilities with Demand Rates

Utility	Utility Type	State	Res. Cust. Served	Rate ID	Fixed Charge ($/mo)	Demand Charge ($/kW-Month) Summer	Demand Charge ($/kW-Month) Winter	Measured Demand Coincidence	Min Demand	Facility Demand	Demand Interval	Summer On-Peak Period	Winter On-Peak Period	Energy Structure	Energy Charge On-Peak Summer	Energy Charge Off-Peak Summer	Energy Charge Super Off-Peak	Energy Charge On-Peak Winter	Energy Charge Off-Peak Winter	Energy Charge Super Off-Peak	Res Segment	Mandatory or Voluntary	Notes
Alaska Electric Light and Power	IOU	AK	13,968	Sch 10	11.93	6.98	11.54	NCP	none	none	15 min	none	none	Flat							<20kW, >20kW	Voluntary / Mandatory	Req. for >5,000kWh/mo for 3mo
Black Hills Energy	IOU	SD	54,617	RD	13.00	8.10	8.10	NCP	none	none	15 min	none	none	Flat							>1k kWh/mo	Voluntary	
Black Hills Energy	IOU	SD	54,617	RD-MVO	13.00	8.10*	8.10*	SCP	none	none	15 min	10a-10p	7a-11p	Flat							>1k kWh/mo	Voluntary	*Off Peak >3x on-peak $8.10/kW
Black Hills Energy	IOU	WY	2,153	RD	15.50	8.25	8.25	NCP	none	none	15 min	none	none	Flat							>1k kWh/mo	Voluntary	
Black Hills Energy	IOU	WY	2,153	RD-MVO	15.50	8.25	8.25	SCP	none	none	15 min	10a-10p	7a-11p	Flat							>1k kWh/mo	Voluntary	
Butler Rural Electric	COOP	KS	7,000	RDS-16	29.00	5.10	5.10	SCP	70% SHD	$ > 15KVA*	60 min	3 - 9 pm		Flat							All	Mandatory	75¢/installed KVA above 15 SHD basedn on July-Aug
Carteret-Craven Electric	COOP	NC	35,269	R-TU	30.00	11.95	9.95	SCP	none	none	15 min	2:30-7:30	6-9 am	Flat							All	Voluntary	3ph has $57.30 Service Chg
City of Kinston	Muni	NC	9,776	E95	14.95	9.35	9.35	Peak Coincident	none	none	15 min	1-7pm	7-9 am	Flat							All	Voluntary	3ph has additonal servcie Chg three on-peak seasons
City of Longmont	Muni	CO	34,697	RD	16.60	5.75	5.75	NCP	none	none	15 min	none	none	Flat							>15k kWh	Voluntary	Designed for Electric Heat
Dakota Electric Association	COOP	MN	94,924	Sch 32	12.00	14.70	11.10	NCP	3 kW	none	15 min	none	none	Flat							>5kW Off Pk	Voluntary	
Edgecombe-Martin Cnty EMC	COOP	NC	10,550	Sched C	31.00	8.75	8.00	SCP	none	none	15 min ?	2-8 pm	6-10 am	Flat							All	Voluntary	
Fort Morgan	Muni	CO	5,273	RD	8.17	10.22	10.22	NCP	none	none	Unknown	none	none	Flat							All	Voluntary	
Lakeland Electric	Muni	FL	101,971	RSD	9.50	5.60	5.60	SCP	none	none	30 min	2-8pm	6-10am	Flat							All	Voluntary	
Louisville Gas and Electric	IOU	KY	348,048	RTOD-D	12.25	7.68	7.68	G&T SCP Dist NCP	none	$3.51NCP	15 min	1-5pm	7-11am	Flat							500 Cust	Voluntary	
Mid-Carolina Electric	COOP	SC	55,000		24.40	12.00	12.00	SCP	none	none	60 min	4-7pm	6-9am	Flat							All	Mandatory	
Midwest Energy Inc	COOP	KS	29,951		22.00	6.40	6.40	NCP	80% SAD	none	15 min	none	none	Flat							<25kW >25 kW	Optional Manditory	SAD - Avg. of June - Aug.
Otter Tail Power Company	IOU	MN	47,699	31-241	11.00	6.08	5.11	NCP	100% WND	none	60 min	none	none	Flat									
Otter Tail Power Company	IOU	MN	47,699		16.00*	6.08	5.11	NCP	100% WND	none	60 min	none	none	Flat							H2O Control	Voluntary	100% Prior Winter Demand * Includes fixed facility charge
Otter Tail Power Company	IOU	ND	44,910	RDC	18.38	6.52	2.63	Any time	100% WND	none	60 min	none	none	Flat							H2O Control	Voluntary	100% Prior Winter Demand
Otter Tail Power Company	IOU	SD	8,648		13.00	7.05	5.93	Any time	100% WND	none	60 min	none	none	Flat							H2O Control	Voluntary	100% Prior Winter Demand
Swanton Village Electric Dept.	Muni	VT	3,208	A-D	11.33	9.17	9.17	NCP	85% AMD	none	15 min	none	none	Flat							<1800 kWh/mo >1800 kWh/mo	Voluntary Mandatory	AMD- prior 11 mo
Tri-County Electric	COOP	FL	15,859	RD	23.00	7	7	NCP	none	none	15 min,	none	none	Flat							All	Voluntary	*$1.50 /kVA of 3ph onlly
Vigilante Electric	COOP	MT	7,889	A	23.00	0.50 per KVA	0.50 per KVA	NCP	none	none	Unk	none	none	Flat							>$700/yr	Mandatory	0-15 kW Free
Xcel Energy (PSCo)	IOU	CO	1,182,093	RD-TDR	8.75	9.73**	6.81**	ist NCPG&T SCP	none	3.65NCP*	60 min	2-6pm**	2-6pm**	Flat							DGRes	Manitory for DG Voluntary - Limited	*Dist Demand **G&T Varies by Season
Central Electric Membership Corp	COOP	NC	19,574	Res-1	34.00	8.55	7.50	SCP	none	3.25 OffPk kW	15 min	2-6 pm	6-10 am	No							All	Voluntary	3ph has $61.00 Service Chg

Sources:
Appendix of Brattle testimony in the Westar Rate Case
Utility tariffs as of Sept 2017
Updated Sept 2017 by KCP&L and BMcD
Available online at https://www.eenews.net/assets/2017/03/24/document_ew_02.pdf

8.0 LOAD ANALYSIS AND TIME OF USE PERIODS

GMO has conducted research and investigation to develop and test TOU periods for both the Residential and Small General Service classes. This Study provides a review of the TOU periods to be considered in the development of TOU rates for GMO. KCP&L develops weather normalized hourly system load for GMO, Residential class load profiles, and Small General Service class load profiles. Typical daily load shapes were prepared by season to select and assess the time periods considered for each class for the purposes of the TOU rate design process.

8.1 System Load Analysis

The GMO system has historically been a summer peaking utility, with peaks typically occurring between the weekday hours of 4 pm and 6 pm. Loads typically reduce significantly during the late-night hours as presented in Figure 8-1. During the eight winter months, GMO has an early morning peak and evening peak as presented in Figure 8-2, however, the evening peak is generally higher. The system winter peak is approximately 20 percent lower than the summer season peak demand.

Figure 8-1: GMO System Summer Daily Load Shape

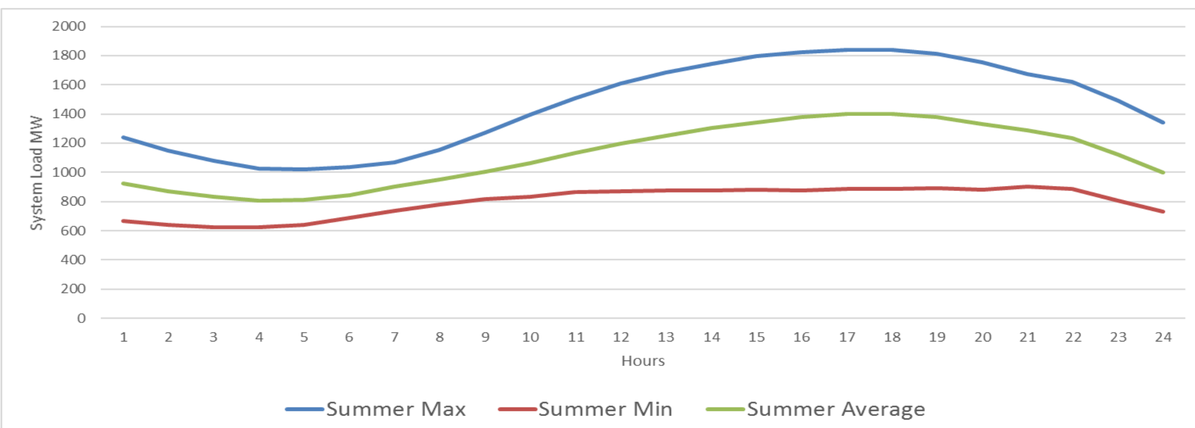
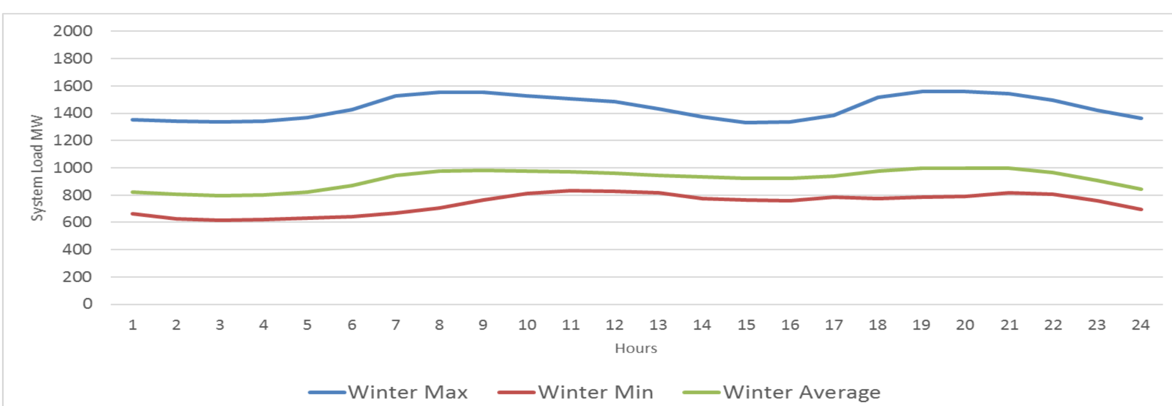


Figure 8-2: GMO System Winter Daily Load Shape



8.2 Residential Load Analysis

As described in the previous section, GMO is a summer peaking utility with the peak typically occurring during the weekday hours of 4 pm and 6 pm. The Residential GU class peak typically occurs later in the evening between 6 pm and 8 pm. Both the Residential GU class load and the GMO system load, reduce significantly between the hours of 12 am and 6 am. Based on the assessment of the Residential GU load shapes and system load shapes, the following periods were selected for the TOU rate design and are graphically presented in Figure 8-3.

- Summer On-Peak: 4:00 pm – 8:00 pm
- Summer Off-Peak: 6:00 am – 4:00 pm; 8:00 pm – 12:00 am
- Summer Super Off-Peak: 12:00 am – 6:00 am

During the eight winter months from October 1st to May 31st, the GMO system load profile is generally lower and flatter, however, both the system and Residential GU class have both an early morning peak and a late evening peak. Like the system load, the evening Residential GU peak load in the winter season is generally higher than the morning peak, however, the morning peak load can occasionally be higher than the evening load in some winter months. Based on an assessment of the Residential GU load shape and the system load shapes, the following periods were selected for the winter TOU rate design and are graphically presented in Figure 8-4.

- Winter On-Peak: 4:00 pm – 8:00 pm
- Winter Off-Peak: 6:00 am – 4:00 pm; 8:00 pm – 12:00 am
- Winter Super Off-Peak: 12:00 am – 6:00 am

The TOU periods identified in this Study may need to be adjusted in the future to address changing customer and system characteristics. GMO should maintain flexibility in its TOU periods and should periodically examine the rates and periods based on the system loads, assets, and costs.

Figure 8-3: GMO Residential GU and System Summer Daily Load Shape and TOU Periods

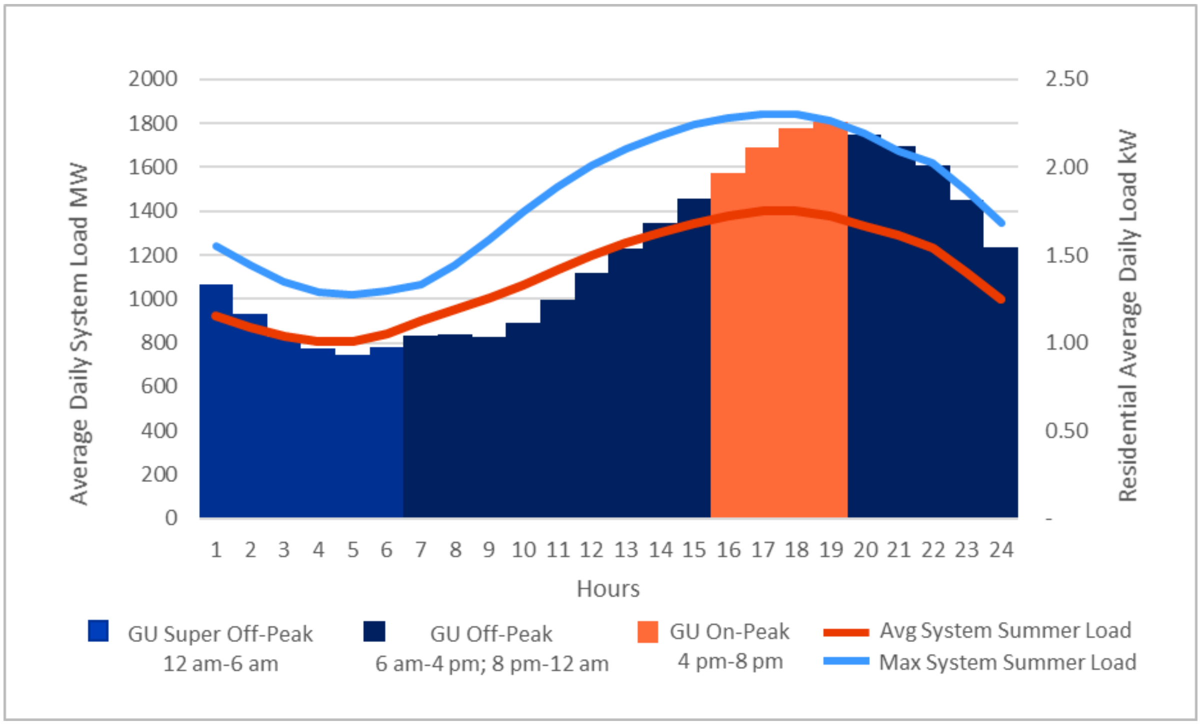
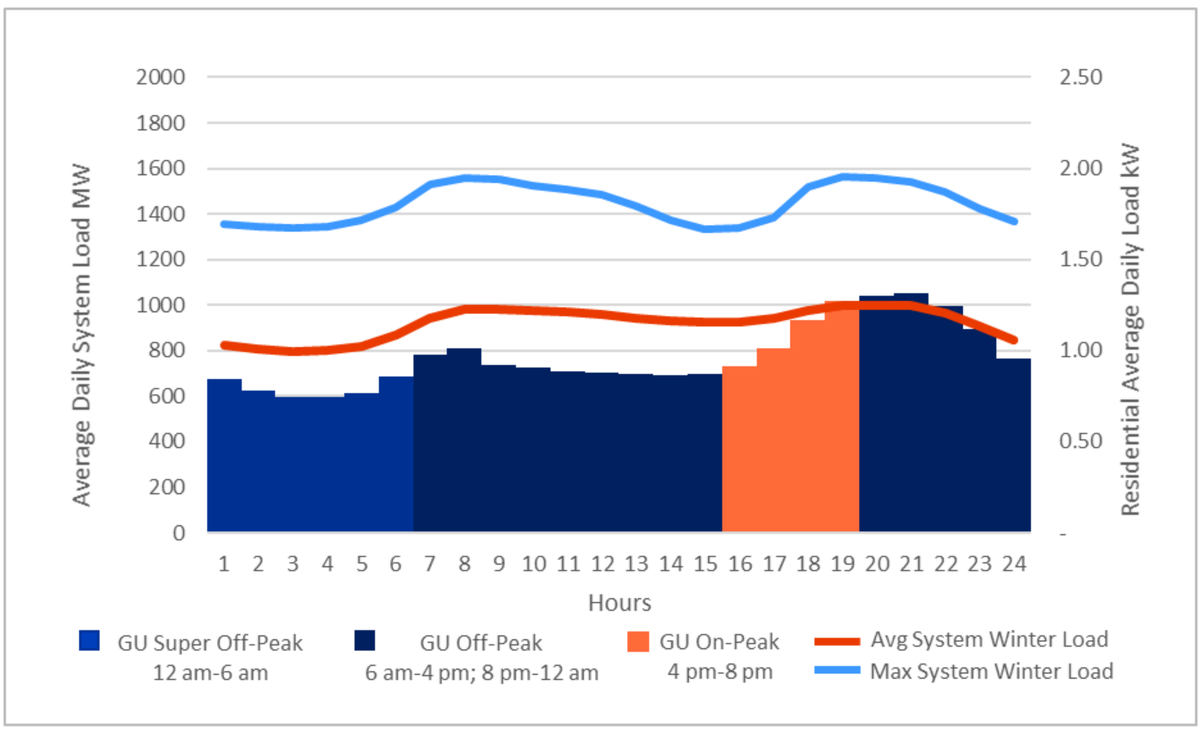


Figure 8-4: GMO Residential GU and System Winter Daily Load Shape and TOU Periods



8.3 Small General Service Load Analysis

As described previously, GMO is a summer peaking utility with the peak typically occurring during the weekday hours of 4 pm and 6 pm. The Small General Service classes typically peak earlier in the day between the hours of 3 pm and 5 pm. Load in the Small General Service classes begins to drop after 6 pm, however, the system load remains relatively high due to other load on the system, such as from the Residential classes. Small General Service load and the GMO system load reduce significantly between the hours of 12 am and 6 am. Based on the assessment of the Small General Service load shapes and system load shapes, the following periods were selected for the TOU rate design and are graphically presented in Figure 8-5 and Figure 8-6.

- Summer On-Peak: 1:00 pm – 6:00 pm
- Summer Off-Peak: 6:00 am – 1:00 pm; 6:00 pm – 12:00 am
- Summer Super Off-Peak: 12:00 am – 6:00 am

During the eight winter months, the GMO system load is generally lower and flatter with both an early morning peak and early evening peak primarily attributed to Residential customers' electric heating loads on the system. Like the summer season, the Small General Service customer classes peak in the mid-afternoon, however, the load is relatively constant between 11 am and 5 pm due to the lower levels of building cooling loads. Based on the assessment of the Small General Service class load shapes and the system load shapes, the following periods were selected for the winter TOU rate design and are graphically presented in Figure 8-7 and Figure 8-8.

- Winter On-Peak: 1:00 pm – 6:00 pm
- Winter Off-Peak: 6:00 am – 1:00 pm; 6:00 pm – 12:00 am
- Winter Super Off-Peak: 12:00 am – 6:00 am

Figure 8-5: GMO SGS Summer Daily Load Shape vs. TOU Periods

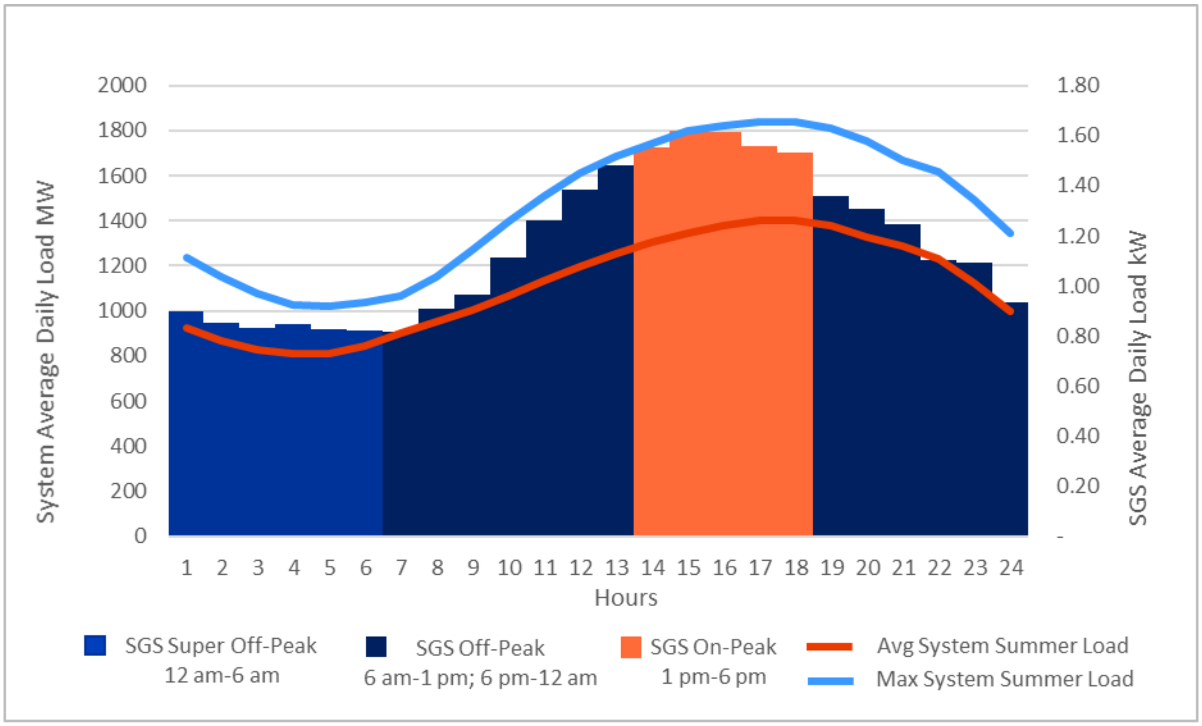


Figure 8-6: GMO SDS Summer Daily Load Shapes vs. TOU Periods

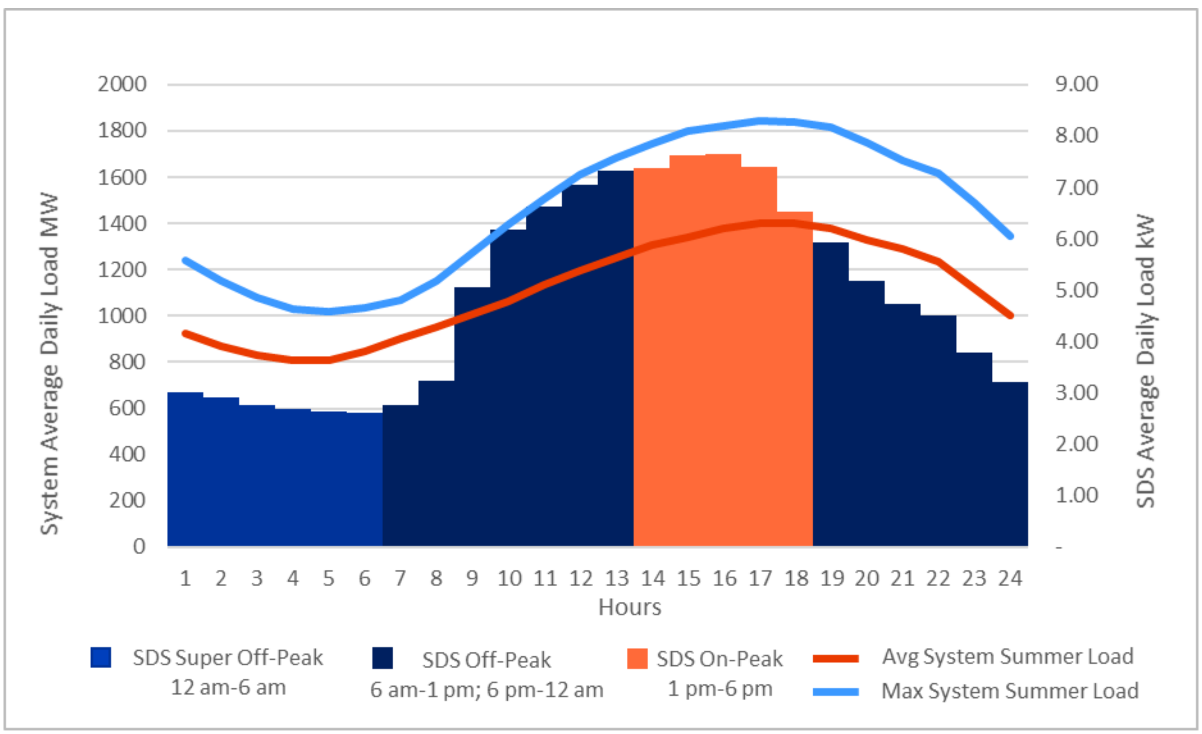


Figure 8-7: GMO SGS Winter Daily Load Shapes vs. TOU Periods

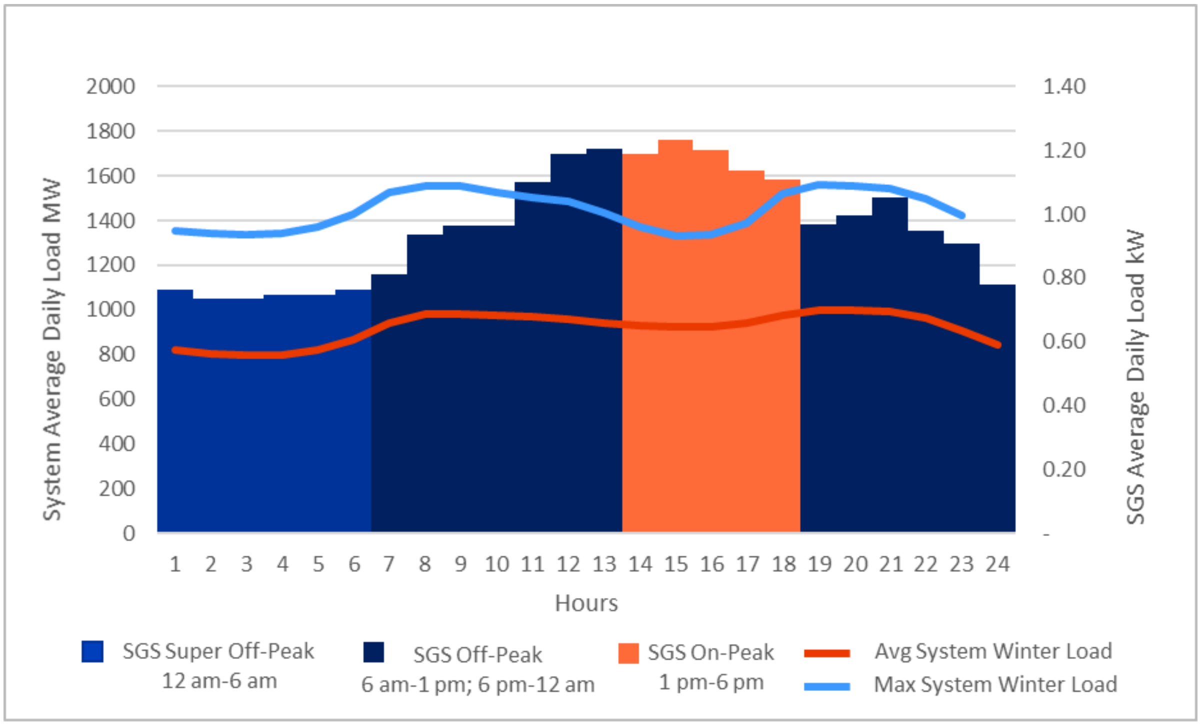
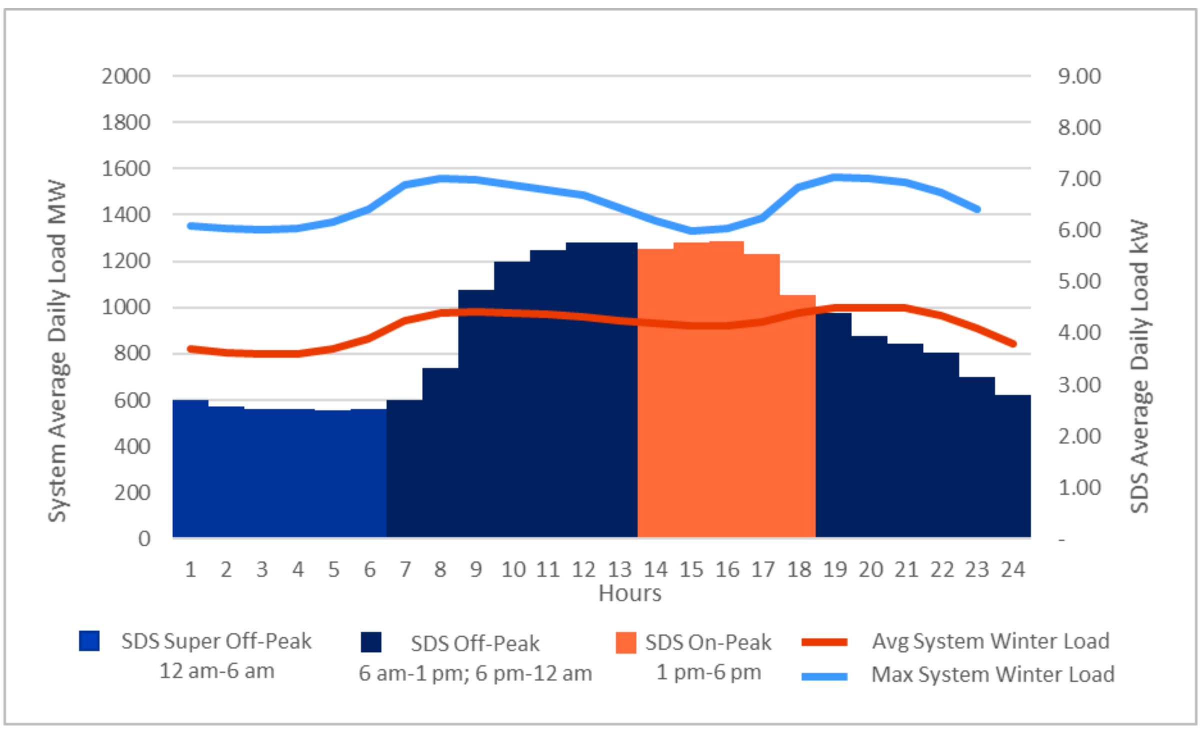


Figure 8-8: GMO SDS Winter Daily Load Shapes vs. TOU Periods



9.0 COST OF SERVICE ANALYSIS

GMO and KCP&L prepare a class cost of service (CCOS) study to support rate design for each of its jurisdictions' rate cases. Following common methods, the CCOS classifies GMO's costs into production, energy, transmission, distribution, and customer costs. These costs are allocated to each customer classification by season such that each cost component of the annual revenue requirement can be identified and used to formulate the basis for subsequent seasonal TOU energy rate design and demand rate design. The GMO 2016 CCOS model[7] filed in the most recent rate case was used to allocate the various components of the seasonal revenue requirement for the TOU rate and demand rate design. It should be noted that this study was offered as part of the consolidation of two rate jurisdictions within GMO. The model was prepared by simply combining two CCOS studies. Although the study is suitable for use in this analysis, it is reasonable to expect variation when future studies are performed using consolidated data and reflect the complete integration of the two, former jurisdictions. The allocation process and rate development associated with the 2016 consolidated study is explained below.

9.1 Cost of Service Based Rate Designs

The conceptual rate transition plan identified several rate design structures that should be developed and implemented. The optional rate structures should be designed to be cost based and reflect industry excepted rate designs for Residential and Small General Service TOU rates and demand rates. Table 7-1 and Table 7-2 summarize how each cost is proposed to be recovered from each rate component for both the Residential and Small General Service optional rates.

Table 9-1: GMO Residential Class Cost Allocations

	Existing General Use Rate					Optional TOU Energy Rate					Optional Demand Rate					Optional TOU Energy and Demand Rate				
	Prod.	Energy	Trans.	Dist. P	Dist. S	Prod.	Energy	Trans.	Dist. P	Dist. S	Prod.	Energy	Trans.	Dist. P	Dist. S	Prod.	Energy	Trans.	Dist. P	Dist. S
Energy	x	x	x	x	x							x	x							
Super Off-Peak						x	x										x			
Off-Peak						x	x		x	x							x			
On-Peak						x	x	x	x	x							x	x		
Demand Charge																				
On-Peak											x			x	x	x			x	x
Max Demand																				
Ratchet NCP																				

[7] Missouri Public Service Commission Case No. ER-2016-0156, Order Approving Stipulations And Agreements, Rejecting Tariffs, Cancelling True-Up Hearing, And Ordering Filing Of Compliance Tariffs, Effective October 8, 2016. The GMO 2016 CCOS model used a 2015 Test Year.

Table 9-2: GMO Small General Service Class Cost Allocations

	Existing SGS Rate					Optional SGS TOU Rate					Existing SDS Rate					Optional SDS TOU Rate				
	Prod.	Energy	Trans.	Dist. P	Dist. S	Prod.	Energy	Trans.	Dist. P	Dist. S	Prod.	Energy	Trans.	Dist. P	Dist. S	Prod.	Energy	Trans.	Dist. P	Dist. S
Energy	x	x	x	x	x						x	x	x							
Super Off-Peak						x	x										x			
Off-Peak						x	x		x	x							x			
On-Peak						x	x	x	x	x							x	x		
Demand Charge																				
On-Peak																x			x	
Max Demand														x						
Ratchet NCP															x					x

9.2 Production Costs

In its last rate case, ER-2016-0156, GMO aggregated all fixed production costs together and allocated those costs to each of its classes by season using the Average and Peak 4 Coincident Peak (4CP) production cost allocation methodology. The production plant, while not specifically identified by resource, is used to meet the base load, the intermediate load, and the peak load of the utility. The total generation portfolio capacity is traditionally sized to meet the on-peak load and hours, however, approximately only one third (1/3) of the capacity is required to support the super off-peak hours, or night time hours, during the year, and approximately two thirds (2/3) is required to serve the off-peak hours. This balance changes over time as resources are retired or built and as customer load shapes change. The average percentage of the total load served during each period is based on the GMO 2015 minimum load, the average off-peak load, and maximum on-peak peak load.[8]

For the Residential TOU Energy Rate and SGS TOU Energy Rate, fixed production costs were allocated over each TOU period such that the super off-peak energy sales recover only base load costs (i.e. 1/3 of production costs), off-peak energy sales recover base and intermediate load costs (i.e. 2/3 of production costs), and on-peak sales recover base, intermediate, and peaking costs (i.e. 100 percent of production costs). The allocated costs, by TOU period, are divided by the energy sales in each TOU period to arrive at the production cost component of the TOU energy charge.

For the Residential Demand Rate, Residential TOU Energy and Demand Rate, and SDS TOU Rate, fixed production costs are proposed to be recovered from a fixed on-peak demand charge. The average monthly production costs by class and season were divided by the monthly on-peak billing demand determinants in the load research data to determine the appropriate demand charge by season. Minor adjustments to the demand charges were made such that the rates were revenue neutral to the existing rates.

[8] The 2015 combined GMO system daily load profile has a minimum annual super off-peak load of 587 MW, an average off-peak load of 1067 MW, and maximum summer on-peak load of 1841 MW.

9.3 Energy Costs

GMO's hourly cost of energy is determined by SPP as part of their pricing models. The energy price, or load aggregate locational marginal price (LMP) is calculated for the "node", or representative point of interconnection with the SPP network. GMO has generation resources that incur variable production costs, and generate revenues and margins; which are included in the GMO CCOS allocated cost of energy by season. However, the GMO hourly cost of energy for its customers is based on the SPP hourly LMP.

For each class and load shape, the load weighted cost of energy was calculated by season and TOU period to arrive at the average cost of energy for the TOU periods specified. The average cost of energy by TOU period and season is based on 2015 hourly load profiles, and 2015 hourly LMPs for the node. As necessary, an adjustment was applied to all sales to address differences in the load weighted 2015 hourly cost of energy and the CCOS allocated cost of energy by class and season.

For the Residential Demand Rate, the seasonal energy costs are proposed to be recovered by flat seasonal energy charges based on the CCOS allocated cost of energy by class and season.

9.4 Transmission Costs

GMO transmission costs are allocated to customers based on the average 12 CP allocation factor, which is the average of each class' share of the monthly peak for a given test year. The 12 CP method allocates cost to all customers based on their proportionate share of using the transmission plant during each month's peak hour throughout the year. As described previously, the monthly system peak demand typically occurs between 4 pm and 6 pm for each month of the year, however, the peak can occasionally occur in the early morning or late evening hours during the winter. Even though GMO may sometimes experience monthly peaks during the morning, SPP will typically peak between 4 pm and 6 pm.

For each TOU rate option transmission costs were allocated to only the on-peak energy sales and hours. Transmission costs not were allocated to the super off-peak or off-peak TOU periods.

For the Residential Demand Rate, the seasonal transmission costs are proposed to be recovered by flat seasonal energy charges based on the CCOS allocated cost of transmission by class and season. The cost of transmission between GU and SH is nearly equal on a seasonal basis.

9.5 Distribution Costs

GMO distribution costs are generally put into three main categories: Primary, Secondary, and Transformation. Each category is allocated to each customer class in alignment with the causation of the costs. The primary distribution system is sized to meet the maximum peak incurred by the customers being served by that substation and primary service line, which may or may not align with the system peak. Because of this, the primary costs are incurred based on the non-coincident peak (NCP) demand and are thus allocated the same way, however, primary distribution facilities across the system are typically sized to serve load from 7 am to 12 pm, or for GMO, the off-peak and on-peak loads. Distribution Secondary and Transformation costs are also allocated on a NCP basis however these local facilities are more dependent on the customer's max demand at any time and are best recovered through a facilities demand charge when possible.

For Residential TOU Energy and SGS TOU Energy rate options, rates are designed such that distribution costs are recovered over off-peak and on-peak hours only. Super off-peak sales occurring from 6 am to 12 am do not recover any distribution costs.

For the Residential Demand Rate and Residential TOU Energy and Demand rate options, the demand charge is set to recover all distribution costs including the primary, secondary, and transformation costs in a single monthly demand charge. The demand charge, for the purposes of this Study, is assumed to be an on-peak demand charge, however, a NCP demand charge would generate a similar level of revenue.

For the SDS TOU rate option, a maximum monthly seasonal demand charge is set to recover the primary distribution system costs, similar to what exists today for the SDS class. A maximum monthly facilities demand charge ratchet is also included and is set to recover the CCOS allocated facilities costs, which include distribution secondary costs and transformation costs.

9.6 Customer Costs

Customer costs are not driven by the time when customers use energy, but rather how many customers are served and what type of service is provided. Historically, GMO has required more sophisticated metering and billing processes for customers desiring to use TOU rates. This required GMO to have a higher customer charge for TOU customers. GMO and KCP&L are installing new meters for all customers that will be capable of measuring energy usage on a TOU basis and bill it without any incremental costs. [9] Customer costs related to metering between non-TOU and TOU customers will be the same, allowing the customer charge to be the same for future TOU rates.

9.7 Cost of Summary

[9] This assumes that the Company will be at 100% implementation of the Automated Metering Infrastructure (AMI), which may not be the case when Time of Use rates are offered to customers. Current plans estimate that the Company may not be 100% AMI until 2020.

The TOU energy cost development and demand cost for each rate options by season is presented in the following tables. The costs components served as the basis for the rate design for the rates considered in the rate transition plan. The development of the rates to recover production cost, energy cost, transmission cost, and distribution cost are provided in the tables for each rate as described in the previous sections.

Table 9-3: GMO Residential Seasonal Cost of Service and TOU Energy Rates

ENERGY		**Winter**			**Summer**	
Energy Cost	**$/customer/month**	$19		**$/customer/month**	$30	
		Winter Usage (kWh/mon.)			**Winter Usage (kWh/mon.)**	
Super Off-Peak		143			195	
Off-Peak		473			756	
On-Peak		97			191	
		Average Cost ($/kWh)	**Total Rate ($/kWh)**		**Average Cost ($/kWh)**	**Total Rate ($/kWh)**
Super Off-Peak		$0.0186	$0.0186		$0.0172	$0.0172
Off-Peak		$0.0254	$0.0254		$0.0308	$0.0308
On-Peak		$0.0273	$0.0273		$0.0380	$0.0380
TRANSMISSION		**Winter**			**Summer**	
Transmission Cost	**$/customer/month**	$7		**$/customer/month**	$12	
	Cost Allocation (%)	**Cost Allocation ($)**		**Cost Allocation (%)**	**Cost Allocation ($)**	
Super Off-Peak	0%	$0		0%	$0	
Off-Peak	0%	$0		0%	$0	
On-Peak	100%	$7		100%	$12	
	Winter Usage (kWh/mon.)	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**	**Summer Usage (kWh/mon.)**	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**
Super Off-Peak	713	$0.0000	$0.0000	1142	$0.0000	$0.0000
Off-Peak	616	$0.0000	$0.0000	951	$0.0000	$0.0000
On-Peak	97	$0.0730	$0.0730	191	$0.0634	$0.0634
PRODUCTION		**Winter**			**Summer**	
Production Cost	**$/customer/month**	$14		**$/customer/month**	$72	
	Cost Allocation (%)	**Cost Allocation ($)**		**Cost Allocation (%)**	**Cost Allocation ($)**	
Super Off-Peak	33%	$4		33%	$24	
Off-Peak	33%	$4		33%	$24	
On-Peak	33%	$4		33%	$24	
	Winter Usage (kWh/mon.)	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**	**Summer Usage (kWh/mon.)**	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**
Super Off-Peak	713	$0.0063	$0.0063	1142	$0.0208	$0.0208
Off-Peak	616	$0.0073	$0.0136	951	$0.0250	$0.0458
On-Peak	97	$0.0461	$0.0597	191	$0.1242	$0.1699
DISTRIBUTION		**Winter**			**Summer**	
Distribution Cost	**$/customer/month**	$27		**$/customer/month**	$21	
	Cost Allocation (%)	**Cost Allocation ($)**		**Cost Allocation (%)**	**Cost Allocation ($)**	
Super Off-Peak	0%	$0		0%	$0	
Off-Peak	100%	$27		100%	$21	
On-Peak	0%	$0		0%	$0	
	Winter Usage (kWh/mon.)	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**	**Summer Usage (kWh/mon.)**	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**
Super Off-Peak	713	$0.0000	$0.0000	1142	$0.0000	$0.0000
Off-Peak	616	$0.0433	$0.0433	951	$0.0226	$0.0226
On-Peak	97	$0.0000	$0.0433	191	$0.0000	$0.0226
Revenue Neutral Adder			$ 0.0077			$ 0.0077
Super Off-Peak Energy Charge			**$0.0326**			**$0.0457**
Off-Peak Energy Charge			**$0.0899**			**$0.1069**
On-Peak Energy Charge			**$0.2109**			**$0.3017**

[1] All monthly costs by component are from the 2016 GMO CCOS model (2015 test year) for the Residential GU class.

[2] Energy sales by TOU period are based on the 2015 GMO Residential GU class load profile.

[3] A revenue neutral adder was incorporated to the energy charges to generate revenue neutral bills by season.

Table 9-4: GMO SGS Seasonal Cost of Service and SGS TOU Rate Development

ENERGY		**Winter**			**Summer**	
Energy Cost	**$/customer/month**	$17		**$/customer/month**	$19	
		Winter Usage (kWh/mon.)			**Winter Usage (kWh/mon.)**	
Super Off-Peak		134			155	
Off-Peak		397			490	
On-Peak		123			171	
		Average Cost ($/kWh)	**Total Rate ($/kWh)**		**Average Cost ($/kWh)**	**Total Rate ($/kWh)**
Super Off-Peak		$0.0169	$0.0169		$0.0152	$0.0152
Off-Peak		$0.0238	$0.0238		$0.0256	$0.0256
On-Peak		$0.0237	$0.0237		$0.0368	$0.0368
TRANSMISSION		**Winter**			**Summer**	
Transmission Cost	**$/customer/month**	$5		**$/customer/month**	$8	
	Cost Allocation (%)	**Cost Allocation ($)**		**Cost Allocation (%)**	**Cost Allocation ($)**	
Super Off-Peak	0%	$0		0%	$0	
Off-Peak	0%	$0		0%	$0	
On-Peak	100%	$5		100%	$8	
	Winter Usage (kWh/mon.)	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**	**Summer Usage (kWh/mon.)**	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**
Super Off-Peak	655	$0.0000	$0.0000	815	$0.0000	$0.0000
Off-Peak	532	$0.0000	$0.0000	644	$0.0000	$0.0000
On-Peak	123	$0.0431	$0.0431	171	$0.0448	$0.0448
PRODUCTION		**Winter**			**Summer**	
Production Cost	**$/customer/month**	$12		**$/customer/month**	$52	
	Cost Allocation (%)	**Cost Allocation ($)**		**Cost Allocation (%)**	**Cost Allocation ($)**	
Super Off-Peak	33%	$4		33%	$17	
Off-Peak	33%	$4		33%	$17	
On-Peak	33%	$4		33%	$17	
	Winter Usage (kWh/mon.)	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**	**Summer Usage (kWh/mon.)**	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**
Super Off-Peak	655	$0.0060	$0.0060	815	$0.0212	$0.0212
Off-Peak	532	$0.0073	$0.0133	644	$0.0268	$0.0480
On-Peak	123	$0.0316	$0.0449	171	$0.1011	$0.1491
DISTRIBUTION		**Winter**			**Summer**	
Distribution Cost	**$/customer/month**	$11		**$/customer/month**	$14	
	Cost Allocation (%)	**Cost Allocation ($)**		**Cost Allocation (%)**	**Cost Allocation ($)**	
Super Off-Peak	0%	$0		0%	$0	
Off-Peak	100%	$11		100%	$14	
On-Peak	0%	$0		0%	$0	
	Winter Usage (kWh/mon.)	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**	**Summer Usage (kWh/mon.)**	**Cost Allocation ($/kWh)**	**Total Rate ($/kWh)**
Super Off-Peak	655	$0.0000	$0.0000	815	$0.0000	$0.0000
Off-Peak	532	$0.0202	$0.0202	644	$0.0223	$0.0223
On-Peak	123	$0.0000	$0.0202	171	$0.0000	$0.0223
Revenue Neutral Adder			$ 0.0250			$ 0.0250
			Total Rate ($/kWh)			**Total Rate ($/kWh)**
Super Off-Peak			$ 0.0479			$ 0.0614
Off-Peak			$ 0.0823			$ 0.1209
On-Peak			$ 0.1570			$ 0.2779

[1] All monthly costs by component are from the 2016 GMO CCOS model (2015 test year) for the SGS class.

[2] Energy sales by TOU period are based on an average 2015 GMO SGS class average load profile.

[3] A revenue neutral adder was incorporated to the energy charges to generate revenue neutral bills by season.

Table 9-5: GMO Residential Seasonal Cost of Service and TOU Energy and Demand Rates

ENERGY		Winter			Summer	
Energy Cost	$/customer/month	$19		$/customer/month	$30	
		Winter Usage (kWh/mon.)			Winter Usage (kWh/mon.)	
Super Off-Peak		143			195	
Off-Peak		473			756	
On-Peak		97			191	
		Average Cost ($/kWh)	Total Rate ($/kWh)		Average Cost ($/kWh)	Total Rate ($/kWh)
Super Off-Peak		$0.0186	$0.0186		$0.0172	$0.0172
Off-Peak		$0.0254	$0.0254		$0.0308	$0.0308
On-Peak		$0.0273	$0.0273		$0.0380	$0.0380
TRANSMISSION		Winter			Summer	
Transmission Cost	$/customer/month	$7		$/customer/month	$12	
	Cost Allocation (%)	Cost Allocation ($)		Cost Allocation (%)	Cost Allocation ($)	
Super Off-Peak	0%	$0		0%	$0	
Off-Peak	0%	$0		0%	$0	
On-Peak	100%	$7		100%	$12	
	Winter Usage (kWh/mon.)	Cost Allocation ($/kWh)	Total Rate ($/kWh)	Summer Usage (kWh/mon.)	Cost Allocation ($/kWh)	Total Rate ($/kWh)
Super Off-Peak	713	$0.0000	$0.0000	1142	$0.0000	$0.0000
Off-Peak	616	$0.0000	$0.0000	951	$0.0000	$0.0000
On-Peak	97	$0.0730	$0.0730	191	$0.0634	$0.0634
Revenue Neutral Adder			$ -			$ -
			Total Rate ($/kWh)			Total Rate ($/kWh)
Super Off-Peak Energy Charge			$ 0.0186			$ 0.0172
Off-Peak Energy Charge			$ 0.0254			$ 0.0308
On-Peak Energy Charge			$ 0.1003			$ 0.1015
PRODUCTION		Winter			Summer	
Production Cost	$/kWh	$0.0164		$/kWh	$0.0624	
Production Cost	$/customer/month	$16		$/customer/month	$73	
Average Billing Demand	kW	6.08		kW	7.14	
Production Demand Cost	$/kW-month	$2.64		$/kW-month	$10.22	
DISTRIBUTION		Winter			Summer	
Production Cost	$/kWh	$0.0285		$/kWh	$0.0208	
Distribution Cost	$/customer/month	$28		$/customer/month	$24	
Average Billing Demand	kW	6.08		kW	7.14	
Distribution Demand Cost	$/kW-month	$4.58		$/kW-month	$3.40	
Revenue Neutral Adder	$/kW-month	$0.53			$1.63	
Demand Charge	$/kW-month	$7.75			$15.25	

[1] All monthly costs by component are from the 2016 GMO CCOS model (2015 test year) for the Residential class.

[2] Energy sales by TOU period are based on the 2015 GMO Residential GU class load profile.

[3] A revenue neutral adder was incorporated to the demand charges to generate revenue neutral bills by class and season.

[4] Seasonal production and distribution costs and billing demand units are for the composite Residential class.

Table 9-6: GMO SDS Seasonal Cost of Service and SDS TOU Rate Development

ENERGY		Winter			Summer	
Energy Cost	$/customer/month	$70		$/customer/month	$87	
		Winter Usage (kWh/mon.)			Winter Usage (kWh/mon.)	
Super Off-Peak		463			506	
Off-Peak		1,659			2,042	
On-Peak		580			799	
		Average Cost ($/kWh)	Total Rate ($/kWh)		Average Cost ($/kWh)	Total Rate ($/kWh)
Super Off-Peak		$0.0169	$0.0169		$0.0152	$0.0152
Off-Peak		$0.0238	$0.0238		$0.0256	$0.0256
On-Peak		$0.0237	$0.0237		$0.0368	$0.0368

TRANSMISSION		Winter			Summer	
Transmission Cost	$/customer/month	$27		$/customer/month	$30	
	Cost Allocation (%)	Cost Allocation ($)		Cost Allocation (%)	Cost Allocation ($)	
Super Off-Peak	0%	$0		0%	$0	
Off-Peak	0%	$0		0%	$0	
On-Peak	100%	$27		100%	$30	
	Winter Usage (kWh/mon.)	Cost Allocation ($/kWh)	Total Rate ($/kWh)	Summer Usage (kWh/mon.)	Cost Allocation ($/kWh)	Total Rate ($/kWh)
Super Off-Peak	2,702	$0.0000	$0.0000	3,346	$0.0000	$0.0000
Off-Peak	2,122	$0.0000	$0.0000	2,548	$0.0000	$0.0000
On-Peak	580	$0.0461	$0.0461	799	$0.0377	$0.0377
Revenue Neutral Adder			$ -			$ -
			Total Rate ($/kWh)			Total Rate ($/kWh)
Super Off-Peak			**$ 0.0169**			**$ 0.0152**
Off-Peak			**$ 0.0238**			**$ 0.0256**
On-Peak			**$ 0.0698**			**$ 0.0745**

PRODUCTION		Winter		Summer
Production Cost	**$/kWh**	**$0.0215**	**$/kWh**	**$0.0613**
Production Cost	**$/customer/month**	**$130**	**$/customer/month**	**$460**
Average Billing Demand	**kW**	**23.34**	**kW**	**28.46**
Production Demand Cost	**$/kW-month**	**$5.58**	**$/kW-month**	**$16.15**

DISTRIBUTION PRIMARY		Winter		Summer
Distribution Primary Cost	**$/kWh**	**$0.0144**	**$/kWh**	**$0.0103**
Distribution Primary Cost	**$/customer/month**	**$87**	**$/customer/month**	**$77**
Average Billing Demand	**kW**	**23.34**	**kW**	**28.46**
Distribution Primary Demand Cost	**$/kW-month**	**$3.74**	**$/kW-month**	**$2.71**
Revenue Neutral Adder	**$/kW-month**	**$2.19**		**$0.15**
Demand Charge	**$/kW-month**	**$11.50**		**$19.00**

[1] All monthly costs by component are from the 2016 GMO CCOS model (2015 test year) for the SDS class.

[2] Energy sales by TOU period are based on an average 2015 GMO SDS average load profile.

[3] A revenue neutral adder was incorporated to the demand charges to generate revenue neutral rates.

[4] Monthly production and distribution costs from the GMO CCOS were scaled up to align with SDS seasonal energy use.

10.0 TIME OF USE RATE DESIGNS

10.1 Approach

The development and design of TOU rates for the Residential and Small General Service classes is based upon stakeholder input received, the qualitative evaluation, conceptual rate transition plan, utility rate benchmarking analysis, TOU load analysis, and the CCOS analysis. Each of the optional TOU rates were designed to be revenue neutral to the existing rates in each class, reflect the utility's CCOS by season and time period, and to meet GMO and KCP&L's rate design objectives described in this report.

10.2 Residential Service Rate Designs and Planned Transitions

The following sections detail how the Residential rate transition plan might be put into action, detailing the relationship between the rate design options and the expected utilization of each. As presented in Section 5 of this Study, these are conceptual rate options planned to occur in orderly "steps" to help ensure proper transition to the new designs. Actual implementation details will be defined at a future date as part of a future general rate proceeding.

10.2.1 Residential General Use Rate

The existing GU rate is assumed to remain in place within each utility jurisdiction and will become the new standard rate offering. The GU Rate will remain available to all customers in Step 1, but will then transition from the Residential GU rate used for most customers, to a limited use rate, in Steps 2 and 3. It will initially be limited to customers with an average usage of less than 30,000 kWh per year or an annual peak of less than 25 kW with the threshold lowered over time.[10]

10.2.2 Residential Electric Space Heating Rate

The following assumptions are used related to the heating rates: In Step 1, the SH rate will remain available to all customers as it currently is today. In Step 2, the existing SH Rate will be frozen for each utility jurisdiction and will only be available to existing SH customers. All existing two-meter water and space heating rates are assumed to be discontinued in Step 3 when an appropriate replacement rate design can be deployed. Customers would be placed on an appropriate single meter rate so that the entire usage at the premise can be service under the replacement rate. All new SH customers will be offered either the

[10] These limits were selected as a reasonable initial design as they are similar to those used within the GMO Small General Service class to distinguish the transition between non-demand and demand rates. The 25kW limit also has relevance within the distribution network where the 25kW size is perceived to match the common size for distribution transformation for these customers. The additional terms (9,000 kWh and 7.5kW) were established to support further reduction of the limits and were derived from a review of load factors for Residential customers.

existing GU Rate, if they are under the applicable usage limits, or one of the three new rate plans. The Demand Rate will be promoted as the recommended rate for new SH customers and will result in a revenue that is neutral to the existing SH Rate.

The Demand Rate will be promoted as the recommended rate for new SH customers and will result in a revenue that is neutral to the existing SH Rate class. It is understood that these changes will need to be approved by the Commission as part of a future rate case and that subsequent assumptions used in this plan, rely on acceptance of these proposals.

10.2.3 Residential Demand Rate

In Step 1, the Demand Rate would be available to a limited number of Residential customers in the pilot program, and is designed to be revenue neutral to both Residential GU and SH customers. Although customers could select other rates, the Demand Rate would generally provide SH customers a lower cost rate than the current GU Rate. Steps 2 and 3 would provide the opportunity for any customer to select the Demand Rate. The Demand Rate option consists of a seasonal flat energy charge and seasonal monthly on-peak demand charges. Fixed production costs and distribution costs are recovered through a seasonal demand charge with small adjustments to achieve revenue neutral bills for GU and SH customers. The seasonal demand charges were derived by determining the monthly on-peak demand charges that generate revenues consistent with the combined Residential (GU and SH) CCOS for production and distribution when applied to the monthly on-peak billing demand determinants. The demand charge is applied only to the highest 15 min on-peak demand during the weekday hours between 4 and 8 pm. Additionally, the use of an annual base demand (ABD) mechanism[11] was employed in the winter months to provide a common demand charge that could be used by both the GU and SH class customers. The ABD charges the lesser of the highest summer on-peak demand or current winter month on-peak demand. The seasonal energy and transmission costs are recovered by seasonal energy charges. The seasonal energy charges were determined by applying the Residential CCOS energy costs for energy and transmission to the seasonal energy usage with small adjustments to achieve revenue neutral bills for GU and SH customers.

10.2.4 Residential TOU Energy Rate

In Step 1, the TOU Energy Rate would be available to a limited number of Residential customers in the pilot program. It is designed to be revenue neutral to the existing Residential GU customers and would be made available to all Residential customers in Steps 2 and 3 who are under the annual usage and peak

[11] The Annual Base Demand mechanism is currently a part of the GMO commercial & industrial rates. The mechanism serves as a seasonal threshold to provide rate recognition for customers who can utilize higher levels of their demand in the non-summer periods.

demand thresholds. The TOU Energy Rate is designed to recover the utility's cost during the hours in which those costs are allocated. The fixed production costs are allocated to super off-peak, off-peak, and peak energy by season. Transmission costs are allocated to peak energy periods by season. The distribution costs are allocated to on-peak and off-peak energy by season. The weighted average energy costs by season and time period are used to build up the energy cost portion of the TOU energy rate. A three period TOU rate structure was used as developed in the Load Analysis section of this report.

10.2.5 Residential TOU Energy and Demand Rate

In Step 1, the TOU Energy and Demand Rate would be available to a limited number of Residential customers in the pilot program. It is designed to be revenue neutral to the existing Residential GU and SH customers and would be made available to all Residential customers in Steps 2 and 3. The rate is designed to recover the utility's cost during the hours in which those costs are allocated. Transmission costs are allocated to on-peak energy periods by season. The weighted average energy costs by season and time period are used to build up the TOU energy portion of the rate. Fixed production costs and distribution costs are recovered through a seasonal demand charge with an adjustment to achieve revenue neutral bills for GU and SH customers similar to the Residential Demand Rate option described above.

10.2.6 Residential Existing and Optional Rate Designs

The existing rates and potential optional rates developed are presented in the table below. The potential optional rates were designed based on the general principles summarized above. Rates were designed and tested with 2015 load research data sets with the goal of generating a set of revenue neutral rates for both Residential GU and SH customers. Not all potential optional rates achieved revenue neutral bills for each customer load profile and type. Modifications were made where appropriate to limit the potential increase or decrease to both the GU class and SH class customers. For consistency between rate options, certain provisions such as customer charges were held constant across rate options. All new rates were designed to maintain seasonality in the rate structure and remove declining block structures in the winter months. The new optional Residential rates' tariffs and their associated provisions will need to include the basic tenants described within this Study but also include various revenue and bill safe guard provisions to minimize potential adverse impacts to the utility and customers.

Table 10-1: GMO - Residential Optional Rate Designs

Existing		Existing		New		New		New	
General use Rate		Space Heating Rate		Optional Demand Rate		Optional TOU Energy Rate		Optional TOU Energy + Demand Rate	
	Price		Price		Price		Price		Price
Customer Charge ($/mo)	$10.43	Customer Charge ($/mo)	$10.43	Customer Charge ($/mo)	$10.43	Customer Charge ($/mo)	$10.43	Customer Charge ($/mo)	$10.43
Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)	
Summer	$0.121	Summer	$0.121	Summer	$0.037	Summer Peak	$0.302	Summer Peak	$0.101
						Summer Off Peak	$0.107	Summer Off Peak	$0.031
						Summer Super Off Peak	$0.046	Summer Super Off Peak	$0.017
Winter, up to 600	$0.106	Winter, up to 600	$0.106	Winter	$0.034	Winter Peak	$0.211	Winter Peak	$0.100
Winter 601 - 1000	$0.078	Winter 601 - 1000	$0.060			Winter Off Peak	$0.090	Winter Off Peak	$0.025
Winter, 1001 +	$0.078	Winter, 1001 +	$0.050			Winter Super Off Peak	$0.033	Winter Super Off Peak	$0.019
Tier 1 Max kWh	600	Tier 1 Max kWh	600	Tier 1 Max kWh	N/A	Tier 1 Max kWh	N/A	Tier 1 Max kWh	N/A
Tier 2 Max kWh	1,000	Tier 2 Max kWh	1,000	Tier 2 Max kWh	N/A	Tier 2 Max kWh	N/A	Tier 2 Max kWh	N/A
Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)	
Summer Demand	N/A	Summer Demand	N/A	Summer Demand	$15.25	Summer Demand	N/A	Summer Demand	$15.25
Winter Demand	N/A	Winter Demand	N/A	Winter Demand	$7.75	Winter Demand	N/A	Winter Demand	$7.75
Summer Demand	N/A	Summer Demand	N/A	Summer Demand	On Peak	Summer Demand	N/A	Summer Demand	On Peak
Winter Demand	N/A	Winter Demand	N/A	Winter Demand	On Peak	Winter Demand	N/A	Winter Demand	On Peak
Utility Cost and Rate Recovery Method									
Customer Cost Recovery	Customer Charge	Customer Cost Recovery	Customer Charge	Customer Cost Recovery	Customer Charge	Customer Cost Recovery	Customer Charge	Customer Cost Recovery	Customer Charge
Energy Cost Recovery	Flat Energy Charge	Energy Cost Recovery	Flat Energy Charge	Energy Cost Recovery	Flat Energy Charge	Energy Cost Recovery	TOU Energy Charge	Energy Cost Recovery	TOU Energy Charge
Transmission Cost Recovery	Flat Energy Charge	Transmission Cost Recovery	Flat Energy Charge	Transmission Cost Recovery	Flat Energy Charge	Transmission Cost Recovery	TOU Energy Charge	Transmission Cost Recovery	TOU Energy Charge
Fixed Production Cost Recovery	Flat Energy Charge	Fixed Production Cost Recovery	Flat Energy Charge	Fixed Production Cost Recovery	On-Peak Demand Charge	Fixed Production Cost Recovery	TOU Energy Charge	Fixed Production Cost Recovery	On-Peak Demand Charge
Fixed Distribution Cost Recovery	Flat Energy Charge	Fixed Distribution Cost Recovery	Flat Energy Charge	Fixed Distribution Cost Recovery	On-Peak Demand Charge	Fixed Distribution Cost Recovery	TOU Energy Charge	Fixed Distribution Cost Recovery	On-Peak Demand Charge
Current Default General Use Rate Small Use Customers		Current Default Space Heat Rate Frozen Space Heat Rate		Optimal Space Heat Rate Default for High Use Customers Revenue neutral to GU and SH classes		Optimal EV Rate Available for all customers Revenue neutral for GU class		Optimal Space Heat + EV Rate Default for High Use Customers Revenue neutral for GU and SH classes	

1. For this analysis, summer months are assumed from June 1 to September 30 for optional rates.
2. TOU Peak from 4 - 8 pm. Off Peak from 6 am to 4 pm and 8 pm to 12 am. Super Off Peak from 12 am to 6 am.
3. Max monthly on-peak demand is billed based on 15 min maximum measured demand from 4 - 8 pm.
4. Existing rates are based on Residential rates effective February 22, 2017.
5. New optional rates are set to recover the same revenues as the existing GU and SH rates.

Figure 10-1: GMO Residential Optional Demand Rate

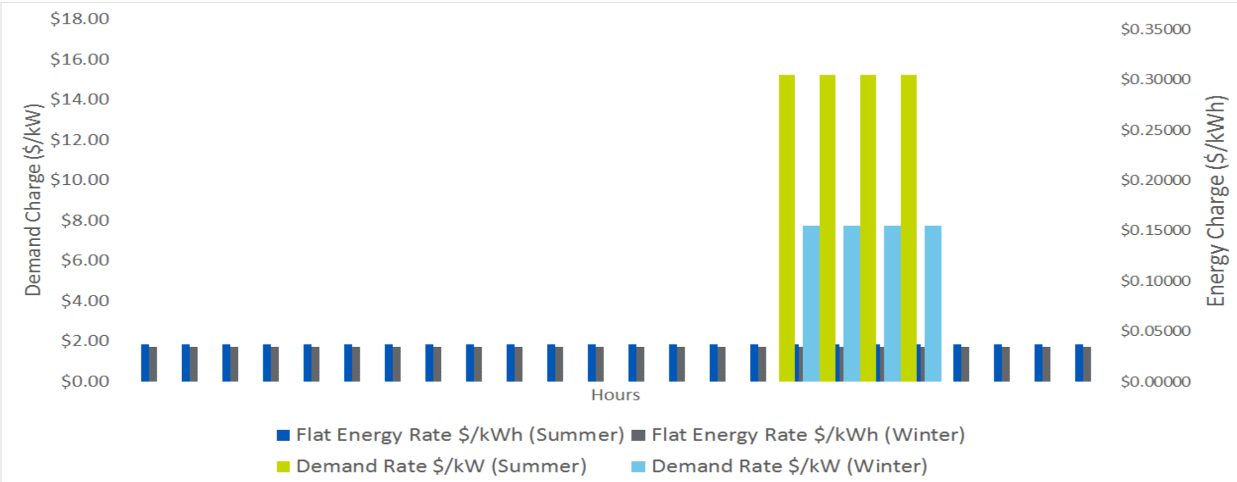


Figure 10-2: GMO Residential TOU Energy Rates

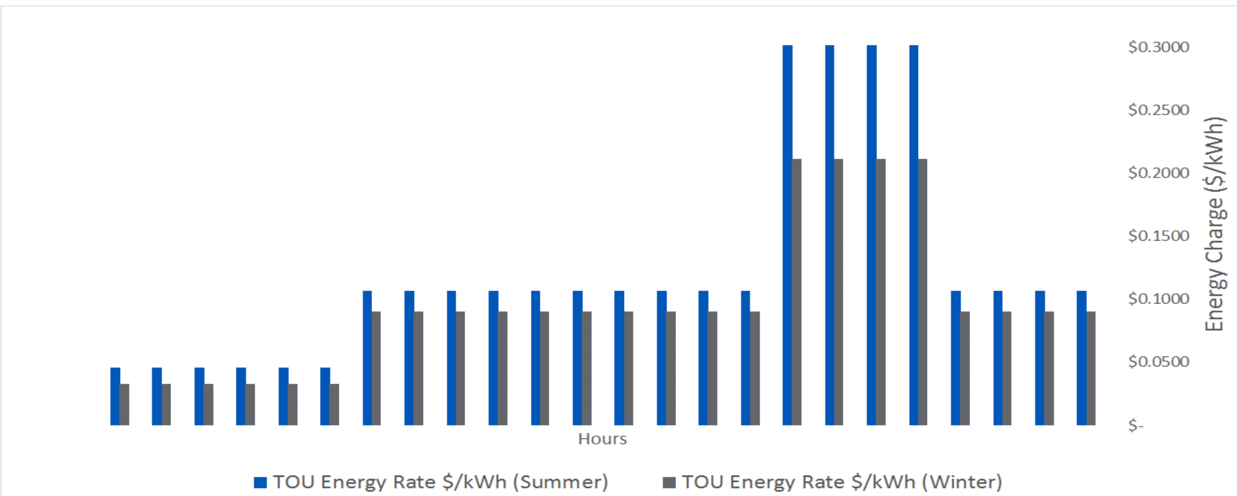
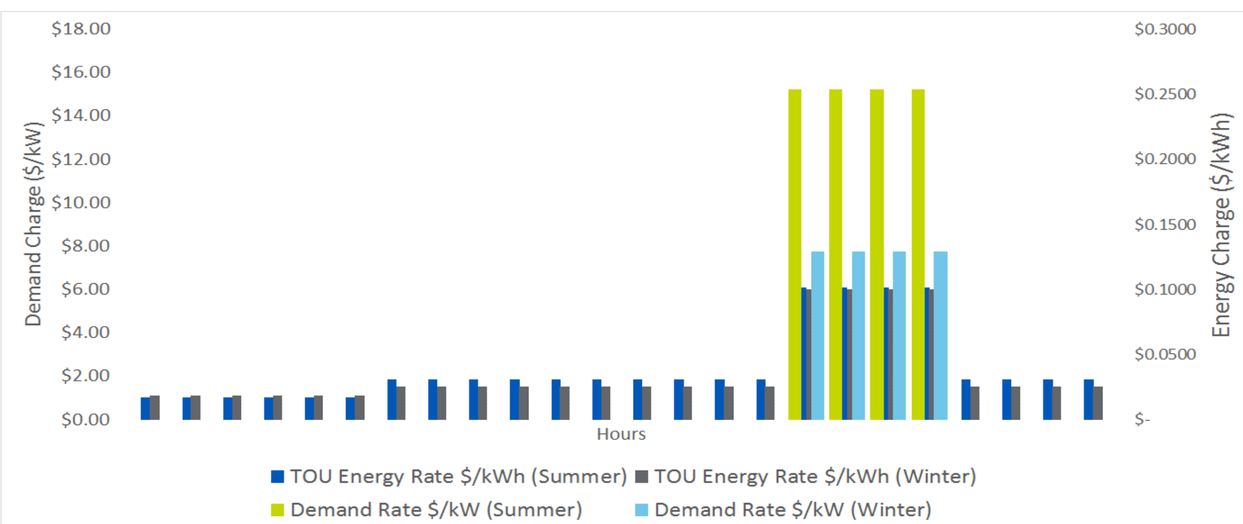


Figure 10-3: GMO Residential TOU Energy and Demand Rate



10.3 Small General Service Rate Designs and Planned Transitions

The following sections detail how the rate transition plan for the Small General Service classes might be put into action, detailing the relationship between the rate design options and the expected utilization of each. As presented in Section 5 of this Study and similar to the approach used for Residential rates, these are conceptual rate options planned to occur in orderly "steps" to help ensure proper transition to the new designs. Actual implementation details will be defined at a future date as part of a future general rate proceeding.

10.3.1 Small General Service Energy Rate

The existing SGS Rate, is assumed to remain in place as it is today. The existing SGS rate, which includes only seasonal energy charges and a customer charge will be available for customers with a peak demand less than 25 kW initially, but its availability would be reduced to customers who have an average usage of less than 30,000 kWh per year or an annual peak demand of less than 10 kW[12] to further increase the utilization of the Small General Service demand rate. In Steps 2 and 3, the SGS rate will be the default plan for new low use SGS customers, with larger customers being placed on one of the demand rates.

10.3.2 Small General Service Demand Rate

The existing SDS Rate, is assumed to remain in place as it is today. In Steps 2 and 3, the SDS Rate will be the default plan for customers who have a maximum annual demand over 25 kW, however, the minimum demand provision would be reduced to 10 kW over time such that customers currently on the SGS Rate will be gradually transitioned into a rate that includes a demand charge similar to Residential customers. Additionally, the minimum demand ratchet would also be reduced over time such that lower use high load factor customers could be placed on the SDS rate without the undue burden of a high demand ratchet. BMcD recommends that the default SDS rate be revised to recover more of the utility's fixed production and distribution demand cost from a demand charge as opposed to the energy charge.

10.3.3 Small General Service TOU Energy Rate

In Step 1, the SGS TOU rate would be available to a limited number of Small General Service customers in the pilot program. It is designed to be revenue neutral to the existing SGS customers with loads under 25 kW, but in Steps 2 and 3, similar to the plan for the SGS and SDS rates, its availability would be reduced to customers who have an average usage of less than 30,000 kWh per year, or an annual peak

[12] For the purpose of this plan, the 10 kW limit is internally accepted as a point where commercial customer load is small enough not to warrant application of the demand charges. The limit could be moved lower in the future.

demand of less than 10 kW. The SGS TOU Rate is designed to recover the utility's cost during the hours in which those costs are allocated. The fixed production costs are allocated to super off-peak, off-peak, and on-peak energy by season. Transmission costs are allocated to on-peak energy periods by season. The distribution costs are allocated to on-peak and off-peak periods by season. The weighted average cost of energy by season and TOU periods are used to build up the energy cost portion of the TOU Energy rate. A three period TOU rate structure was used as developed in the Load Analysis section of this report.

10.3.4 Small General Service Demand TOU Rate

In Step 1, the SDS TOU rate would be available to a limited number of Small General Service customers in the pilot program. In Steps 2 and 3, the SDS TOU Rate is designed to be revenue neutral to the existing SDS customers and is made available to all Small General Service customers. The rate is designed to recover the utility's cost during the hours in which those costs are allocated. Transmission costs are allocated to on-peak energy periods by season. The weighted average cost of energy by season and TOU period are used to build up the TOU energy portion of the rate. Fixed generation production costs and primary distribution costs are recovered through a seasonal maximum monthly demand charge similar to the Residential demand rate described previously. Secondary distribution system costs and transformational costs would be recovered through a ratcheted facility charge like today's rate. While not included within this analysis, it may be appropriate to utilize an ABD winter billing demand mechanism similar to that recommended for the Residential class which would lower the winter demand charge.

10.3.5 Small General Service Existing and Optional Rate Designs

The existing rates and potential optional rates developed are presented in the table below. The potential optional rates were designed based on the general principles summarized above. Rates were designed and tested with 2015 load research data sets with the goal of generating a set of revenue neutral rates for both SGS and SDS customers. Not all potential optional rates achieved revenue neutral bills for each customer load profile and type. Modifications were made where appropriate to limit the potential increase or decrease to both the SGS class and SDS class customers. For consistency between rate options, certain provisions such as customer charges were held constant across rate options. All new rates were designed to maintain seasonality in the rate structure. The new optional SGS and SDS rates' tariffs and their associated provisions will need to include the basic tenants described within this Study but also include various revenue and bill safe guard provisions to minimize potential adverse impacts to the utility and customers.

Table 10-2: GMO Small General Service – Optional Rate Designs

SGS Rate		Optional SDS Rate		Optional SGS TOU Rate		Optional SDS TOU Rate	
	Price		Price		Price		Price
Customer Charge	$23.91	Customer Charge	$23.91	Customer Charge	$23.91	Customer Charge	$23.91
Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)		Energy Charges ($/kWh)	
Summer	$0.140	Summer, up to 180	$0.098	Summer Peak	$0.278	Summer Peak	$0.074
				Summer Off Peak	$0.121	Summer Off Peak	$0.026
				Summer Super Off Peak	$0.061	Summer Super Off Peak	$0.015
Winter	$0.088	Winter, up to 180	$0.071	Winter Peak	$0.157	Winter Peak	$0.070
		Winter, over 180hrs	$0.064	Winter Off Peak	$0.082	Winter Off Peak	$0.024
				Winter Super Off Peak	$0.048	Winter Super Off Peak	$0.017
Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)		Demand Charges ($/kW)	
Distribution Demand	N/A	Distribution Demand	$1.45	Distribution Demand	N/A	Distribution Demand	$1.07
NCP, Ratchet, Peak	N/A	NCP, Ratchet, Peak	Ratchet NCP	NCP, Ratchet or CP	N/A	NCP, Ratchet or CP	Ratchet NCP
NCP Ratchet (%)	N/A	NCP Ratchet (%)	100%	NCP Ratchet (%)	N/A	NCP Ratchet (%)	100%
Summer Demand	N/A	Summer Demand	$1.27	Summer Demand	N/A	Summer Demand	$19.00
Winter Demand	N/A	Winter Demand	$1.24	Winter Demand	N/A	Winter Demand	$11.50
Summer Demand	N/A	Summer Demand	NCP	Summer Demand	N/A	Summer Demand	On Peak
Winter Demand	N/A	Winter Demand	NCP	Winter Demand	N/A	Winter Demand	On Peak
Utility Cost and Rate Recovery Method							
Customer Cost Recovery	Customer Charge	Customer Cost Recovery	Customer Charge	Customer Cost Recovery	Customer Charge	Customer Cost Recovery	Customer Charge
Energy Cost Recovery	Flat Energy Charge	Energy Cost Recovery	Flat Energy Charge	Energy Cost Recovery	TOU Energy Charge	Energy Cost Recovery	TOU Energy Charge
Transmission Cost Recovery	Flat Energy Charge	Transmission Cost Recovery	Flat Energy Charge	Transmission Cost Recovery	TOU Energy Charge	Transmission Cost Recovery	TOU Energy Charge
Fixed Production Cost Recovery	Flat Energy Charge	Fixed Production Cost Recovery	Flat Energy Charge	Fixed Production Cost Recovery	TOU Energy Charge	Fixed Production Cost Recovery	On-Peak Demand Charge
Fixed Distribution (Primary) Cost Recovery	Flat Energy Charge	Fixed Distribution (Primary) Cost Recovery	NCP Demand Charge	Fixed Distribution (Primary) Cost Recovery	TOU Energy Charge	Fixed Distribution (Primary) Cost Recovery	On-Peak Demand Charge
Fixed Distribution (Secondary) Cost Recovery	Flat Energy Charge	Fixed Distribution (Secondary) Cost Recovery	Ratchet NCP Demand Charge	Fixed Distribution (Secondary) Cost Recovery	TOU Energy Charge	Fixed Distribution (Secondary) Cost Recovery	Ratchet NCP Demand Charge
Standard Rate (<25kW)		Standard Rate (>25kW)		Proposed SGS TOU Energy		Proposed SDS TOU Energy + Demand	

1. Summer months from June 1 to September 30 for proposed rates.
2. TOU Peak from 1 - 6 pm. Off Peak from 6 am to 1 pm and 6 pm to 12 am. Super Off Peak from 12 am to 6 am.
3. Max monthly on-peak demand is billed based on 15 minute maximum measured demand from 4 - 8 pm.
4. Ratcheted NCP demand is billed based on 15 minute maximum monthly demand and ratcheted for 12 months
5. Existing rates are based on GMO SGS and SDS rates effective February 22, 2017.
6. New optional SGS TOU Energy Rates are set to recover the same revenues as the existing SGS Rates based on load research profiles.
7. New optional SDS TOU Energy Rates are set to recover the same revenues as the existing SDS Rates based on load research profiles.

Figure 10-4: GMO Small General Service (SGS) TOU Rate

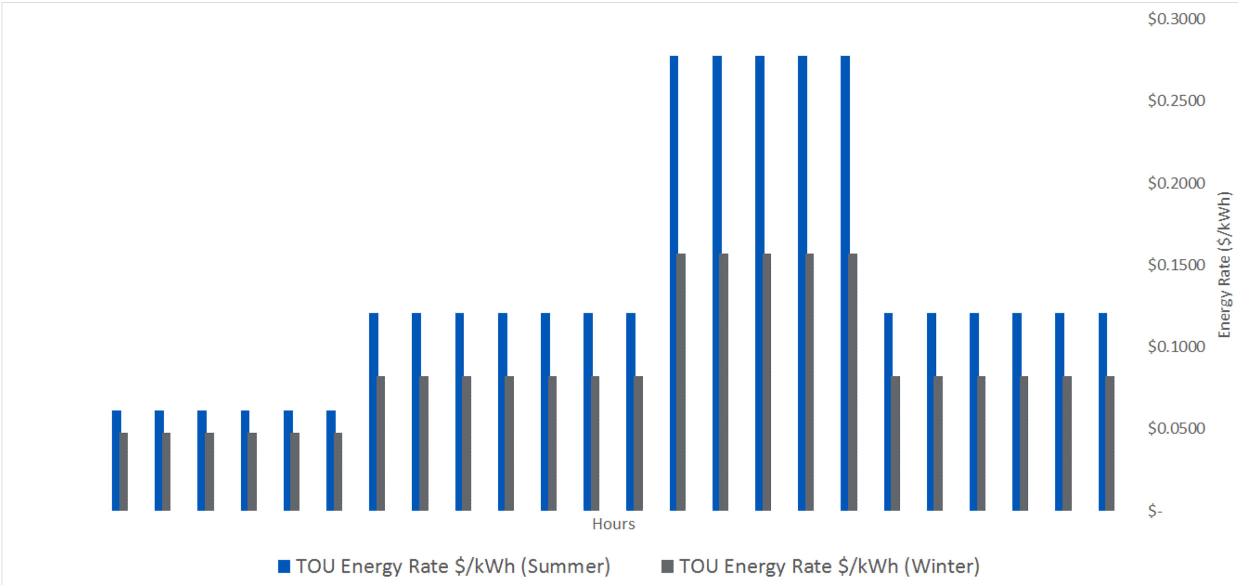
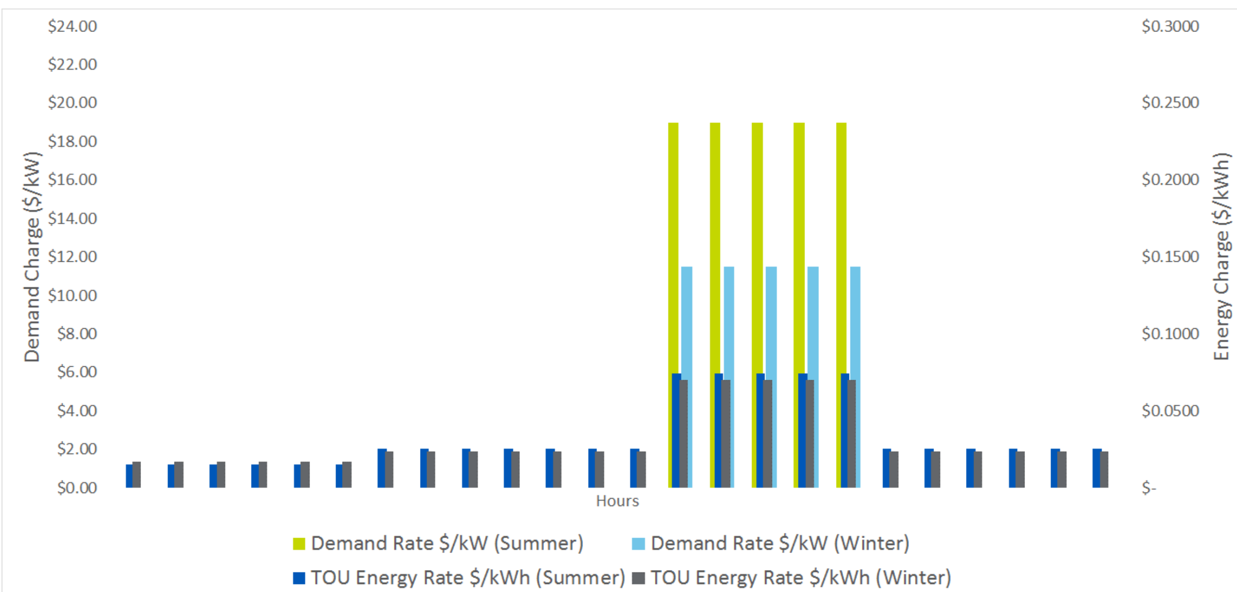


Figure 10-5: GMO Small General Service Demand (SDS) TOU Rate



11.0 REVENUE AND BILL ANALYSIS

11.1 Background

The existing and optional rates developed are designed with the goal of generating revenue neutral rates for Residential and Small General Service customer classes. Not all optional rates generate revenue neutral bills for each customer, resulting in different customers benefiting from varying rates depending on their load profile.

11.2 Approach

For each of the rates, monthly bills are calculated for the load profiles in the load research group data set. When necessary, high usage customer load profiles, deemed to be outliers to the data set, are removed from the data sets to arrive at an adjusted load research data set that is representative of the class in total. Billing demand determinants are based on 15-minute interval data. The annual change in each customer's bill is calculated to determine how each customer would be impacted if they were to switch to the new optional rate design. The potential bill impacts of each customer in the load research groups switching to each of the new rates for Residential and Small General Service classes are presented in Table 11-1, Table 11-2, Table 11-3 and Table 11-4 on the following pages. While this analysis is quite detailed, it is based on load research data from a sample of customers only and may not be totally representative of the customer population in detail.

11.3 Self-Selection Analysis and Participation

The analysis considers the scenario in which customers select the rate that provides them with the lowest annual bill based on perfect knowledge of their energy usage profile without any changes in behavior. From a revenue perspective, this "perfect choice" scenario is the worst-case scenario that could be experienced by the utility. Based on the rates developed, the maximum potential revenue loss from customer switching is 8.8 percent for Residential GU and 9.4 percent for Small General Service SDS.

In addition to the "perfect choice" scenario, several additional scenarios were developed to test the range of potential outcomes. The "baseline" customer switching scenario assumes that approximately 28 percent of all Residential customers, and 13 percent of all Small General Service customers would switch to the rate that provides them with the lowest bill, as opposed to the "perfect choice" as shown on the following pages. The "baseline" scenario is represented as the expected average bill. Assuming 28 percent of all Residential and 13 percent of all SGS customers switch to the lowest rate based on their usage profile ("perfect choice"), the potential revenue loss would range from a high of 2.4 percent in the

Residential GU class to a low of 0.76 percent in the SGS class. It is also possible that customers could switch to a rate that inadvertently causes an increase to their monthly bills, however this was not assessed.

Table 11-1: GMO Residential GU Bill Comparison & Revenue Attrition Estimates

BILL COMPARISONS AND REVENUE ATTRITION ESTIMATES

Penetration: 28%

GMO GU CUSTOMERS

	General Use	General Use	Demand	TOU	TOU + Demand	Perfect Choice	% Change	$/mon change	Perfect Choice	Expected Avg. Bill
SC0086	$ 952.01	$ 952.01	$ 446.62	$ 971.43	$ 431.91	$ 431.91	-54.6%	$ (43.34)	TOU + Demand	$ 806.38
SC0069	$ 1,838.91	$ 1,838.91	$ 1,467.55	$ 1,907.82	$ 1,468.03	$ 1,467.55	-20.2%	$ (30.95)	Demand	$ 1,734.93
SC0074	$ 1,616.00	$ 1,616.00	$ 1,286.93	$ 1,552.96	$ 1,272.23	$ 1,272.23	-21.3%	$ (28.65)	TOU + Demand	$ 1,519.75
SC0067	$ 1,722.03	$ 1,722.03	$ 1,379.92	$ 1,729.45	$ 1,383.39	$ 1,379.92	-19.9%	$ (28.51)	Demand	$ 1,626.24
SC0089	$ 1,369.90	$ 1,369.90	$ 1,081.67	$ 1,265.60	$ 1,061.01	$ 1,061.01	-22.5%	$ (25.74)	TOU + Demand	$ 1,283.41
SD0037	$ 1,626.59	$ 1,626.59	$ 1,370.38	$ 1,634.43	$ 1,370.58	$ 1,370.38	-15.8%	$ (21.35)	Demand	$ 1,554.85
SD0041	$ 1,338.65	$ 1,338.65	$ 1,155.17	$ 1,309.41	$ 1,110.78	$ 1,110.78	-17.0%	$ (18.99)	TOU + Demand	$ 1,274.85
SC0098	$ 1,614.01	$ 1,614.01	$ 1,474.65	$ 1,654.04	$ 1,502.73	$ 1,474.65	-8.6%	$ (11.61)	Demand	$ 1,574.99
SC0066	$ 1,841.64	$ 1,841.64	$ 1,705.24	$ 1,889.16	$ 1,707.44	$ 1,705.24	-7.4%	$ (11.37)	Demand	$ 1,803.45
SC0062	$ 1,391.93	$ 1,391.93	$ 1,298.37	$ 1,423.55	$ 1,323.03	$ 1,298.37	-6.7%	$ (7.80)	Demand	$ 1,365.73
SC0058	$ 1,182.80	$ 1,182.80	$ 1,091.41	$ 1,168.60	$ 1,090.98	$ 1,090.98	-7.8%	$ (7.65)	TOU + Demand	$ 1,157.09
SC0076	$ 1,115.75	$ 1,115.75	$ 1,373.52	$ 1,028.76	$ 1,352.50	$ 1,028.76	-7.8%	$ (7.25)	TOU	$ 1,091.39
SD0034	$ 878.90	$ 878.90	$ 798.91	$ 814.11	$ 793.20	$ 793.20	-9.8%	$ (7.14)	TOU + Demand	$ 854.90
SD0042	$ 648.87	$ 648.87	$ 571.38	$ 650.06	$ 578.39	$ 571.38	-11.9%	$ (6.46)	Demand	$ 627.18
SD0039	$ 809.92	$ 809.92	$ 934.03	$ 737.10	$ 923.31	$ 737.10	-9.0%	$ (6.07)	TOU	$ 789.53
SC0092	$ 845.79	$ 845.79	$ 1,000.00	$ 782.10	$ 988.60	$ 782.10	-7.5%	$ (5.31)	TOU	$ 827.96
SC0091	$ 1,462.10	$ 1,462.10	$ 1,408.49	$ 1,437.95	$ 1,402.04	$ 1,402.04	-4.1%	$ (5.00)	TOU + Demand	$ 1,445.28
SC0080	$ 1,389.47	$ 1,389.47	$ 1,365.63	$ 1,333.76	$ 1,356.51	$ 1,333.76	-4.0%	$ (4.64)	TOU	$ 1,373.87
SC0059	$ 583.22	$ 583.22	$ 532.19	$ 556.07	$ 530.09	$ 530.09	-9.1%	$ (4.43)	TOU + Demand	$ 568.35
SD0038	$ 1,089.74	$ 1,089.74	$ 1,038.52	$ 1,077.91	$ 1,036.83	$ 1,036.83	-4.9%	$ (4.41)	TOU + Demand	$ 1,074.93
SC0072	$ 1,398.56	$ 1,398.56	$ 1,364.43	$ 1,380.04	$ 1,375.34	$ 1,364.43	-2.4%	$ (2.84)	Demand	$ 1,389.00
SC0071	$ 1,096.58	$ 1,096.58	$ 1,213.40	$ 1,062.45	$ 1,214.54	$ 1,062.45	-3.1%	$ (2.84)	TOU	$ 1,087.02
SC0073	$ 1,517.13	$ 1,517.13	$ 1,528.86	$ 1,483.10	$ 1,534.12	$ 1,483.10	-2.2%	$ (2.84)	TOU	$ 1,507.60
SC0075	$ 1,047.97	$ 1,047.97	$ 1,026.85	$ 1,024.05	$ 1,028.84	$ 1,024.05	-2.3%	$ (1.99)	TOU	$ 1,041.27
SC0082	$ 1,727.98	$ 1,727.98	$ 1,706.71	$ 1,836.74	$ 1,734.50	$ 1,706.71	-1.2%	$ (1.77)	Demand	$ 1,722.02
SD0036	$ 728.37	$ 728.37	$ 955.00	$ 709.85	$ 960.73	$ 709.85	-2.5%	$ (1.54)	TOU	$ 723.19
SC0064	$ 378.82	$ 378.82	$ 474.57	$ 360.77	$ 472.46	$ 360.77	-4.8%	$ (1.50)	TOU	$ 373.76
SC0079	$ 1,469.42	$ 1,469.42	$ 1,469.86	$ 1,455.19	$ 1,481.13	$ 1,455.19	-1.0%	$ (1.19)	TOU	$ 1,465.43
SC0070	$ 1,177.24	$ 1,177.24	$ 1,435.64	$ 1,163.32	$ 1,437.93	$ 1,163.32	-1.2%	$ (1.16)	TOU	$ 1,173.34
SC0063	$ 897.63	$ 897.63	$ 966.55	$ 887.84	$ 970.20	$ 887.84	-1.1%	$ (0.82)	TOU	$ 894.89
SC0088	$ 1,551.67	$ 1,551.67	$ 1,785.68	$ 1,547.69	$ 1,751.11	$ 1,547.69	-0.3%	$ (0.33)	TOU	$ 1,550.56
SC0101	$ 974.68	$ 974.68	$ 1,030.74	$ 1,127.04	$ 1,099.17	$ 974.68	0.0%	$ -	General Use	$ 974.68
SC0068	$ 1,175.57	$ 1,175.57	$ 1,447.17	$ 1,208.48	$ 1,472.80	$ 1,175.57	0.0%	$ -	General Use	$ 1,175.57
SC0065	$ 1,217.25	$ 1,217.25	$ 1,450.79	$ 1,270.20	$ 1,475.17	$ 1,217.25	0.0%	$ -	General Use	$ 1,217.25
GU Profiles	$ 41,677	$ 41,677	$ 40,637	$ 41,441	$ 40,692	$ 38,011				$ 40,650.65
% Change		**0.0%**	**-2.5%**	**-0.6%**	**-2.4%**	**-8.8%**				**-2.46%**

Table 11-2: GMO Residential SH Bill Comparison & Revenue Attrition Estimates

BILL COMPARISONS AND REVENUE ATTRITION ESTIMATES

New or Existing: **Existing**

Penetration: **28%**

GMO-SH CUSTOMERS

	Space Heating	General Use	Demand	TOU	TOU+Demand	Perfect Choice	% Change	$/mon change	Perfect Choice	Expected Avg. Bill
SC0010	$ 1,551.57	$ 1,746.00	$ 1,196.15	$ 1,814.18	$ 1,171.48	$ 1,171.48	-24.5%	$ (31.67)	TOU+Demand	$ 1,445.15
SC0028	$ 2,324.01	$ 2,584.13	$ 1,998.19	$ 2,528.41	$ 1,990.75	$ 1,990.75	-14.3%	$ (27.77)	TOU+Demand	$ 2,230.70
SC0032	$ 1,265.21	$ 1,413.71	$ 1,083.74	$ 1,298.47	$ 1,106.63	$ 1,083.74	-14.3%	$ (15.12)	Demand	$ 1,214.40
SC0022	$ 1,820.43	$ 2,028.40	$ 1,657.44	$ 1,980.64	$ 1,661.24	$ 1,657.44	-9.0%	$ (13.58)	Demand	$ 1,774.79
SC0040	$ 1,903.25	$ 2,119.31	$ 1,784.93	$ 2,032.81	$ 1,744.66	$ 1,744.66	-8.3%	$ (13.22)	TOU+Demand	$ 1,858.84
SC0001	$ 1,396.59	$ 1,565.59	$ 1,262.67	$ 1,550.07	$ 1,239.45	$ 1,239.45	-11.3%	$ (13.09)	TOU+Demand	$ 1,352.59
SC0024	$ 1,864.02	$ 2,072.09	$ 1,721.36	$ 2,127.83	$ 1,766.81	$ 1,721.36	-7.7%	$ (11.89)	Demand	$ 1,824.08
SC0033	$ 1,443.17	$ 1,615.17	$ 1,302.33	$ 1,498.29	$ 1,326.34	$ 1,302.33	-9.8%	$ (11.74)	Demand	$ 1,403.73
SC0026	$ 1,577.51	$ 1,766.94	$ 1,442.36	$ 1,656.18	$ 1,473.66	$ 1,442.36	-8.6%	$ (11.26)	Demand	$ 1,539.67
SD0008	$ 2,000.53	$ 2,217.88	$ 1,893.92	$ 2,257.83	$ 1,917.25	$ 1,893.92	-5.3%	$ (8.88)	Demand	$ 1,970.68
SC0023	$ 1,879.12	$ 2,089.79	$ 1,780.96	$ 2,179.40	$ 1,810.92	$ 1,780.96	-5.2%	$ (8.18)	Demand	$ 1,851.64
SC0021	$ 1,937.20	$ 2,149.00	$ 1,860.88	$ 2,245.19	$ 1,903.53	$ 1,860.88	-3.9%	$ (6.36)	Demand	$ 1,915.83
SC0030	$ 1,710.16	$ 1,907.33	$ 1,661.87	$ 1,935.14	$ 1,715.80	$ 1,661.87	-2.8%	$ (4.02)	Demand	$ 1,696.64
SC0012	$ 770.40	$ 885.62	$ 749.07	$ 1,033.35	$ 722.95	$ 722.95	-6.2%	$ (3.95)	TOU+Demand	$ 757.11
SC0034	$ 1,670.97	$ 1,878.25	$ 1,665.25	$ 1,864.06	$ 1,634.17	$ 1,634.17	-2.2%	$ (3.07)	TOU+Demand	$ 1,660.66
SC0003	$ 1,128.34	$ 1,263.00	$ 1,134.52	$ 1,091.82	$ 1,131.22	$ 1,091.82	-3.2%	$ (3.04)	TOU	$ 1,118.11
SD0002	$ 1,112.20	$ 1,246.56	$ 1,333.17	$ 1,077.87	$ 1,324.94	$ 1,077.87	-3.1%	$ (2.86)	TOU	$ 1,102.59
SC0020	$ 1,662.60	$ 1,887.99	$ 2,130.68	$ 2,031.15	$ 2,066.54	$ 1,662.60	0.0%	$ -	Space Heating	$ 1,662.60
SC0004	$ 1,268.65	$ 1,421.03	$ 1,440.20	$ 1,388.84	$ 1,416.18	$ 1,268.65	0.0%	$ -	Space Heating	$ 1,268.65
SC0019	$ 1,535.52	$ 1,730.59	$ 1,617.24	$ 1,799.51	$ 1,584.26	$ 1,535.52	0.0%	$ -	Space Heating	$ 1,535.52
SC0007	$ 1,229.77	$ 1,381.56	$ 1,408.84	$ 1,238.99	$ 1,398.17	$ 1,229.77	0.0%	$ -	Space Heating	$ 1,229.77
SD0001	$ 1,111.48	$ 1,241.64	$ 1,251.88	$ 1,120.47	$ 1,260.99	$ 1,111.48	0.0%	$ -	Space Heating	$ 1,111.48
SC0002	$ 1,422.71	$ 1,597.54	$ 1,621.56	$ 1,615.04	$ 1,603.91	$ 1,422.71	0.0%	$ -	Space Heating	$ 1,422.71
SD0005	$ 1,609.77	$ 1,822.69	$ 1,825.78	$ 2,086.78	$ 1,808.13	$ 1,609.77	0.0%	$ -	Space Heating	$ 1,609.77
SC0005	$ 1,430.22	$ 1,599.45	$ 1,790.42	$ 1,549.18	$ 1,766.01	$ 1,430.22	0.0%	$ -	Space Heating	$ 1,430.22
SC0009	$ 1,675.39	$ 1,874.20	$ 2,056.31	$ 1,828.92	$ 2,041.56	$ 1,675.39	0.0%	$ -	Space Heating	$ 1,675.39
SC0011	$ 1,539.84	$ 1,728.17	$ 1,872.04	$ 1,780.49	$ 1,874.06	$ 1,539.84	0.0%	$ -	Space Heating	$ 1,539.84
SC0008	$ 1,745.22	$ 1,956.49	$ 1,804.08	$ 1,891.16	$ 1,775.92	$ 1,745.22	0.0%	$ -	Space Heating	$ 1,745.22
SC0018	$ 1,336.84	$ 1,512.03	$ 1,684.39	$ 1,554.71	$ 1,669.63	$ 1,336.84	0.0%	$ -	Space Heating	$ 1,336.84
SD0007	$ 1,426.74	$ 1,612.79	$ 1,812.78	$ 1,689.65	$ 1,799.71	$ 1,426.74	0.0%	$ -	Space Heating	$ 1,426.74
SD0003	$ 1,637.71	$ 1,828.94	$ 1,731.37	$ 1,835.61	$ 1,746.45	$ 1,637.71	0.0%	$ -	Space Heating	$ 1,637.71
SC0037	$ 1,500.95	$ 1,676.13	$ 1,723.78	$ 1,640.79	$ 1,749.42	$ 1,500.95	0.0%	$ -	Space Heating	$ 1,500.95
SC0016	$ 1,774.67	$ 1,996.45	$ 2,042.13	$ 2,127.88	$ 2,055.08	$ 1,774.67	0.0%	$ -	Space Heating	$ 1,774.67
SC0039	$ 1,792.72	$ 2,009.81	$ 2,079.02	$ 2,055.73	$ 2,066.60	$ 1,792.72	0.0%	$ -	Space Heating	$ 1,792.72
SC0038	$ 2,140.42	$ 2,392.09	$ 2,318.36	$ 2,580.50	$ 2,344.21	$ 2,140.42	0.0%	$ -	Space Heating	$ 2,140.42
SC0029	$ 1,905.09	$ 2,123.45	$ 2,046.15	$ 2,268.83	$ 2,099.40	$ 1,905.09	0.0%	$ -	Space Heating	$ 1,905.09
SC0031	$ 1,849.39	$ 2,057.35	$ 2,073.60	$ 2,096.00	$ 2,065.55	$ 1,849.39	0.0%	$ -	Space Heating	$ 1,849.39
SC0025	$ 1,933.63	$ 2,143.97	$ 1,971.01	$ 2,258.24	$ 2,018.44	$ 1,933.63	0.0%	$ -	Space Heating	$ 1,933.63
SD0004	$ 1,670.13	$ 1,882.41	$ 1,855.25	$ 2,124.48	$ 1,878.23	$ 1,670.13	0.0%	$ -	Space Heating	$ 1,670.13
SC0041	$ 1,973.46	$ 2,198.34	$ 2,225.96	$ 2,248.94	$ 2,225.15	$ 1,973.46	0.0%	$ -	Space Heating	$ 1,973.46
SH Profiles	$ 64,527.6	$ 72,223.9	$ 67,911.6	$ 72,983.4	$ 67,955.4	$ 62,250.9				$ 63,890.14
% Change		**11.9%**	**5.2%**	**13.1%**	**5.3%**	**-3.5%**				**-1.0%**

Table 11-3: GMO SGS Bill Comparison & Revenue Attrition Estimates

BILL COMPARISONS AND REVENUE ATTRITION ESTIMATES

Penetration: **13%**

GMO - SGS CUSTOMERS

	SGS	SGS	Demand	SGS TOU	SDS TOU	Perfect Choice	% Change	$/mon change	Perfect Choice	Expected Avg. Bill
SC0113	$ 1,309.76	$ 1,309.76	$ 2,446.42	$ 1,028.11	$ 1,113.52	$ 1,028.11	-21.5%	$ (23.47)	SGS TOU	$ 1,273.14
SC0120	$ 1,127.69	$ 1,127.69	$ 2,330.72	$ 866.47	$ 853.16	$ 853.16	-24.3%	$ (22.88)	SDS TOU	$ 1,092.00
SC0129	$ 1,815.72	$ 1,815.72	$ 2,746.95	$ 1,730.72	$ 1,420.84	$ 1,420.84	-21.7%	$ (32.91)	SDS TOU	$ 1,764.39
SC0124	$ 1,625.05	$ 1,625.05	$ 2,541.85	$ 1,526.13	$ 1,348.21	$ 1,348.21	-17.0%	$ (23.07)	SDS TOU	$ 1,589.06
SC0117	$ 749.70	$ 749.70	$ 2,090.56	$ 661.97	$ 848.57	$ 661.97	-11.7%	$ (7.31)	SGS TOU	$ 738.30
SC0116	$ 1,192.76	$ 1,192.76	$ 2,381.71	$ 1,119.66	$ 1,091.54	$ 1,091.54	-8.5%	$ (8.43)	SDS TOU	$ 1,179.60
SC0135	$ 1,239.47	$ 1,239.47	$ 2,371.05	$ 1,173.63	$ 2,032.90	$ 1,173.63	-5.3%	$ (5.49)	SGS TOU	$ 1,230.91
SC0115	$ 1,270.40	$ 1,270.40	$ 2,434.49	$ 1,216.19	$ 1,759.52	$ 1,216.19	-4.3%	$ (4.52)	SGS TOU	$ 1,263.35
SC0118	$ 1,079.43	$ 1,079.43	$ 2,322.26	$ 1,038.35	$ 1,435.75	$ 1,038.35	-3.8%	$ (3.42)	SGS TOU	$ 1,074.09
SC0127	$ 1,018.23	$ 1,018.23	$ 2,233.70	$ 983.83	$ 1,878.13	$ 983.83	-3.4%	$ (2.87)	SGS TOU	$ 1,013.76
SC0119	$ 864.48	$ 864.48	$ 2,176.83	$ 832.77	$ 1,454.61	$ 832.77	-3.7%	$ (2.64)	SGS TOU	$ 860.36
SC0125	$ 1,199.37	$ 1,199.37	$ 2,319.60	$ 1,172.97	$ 1,195.91	$ 1,172.97	-2.2%	$ (2.20)	SGS TOU	$ 1,195.94
7658197596	$ 1,009.75	$ 1,009.75	$ 2,234.41	$ 998.44	$ 1,431.44	$ 998.44	-1.1%	$ (0.94)	SGS TOU	$ 1,008.28
SC0107	$ 1,263.30	$ 1,263.30	$ 2,393.18	$ 1,324.80	$ 1,458.85	$ 1,263.30	0.0%	$ -	SGS	$ 1,263.30
SC0121	$ 1,152.99	$ 1,152.99	$ 2,299.93	$ 1,153.00	$ 1,616.85	$ 1,152.99	0.0%	$ -	SGS	$ 1,152.99
SC0137	$ 1,626.64	$ 1,626.64	$ 2,608.76	$ 1,704.71	$ 2,016.47	$ 1,626.64	0.0%	$ -	SGS	$ 1,626.64
SC0122	$ 1,114.62	$ 1,114.62	$ 2,288.35	$ 1,194.09	$ 1,453.37	$ 1,114.62	0.0%	$ -	SGS	$ 1,114.62
SC0123	$ 1,237.51	$ 1,237.51	$ 2,369.82	$ 1,343.39	$ 1,509.23	$ 1,237.51	0.0%	$ -	SGS	$ 1,237.51
SC0102	$ 952.18	$ 952.18	$ 2,187.44	$ 1,048.75	$ 1,296.97	$ 952.18	0.0%	$ -	SGS	$ 952.18
SC0225	$ 796.63	$ 796.63	$ 2,110.19	$ 921.66	$ 1,419.45	$ 796.63	0.0%	$ -	SGS	$ 796.63
SC0138	$ 1,674.28	$ 1,674.28	$ 2,682.19	$ 1,998.79	$ 2,366.13	$ 1,674.28	0.0%	$ -	SGS	$ 1,674.28
SC0126	$ 969.05	$ 969.05	$ 2,207.40	$ 1,169.89	$ 1,464.71	$ 969.05	0.0%	$ -	SGS	$ 969.05
SC0134	$ 1,809.51	$ 1,809.51	$ 2,747.38	$ 2,157.20	$ 2,862.25	$ 1,809.51	0.0%	$ -	SGS	$ 1,809.51
SC0114	$ 792.06	$ 792.06	$ 2,113.60	$ 895.31	$ 1,459.59	$ 792.06	0.0%	$ -	SGS	$ 792.06
	$ 28,891	$ 28,891	$ 56,639	$ 29,261	$ 36,788	$ 27,209		$ (140.15)		$ 28,671.92
		0.0%	**96.0%**	**1.3%**	**27.3%**	**-5.8%**				**-0.76%**

Table 11-4: GMO SDS Bill Comparison & Revenue Attrition Estimates

BILL COMPARISONS AND REVENUE ATTRITION ESTIMATES

New or Existing: **Existing**

Penetration: 13%

GMO - SDS CUSTOMERS

	SDS	SDS	DEMAND	SGS TOU	SDS TOU	Perfect Choice	% Change	$/mon change	Perfect Choice	Expected Avg. Bill
SC0136	$ 5,612.94	$ 5,612.94	$ 5,613.34	$ 4,470.46	$ 3,585.21	$ 3,585.21	-36.1%	$ (168.98)	SDS TOU	$ 5,349.34
SC0131	$ 5,373.08	$ 5,373.08	$ 5,373.48	$ 5,617.30	$ 3,329.95	$ 3,329.95	-38.0%	$ (170.26)	SDS TOU	$ 5,107.48
SC0151	$ 9,793.38	$ 9,793.38	$ 9,793.78	$ 12,305.70	$ 6,864.80	$ 6,864.80	-29.9%	$ (244.05)	SDS TOU	$ 9,412.67
SC0155	$ 7,070.00	$ 7,070.00	$ 7,070.40	$ 8,179.13	$ 5,011.70	$ 5,011.70	-29.1%	$ (171.52)	SDS TOU	$ 6,802.42
SC0130	$ 4,379.36	$ 4,379.36	$ 4,379.76	$ 4,144.26	$ 3,746.05	$ 3,746.05	-14.5%	$ (52.78)	SDS TOU	$ 4,297.03
SC0140	$ 5,895.15	$ 5,895.15	$ 5,895.55	$ 6,425.68	$ 4,829.54	$ 4,829.54	-18.1%	$ (88.80)	SDS TOU	$ 5,756.62
SC0142	$ 7,396.52	$ 7,396.52	$ 7,396.92	$ 9,007.09	$ 6,307.47	$ 6,307.47	-14.7%	$ (90.75)	SDS TOU	$ 7,254.94
SC0139	$ 8,600.17	$ 8,600.17	$ 8,600.99	$ 8,252.97	$ 10,887.70	$ 8,252.97	-4.0%	$ (28.93)	SGS TOU	$ 8,555.03
SC0132	$ 4,568.36	$ 4,568.36	$ 4,568.76	$ 4,973.51	$ 4,406.51	$ 4,406.51	-3.5%	$ (13.49)	SDS TOU	$ 4,547.32
SC0133	$ 5,580.88	$ 5,580.88	$ 5,581.30	$ 6,405.87	$ 5,409.98	$ 5,409.98	-3.1%	$ (14.24)	SDS TOU	$ 5,558.66
SC0148	$ 7,408.62	$ 7,408.62	$ 7,409.02	$ 9,785.62	$ 7,118.10	$ 7,118.10	-3.9%	$ (24.21)	SDS TOU	$ 7,370.85
SC0178	$ 8,320.97	$ 8,320.97	$ 8,321.55	$ 10,199.60	$ 7,318.61	$ 7,318.61	-12.0%	$ (83.53)	SDS TOU	$ 8,190.66
SC0147	$ 8,073.89	$ 8,073.89	$ 8,074.38	$ 10,524.92	$ 8,608.58	$ 8,073.89	0.0%	$ -	SDS	$ 8,073.89
SC0144	$ 8,502.13	$ 8,502.13	$ 8,502.61	$ 11,465.43	$ 8,437.85	$ 8,437.85	-0.8%	$ (5.36)	SDS TOU	$ 8,493.78
SC0146	$ 8,945.07	$ 8,945.07	$ 8,945.67	$ 11,714.13	$ 10,090.34	$ 8,945.07	0.0%	$ -	SDS	$ 8,945.07
SC0149	$ 8,295.89	$ 8,295.89	$ 8,296.49	$ 11,187.75	$ 10,521.70	$ 8,295.89	0.0%	$ -	SDS	$ 8,295.89
SC0141	$ 11,031.70	$ 11,031.70	$ 11,032.39	$ 14,526.66	$ 12,234.92	$ 11,031.70	0.0%	$ -	SDS	$ 11,031.70
SC0145	$ 9,017.03	$ 9,017.03	$ 9,017.79	$ 11,421.28	$ 12,004.53	$ 9,017.03	0.0%	$ -	SDS	$ 9,017.03
SC0150	$ 11,824.81	$ 11,824.81	$ 11,825.90	$ 13,901.53	$ 16,625.47	$ 11,824.81	0.0%	$ -	SDS	$ 11,824.81
SC0154	$ 7,896.98	$ 7,896.98	$ 7,897.38	$ 10,367.51	$ 7,291.97	$ 7,291.97	-7.7%	$ (50.42)	SDS TOU	$ 7,818.33
	$ 153,586.9	$ 153,586.9	$ 153,597.5	$ 184,876.4	$ 154,631.0	$ 139,099.1		$ (1,207.3)		$ 151,703.50
		0.0%	**0.0%**	**20.4%**	**0.7%**	**-9.4%**				**-1.2%**

It is also possible that Residential and Small General Service customers only switch to a new optional rate plan if it provides a minimum amount of monthly bill savings. For example, customers may not be willing to switch to a new rate unless it saves them $5 per month. Several scenarios are provided in Table 11-5 and Table 11-6 with the "perfect choice" scenario. A 28 percent penetration was assumed for Residential, and 13 percent penetration was assumed for Small General Service.   The scenarios are defined as follows.

1. ***Perfect choice scenario*** – This is the $0.00 savings threshold scenario. This assumes all customers that would save from an optional rate would switch to the optimal rate and the average bill reduction of all customers would be $8.99 per month and the total revenue loss would be 8.8 percent.
2. ***Saving thresholds scenarios*** – These scenarios determine the average bill reduction and total revenue loss assuming customers would switch to an optional rate for at least a specific threshold of savings. In the $2.50 threshold scenario, 67 percent of all GMO GU customers would switch to an optional rate and the average savings would be $8.68 per month with a total revenue loss of 8.5 percent.
3. ***28 percent penetration rate scenario -*** This scenario represents the estimated average bill reduction and percent revenue change assuming 28 percent of all customers switched to the optimal rate. In this scenario, the average bill reduction of all GMO GU customers would be $2.52 per month with a total revenue loss of 2.46 percent.

Table 11-5: GMO Residential Classes Saving Thresholds

General Use	[1] Perfect Choice	[2] Savings Threshold	[2] Savings Threshold	[2] Savings Threshold	[3] 28% Penetration
Savings Threshold $/month	$0.00	$2.50	$5.00	$7.50	N/A
Avg Bill Reduction $/month	($8.99)	($8.68)	($1.27)	($1.27)	($2.52)
Revenue Change %	-8.80%	-8.50%	-1.25%	-1.25%	-2.46%
Customers Switched %	91.2%	67.6%	2.9%	2.9%	28.0%

Electric Space Heating	[1] Perfect Choice	[2] Savings Threshold	[2] Savings Threshold	[2] Savings Threshold	[3] 28% Penetration
Savings Threshold $/month	$0.00	$2.50	$5.00	$7.50	N/A
Avg Bill Reduction $/month	($1.36)	($1.07)	($0.43)	($0.43)	($1.33)
Revenue Change %	-1.01%	-0.80%	-0.32%	-0.32%	-0.99%
Customers Switched %	59.4%	28.1%	6.3%	6.3%	28.0%

Table 11-6: GMO Small General Service Classes Saving Thresholds

SGS	[1] Perfect Choice	[2] Savings Threshold	[2] Savings Threshold	[2] Savings Threshold	[3] 13% Penetration
Savings Threshold $/month	$0.00	$2.50	$5.00	$7.50	N/A
Avg Bill Reduction $/month	($4.12)	($4.03)	($0.97)	($0.97)	($0.76)
Revenue Change %	-4.11%	-4.02%	-0.96%	-0.96%	-0.76%
Customers Switched %	40.6%	34.4%	3.1%	3.1%	13.0%

SDS	[1] Perfect Choice	[2] Savings Threshold	[2] Savings Threshold	[2] Savings Threshold	[3] 13% Penetration
Savings Threshold $/month	$0.00	$2.50	$5.00	$7.50	N/A
Avg Bill Reduction $/month	($4.02)	($3.91)	($3.74)	($3.39)	($7.85)
Revenue Change %	-0.63%	-0.61%	-0.58%	-0.53%	-1.23%
Customers Switched %	43.8%	34.4%	28.1%	21.9%	13.0%

12.0 DEMAND RESPONSE ANALYSIS

12.1 Demand Response Assumptions

When optional rates are offered, there is a risk of revenue attrition due to both rate option self-selection and demand reduction and load shifting. Demand response (DR) will occur when customers change their usage behaviors in response to changes in the price of energy or demand throughout the day. The larger the energy price or demand price differential between on-peak and off-peak time periods the higher the expected level of response.

For this Study, it is assumed that the Residential TOU Energy rates and Demand rates developed would generate a system peak load reduction of 10 percent for Residential GU and SH customers for those that select the rate. This is similar to the rate designs included in KCP&L's 2016 DSM Potential study[13]. The assumed peak demand reduction and usage shift from on-peak to off-peak TOU periods is reasonable based on the elasticity of substitution (EOS) factors achieved in the KCP&L Smart Grid TOU Pricing Pilot[14] and TOU rate designs developed in this Study.[15] Individual customer peak demand and combined system load response estimates were prepared to validate that estimates were within reason, given a Residential EOS of -0.13 and the TOU on-peak and off-peak rates developed within this Study which have a price differential of 3 to 1. The Residential Demand rates developed within this Study, which are approximately 70 percent higher than those in the DSM Potential Study, would most likely generate a slightly higher level of demand response than 10 percent however there has not been enough research or Pilot studies with rates of this nature to support estimates higher than 10 percent. Actual response will almost certainly vary and will need to be tracked and analyzed once implemented to understand actual shift.

For the Small General Service classes, it is assumed that the SGS TOU and SDS TOU rates would generate a peak load reduction at the meter of 0.4 percent similar to that estimated in the KCP&L 2016

[13] KCP&L 2016 DSM Potential Study-Volume 3: Potential Analysis Final Report, Applied Energy Group, Inc., 2017, Pg. 54.

[14] KCP&L Green Impact Zone SmartGrid Demonstration Project Final Technical Report, version 2.0, dated May 22, 2015. Available at: https://www.smartgrid.gov/files/OE0000221_KCPL_FinalRep_2015_04.pdf

[15] Caution is urged when setting expectations for the potential response from TOU rates. BMcD notes that EPRI, in its 2014-2015 study Measuring Customer Preferences for Alternative ESPs completed for KCP&L, observed that customers, for some unidentified reason, are less likely to select a TOU rate than individuals in the other surveyed utility service territories.

DSM Potential Study[16]. The cost of service based TOU rates developed for SGS TOU and SDS TOU both have an on-peak to off-peak price differential of approximately 3 to 1, which is similar to that assumed in the DSM Potential Study. GMO or KCP&L have not completed any recent pilot studies to test and validate that these levels of DR are reasonable, however, small commercial customers are traditionally less price responsive to TOU rates due to their inability to turn off load during normal business hours. Actual response will almost certainly vary and will need to be tracked and analyzed once implemented to understand actual shift.

For each customer load profile in the load research groups, energy usage was shifted from on-peak to off-peak periods, and the monthly 15-minute peak demand was reduced to determine the impact to each monthly bill, assuming DR occurs. The monthly and annual revenue reduction by customer and class was estimated to determine the potential revenue loss from DR. The average Residential customer load profile switching to one of the TOU rates would not see any change in their bill. However, if the customer were to shift 10 percent of their on-peak load to off-peak hours, their annual bill would reduce by approximately 2 percent or $2 per month. A 20 percent shift would generate a savings of $4 per month. Typical summer load shapes with and without DR impacts for both Residential TOU and SDS TOU Rate customers are provided in the following figures along with the hourly TOU rates.

[16] KCP&L 2016 DSM Potential Study-Volume 3: Potential Analysis Final Report, Applied Energy Group, Inc., 2017, Pg. 54.

Figure 12-1: GMO Residential Summer TOU Rates and Demand Response Profile

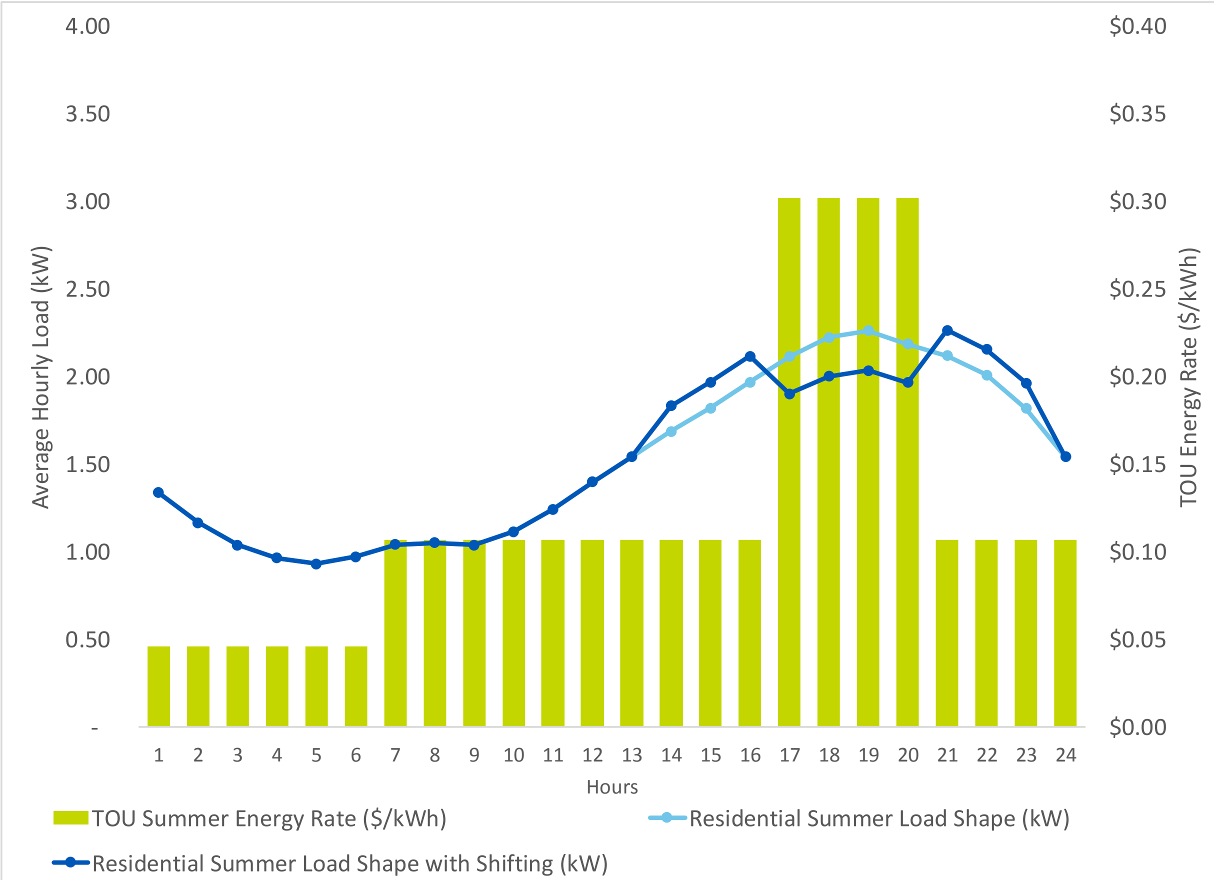
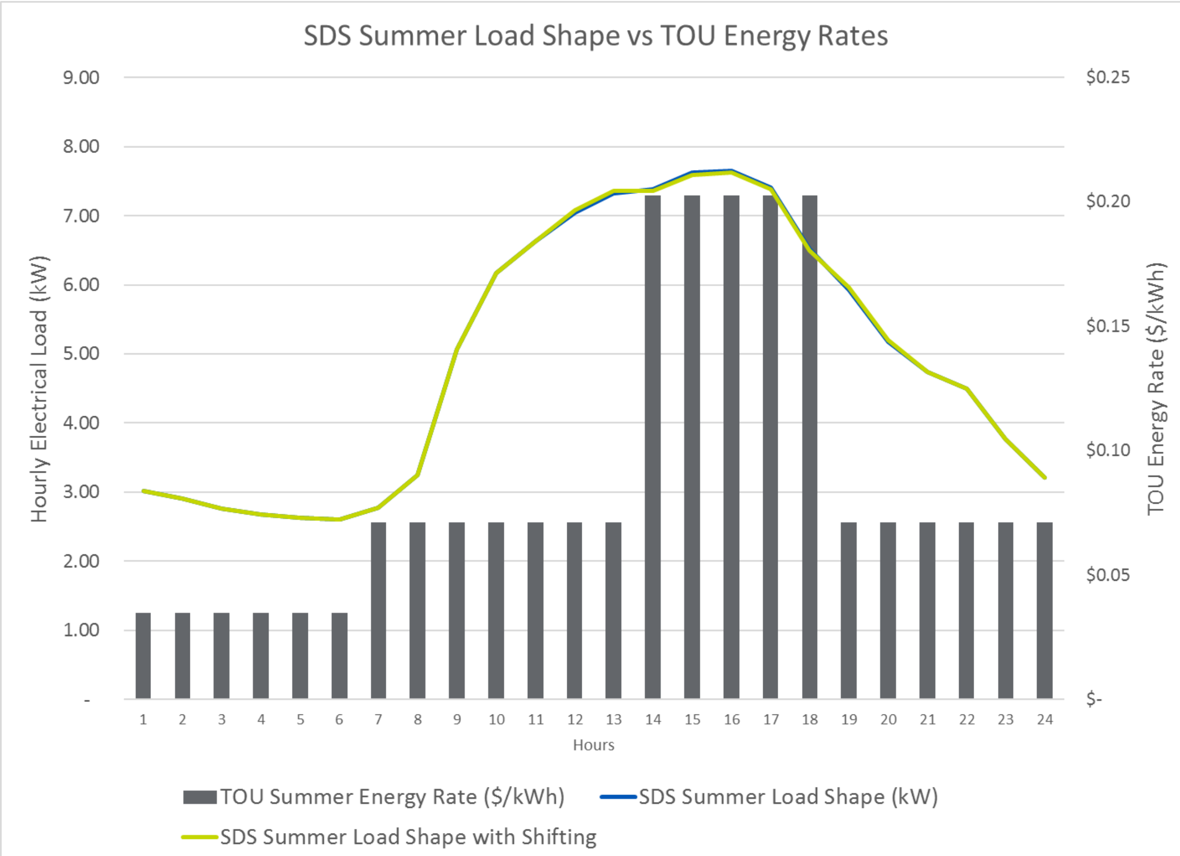


Figure 12-2: GMO Small General Service Summer TOU Rates and Demand Response Profile



12.2 Demand Response Revenue Attrition and Recovery

The estimated DR resulting from the implementation of new optional rates along with the estimated loss is presented below. The scenarios assume that customers' DR revenue reduction is incremental to self-selection and that only customers who switch to a time variant rate would respond. The revenue change and demand reduction for the "perfect choice" case and realistic achievable penetration rate for Residential and Small General Service classes, are presented with and without DR. If customers both switch and respond as predicted, the potential revenue loss would increase as presented. It should be noted that DR and resulting revenue attrition is extremely difficult to estimate. The revenue losses shown here have specific assumptions and include elasticities that were utilized in the 2016 DSM Market Potential Study. However, actual revenue losses may vary, going up or down. As such, for purposes of recovery, it will be critical that actual revenue losses be monitored and tracked and ideally, recovered as part of a MEEIA type program or like mechanism that recognizes the need for the Company to be kept whole when promoting energy efficiency, demand response rate programs, and demand side rates that impacts the company's revenue requirement and ability to recover fixed costs. However, while 28% penetration rates were assumed, based on Potential Study assumptions, expected penetration rates will likely vary given the rate designs outlined here vary from those used in the Potential Study. The scenarios are defined as follows.

1. ***Perfect choice scenario*** – This is the $0.00 savings threshold scenario. This assumes all customers that would save from an optional rate would switch to the optimal rate. For the GMO GU customers, the average bill reduction of all customers would be $8.99 per month and the total revenue loss would be 8.8 percent.
2. ***Demand response and perfect choice scenario*** – This is the $0.00 savings threshold scenario coupled with expected demand response. This assumes all customers that would save from an optional rate would switch to the optimal rate and shift their load off the on-peak time periods resulting in additional revenue reduction and bill savings. For the GMO GU customers, the average bill reduction for all customers would be $13.16 per month and the total revenue loss would be 12.88 percent.
3. ***28 percent penetration rate scenario*** **-** This scenario represents the estimated average bill reduction and percent revenue change assuming 28 percent of all customers switched to the optimal rate. In this scenario, the average bill reduction of all GMO GU customers would be $2.52 per month with a total revenue loss of 2.46 percent.
4. ***Demand response and 28 percent penetration scenario*** **-** This scenario represents the estimated average bill reduction and percent revenue change assuming 28 percent of all customers switched to the optimal rate and shift their load off the on-peak time periods resulting in additional revenue reduction and bill savings. In this scenario, the average bill reduction of all GMO GU customers would be $3.68 per month with a total revenue loss of 3.61 percent.

Table 12-1: Residential Self Selection and Demand Response Revenue Loss

	[1]	[2]	[3]	[4]
General Use	Perfect Choice	Demand Response Perfect Choice	28% Penetration	Demand Response 28% Penetration
Savings Threshold $/month	$0.00	$0.00	N/A	N/A
Avg Bill Reduction $/month	($8.99)	($13.16)	($2.52)	($3.68)
Revenue Change %	-8.80%	-12.88%	-2.46%	-3.61%
Customers Switched %	91.2%	94.1%	28.0%	28.0%
Demand Response %	0.0%	-9.2%	0.0%	-2.6%

	[1]	[2]	[3]	[4]
Electric Space Heating	Perfect Choice	Demand Response Perfect Choice	28% Penetration	Demand Response 28% Penetration
Savings Threshold $/month	$0.00	$0.00	N/A	N/A
Avg Bill Reduction $/month	($1.36)	($2.36)	($1.33)	($2.30)
Revenue Change %	-1.01%	-1.76%	-0.99%	-1.71%
Customers Switched %	59.4%	71.9%	28.0%	28.0%
Demand Response %	0.0%	-5.3%	0.0%	-1.5%

Table 12-2: Small General Service Self Selection and Demand Response Revenue Loss

SGS	[1] Perfect Choice	[2] Demand Response Perfect Choice	[3] 13% Penetration	[4] Demand Response 13% Penetration
Savings Threshold $/month	$0.00	$0.00	N/A	N/A
Avg Bill Reduction $/month	($4.12)	($4.13)	($0.76)	($0.76)
Revenue Change %	-4.11%	-4.12%	-0.76%	-0.76%
Customers Switched %	40.6%	43.8%	13.0%	13.0%
Demand Reduction %	0.00%	-0.20%	0.00%	-0.03%

SDS	[1] Perfect Choice	[2] Demand Response Perfect Choice	[3] 13% Penetration	[4] Demand Response 13% Penetration
Savings Threshold $/month	$0.00	$0.00	N/A	N/A
Avg Bill Reduction $/month	($4.02)	($4.08)	($7.85)	($7.95)
Revenue Change %	-0.63%	-0.64%	-1.23%	-1.24%
Customers Switched %	43.8%	43.8%	13.0%	13.0%
Demand Reduction %	0.00%	-0.22%	0.00%	-0.03%

12.3 Demand Response Benefit Cost Savings Evaluation

GMO may reduce its system peak demand due to customers responding to demand rates and TOU rates. The level of response realized by customers may result in peak demand costs being avoided by GMO. The value of the peak demand savings to GMO and how those savings can be realized will depend on how the Commission establishes the value for peak demand reduction achieved from demand side rates.

It is expected that customers will slowly transition to the new TOU rates over several years and that GMO will not reach the realistic achievable penetration rates estimated in the KCP&L 2016 DSM Potential Study for some time. The earliest that new TOU rates could be available for parts of the GMO service area is sometime after the next rate case and after the new CIS is available. The new advanced meters that can measure TOU energy usage and peak demand are currently being deployed in the GMO service area with all installations expected to be completed by 2020.

The revenue losses due to customer self-selection and DR would increase slowly over time as customers switched to TOU rates. Customer switching would likely only occur in combination with marketing and other educational programs implemented by GMO, which would increase costs in the early years of the optional rate programs. The estimated annual revenue losses from the optional TOU rates should be closely tracked and monitored. This would allow GMO to quantify revenue losses due to customer self-selection and demand response in its future rate cases, since the loss will be immediate when it occurs.

The potential annual peak demand cost savings resulting from customers shifting load may offset a portion of the estimated revenue losses resulting from customer switching and DR. However, as noted earlier, actual revenue losses will require monitoring and tracking to size, and any peak demand cost savings, likely to be more long term in realization, will require clarity on the value of peak demand savings, to determine true impact. As a demand-side option, GMO should explore implementing the optional rates as programs in its MEEIA program portfolio to recover the program costs and revenue losses.

13.0 CUSTOMER BILL ANALYSIS

13.1 Background

The implementation of optional TOU rates and acceptance of those rates will depend on several factors as explained in previous sections of this report. These will include GMO's promotional activities to encourage adoption of optional rates. Some future customers may be automatically be placed on certain rates by default, while others will be able to choose the rate that provides them with the most benefits based on their usage patterns and ability to change their behavior.

13.2 Residential

Typical bills were prepared to demonstrate how customer bills would be impacted by choosing one of three optional rates over the existing Residential rates without any demand response. Typical bills for low, medium, and high usage customers; with low, medium, and high load factors are provided in Table 13-1. Based on a review of the bills there are several points that should be made regarding the optional rates as it relates to the various types of customers.

- General Use Customers – Low load factor customers will be inclined to select the existing GU rates while high load factor customers will be better off to choose one of the demand rates. In the short term, GMO high use customers will elect to remain on the GU Rate due to the DBR. Some GU customers may choose the TOU Energy rate option due to either (1) their load profile or (2) their ability to respond to price signals with changes in behavior that reduce their bill.
- Electric Space Heating Customers – Most existing low load factor customers would likely choose to stay on the existing SH Rate until it is no longer available to them. New electric space heating customers would be placed on the Demand Rate in the future by default however some low load factor customers may benefit from the GU Rate. New space heating customers may pay slightly more on average than existing space heating customers.
- Electric Vehicle Customers – Existing and future customers with EVs would be best served by switching to one of the new optional rates depending on their non-EV usage. The TOU Energy Rate and TOU Energy and Demand Rate would allow customers to delay their charging to late night hours at prices lower than the other rates. Typical bills for various customer profiles with off-peak EV charging included are considered in greater detail in Table 14-1 later in the report.
- Distributed Generation Customers – All future DG customers should be placed on either the Demand Rate or the TOU Energy and Demand Rate subject to statutory limitations in Missouri. Under the current regulatory framework in Missouri, DG customers would likely choose to be on the GU Rate until which time their maximum monthly demand forces them into one of the Demand Rates. Absent

any changes in usage, bills would increase over the existing rate, reducing the current subsidy inherent in the existing GU Rate. The bill analysis assumes that the DG customer has 5 kW of solar and is forced into one of the demand rates in the future.

Table 13-1: GMO Residential Customer Bill Analysis

Load profile	Average Load Factor	Energy	Existing Residential	Optional Demand	Optional TOU	Optional TOU + Demand	Minimum	Change from Existing	
	%	kWh	$ / Year	$ / Year	$ / Year	$ / Year	$ / Year	$ / Year	%
Res. General Use - GMO	36.7%	5,000	$699	$916	$682	$917	$682	($17)	-2%
Res. General Use - GMO	36.7%	10,274	$1,296	$1,106	$1,270	$1,109	$1,106	($189)	-15%
Res. General Use - GMO	36.7%	15,000	$1,813	$1,277	$1,796	$1,280	$1,277	($536)	-30%
Res. General Use - GMO	25.2%	5,000	$698	$1,223	$687	$1,228	$687	($11)	-2%
Res. General Use - GMO	25.2%	10,274	$1,298	$1,413	$1,279	$1,423	$1,279	($20)	-2%
Res. General Use - GMO	25.2%	15,000	$1,800	$1,583	$1,809	$1,598	$1,583	($217)	-12%
Res. General Use - GMO	22.0%	5,000	$684	$1,290	$653	$1,290	$653	($31)	-5%
Res. General Use - GMO	22.0%	10,274	$1,228	$1,477	$1,210	$1,478	$1,210	($18)	-1%
Res. General Use - GMO	22.0%	15,000	$1,680	$1,644	$1,709	$1,646	$1,644	($35)	-2%
Res. Electric Heat - GMO	48.8%	7,500	$974	$1,084	$939	$1,081	$939	($35)	-4%
Res. Electric Heat - GMO	48.8%	15,051	$1,674	$1,354	$1,758	$1,348	$1,348	($326)	-19%
Res. Electric Heat - GMO	48.8%	22,500	$2,290	$1,620	$2,566	$1,612	$1,612	($678)	-30%
Res. Electric Heat - GMO	29.9%	7,500	$919	$1,455	$889	$1,443	$889	($30)	-3%
Res. Electric Heat - GMO	29.9%	15,051	$1,565	$1,723	$1,657	$1,698	$1,565	$0	0%
Res. Electric Heat - GMO	29.9%	22,500	$2,145	$1,987	$2,415	$1,950	$1,950	($195)	-9%
Res. Electric Heat - GMO	64.7%	7,500	$866	$873	$883	$861	$861	($5)	-1%
Res. Electric Heat - GMO	64.7%	15,051	$1,864	$2,004	$1,949	$1,801	$1,801	($64)	-3%
Res. Electric Heat - GMO	64.7%	22,500	$1,911	$1,399	$2,399	$1,366	$1,366	($545)	-29%
110v EV Charger [1]		-	$554	$262	$268	$195	$195	($358)	-65%
220v EV Charger [1]		-	$554	$262	$268	$195	$195	($358)	-65%
5kW Solar [2]		12,000	$631	$920	$664	*$964*	$920	$289	46%

[1] EV charger only includes super off peak EV charging load of 3860 kWh per year.
[2] Solar profile is based on NREL profiles for Missouri.

13.3 Small General Service

Typical bills were prepared to demonstrate how customer bills would be impacted by choosing one of three optional rates over their existing SGS and SDS rates without any demand response. Typical bills for low, medium, and high usage customers; with low, medium, and high load factors are provided in the table below. Based on a review of the bills there are several points that should be made regarding the proposed rates as it relates to the various types of customers.

- Small General Service Customers – Low load factor customers who are under the current threshold of 25 kW, will be inclined to select the SGS Rate or SGS TOU Rate, while high load factor customers may be better off by choosing the SDS TOU Rate. Additionally, SGS customers with greater levels of off-peak usage would likely switch to the SGS TOU Rate while customers with relatively greater levels of on-peak usage would elect to remain on the SGS Rate until forced onto the SDS or SDS

TOU rate. Some SGS customers may choose the TOU Energy rate option due to either (1) their load profile or (2) their ability to respond to price signals with changes in behavior that reduce their bill.

- Small General Service Customers with Demand – Low load factor customers would likely choose to stay on the existing SDS Rate, while high load factor customers would benefit by switching to the SDS TOU Rate as designed. Additionally, SDS customers with greater levels of off-peak usage would likely switch to SDS TOU Rate while customers with relatively greater levels of on-peak usage would elect to remain on the SDS Rate. Some SDS customers may choose the SDS TOU rate option due to either (1) their load profile or (2) their ability to respond to price signals with changes in behavior that reduce their bill.

Table 13-2: GMO Small General Service Customer Bill Analysis

Load profile	Average Load Factor	Energy	Existing SGS	Optional SDS	Optional SGS TOU	Optional SDS TOU	Minimum	Change from Existing	
	%	kWh	$ / Year	$ / Year	$ / Year	$ / Year	$ / Year	$ / Year	%
SGS - GMO	9.6%	4,250	$759	$1,121	$737	$900	$737	($22)	-3%
SGS - GMO	9.6%	8,500	$1,231	$1,583	$1,186	$1,513	$1,186	($44)	-4%
SGS - GMO	9.6%	12,750	$1,703	$2,046	$1,636	$2,126	$1,636	($67)	-4%
SGS - GMO	26.7%	4,250	$765	$1,058	$811	$751	$751	($14)	-2%
SGS - GMO	26.7%	8,500	$1,244	$1,458	$1,336	$1,216	$1,216	($28)	-2%
SGS - GMO	26.7%	12,750	$1,722	$1,857	$1,860	$1,680	$1,680	($42)	-2%
SGS - GMO	54.9%	4,250	$820	$1,076	$780	$677	$677	($143)	-17%
SGS - GMO	54.9%	8,500	$1,352	$1,494	$1,274	$1,066	$1,066	($286)	-21%
SGS - GMO	54.9%	12,750	$1,885	$1,911	$1,767	$1,456	$1,456	($429)	-23%
SDS - GMO	22.9%	38,500	$4,235	$4,235	$5,375	$4,975	$4,235	$0	0%
SDS - GMO	22.9%	77,000	$8,026	$8,026	$10,464	$9,662	$8,026	$0	0%
SDS - GMO	22.9%	115,500	$11,895	$11,895	$15,553	$14,350	$11,895	$0	0%
SDS - GMO	36.6%	38,500	$4,053	$4,053	$5,043	$4,207	$4,053	$0	0%
SDS - GMO	36.6%	77,000	$7,475	$7,475	$9,799	$8,127	$7,475	$0	0%
SDS - GMO	36.6%	115,500	$11,064	$11,064	$14,555	$12,047	$11,064	$0	0%
SDS - GMO	47.3%	38,500	$4,079	$4,079	$4,137	$3,364	$3,364	($715)	-18%
SDS - GMO	47.3%	77,000	$1,864	$2,004	$1,949	$1,801	$1,801	($64)	-3%
SDS - GMO	47.3%	115,500	$11,125	$11,125	$11,837	$9,518	$9,518	($1,607)	-14%

14.0 ELECTRIC VEHICLE TOU RATES

This Study includes an assessment of TOU rates and how they apply to Residential customers with EV charging loads. As previously stated in this report, GMO and KCP&L do not plan to offer rates that depend on end-use loads behind the Residential meter, or rates that depend on a new sub-meter. Rate designs should reflect the utility's cost to provide service by time and season so that customers who use more energy in off-peak time periods are not charged the same amount as those who use more energy during on-peak time periods. Rate options that are developed for customers should allow for cost and time effective EV charging, which in turn will benefit both the utility, Residential EV owners, and other customer classes. This section of the report considers the utilization and application of TOU rates for Residential EV charging.

14.1 Residential EV Charging

According to studies completed by Idaho National Labs (INL), 84 to 87 percent of EV owners charge their EV at home, instead of at a public charging station.[17] In addition to charging at home, some EV owners also use a Level 2 charging station that is available to them at their workplace, while others use a public charging station that is either a Level 2 charging station or a direct current fast charge (DCFC) charging station. Relying on public charging stations, though, can be unpredictable and contributes to why most EV charging is done in the home. Residential EV loads range from 1.4 kW to 7.7 kW depending on the charging infrastructure installed in the home, and depending on the type of EV the customer owns.[18] EV charging load in the GMO service territory, if placed on the system during the on-peak hours, could significantly increase local distribution system peak loads, as well as contribute to the system peak.

14.2 Residential EV TOU Demand Response

Implementing a TOU rate that includes super-off-peak pricing has been proven to effectively shift EV charging loads from on-peak to super off-peak time periods. For example, the San Diego Gas & Electric Plug-in Electric Vehicle TOU Pricing and Technology Study found that EV owners conducted approximately 80 percent of their charging during the super off-peak periods when offered a 2:1 or 4:1 on-peak to super off-peak price ratio and that ratios greater than 6:1 had little incremental impact .[19] The EV TOU pilot conducted by INL demonstrated that utilities who offered a cost based TOU rate were far

[17] Idaho National Labs. (2013). Plugged In: How Americans Charge Their Electric Vehicles, pp. 8
[18] Idaho National Labs. (2013). How do PEV owners respond to time-of-use rates while charging EV Project vehicles? pp. 8
[19] Nexant. (2014). Final Evaluation for San Diego Gas & Electric's Plug-in Electric Vehicle TOU Pricing and Technology Study, pp. 3

more successful in having customers shift EV charging loads to off-peak time periods, as compared to utilities who did not offer a TOU rate. Figure 14-1 and Figure 14-2 demonstrates Pacific Gas & Electric's (PG&E) three-time period TOU rate and its effectiveness in shifting EV charging load to super off-peak time periods.[20] This is compared to the EV load profiles of Nashville Electric Service (NES) in Figure 14-3 and Figure 14-4 where a TOU rate is not in place.[21] If a TOU rate is not available, as in NES's case, the majority of EV charging load occurs during on-peak hours, since there is not a price benefit for customers to charge during off-peak hours.

Figure 14-1: Weekday Residential EV Charging Availability in PG&E Territory, Q1 2013

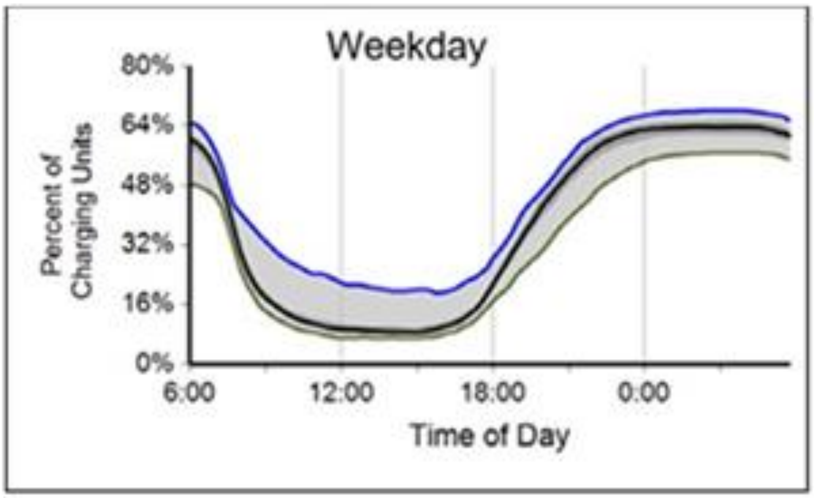
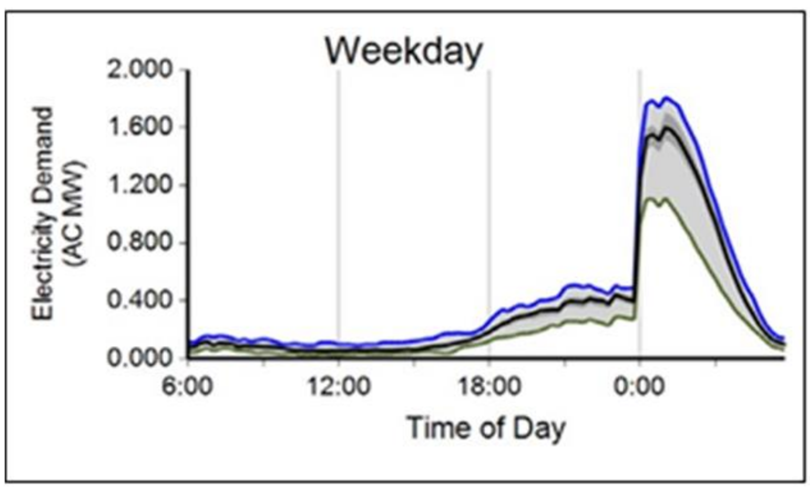


Figure 14-2: Weekday Residential EV Charging Demand in PG&E Territory, Q1 2013



[20] Idaho National Labs. (2013). Plugged In: How Americans Charge Their Electric Vehicles, pp. 2
[21] Idaho National Labs. (2013). Plugged In: How Americans Charge Their Electric Vehicles, pp. 3

Figure 14-3: Weekday Residential EV Charging Availability in NES Territory, Q1 2013

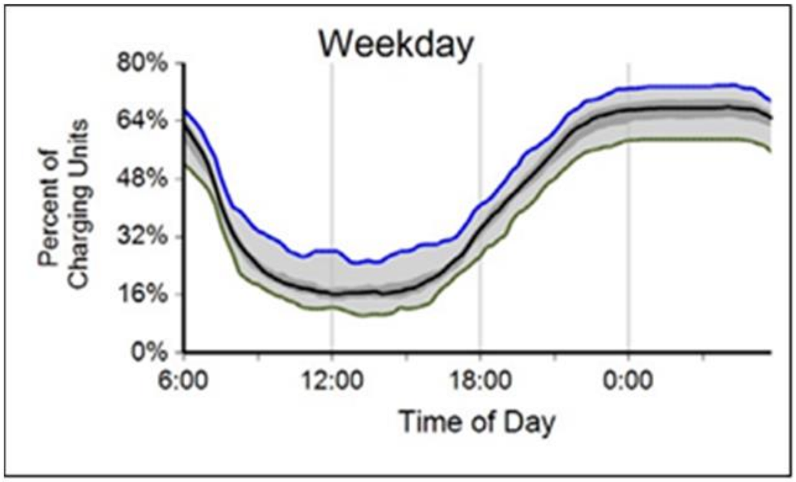
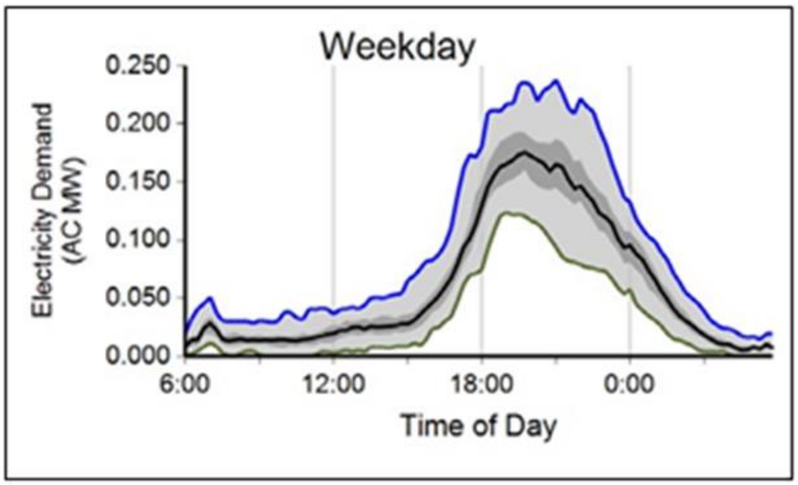


Figure 14-4: Weekday Residential EV Charging Demand in NES Territory, Q1 2013



14.3 Residential EV TOU Rate Design Options

As of June 2015, at least 28 utilities across the country offered special EV rates to their customers.[22] In addition, over 200 utilities offered TOU rates to their residential customers that could help encourage off-peak charging of EVs.[23] TOU rates can be beneficial to GMO and KCP&L by increasing demand for electricity during off-peak hours when there is a significant amount of underutilized generating capacity. TOU rates can also be economically beneficial to EV owners who take advantage of the less expensive electricity prices during off-peak hours. While switching from a gasoline vehicle to an EV results in reduced operating costs, the additional savings offered by a TOU rate can provide incremental savings over a flat rate, and significantly more savings over a default IBR. Several examples of TOU rate options

[22] Salisbury, Toor. (2016). How Leading Utilities are Embracing Electric Vehicles, pp. 11
[23] Id.

that enable cost-based EV charging include (1) TOU single meter, (2) EV TOU Single Meter, and (3) EV TOU Separately Metered. Each of these are briefly discussed below along with how they apply to GMO and KCP&L.

14.3.1 TOU Single Meter Rate

As noted earlier, many utilities have offered a general TOU rate, as opposed to a specific EV TOU rate. This employs effective rate design philosophy and provides EV owners the opportunity to save by charging during off-peak time periods. GMO and KCP&L plan to offer TOU rate options to all Residential customers, which would not only benefit EV owners, but would also benefit Residential customers who shift their non-EV loads to off-peak time periods. The optional Residential TOU single meter rates, as designed, will provide the price signals necessary for all Residential GU and SH customers to receive value from shifting their EV charging load to super off-peak time periods using their EV charging station timers or on-board EV timers.

14.3.2 EV TOU Single Meter Rate

As previously stated, approximately 28 utilities offer a special EV TOU rate to Residential customers. These rates are usually accompanied by enrollment and verification processes where the utility confirms the EV and then monitors that the EV is retained and charged as expected. While the reasons vary between jurisdictions, GMO and KCP&L does not intend to develop special end-use rates for any classes; such as a EV TOU rate. TOU rates, when designed well, should reflect the utility's cost structure and be available to all customers. If GMO and KCP&L designs a TOU rate for EV customers, it should be the same TOU rate offered to other customers to ensure that the same rates are offered to customers with similar service delivery characteristics.

14.3.3 EV TOU Separate Meter Rate

Some utilities have offered to separately metered EV charging loads on an EV-specific meter so that the entire household's electricity consumption is not subject to TOU rates. The cost of the separate EV meter and installation costs, which can range from a few hundred dollars to well over $1,000, have been found to often outweigh the benefits of these sub-metered rate offerings to a Residential customer. Further, installations of this type are prone to change as customers add new load to their internal electrical panels without consideration of the separate, specific use. GMO and KCP&L have had sub-metered rates in the past such as a special end use rate for SH customers, however, GMO has frozen many of those rates and rolled the sub-metered loads into the single metered load.

14.4 Residential Optional TOU Rates Applicability to EV Customers

GMO plans to offer three new optional rates to existing and future Residential GU and SH customers. The optional rates will be available to all customers, including those who own an EV. Each of the optional rates will provide value to those customers who shift their EV charging load to off peak periods, to those who shift some of their non-EV load to off-peak periods, and to those who reduce their current household peak demand. As part of this Study, each of the optional rates were evaluated with a typical super off-peak EV charging load profile at various existing usage levels and with various load factors. This was done to validate that switching to the optional cost-based rates provide more of a benefit to EV owners, as compared to remaining on the existing Residential GU and SH rates. The EV load profile used in assumes a usage of 3,860 kWh per year based on 12,000 miles per year, with all EV charging occurring during the super off-peak period. The results of the typical bill analysis are presented in Table 14-1.

Table 14-1: GMO Residential EV Customer Bill Analysis

Load profile	Average Load Factor	Energy	Existing Residential	Optional Demand	Optional TOU	Optional TOU + Demand	Minimum	Change from Existing	
	%	kWh	$ / Year	$ / Year	$ / Year	$ / Year	$ / Year	$ / Year	%
Res. General Use - GMO	46.1%	5,000	$1,123	$1,053	$825	$987	$825	($298)	-27%
Res. General Use - GMO	46.1%	10,274	$1,680	$1,243	$1,413	$1,179	$1,179	($501)	-30%
Res. General Use - GMO	46.1%	15,000	$2,169	$1,413	$1,939	$1,350	$1,350	($818)	-38%
Res. General Use - GMO	31.7%	5,000	$1,123	$1,360	$829	$1,298	$829	($294)	-26%
Res. General Use - GMO	31.7%	10,274	$1,672	$1,550	$1,421	$1,493	$1,421	($250)	-15%
Res. General Use - GMO	31.7%	15,000	$2,157	$1,720	$1,952	$1,668	$1,668	($489)	-23%
Res. General Use - GMO	27.7%	5,000	$1,088	$1,426	$796	$1,360	$796	($292)	-27%
Res. General Use - GMO	27.7%	10,274	$1,589	$1,613	$1,352	$1,548	$1,352	($236)	-15%
Res. General Use - GMO	27.7%	15,000	$2,036	$1,781	$1,851	$1,716	$1,716	($319)	-16%
Res. Electric Heat - GMO	57.1%	7,500	$1,328	$1,220	$1,081	$1,151	$1,081	($246)	-19%
Res. Electric Heat - GMO	57.1%	15,051	$1,947	$1,490	$1,900	$1,418	$1,418	($528)	-27%
Res. Electric Heat - GMO	57.1%	22,500	$2,574	$1,757	$2,708	$1,682	$1,682	($892)	-35%
Res. Electric Heat - GMO	35.1%	7,500	$1,270	$1,591	$1,031	$1,513	$1,031	($239)	-19%
Res. Electric Heat - GMO	35.1%	15,051	$1,860	$1,859	$1,800	$1,768	$1,768	($92)	-5%
Res. Electric Heat - GMO	35.1%	22,500	$2,430	$2,123	$2,558	$2,020	$2,020	($409)	-17%
Res. Electric Heat - GMO	75.8%	7,500	$1,195	$1,009	$1,026	$931	$931	($264)	-22%
Res. Electric Heat - GMO	75.8%	15,051	$1,864	$2,004	$1,949	$1,801	$1,801	($64)	-3%
Res. Electric Heat - GMO	75.8%	22,500	$2,195	$1,536	$2,541	$1,436	$1,436	($759)	-35%
110v EV Charger [1]		-	$554	$262	$268	$195	$195	($358)	-65%
220v EV Charger [1]		-	$554	$262	$268	$195	$195	($358)	-65%
5kW Solar [2]		12,000	$631	$920	$664	*$964*	$920	$289	46%

[1] EV charger only includes super off peak EV charging load of 3860 kWh per year.

As presented in Table 14-1, the majority of both Residential GU and SH customers who charge their EVs during the super off-peak hours, would be better off on one of the optional rates. Nearly all Residential customers currently on the existing lower winter SH rates in GMO would also benefit by switching to one of the new optional rates if the customer were to charge their EVs during the super off-peak periods.

Summer loads shapes of an average Residential customer with an EV on the GU Rate and TOU Energy Rate are presented in Figure 14-5 and Figure 14-6. As demonstrated, customers would pay 50 percent less on the TOU Energy rate for their EVs energy use as compared to the GU Rate. With EV charging load comprising nearly 30 percent of a customers' annual energy use, nearly all customers with EVs would choose to switch to a TOU rate, which aligns with the INL Study and the 2016 KCP&L DSM Potential Study. The EV load is assumed to have an estimated load of 6.6 kW on a 220 V circuit when charging.

Figure 14-5: GMO Residential Summer GU Rates and On-Peak EV Charging Profile

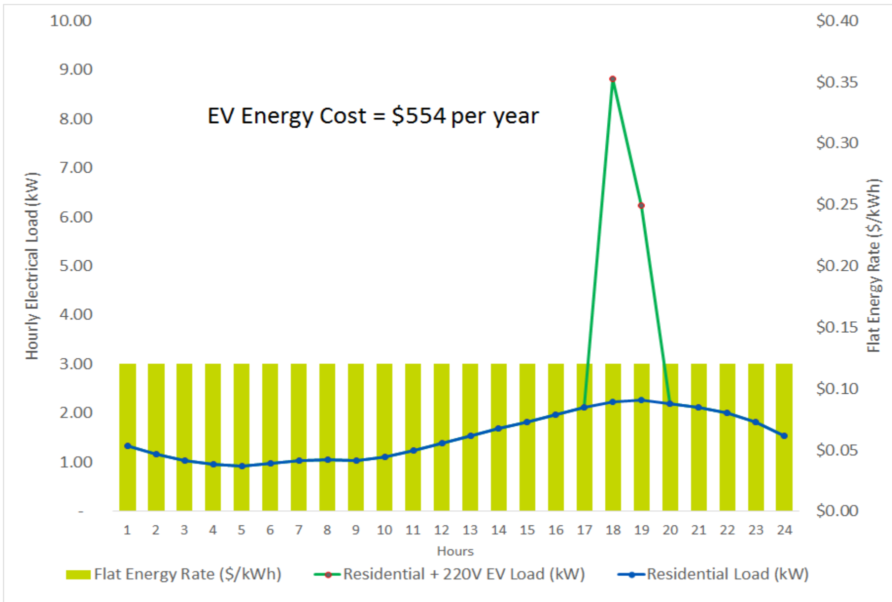
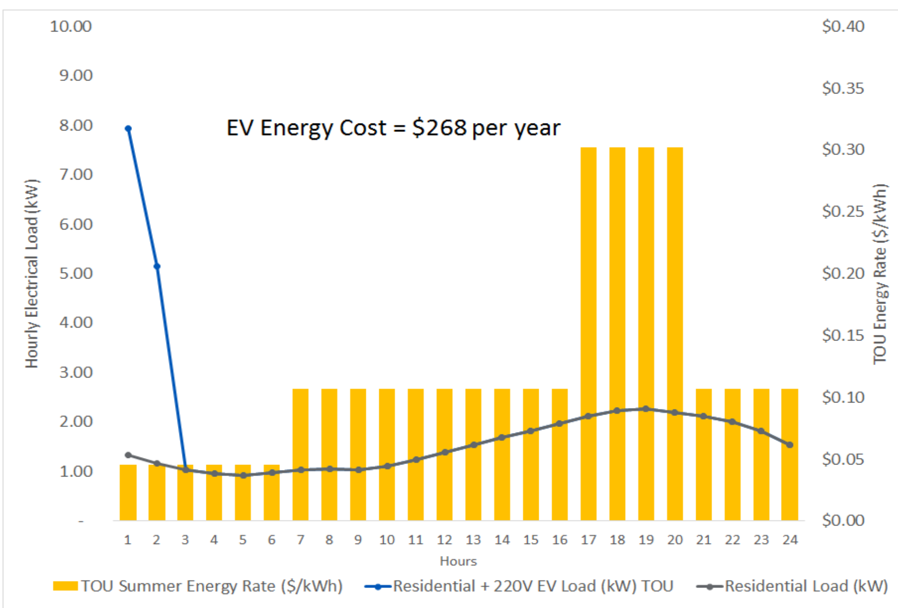


Figure 14-6: GMO Residential Summer TOU Rates and Super Off-Peak EV Charging Profile



14.5 Residential EV TOU Rate Recommendation

GMO should implement the optional rates described within this report for EV customers to use for beneficial off-peak electrical usage. The three-part rate structure with a 6 to 1 on-peak to super off-peak price ratio will provide a sufficient price signal for customers to shift their EV charging to super off-peak periods.

15.0 STUDY RECOMMENDATIONS

BMcD recommends several actions be taken by GMO based on the investigations, findings, and analyses conducted in this Study and previous Studies referenced in this report. The Study recommendations are presented herein.

- GMO should remove the existing frozen Residential and Small General Service TOU rates from its rate tariff manual and move the few remaining customers on those rates to one of the new optional rates in this Study or place them onto the appropriate default rate for their class.

- GMO should make modifications to its existing Residential rates and offer new optional rates that are consistent with internal stakeholder input summarized in Section 3.0 of this Study. If expected impacts warrant, modifications to existing rates, such as Residential General Use or Small General Service, should be made gradually.

- GMO should implement new optional rates for both the Residential and Small General Service classes that best meet GMO and KCP&L's goals and objectives and are consistent with trends geographically and nationally as outlined in Section 4.0 of this Study. GMO should continue to monitor state, regional, and national regulatory and rate trends as new rates are implemented.

- GMO should follow the Rate Transition Plan in Section 5.0 of this Study. This plan initially includes offering three new Residential rate options as part of a pilot in the next rate case that include (1) a Demand Rate, (2) a TOU Energy rate, and (3) a TOU Energy and Demand Rate. Results of the pilot will 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.

- GMO should update the new optional Residential and Small General Service rates developed in this Study following the rate design approach described in Section 6.0 in the future as needed. Future updates to optional rates should reflect GMO's CCOS model described in Section 9.0 and provide rate revenues similar to the GU rates and SH rates described in Section 10.0.

- The optional rates should be marketed to all Residential customers through a small rollout and initially made available to a limited number of GMO's Residential GU and SH.

- GMO will need to measure and verify the impacts of the new optional rates implemented in the pilot. Several key results that will need to be quantified prior to offering rates to all Residential and Small

General Service customers will include revenue loss from self-selection as described in Section 11.0 and customer demand response and revenue impacts as described in Section 12.0.

- GMO should use MEEIA as the foundation for the optional rates and these rates should be MEEIA programs for the next MEEIA plan. 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 (Integrated Resource Planning or "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 type program or like mechanism 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.

- GMO should offer the optional Demand, TOU Energy, and TOU Energy and Demand rates in this Study for all Residential customers and promote them as the rates to use for Residential in home EV charging as described in Section 14.0 of this Study. These new optional rates will support cost effective EV charging and other off-peak use. GMO should not implement new rates that require specific customer end-use equipment and should not offer sub-metered rates.

BURNS & McDONNELL

CREATE AMAZING.

KCP&L Greater Missouri Operations
2018 RATE CASE - DIRECT
TY 6/30/17; Update TBD; K&M 6/30/18
Cost of Service

Allocation Method: Production - Avg & Excess 4 CP, Transmission - Avg 12 CP

LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GMO RETAIL	RESIDENTIAL	GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	GENERAL TOD SERVICE	THERMAL SERVICE	LIGHTING
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**									
0020										
0030	OPERATING REVENUE									
0040	RETAIL SALES REVENUE	TSFR 9 30	739,293,032	380,547,793	98,276,013	115,987,834	130,321,978	35,256	529,781	13,594,378
0050	OTHER SALES REVENUE (447)	TSFR 9 120	119,157,171	51,222,934	13,923,143	22,512,208	30,407,855	5,645	122,648	962,738
0060	OTHER SALES REVENUE (449)	TSFR 9 160	465,487	294,467	50,864	53,459	38,922	14	262	27,499
0070	OTHER OPERATING REVENUE	TSFR 9 290	19,062,683	9,862,664	2,126,877	3,286,012	3,566,425	831	14,566	205,309
0080	TOTAL OPERATING REVENUE		877,978,372	441,927,857	114,376,897	141,839,513	164,335,180	41,747	667,257	14,789,923
0090										
0100	OPERATING EXPENSES									
0110	FUEL	TSFR 9 4080	80,650,017	34,905,908	9,421,356	15,153,731	20,439,682	3,852	84,755	640,733
0120	PURCHASED POWER	TSFR 9 4090	238,554,773	102,551,635	27,874,232	45,069,466	60,875,198	11,302	245,536	1,927,405
0130	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR 9 4100	244,646,695	148,138,059	26,199,798	32,976,478	33,591,040	9,430	158,426	3,573,465
0140	DEPRECIATION EXPENSES (AFTER CLEARINGS)	TSFR 5 1460	95,918,984	55,578,690	10,231,935	13,682,192	12,737,037	3,648	65,420	3,620,063
0150	AMORTIZATION EXPENSES	TSFR 9 4600	7,352,566	4,029,690	758,986	1,242,722	1,282,439	340	6,074	32,316
0160	TAXES OTHER THAN INCOME TAXES	TSFR 9 4710	48,435,890	28,095,066	5,190,054	7,088,572	6,784,371	1,896	33,993	1,241,938
0170	FEDERAL AND STATE INCOME TAXES	TSFR 11 950	30,583,283	11,379,836	7,662,792	5,044,761	5,576,565	2,415	10,249	906,664
0180	TOTAL ELECTRIC OPERATING EXPENSES		746,142,208	384,678,884	87,339,152	120,257,922	141,286,331	32,882	604,453	11,942,584
0190										
0200	NET ELECTRIC OPERATING INCOME		131,836,165	57,248,972	27,037,745	21,581,591	23,048,849	8,864	62,804	2,847,339
0210										
0220	RATE BASE									
0230	TOTAL ELECTRIC PLANT	TSFR 3 210	3,655,504,019	2,103,868,053	391,994,446	542,109,703	515,187,641	144,051	2,593,784	99,606,343
0240	LESS: ACCUM. PROV. FOR DEPREC	TSFR 3 300	1,328,020,451	773,723,135	142,514,938	191,323,002	178,331,038	50,849	912,559	41,164,930
0250	NET PLANT		2,327,483,568	1,330,144,918	249,479,508	350,786,701	336,856,602	93,201	1,681,225	58,441,413
0260	PLUS:									
0270	CASH WORKING CAPITAL	TSFR 2 40	(52,906,934)	(28,715,464)	(6,144,608)	(8,178,667)	(8,747,172)	(2,266)	(39,493)	(1,079,265)
0280	MATERIALS & SUPPLIES	TSFR 2 50	43,924,115	25,279,836	4,710,160	6,513,928	6,190,435	1,731	31,167	1,196,858
0290	EMISSION ALLOWANCES	TSFR 2 60	237,349	102,726	27,727	44,597	60,153	11	249	1,886
0300	PREPAYMENTS	TSFR 2 100	2,314,089	1,331,837	248,149	343,178	326,136	91	1,642	63,055
0310	FUEL INVENTORY	TSFR 2 160	25,944,916	11,229,146	3,030,828	4,874,919	6,575,396	1,239	27,266	206,122
0320	DEFERRAL OF DSM/EE COSTS	TSFR 2 180	6,712,507	3,410,788	752,214	1,186,657	1,305,944	298	5,195	51,412
0330	REGULATORY ASSETS	TSFR 2 260	38,443,185	22,405,919	4,051,737	5,722,732	5,910,890	1,586	27,819	322,501
0340	LESS:									
0350	CUSTOMER ADVANCES FOR CONSTRUCTION	TSFR 2 310	5,075,955	3,211,048	554,654	582,954	424,429	153	2,856	299,861
0360	CUSTOMER DEPOSITS	TSFR 2 320	7,182,331	6,324,714	802,445	50,968	4,137	45	22	0
0370	TOTAL ACCUMULATED DEFERRED TAXES	TSFR 2 330	472,013,338	271,659,880	50,615,895	69,999,379	66,523,094	18,600	334,920	12,861,570
0380	TOTAL RATE BASE		1,907,881,169	1,083,994,065	204,182,720	290,660,744	281,526,725	77,093	1,397,272	46,042,550
0390										
0400	RATE OF RETURN		6.910%	5.281%	13.242%	7.425%	8.187%	11.498%	4.495%	6.184%
0410	RELATIVE RATE OF RETURN		1.00	0.76	1.92	1.07	1.18	1.66	0.65	0.89
0420										
0430										
0440										
0450										
0460										
0470										
0480										

Allocation Method: Production - Avg & Excess 4 CP, Transmission - Avg 12 CP

LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GMO RETAIL	RESIDENTIAL	GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	GENERAL TOD SERVICE	THERMAL SERVICE	LIGHTING
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
0490										
0500										

KCP&L Greater Missouri Operations
2018 RATE CASE - DIRECT
TY 6/30/17; Update TBD; K&M 6/30/18
Cost of Service

TABLE 4
Cost of Service Results – Unbundled Customer, Demand and Energy Cost Components

		Uniform Rate of Return @ 7.66%		
Line No.	Customer Class (a)	Monthly ($) Customer Charge (b)	Energy Costs ($/kWh) Annual (c)	Demand Costs ($/kWh) Annual (f)
1	RESIDENTIAL	$14.50	0.0264	0.0794
2	General Use	$14.13	0.0266	0.0871
3	Space Heating	$15.14	0.0261	0.0705
4	Other Use	$13.62	0.0258	0.0842
5	Net Metering - General Use	$14.34	0.0260	0.0776
6	Net Metering - Space Heating	$15.91	0.0255	0.0822
7				
8	GENERAL SERVICE	$15.13	0.0262	0.0552
9	No Demand - Secondary	$15.65	0.0263	0.0553
10	Net Metering No Dem - Sec	$12.22	0.0257	0.0512
11	Sep Met - Space Htg/Water Htg	$13.48	0.0258	0.0544
12	Secondary	$14.56	0.0262	0.0551
13	Net Metering Demand - Sec	$20.62	0.0261	0.0570
14	Primary	$16.35	0.0253	0.0392
15				
16	LARGE GENERAL SERVICE	$50.55	0.0260	0.0499
17	Secondary	$50.55	0.0261	0.0503
18	Primary	$50.55	0.0252	0.0399
19	Net Metering - Secondary	$50.55	0.0260	0.0520
20				
21	LARGE POWER SERVICE	$589.10	0.0256	0.0352
22	Secondary	$569.67	0.0260	0.0379
23	Net Metering - Secondary	$569.66	0.0260	0.0363
24	Primary	$655.82	0.0253	0.0347
25	RTP Primary	$655.89	0.0251	0.0320
26	Substation	$655.60	0.0248	0.0303
27	Transmission	$655.52	0.0243	0.0231
28				
29	GENERAL SERVICE TOD	$50.55	0.0262	0.0527
30				
31	THERMAL SERVICE	$569.67	0.0263	0.0440
32				
33	METERED LIGHTING	$1,169.06	0.0260	0.0306
34				
35	NON-METERED LIGHTING	$42.82	0.0259	0.0307

Notes:
(1) Allocation Method: Production - Avg & Excess 4 CP, Transmission - Avg 12 CP

KCP&L Greater Missouri Operation Class Revenue - For Direct filing - ER-2018-0146

	(A)		(B)	(C)	(D)	(E)		(F)	H=F*% **2.61%**	-0.32%	
GMO RATE CLASSIFICATION	**kWh**	**Revenue from Existing Rates (Including FAC, DSIM, RESRAM, and EDR)**	**FAC Adjustments**	**DSIM Adjustments**	**RESRAM Adjustments**	**EDR credits**	**Misc. Adj***	**Revenue from Existing Rates less FAC & DSIM adjustments****	**Requested Increase- from Rev Model excluding EDR gross-up (Equal increase)**	**Adj Request Increase- FAC impact**	**Proposed Revenue**
LARGE POWER TOTAL	2,091,080,680	$ 136,238,390	$ (3,962,418)	$ 7,268,804	$ 1,710,588	$ (561,113)	$ (899,438)	$ 130,321,978	$ 3,403,422	-$3,881,726	$ 126,425,598.27
LARGE GEN SVC TOTAL	1,522,611,697	$ 122,504,745	$ (2,373,172)	$ 7,854,502	$ 1,035,425	$ (392,665)		$ 115,987,991	$ 3,029,083	-$2,551,430	$ 113,426,306.04
SMALL GEN SVC TOTAL	940,160,940	$ 104,090,019	$ (1,673,021)	$ 6,058,229	$ 738,181	$ -		$ 98,966,630	$ 2,584,562	-$1,224,650	$ 97,741,980.22
RESIDENTIAL TOTAL	3,458,739,477	$ 381,663,187	$ (5,842,881)	$ 4,993,577	$ 2,655,316	$ -		$ 379,857,176	$ 9,920,155	$5,354,088	$ 385,211,263.75
GENERAL TOD	381,187	$ 37,291	$ (641)	$ 2,379	$ 297	$ -		$ 35,256	$ 921	-$560	$ 34,695.82
THERMAL	8,281,604	$ 573,819	$ (13,969)	$ 51,357	$ 6,649	$ -		$ 529,781	$ 13,835	-$15,253	$ 514,527.96
METERED LIGHTING	1,346,035	$ 128,665	$ (2,714)	$ -	$ 1,038	$ -		$ 130,341	$ 3,404	-$1,902	$ 128,439.73
GMO Metered TOTALS	**8,022,601,620**	**$ 745,236,115**	**$ (13,868,817)**	**$ 26,228,847**	**$ 6,147,493**	**$ (953,778)**	**$ (899,438)**	**$ 725,829,153**	**$ 18,955,382**	**$ (2,321,433)**	**$ 723,482,812**
UNMETERED LIGHTING	78,298,172	$ 13,960,071	$ (142,969)	$ -	$ 48,560	$ -	$ (590,444)	$ 13,464,037	$ 351,620	-$33,804	$ 13,430,232.27
GMO TOTAL	**8,100,899,792**	**$ 759,196,187**	**$ (14,011,786)**	**$ 26,228,847**	**$ 6,196,053**	**$ (953,778)**	**$ (1,489,883)**	**$ 739,293,190**	**$ 19,307,002**	**$ (2,355,237)**	**$ 736,913,044**

*Adjustment includes Co Use which is NOT part of billed revenues. Additionally, across all classes, consistent with the MEEIA S&A, an 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 $899,438. Note: All other adjustments were made at the customer level consistent with all other LPS adjustment/revenues.

**A late rate switcher factor adjustment affected LGS revenues by $157

KCP&L Greater Missouri Operation Class Revenue - For Direct filing - ER-2018-0146

	(A)		(B)	(C)	(D)	(E)		(F)	H=F*% **2.61%**		
GMO RATE CLASSIFICATION	**kWh**	**Revenue from Existing Rates (Including FAC, DSIM, RESRAM, and EDR)**	**FAC Adjustments**	**DSIM Adjustments**	**RESRAM Adjustments**	**EDR credits**	**Misc. Adj***	**Revenue from Existing Rates less FAC & DSIM adjustments****	**Requested Increase- from Rev Model excluding EDR gross-up (Equal increase)**	**Requested Increase with Rev Shifts including EDR gross up**	**Proposed Revenue**
LARGE POWER TOTAL	2,091,080,680	$ 136,238,390	$ (3,962,418)	$ 7,268,804	$ 1,710,588	$ (561,113)	$ (899,438)	$ 130,321,978	$ 3,403,422	$ 1,716,365	$ 132,023,689
LARGE GEN SVC TOTAL	1,522,611,697	$ 122,504,745	$ (2,373,172)	$ 7,854,502	$ 1,035,425	$ (392,665)		$ 115,987,991	$ 3,029,083	$ 1,524,796	$ 117,502,532
SMALL GEN SVC TOTAL	940,160,940	$ 104,090,019	$ (1,673,021)	$ 6,058,229	$ 738,181	$ -		$ 98,966,630	$ 2,584,562	$ 1,292,281	$ 100,258,911
RESIDENTIAL TOTAL	3,458,739,477	$ 381,663,187	$ (5,842,881)	$ 4,993,577	$ 2,655,316	$ -		$ 379,857,176	$ 9,920,155	$ 14,613,576	$ 394,470,752
GENERAL TOD	381,187	$ 37,291	$ (641)	$ 2,379	$ 297	$ -		$ 35,256	$ 921	$ 460	$ 35,716
THERMAL	8,281,604	$ 573,819	$ (13,969)	$ 51,357	$ 6,649	$ -		$ 529,781	$ 13,835	$ 6,918	$ 536,699
METERED LIGHTING	1,346,035	$ 128,665	$ (2,714)	$ -	$ 1,038	$ -		$ 130,341	$ 3,404	$ 1,702	$ 132,043
GMO Metered TOTALS	**8,022,601,620**	**$ 745,236,115**	**$ (13,868,817)**	**$ 26,228,847**	**$ 6,147,493**	**$ (953,778)**	**$ (899,438)**	**$ 725,829,153**	**$ 18,955,382**	**$ 19,156,098**	**$ 744,960,343**
UNMETERED LIGHTING	78,298,172	$ 13,960,071	$ (142,969)	$ -	$ 48,560	$ -	$ (590,444)	$ 13,464,037	$ 351,620	$ 175,810	$ 13,639,846
GMO TOTAL	**8,100,899,792**	**$ 759,196,187**	**$ (14,011,786)**	**$ 26,228,847**	**$ 6,196,053**	**$ (953,778)**	**$ (1,489,883)**	**$ 739,293,190**	**$ 19,307,002**	**$ 19,331,908**	**$ 758,600,189**

KCP&L Greater Missouri Operations Proposed Non-Rate Tariff Revisions
Case No. ER-2018-0146

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
Rates	1	Table of Contents	Retire Schedule MO721, Schedule MO731, and MO737	The Company is proposing to eliminate the non-residential Real-Time Pricing program. 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.
	(1,2)		Mark Private Area Lighting as Frozen	The Company is proposing to freeze these rate schedules and implement an original Private Unmetered LED Lighting Service for new customers.
			In reference to Thermal Energy Storage Pilot, change rate code MO659 to MO650.	To correctly reflect the Thermal Energy Storage Pilot Program rate code.
			Include the proposed Schedule MORPL and Schedule MOCPL.	The Company is proposing to add an original Private Unmetered LED Lighting Service to its Rate Book 1 to phase out its current Private Area Lighting rate schedules.
			Include the proposed Schedule SSP.	The Company is proposing to add a Solar Subscription Pilot Rider to its Rate Book 1 for residential and non-residential customers.
			Include the proposed Schedule MORT, Schedule MORD, and Schedule MORDT.	The Company is proposing to add three Residential pilot programs to its Rate Book 1: (1) Residential Time of Use (Pilot); (2) Residential Demand (Pilot); and (3) the Residential Demand plus Time of Use (Pilot) based on findings supported within the multiple rate design reports being filed.
	2		Adjust schedules by page number within each class or section.	To maintain consistency of rate books across jurisdictions.
	2.1		Create an original Sheet 2.1.	An original Sheet 2.1 is necessary to make room for various Rate Book 1 proposals being made by the Company.
			Include the Primary Discount Rider	The current Sheet 2 does not include the Primary Discount Rider.
			Add an Riders and Surcharges section.	To maintain consistency of rate books across jurisdictions.
	(1,2.1)		Include the proposed Schedule MOPS-1	The Company is proposing to add a Large Power Off-Peak rider to its Rate Book 1 to maintain consistency across jurisdictions.
			Include the proposed Schedule RER	The Company is proposing to add a Renewable Energy Rider Program Rider to its Rate Book 1 to provide non-Residential Customers a voluntary opportunity to purchase renewable energy.

KCP&L Greater Missouri Operations Proposed Non-Rate Tariff Revisions
Case No. ER-2018-0146

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
			Include Schedule SSR	The Company is proposing to add an original Standby Service Rider
			Include the proposed Schedule CCN	The Company is proposing to add a Public Electric Vehicle Charging Station Service to its Rate Book 1 for both residential and non-residential customers.

KCP&L Greater Missouri Operations Proposed Non-Rate Tariff Revisions
Case No. ER-2018-0146

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
	47, 48, 91, 92, 135	Misc. Unmetered Lighting	Add rate codes to section headers.	To maintain consistency across Rate Book 1.
	47-49, 91-94	Private Area Lighting	Freeze tariffs	The Company is proposing to freeze these rate schedules and offer an original Private Unmetered LED Lighting Service to new customers.
	50.1, 95.1	Application for Private Area Lighting Service	Retire Sheet 50.1 and Sheet 95.1.	The Company's proposal to freeze its Private Area Lighting service will make it unavailable to new customers, and render the Application for Private Area Lighting Service irrelevant.
	50	Outdoor Night Lighting	Adjust language to remove second sentence of final paragraph under the Special Rules section.	The language is repeated in the Adjustments and Surcharges section on the same sheet.
	73-77	Real-Time Pricing Program	Delete language and make Reserved For Future Use	The Company is proposing to eliminate the non-residential Real-Time Pricing program. 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.
	102	CoGeneration Purchase Schedule	Rename the schedule Parallel Generation Contract Service and adjust the language of Schedule MO700.	The Company is proposing to adjust language to incorporate safety, interconnection, and metering requirements and to rename the schedule to Parallel Generation Contract Service to align with other jurisdictions.
	103-104	Special Isolated Generating Plant Service	Retire schedule.	The Company is proposing to eliminate the non-residential Real-Time Pricing program. 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.
	109, 109.(1-3)	Solar Subscription Pilot Rider (New)	Create original Schedule SSP.	The Company is proposing to add a Solar Subscription Pilot Rider to its Rate Book 1 to give residential and non-residential customers an opportunity to subscribe to solar resource electricity.

KCP&L Greater Missouri Operations Proposed Non-Rate Tariff Revisions
Case No. ER-2018-0146

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
	127.(1-11), 127.(13-23)	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. 127.1 – 127.11 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 127.13 – 127.23 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.
	128, 128.(1-4)	Standby Service Rider (New)	Create original Schedule SSR.	The Company is proposing to add a Standby Service Rider in an effort to maintain the consistency of rate books across jurisdictions.
	139, 139.(1-5)	Renewable Energy Rider (New)	Create original Schedule RER.	The Company is proposing to add a Renewable Energy Rider in an effort to provide non-residential customers a voluntary opportunity to purchase clean energy from renewable energy sources contracted by the Company.
	140	Primary Discount Rider	Adjust availability language.	The Company is proposing to make the Primary Discount Rider available to all non-residential customers.
	141-145	Special Contract Rate	Adjust all language and retire Sheet Nos. 143-145.	The Company is proposing to adjust the language of its Special Contrat Rate in order to reflect its proposed elimination of the Real-Time Pricing program and to maintain consistency of rate books across jurisdictions.
	146.(5-6)	Residential Time of Use (New)	Create original Schedule MORT.	The Company is proposing to add a Residential Time of Use pilot program to its Rate Book 1 based on findings supported within the multiple rate design reports being filed.
	146.(7-8)	Residential Demand (New)	Create original Schedule MORD.	The Company is proposing to add a Residential Demand pilot program to its Rate Book 1 based on findings supported within the multiple rate design reports being filed.
	146.(9-10)	Residential Demand plus Time of Use (New)	Create original Schedule MORDT.	The Company is proposing to add a Residential Demand plus Time of Use pilot program to its Rate Book 1 based on findings supported within the multiple rate design reports being filed.

KCP&L Greater Missouri Operations Proposed Non-Rate Tariff Revisions
Case No. ER-2018-0146

Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
	149	Large Power Service	Adjust language defining a Primary voltage customer.	The Company is proposing to delete the second sentence within the definition of a primary voltage customer to better align the language with the Company's operating conditions.
	152, 152.(1-4)	Private Unmetered LED Lighting Service (New)	Create Original Schedule MORPL and Schedule MORCPL	The Company is proposing to add an original Private Unmetered LED Lighting Service for both residential and non-residential custmers to its Rate Book 1 in an effort to replace its current Private Area Lighting rate schedules.
	153-153.1	Large Power Off-Peak Rider (New)	Create original Schedule MOPS-1	The Company is proposing to add a Large Power Off-Peak rider to its Rate Book 1 to maintain consistency across jurisdictions.
	154, 154.(1-2)	Clean Charge Network (New)	Create original Schedule CCN.	The Company is proposing to add a Clean Charge Network to its Rate Book 1 for both residential and non-residential customers.

KCP&L Greater Missouri Operations Proposed Non-Rate Tariff Revisions
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Tariff Book	Tariff Sheet No.	Name of Schedule	Proposed Change	Support
Rules and Regulations	R-1	Table of Contents	Adjust language referencing Rule 5.05 to Sheet No. R-33.2.	The Company is proposing to move the current language of Rule 5.05 to an original sheet 33.2 to maintain chronological order of its Rules and Regulations Book 1.
	R-2	Table of Contents	Adjust language referencing Rule 7.07 Extension Upgrade to Sheet No. R-52.	The Company is proposing to move the current language of Rule 7.07 Extension Upgrade to Sheet No. R-52 to accommodate additional language to Rule 7.04(D) on Sheet No. R-51.
	R-20	Charge for Reconnection or Collection	Adjust and add language in Rule 2.07.	The Company is proposing to add language to its Rules and Regulations Book 1 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. This proposed language will maintain consistency of Rules and Regulations books across jurisdictions.
	R-33.2, R-33.3	Non-Standard Metering Service	Create an original Sheet R-33.2 to contain language on 33.3, and retire Sheet R-33.3.	To move the current language of Sheet No. R-33.3 to an original Sheet No. R-33.2 to maintain chronological order of its Rules and Regulations Book 1.
	R-50, R-51	Extension of Electric Facilities	Add language in Rule 7.04(D) to coincide with proposed language added by Order in KCP&L-MO Rule 9.04(D)	The Company is proposing to add Rule 7.04(D) to its Rules and Regulations Book 1 identifying construction charge reduction amounts specific for Residential and Non-Residential customers who locate Distribution Extensions on underutilized circuits. This proposed language will maintain consistency of Rules and Regulations books across jurisdictions.
	R-52	Extension Upgrade	Remove language from Sheet R-51 and place on Sheet R-52.	The Company's proposal to add Rule 7.04(D) requires the move of Rule 7.07 to Sheet No. R-52.
	R-63	Summary of Types and Amount of Reimbursements Allowed	Remove Rule 10.12 from table.	The Company is proposing to eliminate its MEEIA Cycle I Mpower Rider program from its Rules and Regulations Book 1 because the program is not available after December 31, 2015.
	R-63.(22-26)	Mpower Rider	Eliminate Rule 10.12.	The Company is proposing to eliminate its MEEIA Cycle I Mpower Rider program from its Rules and Regulations Book 1 because the program is not available after December 31, 2015.
	R-66	Summary of Types and Amount of Charges Allowed	Adjust language to correct a misslabel in the Type of Charge column and define the proposed Restoration Charge.	The Company is proposing to: (1) adjust the language identifying the Reconnection Charge in Rule 2.07(A) as a Reconnection Charge; and (2) to add language defining the Restoration Charge proposed through Rule 2.07.