COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of
Kentucky Utilities Company for an
Adjustment of its Electric Rates

Case No. 2014-00371

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

SIERRA CLUB

Resource Insight, Inc.

MARCH 6, 2015

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I. IDENTIFICATION AND QUALIFICATIONS

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further described in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred and eighty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-three states, six Canadian provinces, and two U.S. Federal agencies.

Q: Have you testified previously before the Kentucky Public Service Commission?

A: Yes. I testified in Case No. 2011-00375, on the application of Louisville Gas and Electric Company and Kentucky Utilities Company to build the Cane Run combined-cycle plant.

II. INTRODUCTION

Q: On whose behalf are you testifying in this rate case proceeding?

A: I am testifying on the behalf of the Sierra Club.

Q: What is the purpose of your testimony?

A: On November 26, 2014, Kentucky Utilities Company (KU or "the Company") filed an application (including supporting testimony) for authority to adjust its electric rates. My testimony addresses the following aspects of the Company's filing:

- The Company's proposal to increase the monthly residential basic service charge from $10.75 to $18.00.
- The Company's proposal to offer optional time-of-day (TOD) rates to residential customers.

Both of these proposals are supported in pre-filed direct testimony by Company witnesses Dr. Martin Blake and Robert M. Conroy.

Q: Please summarize your findings and recommendations.

A: The Company lacks a reasonable basis for its plan to shift allegedly "fixed" costs from the residential energy charge to the basic service charge. Restructuring residential rates in the fashion proposed by KU would inappropriately shift load-related costs to the basic service charge, dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and exacerbate the subsidization of larger residential customers' costs by these lower-usage customers. Consequently, the Commission should reject the Company's proposal to increase the monthly basic service charge to $18.00 and instead find that it is reasonable to maintain the monthly charge at its current level of $10.75.

The Company proposes to implement two voluntary residential time-of-day rates, with either a time-of-day demand charge or a time-of-day energy charge. The Commission should reject the Company's proposal to implement a time-of-day rate with a demand charge. In addition, the time-of-day energy rate should be modified to move April and October into the summer period, to include the winter evening in the peak period, and to reduce the differentials between the peak and off-peak rates.

My recommendations regarding both the basic service charge and the optional time-of-day rates are intended to promote rate designs that provide revenue adequacy, reasonably mitigate intra-class subsidies, and, in accordance with the Commission's ratemaking standards, promote efficient behavior with appropriate price signals for conservation:

> For over 30 years, the Commission has historically noted the importance of energy efficiency (conservation) as a ratemaking standard. "It is intended to minimize the 'wasteful' consumption of electricity and to prevent consumption of scarce resources…."
>
> [W]ith the potential for huge increases in the costs of generation and transmission as a result of aging infrastructure, low natural gas prices, and stricter environmental requirements, we will strive to avoid taking actions that might disincent energy efficiency.[1]

III. Residential Basic Service Charge

Q: What is the Company's proposal with respect to the basic service charge for residential customers?

A: The Company proposes a radical restructuring of residential rates in order to shift recovery of allegedly "fixed" costs from the energy charge to the basic service charge. Specifically, KU proposes to dramatically increase the monthly basic service charge for residential customers from $10.75 to $18.00, or by about 67%.

Q: What are the "fixed" costs that KU proposes to recover through the residential basic service charge?

A: Company witness Dr. Blake considers all embedded costs classified as either demand-related or customer-related in the Company's cost of service study (COSS) as fixed. Dr. Blake further distinguishes between "volumetric" (i.e., demand-related) and "non-volumetric" (i.e., customer-related) fixed costs. According to Dr. Blake, the non-volumetric fixed cost per customer represents "the cost of installing, operating and maintaining the minimum set of equipment necessary to provide service to customers" and thus does not vary based on customer usage.[2]

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[1] *Order*, Case No. 2012-00221, December 20, 2012, pp. 7, 20.

[2] Company Response to Sierra Club Initial Data Request No. 9.

The Company proposes to shift recovery of these supposedly non-volumetric fixed costs from the energy charge to the basic service charge. According to Dr. Blake, residential customer-related distribution-plant and customer-service costs in the Company's COSS amount to $21.47 per customer per month.[3] Consequently, the $18.00 monthly basic service charge proposed by the Company would recover about 84% of the costs categorized by Dr. Blake as non-volumetric fixed costs.

Q: Why does Dr. Blake consider all demand-related and customer-related costs to be "fixed"?

A: Dr. Blake does not explain why he categorizes all demand-related and customer-related costs as fixed costs. Utilities frequently conflate two meanings of the term "fixed cost." One meaning of fixed with reference to costs is fixed over load, so that the cost is constant for customers of any size; that is the definition of fixed that is relevant to guiding rate design. Another meaning of fixed is fixed over the year; the cost does not vary in the short run. For example, the Company's costs of transmission in 2016 are largely determined by the cumulative investment and construction commitments at the end of 2015. Even though such transmission costs are predominantly fixed over the year, they are not are fixed over load. Rather, the Company's transmission costs in 2016 will be the result of past loads and expected loads in 2016 and the near future.

Dr. Blake appears to generally use the term "fixed cost" in the second sense, i.e., to describe a cost that does not vary in the short run. However, for rate-design purposes, Dr. Blake apparently recognizes the distinction between

[3] *Testimony of Dr. Martin Blake*, Case No. 2014-00371, November 26, 2014, p. 19, ll. 14-16.

fixed costs that vary over the long run with customer usage (i.e., "volumetric" demand-related costs) and those that do not (i.e., "non-volumetric" customer-related costs). As noted above, the Company proposes to recover most of the non-volumetric fixed costs through the basic service charge based on the presumption that such costs do not vary with customer usage.

Q: Would it be appropriate to recover volumetric (i.e., demand-related) fixed costs through the basic service charge?

A: No. Such costs may appear "fixed" when considered in the short-term context of utility cost recovery, since the revenue requirements associated with debt service and maintenance in any year are unlikely to vary much with load or sales in that year. However, from the longer-term perspective of cost-causation and price signals, plant investments and fixed O&M are variable with respect to customer demand. Shifting recovery of such demand-related costs to the basic service charge would seriously distort price signals, since consumers would no longer benefit from actions that reduce maximum demand and thus reduce demand-related costs. Likewise, consumers would no longer be discouraged from increasing their usage, including their contribution to various peak loads. In other words, recovering volumetric fixed costs through the basic service charge would misleadingly and inefficiently signal to consumers that there is no economic gain or loss associated with changes in usage.[4]

Q: What costs are classified as customer-related in the Company's COSS?

[4] In fact, shifting recovery of volumetric fixed costs to the basic service charge could further and needlessly increase basic service charges in the future, in order to recover uneconomic plant investment required to meet demand growth resulting from misleading price signals.

A: According to Dr. Blake, the cost of services and meters and all customer-service expenses are deemed to be customer-related in the Company's COSS. In addition, the COSS classifies a portion of conductor and secondary transformer costs as customer-related, based on the results of a zero-intercept analysis of such distribution plant costs.

Q: Please describe the Company's zero-intercept analysis of conductor and line-transformer costs.

A: The objective of a zero-intercept analysis is to estimate the non-load-related or "minimum" cost of the Company's existing conductors or line transformers, i.e., what the cost of the Company's existing conductors or line transformers would be if those conductors or transformers were sized to carry zero load. The Company's COSS classifies the minimum cost of its existing conductors or line transformers as customer-related, and classifies costs in excess of the minimum as demand-related.

A zero-intercept analysis attempts to estimate a functional relationship between equipment cost and equipment size based on the current system, and then to extrapolate that cost function to estimate the unit cost of equipment (e.g., cost per transformer or per conductor-feet) that carries zero load (e.g., 0-kVA transformers) or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). This zero-intercept unit cost is a constant value across all installed equipment (either conductors or transformers) and thus represents an estimate of the non-load-related portion of the actual cost for each piece of equipment regardless of the size or load-serving capacity of that equipment.

For example, according to Exhibit MJB-7 of Dr. Blake's testimony, there are currently 251,790 line transformers on the Company's distribution system, with sizes ranging from 0.6 kVA to 3,000 kVA.[5] The Company's zero-intercept analysis of transformer costs estimates a zero-intercept unit cost of about $416 per transformer.[6] Thus, the Company's zero-intercept analysis estimates a total non-load-related or minimum cost across all 251,790 transformers of about $105 million. In other words, the Company's zero-intercept analysis estimates that the cost of existing transformers on the Company's distribution system would have been about $105 million if all 251,790 transformer were sized at zero kVA. This amount represents about 48% of the total cost of all 251,790 transformers. The Company's zero-intercept analysis of transformer costs therefore estimates that 52% of the total cost for all 251,790 transformers was incurred to size existing transformers at the actual sizes installed to reliably serve customer load.

Q: Do you agree with Dr. Blake's assertion that the non-volumetric distribution cost per customer represents the minimum cost to serve a customer regardless of that customer's usage level?

A: No. To the contrary, the non-volumetric distribution cost per customer represents the minimum cost to serve an *average-usage* customer. In fact, the minimum distribution cost per customer will vary with the usage of the customers served by the distribution equipment. Consequently, the true minimum cost to serve a customer with very little usage is likely to be less than the non-volumetric fixed cost per customer.

For example, as discussed above, the Company's zero-intercept analysis of line-transformer costs estimates a minimum cost of about $416 per

[5] More precisely, these are the number and sizes of transformers in the sample used in the Company's zero-intercept analysis.

[6] Dr. Blake Testimony, Exhibit MJB-7, p. 1.

transformer, for a total minimum cost of about $105 million across all 251,790 transformers on the Company's distribution system. The Company's COSS assumes that there are 537,043 customers served by line transformers, implying that each transformer serves about two average-usage customers. With each transformer serving about two average-usage customers, the minimum transformer cost per *average-usage* customer (i.e., the non-volumetric distribution cost per customer) is about $195, or about 50% of the minimum cost per transformer.

In contrast, the minimum transformer cost per *low-usage* customer is likely to be less than that for an *average-usage* customer, because each transformer could serve more low-usage than average-usage customers. For example, with a minimum cost per transformer of $416, the minimum cost per low-usage customer would be only $104 if each transformer could serve four low-usage customers. As such, I would expect the minimum distribution cost per low-usage customer to be less than the non-volumetric distribution cost per customer.

Q: Other than the sharing of transformers, are other considerations ignored in the Company's minimum-cost calculation?

A: Yes. The following are examples of other factors that indicate that the Company's calculation likely overstates the minimum cost of reaching a fixed number of customers over a fixed area:

- The Company's minimum conductor computations (Exhibits MJB-5 and MJB-6) assume that the length of conductor is determined solely by the number of customers on the system. In reality, the length of conductors is also determined by load levels; higher loads may require three-phase service, overbuilt feeders, and parallel feeders, all of which increase the length of conductors needed, independent of the number of customers.

- Similarly, the determination of minimum underground conductor costs (Exhibit MJB-6) does not reflect the reality that the decision to underground distribution frequently results from high load levels in urban environments, in which overhead service can be impractical. With lower loads, more of the system might well be served by less-expensive overhead conductor.
- The Company's estimated zero-intercept transformer cost of $416 is 350% of the average cost of the Company's smallest transformers sized at 3 kVA or less. Thus, if the system had actually been built for customers with miniscule load, the smallest transformers would have been installed at a cost that is much lower than the minimum cost per transformer estimated by the Company's zero-intercept analysis.

All of these examples illustrate the point that the Company's zero-intercept analysis likely overstates the cost of the "minimum" system by including load-related costs in the estimate of minimum cost.

Q: Would it be reasonable to set the basic service charge to recover all non-volumetric fixed costs per customer, as the Company proposes?

A: No. If such costs were recovered through the basic service charge, then the smallest residential customers (with the lowest cost to connect) would be required to pay the average of non-volumetric fixed costs attributable to all sizes of residential customers. In this case, small customers would subsidize larger customers' distribution costs.

Moreover, to the extent that the basic service charge exceeds minimum connection cost, the energy charge will understate the extent to which the

Company's distribution costs are driven by customer usage. Thus, the Company's proposal to shift recovery of most non-volumetric fixed costs from the energy charge to the basic service charge would yield inaccurate energy price signals. I discuss the impact of the Company's proposal on energy price signals in greater detail below.

Q: What costs are appropriately recovered through the basic service charge?

A: The basic service charge is intended to reflect the incremental costs imposed by the continued presence of a customer who uses very little energy. Thus, the basic charge should not be expected to cover the non-volumetric fixed costs for the average residential customer, but only the incremental cost to connect one more very small customer. Since the Company would probably not need to add secondary conductor or a transformer to connect a very small customer, incremental connection costs would likely be limited to installation and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer service expenses.[7]

Q: What is the incremental cost to connect a residential customer in the Company's service territory?

A: Based on Dr. Blake's calculation of the minimum connection cost per customer in Exhibit MJB-10, I estimate an incremental connection cost of $9.40 per customer per month.[8] As indicated in Exhibit PLC-2, customer-related

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[7] Remote vacation homes or hunting cabins might also require a line extension and a small transformer in order to connect to the distribution system.

[8] The spreadsheet version of Exhibit MJB-10 is part of the Company's COSS spreadsheet model. The COSS model was provided in response to Commission Staff Data Request No. 2-60.

distribution costs account for $2.58 of the total $9.40 incremental cost, while customer-service expenses account for the remaining $6.82.[9]

Thus, a monthly residential basic service charge of $18.00, as proposed by the Company, would overstate the minimum connection cost by almost a factor of two. In contrast, the current basic service charge of $10.75 reasonably reflects the minimum cost to connect a residential customer in the Company's service territory.

Q: Why is the Company proposing to shift recovery of customer-related costs from the energy charge to the basic service charge?

A: According to Company witness Mr. Conroy, the basic objective of the Company's proposed rate restructuring is to "continue bringing both the structure and the charges of the rate design in line with the results of the cost of service study."[10] Specifically, Mr. Conroy asserts that "basic cost-causation principles dictate that utilities should recover fixed costs through fixed charges and variable costs through variable charges."[11] From the Company's perspective, then, all costs that are classified in the COSS as customer-related for the purposes of cost allocation are appropriately treated as fixed costs for the purposes of rate design.

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[9] The only change I made to the calculations in Exhibit MJB-10 was to exclude the customer-related portions of conductor and transformer costs from the calculation of minimum distribution cost. As discussed above, it is not appropriate to include customer-related conductor or transformer costs in an estimate of the incremental cost to serve the Company's smallest customers. I adopted all other input assumptions and calculations in Exhibit MJB-10 for the purposes of deriving Exhibit PLC-2.

[10] *Testimony of Robert M. Conroy*, Case No. 2014-00371, November 26, 2014, p. 16, ll. 10-11.

[11] Company Response to Sierra Club Initial Data Request No. 17.

Q: Is this a reasonable approach to rate design?

A: No. The primary objective of a cost of service study is to equitably divide up a fixed set of revenue requirements among customer classes based on broad considerations of cost drivers. The total size of the bucket of costs allocated to a class does not directly affect the behavior of customers, so the cost-allocation process is primarily driven by considerations of the equity of cost allocations, rather than of behavioral responses to such allocations.

Once revenue requirements are determined and allocated to classes, the considerations in designing rates are very different from those that drive class cost allocation. The determination of actual rate components represents a utility's major opportunity to influence customer decisions. While revenue requirements are *determined* and costs are *allocated*, rates are *designed* to tie together costs and customer behavior. Subject to the major constraint that rates must collect the class's assigned revenue requirement, rates should be designed to provide price signals for customer behavior.[12]

Accordingly, while it may be reasonable to classify certain load-related costs as customer-related for cost-allocation purposes, it does not follow that all such costs should be recovered through a fixed basic service charge.

Q: Does Mr. Conroy offer any other justification for the Company's proposal to increase the residential basic service charge?

A: Yes. Mr. Conroy notes that increasing the basic service charge could reduce monthly bill volatility:

[12] In some cases, equitable treatment among and between various sub-groups within the class may also be relevant as secondary considerations.

> Increasing the basic service charge to more closely align with customer specific fixed costs will reduce the amount of fixed costs embedded in energy rates. This relative reduction of volumetric energy rates will help mitigate bill fluctuations caused by energy-usage spikes, including the impacts of any future extreme weather events.[13]

Q: Would the Company's proposal dampen variations in consumer bills?

A: Yes. However, the Company does not need to restructure rates and dampen price signals in order to moderate monthly bill fluctuations. Instead, the Company can simply encourage customers to sign up for budget billing under the Company's Budget Payment Plan.

Q: How does this proposed increase to the basic service charge affect the residential energy charge?

A: With the basic service charge set at $18.00, the Company proposes to increase the energy charge to 8.057¢/kWh in order to recover the test-year revenue requirement allocated to the residential class. If, instead, the basic service charge remained at its current rate of $10.75, the energy charge would have to be increased to 8.661¢/kWh to recover the same allocated revenue requirement.[14] Thus, the energy charge under the Company's proposal to increase the basic service charge by $7.25 would be 0.6¢/kWh, or about 7%, less than the energy charge without the proposed increase to the basic service charge.

As discussed above, a monthly residential basic service charge of $18.00, as proposed by the Company, would overstate the minimum connection cost by almost a factor of two. As a result, the energy charge proposed by the Company would understate the extent to which the Company's distribution

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[13] Conroy Testimony, p. 19, ll. 12-16.

[14] Company Response to Sierra Club Second Data Request No. 6.

costs are driven by customer usage. Thus, the lower energy charge under the Company's proposal for an $18.00 basic service charge would provide inaccurate energy price signals.

Q: To what extent would the lower energy charge under the Company's proposal for the basic service charge dampen price signals for conservation?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, the ratio of the percentage change in consumption to the percentage change in marginal price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term.

Most studies of electric price response have estimated the change in consumption that results from a change in the customer's average rate. For example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand published between 1971 and 2000 reports short-run average-rate elasticity estimates of about −0.35 on average across studies and long-run average-rate elasticity estimates of about −0.85 on average across studies.[15]

In contrast, some studies have examined the change in usage as a function of changes in the marginal rate paid by the customer.[16] The response to marginal price incentives is typically lower than the response to average rates,

[15] In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% change in average rates.

[16] For the Company, that would be the energy rate.

but not insubstantial. Table 1 lists the results of seven studies of marginal-price elasticity over the last forty years.[17]

Table 1: Summary of Residential Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al, on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal price elasticity for changes in the residential energy rate?

A: From Table 1, it appears that –0.3 would be a reasonable mid-range estimate of the effect over a few years.

Q: What would be a reasonable estimate of the effect on energy use from the 7% reduction to the residential energy rate under the Company's proposal to increase the basic service charge?

A: An elasticity of –0.3 and a 7% reduction in energy price would result in a 2% increase in energy consumption. This means that all else equal, residential load would be expected to increase by 2% over a several-year period as a result of implementing the Company's proposed basic service charge increase, rather than recovering the additional revenue requirement through energy charges.

For comparison, KU and Louisville Gas and Electric project that each year's installations under their Residential Incentives energy-efficiency

[17] The citations for these studies are provided in Exhibit PLC-3.

program will save about 0.2% of their combined residential load. Consequently, the consumption increase due to the Company's proposed increase in its basic service charge (and the resulting decrease in the energy charge) would undo about ten years of savings from the Residential Incentives program.

Q: What do you recommend with regard to the Company's proposal to restructure residential rates and increase the residential basic service charge?

A: The Commission should reject the Company's proposal to shift recovery of allegedly fixed costs from the residential energy charge to the basic service charge. The Company's proposal would inappropriately shift load-related costs to the basic service charge, dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and exacerbate the subsidization of larger residential customers' costs by these lower-usage customers. Consequently, the Commission should reject the Company's proposal to increase the monthly basic service charge to $18.00 and instead find that it is reasonable to maintain the monthly charge at its current level of $10.75.

IV. OPTIONAL TIME-OF-DAY RATES

Q: What does the Company propose with regard to time-of-day rates?

A: The Company proposes to offer two voluntary residential time-of-day rates, designated as follows:

- Rate RTOD-Energy, which has a four-hour peak period on weekdays (with different peak hours in the summer and winter) with an energy rate of about 25¢/kWh and an off-peak rate of about 5¢/kWh.

- Rate RTOD-Demand, under which a customer would be charged a \$11.56/kW demand charge based on its highest 15-minute load in the same four-hour peak period of the month and a \$3.25/kW demand charge for its highest 15-minute load outside the peak period. The customer would pay an energy charge of 4¢/kWh in both periods.

These rates would replace the current LEV rate option, which has three energy pricing periods. While Mr. Conroy insists that the new TOD would not be a pilot rate, it would be a very limited offering, available to no more than 500 residential customers.[18]

A. Principles of Time-of-Day Rate Design

Q: Why implement a time-of-day rate?

A: The fundamental purpose of time-of-day rates is to induce customers to shift consumption away from peak demand periods, thereby reducing overall system costs.

Q: What considerations should the Commission bear in mind in the design of time-of-day rates?

A: The Commission should carefully review the range of costs and cost drivers included in the design of time-of-day rates, the definition of pricing periods within each season, the definition of seasonal periods, and the price differentials between time periods. In addition, the Commission should consider whether a proposed rate design is an improvement over rates it would replace; in this case, the relevant comparison is to the LEV rate.

[18] Conroy Testimony, p. 20, ll. 11-14.

Q: What are the important considerations relating to the costs reflected in time-of-day rates?

A: Time-of-day rates should reflect differentials across time periods in the total private and social costs of generation, transmission and distribution capacity, with the demand-related generation costs allocated across time periods in proportion to the periods' contribution to the need for capacity (as measured by loss-of-load expectation, unserved energy, or similar metrics), and T&D costs allocated in proportion to the percentage of equipment experiencing maximum stress in each period.[19] Appropriate time periods may thus vary between classes, especially between classes served at secondary and those served at transmission.

The cost differentials across time periods should also reflect the environmental costs of energy generation, including the dispatch-related compliance costs borne by customers (such as allowances and limestone for scrubbers), non-dispatch costs borne by ratepayers (e.g., addition of controls), compliance costs borne by other parts of the economy (e.g., industrial and transportation emission to meet air-quality standards) due to increased electric-generation emissions, and health damages. As the Company and the region move to a system with gas on the margin in most high-load hours, and coal on the margin off-peak, the off-peak environmental costs are likely to exceed the on-peak environmental costs.

[19] While maximum loading is a good general guide to time allocation of T&D equipment, types of facilities may be driven by other factors, and should be allocated in proportion to those factors. For example, some portion of transformer and underground-line investments are driven by the reduction of line capacity and operating life due to heat buildup over the course of high-load days, rather than the peak hours alone; those costs should be allocated over all time periods in the critical months for the equipment.

Q: What are the important considerations in the selection of time periods for time-of-day rates?

A: The choice of time periods should be driven by cost, while avoiding excessive complexity and recognizing practical constraints. The definition of time periods includes the number of periods, the timing of the periods, the treatment of weekends, and the grouping of months into pricing seasons.

It is important that the definition of time-of-day periods be subject to revision over time, as load shapes and costs change in response to changes in underlying demand (e.g., increased end-use efficiency, addition of electric vehicle load and other electrification) and supply (e.g., addition of centralized and distributed renewable generation, changing fuel prices, retirement of steam plants in Kentucky and neighboring regions). Time-of-day rate designs that reflect cost patterns in 2014 may be inconsistent with the cost patterns of 2020.

Q: What are the important considerations in determining the number of time periods for time-of-day rates?

A: While a time-of-day rate with just two time periods in each season is simple and easy to understand, two periods may not capture the variation in costs among periods. With just two periods, one or both periods may need to be too broad, including hours with a wide range of costs. A two-period rate will also require that weekend hours be classified as either peak or off-peak, even if a large number of those hours are intermediate in cost.

Q: What are the important considerations in the timing of rating periods for time-of-day rates?

A: The choice of periods affects both pricing and customer incentives. For example, a shorter peak period will tend to result in a higher price for the peak period and lower price for the off-peak period, compared to a broader peak.

Lumping too many hours into a single period may obscure important differences between the hours in the period. A long peak period may encourage some customers to move some loads into the far off-peak, but not all end-uses can be moved forward or back by four or five hours. A long peak period will do nothing to encourage shifting of loads from the highest-cost hours to lower-cost hours within that broad period.

Q: What are the important considerations in the grouping of months for time-of-day rates?

A: Time-of-day rate design should avoid lumping together months with very different price patterns. Providing reasonably accurate price signals requires that similar months be grouped together. If the timing of high costs and/or the level of costs varies enough among the months, time-of-day rates may need to be set for more than two seasons.

B. The Company's Proposed Voluntary Residential TOD Rates

Q: What is the Company's stated purpose in proposing voluntary residential time-of-day rates?

A: Dr. Blake explains the Company's purpose in pursuing residential time-of-day rates as follows:

> Production and transmission plant costs are designed to meet the maximum load requirements placed on the systems. Because loads vary significantly throughout the course of a day, the likelihood of maximum loads occurring during certain hours greatly exceeds the likelihood of maximum system loads occurring during other hours of the day. It is therefore reasonable from a cost of service perspective to recover the majority of the Company's fixed production and transmission costs through the application of higher charges that would be applicable during on-peak periods. Time-of-day rates also send a better price signal to customers encouraging them to reduce their loads during hours of the day for which the Company would have to install new production and transmission facilities to meet load increases on the system in the future. Time-of-day rates represent a standard ratemaking tool to encourage the efficient utilization of KU's generation and transmission resources on the part of customers.[20]

As I discuss below, this approach considers only peak-related costs, rather than the variation in costs over various time periods, which can also be considerable.

Q: Should the Commission be less concerned about the design of the proposed time-of-day rates, since the proposed rates would be voluntary and limited to few customers?

A: No. The reasons for introducing a time-of-day rate include inducing customers to change the pattern of their usage, testing the level of those responses to rate designs, and educating customers about time-of-day rates in preparation for wider application of time-varying rates. The changes in load shape are only valuable if they are shifting load in desirable directions, so the definition and pricing of time periods should be reasonably related to the cost patterns over time. Similarly, the information about customer response and the educational effects are only useful if rate designs are reasonably similar to later, perhaps default or mandatory, time-of-day rate designs.

[20] Dr. Blake Testimony, p. 23, ll. 8-19.

Q: On which issues will you comment, regarding the proposed residential time-of-day rates?

A: I will comment on the option using a demand charge, the choice of seasonal peak hours, the grouping of months into seasons, and the differential between peak and off-peak prices.

1. The Residential Demand Charge

Q: What is the Company's residential demand-charge proposal?

A: The Company proposes to offer an option of Rate RTOD-D, which would recover over half the non-customer-charge revenue through demand charges of $3.25/kW-month in the off-peak period and $11.56/kW-month in the peak period.[21] The demand charges would be the only time-differentiated portion of this rate. The alternative Rate RTOD-E recovers all the non-customer-charge revenue through time-differentiated energy charges.

Q: Is the proposed residential demand-charge tariff a reasonable rate option?

A: No. Demand charges are a particularly ineffective means for providing price signals, especially for residential and other small customers, for the following reasons:

- Demand charges do not reflect the variation in marginal energy costs or in market prices.

[21] The tariff does not specify whether a customer would pay (1) $11.56 times his maximum demand in the peak period, plus $3.25 times his maximum demand in the off-peak period, or (2) his maximum demand in the month times $11.56 if that maximum is in the peak period or $3.25 if the maximum is off peak. Dr. Blake appears to intend the first interpretation. The second interpretation of the tariff would allow customers to reduce their bill by increasing their off-peak maximum demand.

- The demand-charge portion of the electric bill is determined by the customer's individual maximum demand at any time in the month. Capacity costs of generation, transmission and distribution are driven by coincident loads at the times of high loads on the equipment, not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, sub-transmission lines, transmission lines and generation, and the time of greatest need for generation (reflecting outages) all occur at different times.
- Customer maximum demands occur at a wide variety of times, depending on essentially random events specific to various customers, such as when they have parties, when they return from vacation and turn up the heat or air conditioning to make the house comfortable, when the college-aged children come to visit with many friends, when power is restored after a distribution outage, when the house is aired out because of interior painting, a smoky kitchen event, or other problem.
- Demand charges provide little or no incentive to control or shift load from those times that are off the customers' peak hours but that are very much on the generation and T&D peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on the transmission peak, or on the Company's peak hour. This will cause customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, or the regional generation system.

- Demand charges eliminate the incentive to conserve after the customer hits its monthly peak. Even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour. Under the Company's proposal, if a customer realizes that she left the thermostat turned up and ran the laundry one winter weekday morning early in the month, there is no point in her trying to reduce that load for the rest of the month.
- Rather than promoting conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times. For instance, in order to respond to demand charges effectively, customers will need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads. Moreover, collecting a large amount of revenue through demand charges will result in lower energy charges, encouraging increased electric use, some of which will likely occur in the peak period.
- Demand charges are difficult for customers to understand, since most goods are priced per unit consumed (like energy), rather than on the basis of the rate of consumption. This is a problem for small commercial customers and would be even worse for residential customers.
- Even for the larger non-residential customers who understand them, demand charges are difficult to avoid.

Q: What pricing signals do demand charges give to customers?

A: Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs. Under the Company's proposal, a household with a 7 AM winter peak could reduce its bill by moving some load to 9 AM, when energy costs and system demands are higher.

Q: Is there any rationale for including demand charges for small customers with time-of-day rates?

A: No. Time-of-day energy charges provide better conservation and load-shifting incentives than demand charges. Demand charges for commercial and industrial customers are largely a relic of the era before interval energy metering became practical, and should be reduced (or in some cases, eliminated) in favor of time-differentiated rates. Introducing demand charges for residential customers would be a step in the wrong direction.

2. Pricing Periods

Q: What pricing periods does the Company propose?

A: Company witness Dr. Blake proposes peak periods on weekdays from 7:00 AM until 11:00 AM in the winter (October–April) and from 1:00 PM until 5:00 PM in the summer (May–September).

Q: What is the basis for the proposed peak periods?

A: Dr. Blake selected these periods so that the peak period would have covered 76.7% of the monthly peaks of the last 15 years.[22]

Q: Are those definitions of peak periods appropriate?

A: If the sole goal in defining the peak periods were to maximize the number of monthly peaks included in the peak periods, then Dr. Blake's definitions would be appropriate. I calculate that shifting the winter period one hour earlier would capture about 2% more of the peak hours, as shown in Table 2. Of course, peak periods longer than four hours could cover even more of the monthly peaks.

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[22] Dr. Blake Testimony, Exhibit MJB-11.

Table 2: Winter Monthly Peaks in Winter Peak Period, Blake Proposed Seasons

Hour Beginning		Blake Proposed Peak Hours	Alternative Peak Hours
	6	6	6
	7	42	42
	8	13	13
	9	3	3
	10	4	4
	11	0	0
	12	0	0
	13	3	3
	14	2	2
	15	11	11
	16	3	3
	17	1	1
	18	7	7
	19	5	5
	20	2	2
Total Months		102	102
Peaks in Peak Period		62	64
% of monthly peaks in Peak Period		60.8%	62.7%

Q: Are there other important considerations in selecting the peak periods?

A: Yes, there are at least three important considerations other than the number of monthly peak hours included in the peak period:

- Loads in some months are higher than those in other months. In 2013, 74 July hours had loads higher than the May peak, while 279 July hours and 316 August hours had loads higher than the April peak.
- Winter months have an important secondary peak in the evening, slightly lower than the morning peak targeted by the Company's proposed rate design. Strong price signals that shift load off the morning peak may just create a new evening peak.

- In addition to the timing of peak loads, the variation in energy costs and prices over the day should be considered in setting peak periods.

Q: How important are the differences among monthly peaks?

A: The differences are significant, in terms of the variation in the absolute peak and the number of high-load hours across months. Table 3 summarizes the monthly peak loads in 2013.[23]

Table 3: Monthly Peak Loads, 2013

Month	MW	% of Annual Peak
Jan	5,907	92%
Feb	5,901	92%
Mar	5,346	83%
Apr	4,540	71%
May	5,654	88%
Jun	6,288	98%
Jul	6,409	100%
Aug	6,333	98%
Sep	6,434	100%
Oct	5,235	81%
Nov	5,165	80%
Dec	5,721	89%

Table 4 shows the ranking among annual hours of the peak load for each month in 2013. The annual peak load was in September, which thus has a peak-load ranking of 1, while the third-highest annual hour was the July peak and the January peak was the 102nd-highest hour in the year.

[23] The load data provided in Table 3 and all tables that follow were compiled from data in the spreadsheet 'Att_KU_PSC_2-60_LKESysLoadShapeTOUPeak.xlsx', provided in Company Response to PSC Staff Second Data Request No. 60.

Table 4: Ranking of Monthly Peak Hours

Month	Annual Rank of Peak Hour
Jan	102
Feb	104
Mar	382
Apr	1978
May	193
Jun	10
Jul	3
Aug	7
Sep	1
Oct	495
Nov	584
Dec	163

Table 5 shows the distribution over other months of the hours higher than the peak in each month. For example, of the 101 hours higher than the January peak, 10 were in June and 48 were in July.

Table 5: Distribution of Hours with Loads Higher than Peak in a Given Month, 2013

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Jan		–	–	–	–	10	48	27	16	–	–	–	101
Feb	1		–	–	–	10	48	27	17	–	–	–	103
Mar	28	14		–	14	61	108	109	35	–	–	12	381
Apr	256	169	155		88	242	279	316	149	31	82	210	1,977
May	6	4	–	–		25	74	56	25	–	–	2	192
Jun	–	–	–	–	–		4	2	3	–	–	–	9
Jul	–	–	–	–	–	–		–	2	–	–	–	2
Aug	–	–	–	–	–	–	3		3	–	–	–	6
Sep	–	–	–	–	–	–	–	–		–	–	–	–
Oct	39	19	5	–	21	81	119	138	51		–	21	494
Nov	49	21	11	–	26	95	128	163	59	2		29	583
Dec	4	4	–	–	–	15	70	47	22	–	–		162

Considering the large differences in monthly peak loads, and the number of hours in high-load months that exceed the peak load in low-load months, simply adding up the number of monthly peaks covered by the peak period probably does not adequately measure the extent to which the peak period represents the hours that stress system reliability and require additional capacity.

Q: Are you suggesting that the peak loads in the low-load months have no effect on the Company's demand costs?

A: No. The Company (and the broader regions to which the Company is interconnected) needs low-load periods in which generators and transmission lines can be taken out of service for major maintenance outages. If too much maintenance must be undertaken in some low-load months, or if some of the maintenance spills onto high-load months, the reliability of the generation and transmission system would suffer, requiring a higher reserve margin and more capacity. Unplanned outages have a similar effect of spreading out the responsibility for additional capacity; the Company's system needs less installed capacity at a 6,400 MW annual peak with all capacity available than at a 5,900 MW load with 600 MW out of service.

Overall, the peak loads in most months probably contribute to the Company's capacity need, with the high-load months contributing more to that need. Indeed, in the cost-of-service study, Dr. Blake uses just one summer hour to allocate peaking capacity and one winter hour to allocate intermediate capacity. That treatment of capacity costs in the cost-of-service study is too extreme in the other direction, since many hours contribute to the risk of insufficient capacity.

Q: Are all demand-related costs driven by the system peak hours?

A: No. Distribution costs are driven by the number of transformers, feeders, substations and other equipment peaking at various times, as well as the total energy load on transformers and underground lines during high-load periods and around-the-clock on high-load days.

Q: Are there factors other than load levels that should be considered in defining the peak hours?

A: Yes. Marginal hourly energy costs, whether measured by the Company's system lambda (the incremental dispatch cost) or by market prices in the adjoining regional markets, should also be considered in determining the peak hours. While high-load hours tend to be high-cost hours within a particular day, the relationships are not linear.

Figure 1 depicts the maximum load in each weekday hour for January and July, averaged across 2000–2014, and then normalized so the average weekday load in the month is 100%.[24] Figure 1 also shows the normalized lambda, averaged over 2006–2013, from the LG&E-KU Form 714 filing with FERC.[25]

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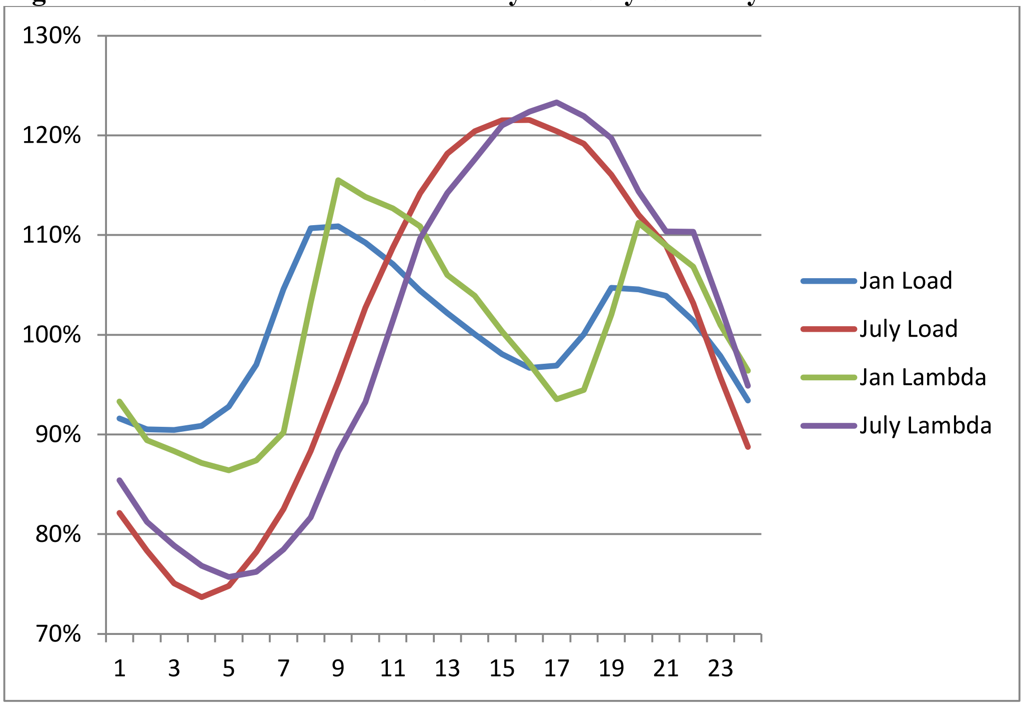
[24] Hourly load data are from the spreadsheet 'Att_KU_PSC_2-60_LKESysLoad ShapeTOUPeak.xlsx', provided in Company Response to PSC Staff Second Data Request No. 60.

[25] Hourly marginal cost patterns are likely to change over time, as coal plants are retired and replaced by existing and new gas plants (and to some extent, renewable energy resources) and as the limits on carbon emissions under the Clean Power Plan result in adders to the dispatch prices of fossil plants, especially coal plants. Since I do not have projections of hourly costs, I have shown the available historical data.

Figure 1: Normalized Maximum January and July Weekday Loads and Lambda



The summer load and lambda have very similar shapes, as do the winter load and lambda.[26] It is clear that the summer load and prices peak in the afternoon, somewhere between 11 AM and 6 PM. The winter has two daily peaks, in the morning (7 AM to 11 AM) and in the evening (roughly 6 to 10 PM). The evening peak is more pronounced in terms of price than in terms of load. Because the Company proposes only a winter-morning peak period, customers will have no incentive to avoid consumption during winter evenings, when energy prices are substantially higher than in the early afternoon or overnight.

In Figure 2, I present similar information on the winter patterns of market prices, as reported by PJM for the East Kentucky Power Cooperative (average weekday load by hour, excluding New Year's Day). The double peak is again obvious, with the evening peak sometimes exceeding the morning.

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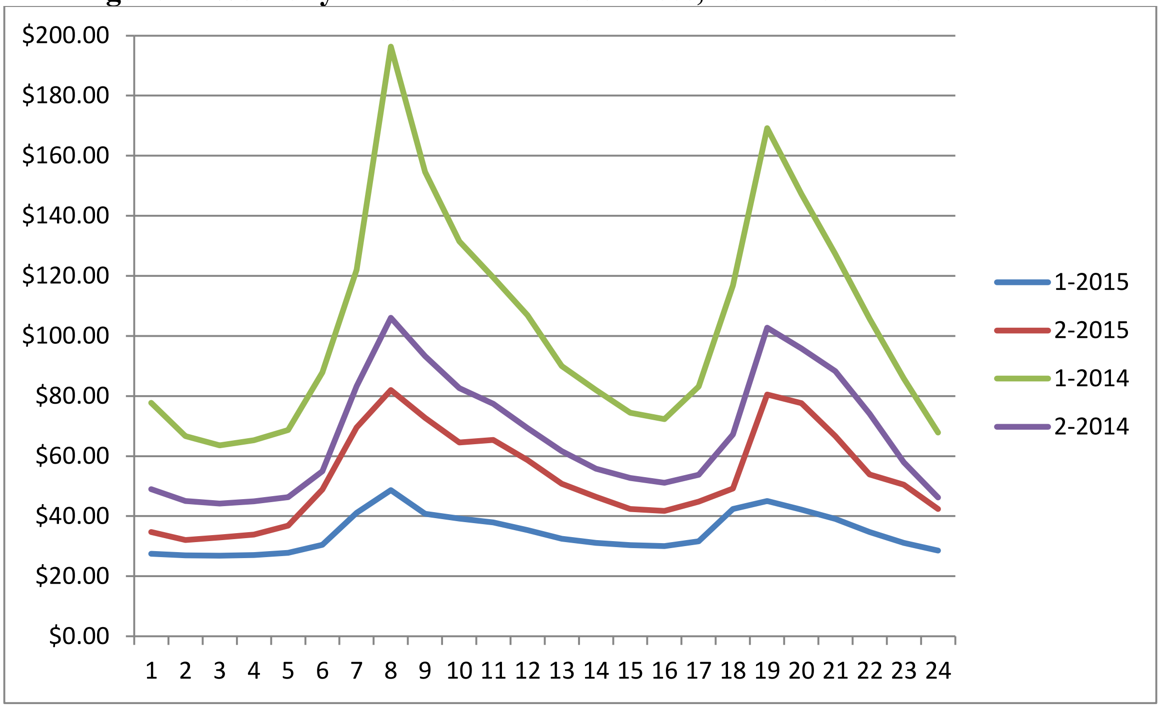
[26] The apparent one-hour lag in lambda, compared to load, may be due to differences in the definition of the hours in various data bases.

Figure 2: Weekday Patterns in Market Prices, 2014 and 2015



Q: Have the Company's patterns of loads and lambdas changed over time?

A: Yes. As shown in Figure 3, it appears that the summer peaks have been consistently starting later over the years, with the five-year average showing about an hour's lag compared to the fifteen-year average. The winter loads are very similar over the last 15 years and the last 10 years, but over the last 5 years, the morning peak has been lower and the evening peak higher, leaving the two peaks at very similar levels.

Figure 3: Normalized Loads over Time

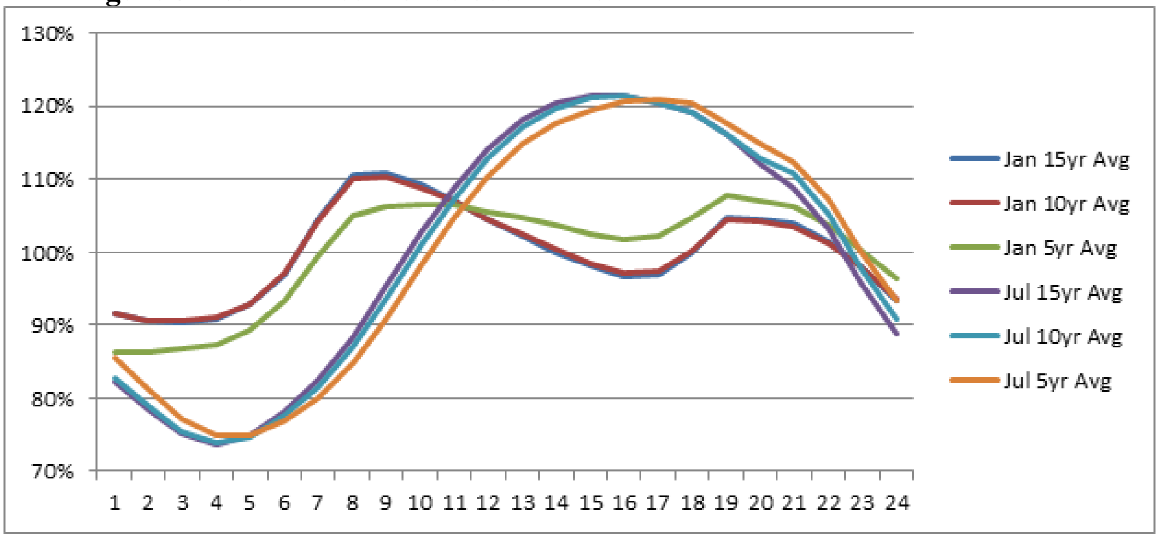
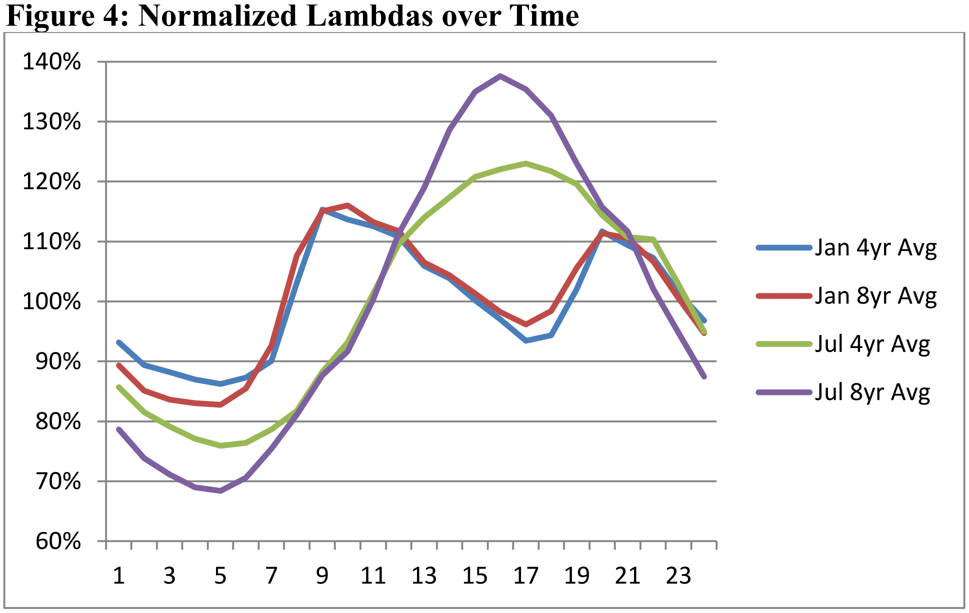


Figure 4 provides similar information for the Company's lambdas, for the entire eight-year period for which I have data (2006–2013) for the last four years. Again, the summer afternoon peak has flattened considerably, while the peak winter lambdas have remained relatively consistent.

Figure 4: Normalized Lambdas over Time



The difference between the morning and evening winter peaks is modest. Over the five years of data analyses, the average difference between morning and evening peaks is 2.2% over the months November through March.[27] The daily average peak/off-peak ratio for the weekdays of each month are summarized in Table 6. There are many months in which rather modest shifts of load from the morning to the evening would increase average daily peaks.

Table 6: Ratio of Morning to Evening Peak Loads, All Days by Month

	January	February	March	November	December	Avg
2010	103.0%	104.8%	105.9%	100.9%	103.2%	101.0%
2011	102.1%	102.9%	104.0%	100.7%	101.2%	100.7%
2012	102.5%	105.2%	98.5%	104.4%	99.2%	100.1%
2013	101.4%	104.3%	107.3%	102.9%	102.5%	101.4%
2014	102.9%	105.4%	109.6%			103.4%
Avg	102.4%	104.5%	105.0%	102.2%	101.6%	101.1%

Table 7 shows similar data for the maximum morning load in each winter month and the maximum evening load in that month, for the last five years. Again, the evening peak is already sometimes higher than the morning peak, and small shifts to the evening would create new monthly peaks.

Table 7: Ratio of Morning to Evening Monthly Peak Loads

	January	February	March	November	December
2010	103%	104%	106%	102%	104%
2011	99%	109%	98%	102%	104%
2012	101%	107%	102%	106%	104%
2013	104%	108%	103%	99%	106%
2014	99%	112%	104%		

Q: What are the implications of the load and cost data for the Company's choice of time periods?

A: The major issue is that the winter rate design proposed by the Company will encourage customers to shift loads from the morning to any other time, without providing any incentive to shift to low-cost times. For customers who are out

[27] Including April and October in the average would reduce the ratio to 1.1%. As I explain below, those months really do not belong in the winter.

of the house most of the day, that would probably mean doing laundry and running the dishwasher to the evening, when loads and costs are just about as high as in the morning. Ignoring the evening peak in the winter may result in price signals that encourage the shifting of loads from one high-cost period to another, rather than from the high-cost periods to the overnight period. In addition, where customers have a choice of running loads in the evening or late at night (again, mostly for dishwashers, clothes washers and clothes driers, and potentially electric cars and other recharging loads), the Company's proposal gives no incentive to shift costs into the lower-cost hours.

Q: Does the Company use other time-of-day periods for other tariffs?

A: Yes. In Rate LEV, the Company uses three pricing periods (off-peak, intermediate and peak). The intermediate periods provide energy charges between the off-peak and peak prices in the summer mid-day and late evening, and in the winter afternoon and evening. That approach would tend to encourage customers to shift load to hours with lower costs and loads, compared to the Company's very narrow peak periods in Rate RTOD-E. In some respects, the Company's proposal to replace Rate LEV with Rate RTOD-E is a step in the wrong direction.

3. Grouping Months into Seasons

Q: Has Dr. Blake properly identified the months that should be in each season?

A: No. His decision to include April and October in the winter does not seem appropriate. While deep winter and summer months have load shapes with pronounced swings, the shoulder months April and October do not. Figure 5 depicts the 15-year average maximum load by hour and illustrates the differences in load shapes.

Figure 5: Comparison of Winter, Summer and Shoulder Hourly Loads

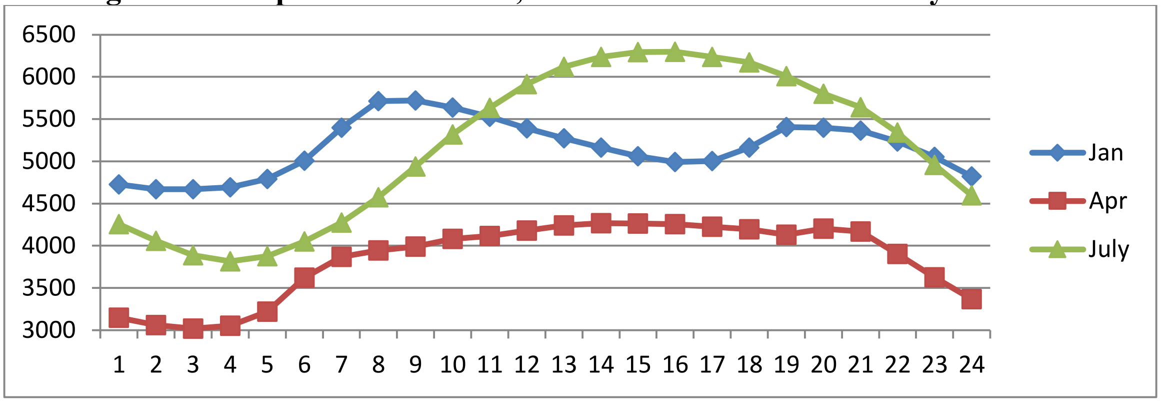


Table 8 summarizes the monthly peaks over the available data period (14 to 15 years, depending on the month), showing the number of peaks in each hour for the summer as defined by the Company (May to September), April and October, and the rest of the Company's winter period (November to March). Many more April and October peaks fall in the peak period that the Company defined for the summer season than in the peak period that the Company defined for the winter (shown by the green boxes). Moving April and October to the summer increases the count of peak hours captured by the definition of the peak periods by 17 hours, about 10% of the total hours.

Table 8: Monthly Peaks in Peak Period, Alterative Season Definitions

	Peak Count by Period			April & October in Winter		April & October in Summer	
Hour Beginning	May to September	April & October	November to March	Summer	Winter	Summer	Winter
6	0	5	1	0	6	5	1
7	0	2	40	0	42	2	40
8	0	0	13	0	13	0	13
9	0	0	3	0	3	0	3
10	0	0	4	0	4	0	4
11	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0
13	4	3	0	4	3	7	0
14	22	2	0	22	2	24	0
15	42	11	0	42	11	53	0
16	5	3	0	5	3	8	0
17	0	1	0	0	1	1	0
18	1	1	6	1	7	2	6
19	0	1	4	0	5	1	4
20	0	0	2	0	2	0	2
Peaks	74	29	73	74	102	103	73
Peaks in Peak Period				73	62	92	60
Total peaks covered				135		152	
As % of monthly peaks				76.7%		86.4%	

Within the approach that Dr. Blake uses (counting the number of peak hours over the last 15 years that would be in the peak period), these two months would be better characterized as part of the summer season. These two months have 67% and 86% of the peak hours in the afternoon instead of the morning. By transferring the shoulder months April and October from the winter period to the summer, 17 additional peaks can be captured. This raises the percentage of included peaks up to 86.4% while keeping a two season schedule each with a single four-hour peak period.

Q: What do you conclude about the seasonal periods?

A: If the Commission favors the simplicity of only two seasonal periods, April and October should be moved to the summer. Introducing a shoulder season, including April, October and possibly May and November, would open up additional options, allowing for pricing during those months that properly reflects system costs.

4. Pricing

Q: How does the Company set the prices for the on-peak and off-peak periods?

A: The Company proposes energy rates in Rate RTOD-E of about 5¢/kWh off-peak and 25¢/kWh on-peak. Dr. Blake derives these rates by assigning all demand-classified distribution costs from the COSS to the off-peak period, and all demand-classified production and transmission costs to the on-peak period. The same average energy-classified costs are added to the rates for both periods.

Q: Is this approach appropriate?

A: No, for several reasons:

- The Company's COSS classifies the costs of the Company's existing system between demand-related and energy-related components, and allocates those embedded costs among classes. The COSS is not designed to estimate the incremental costs of serving an additional kilowatt-hour on peak versus off-peak.
- The Company's approach is inconsistent even within the framework of the embedded-cost analysis, since the Base-Intermediate-Peak (BIP) computation allocates 35% of production and transmission costs on the basis of minimum load, which would be in the off-peak period, but the Company assigns 100% of those costs to the peak period. Shifting that portion of production and transmission costs from the peak rate to the off-

peak rate in Exhibit MJB-11 would reduce the peak rate by about 7¢/kWh and increase the off-peak by about 1¢/kWh.[28]

- The Company's approach does not reflect the market value of energy. As indicated in Figure 2, peak energy prices are substantially higher than off-peak prices, but not by enough to justify the five-to-one price ratio in the Company's proposal.

Given these factors, it would be mostly coincidental if the Company's proposed 20¢/kWh rate differential approximated the savings that could be realized if customers changed their usage patterns. That differential appears to be substantially overstated.

Q: Could the time-of-day pricing proposed by the Company cause problems?

A: Yes. The very high differential in energy prices between peak and off-peak proposed by the Company may encourage uneconomic investment in storage water and space heating (and even storage air conditioning) and inefficient load-shifting strategies, such as pre-chilling a home before the summer peak period or over-heating the home in the early morning, before the winter peak. The very low off-peak rates may also tend to encourage the use of electricity for space and water heating, even where gas would be more efficient and contribute less to pollution and greenhouse-gas emissions. Even where socially desirable actions might be encouraged by the very low off-peak rates (such as adoption of electric cars) or the very high on-peak rates (e.g., rooftop solar), the Commission should be leery of approving such wide differentials, unless it is sure that they are cost-justified and sustainable. Dramatically flattening

[28] A small part of this change in rates would be offset by spreading the distribution costs over all hours, since distribution equipment can reach its maximum loads (or be otherwise stressed) in peak hours, as well as off-peak hours.

the rate differentials in the future may disrupt industries (rooftop solar, electric vehicle sales and service) that develop on the basis of the Company's exaggerated incentives.

Q: What do you recommend with regard to the Company's proposal for residential time-of-day rates?

A: The Commission should reject the Company's proposal to implement the demand-charge option (RTOD-D). In addition, the Commission should direct the Company to modify the energy-charge option (RTOD-E) to move April and October into the summer period, to include the winter evening in the peak period, and to reduce the differentials between the peak and off-peak rates in order to better reflect differentials in incremental cost and provide accurate price signals for load-shifting.

Q: Does this conclude your direct testimony?

A: Yes.

CERTIFICATE OF SERVICE

I hereby certify, this the 6th day of March, 2015, that the attached Direct Testimony of Paul Chernick on Behalf of Sierra Club is a true and correct copy of the document being filed in paper medium; that the electronic filing has been transmitted to the Commission on March 6, 2015; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; that an original and one copy of this document is being mailed to the Commission for filing on March 6, 2015; and that an electronic notification of the electronic filing will be provided to all counsel listed on the Commission's service list in this proceeding.

JOE F. CHILDERS