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<u>VIA COURIER AND ELECTRONIC FILING</u>

March 6, 2014

Jeff R. Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

**Re: Direct Testimony of Paul Chernick on Behalf of Sierra Club
Case No. 2014-00371**

Dear Mr. Derouen,

Please find enclosed for filing one copy of the Direct Testimony of Paul Chernick on Behalf of Sierra Club in Case No. 2014-00371 before the Kentucky Public Service Commission. This document is being filed electronically.

The electronically filed documents are a true representation of the original documents to be filed with the Commission. This filing contains no confidential information.

Thank you for your attention to this matter.

Sincerely,

JOE F. CHILDERS

Enc.

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?

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[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

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[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

[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

[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.

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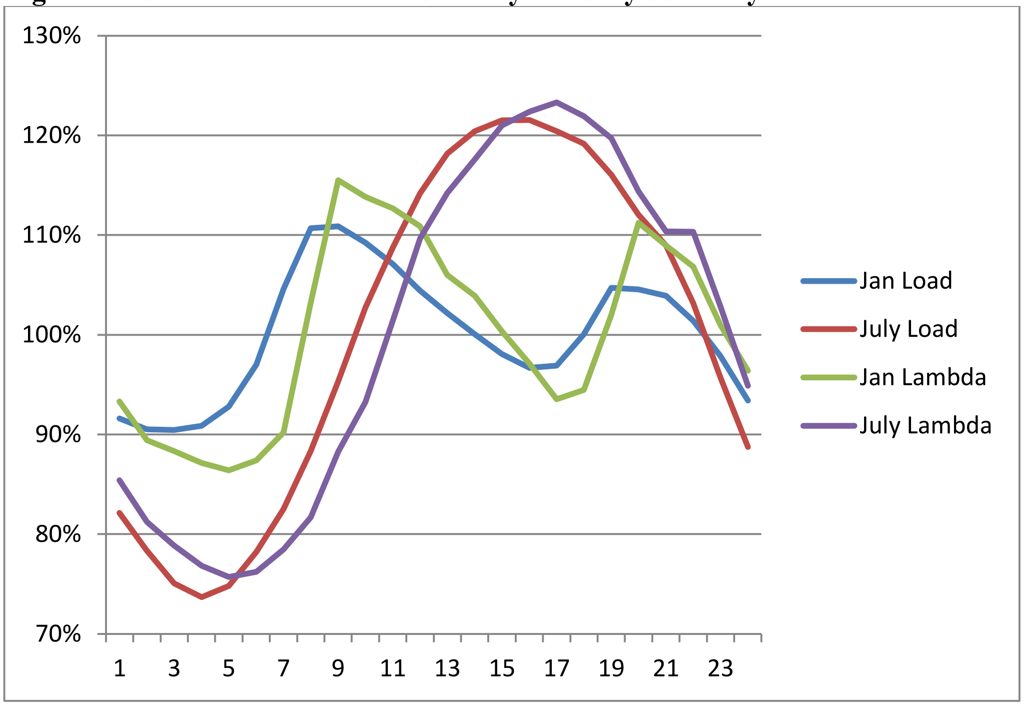
[24] Hourly load data are from the spreadsheet 'Att_KU_PSC_2-60_LKESysLoad ShapeTOUPeak.xlsx', provided in Company Response to PSC Staff Second Data Request No. 60.

[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

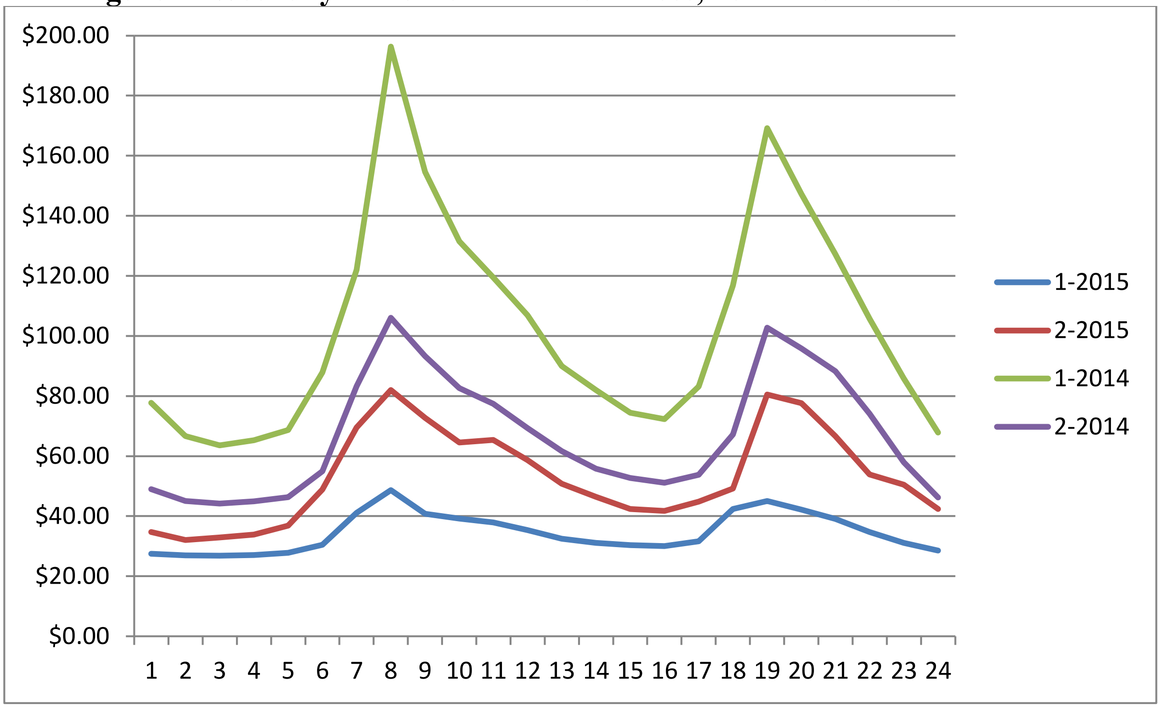


The summer load and lambda have very similar shapes, as do the winter load and lambda.[26] It is clear that the summer load and prices peak in the afternoon, somewhere between 11 AM and 6 PM. The winter has two daily peaks, in the morning (7 AM to 11 AM) and in the evening (roughly 6 to 10 PM). The evening 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.

[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

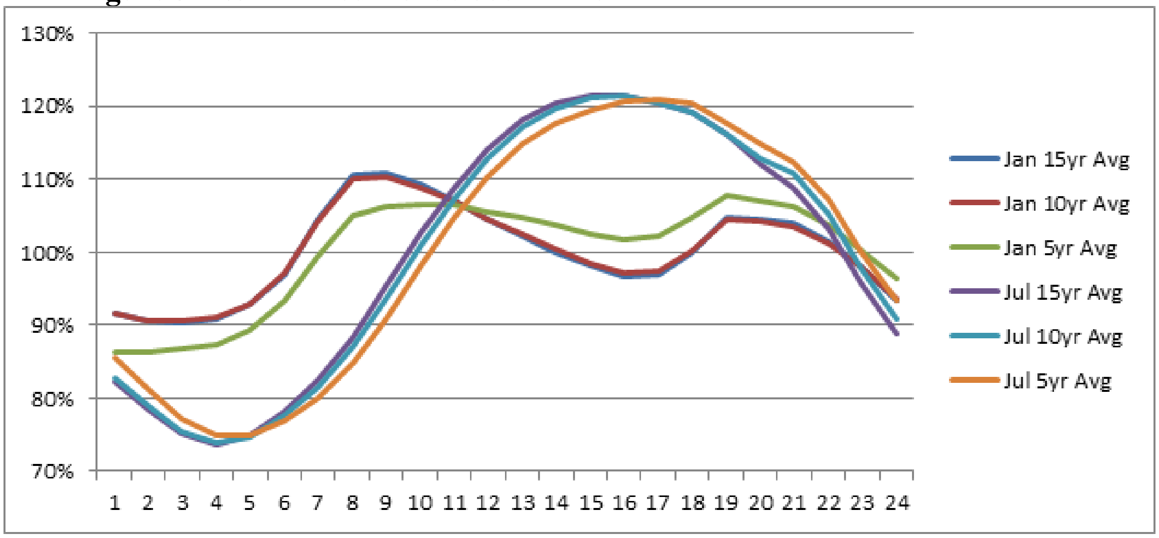
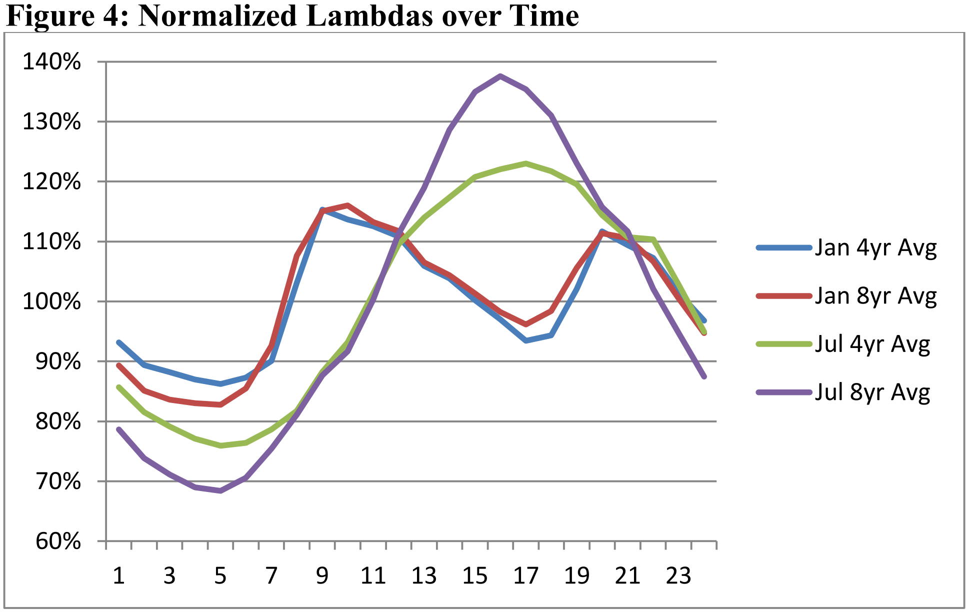


Figure 4 provides similar information for the Company's lambdas, for the entire eight-year period for which I have data (2006–2013) for the last four years. Again, the summer afternoon peak has flattened considerably, while the peak winter lambdas have remained relatively consistent.

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

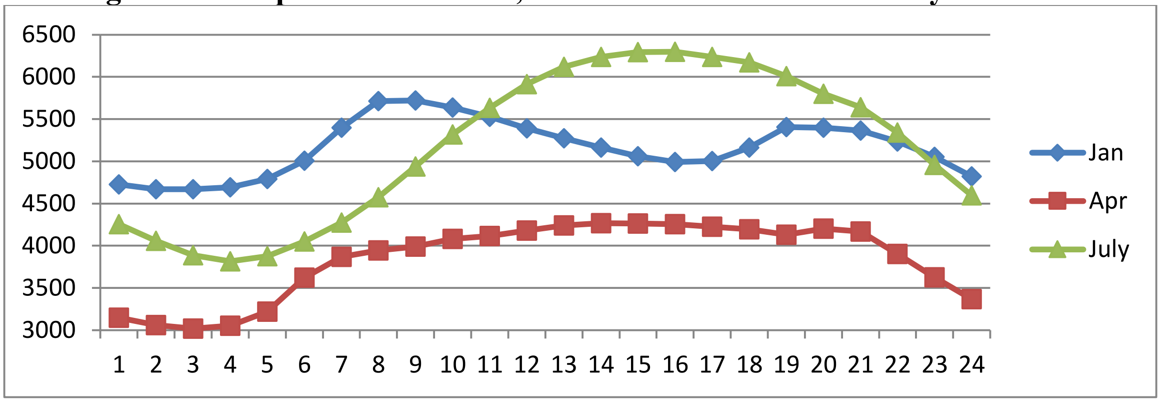


Table 8 summarizes the monthly peaks over the available data period (14 to 15 years, depending on the month), showing the number of peaks in each hour for the summer as defined by the Company (May to September), April and October, and the rest of the Company's winter period (November to March). Many 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

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of	)	
Kentucky Utilities Company for An	)	**CASE NO. 2014-00371**
Adjustment of Its Electric Rates	)	

AFFIDAVIT OF PAUL L. CHERNICK FOR DIRECT TESTIMONY

State of)
Massachusetts)

Paul L. Chernick, being first duly sworn, states the following: The prepared Direct Testimony and associated exhibits filed on Friday, March 6, 2015 constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Direct Testimony, if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct.

Paul L. Chernick

SUBSCRIBED AND SWORN to before me this 5th day of March 2015.

Notary Public

My Commission Expires:

Commonwealth of Massachusetts
On this 5th day of March, 20__
I certify that the Paul Chernick
document is ~~a true, exact~~, complete and unaltered copy
of the original.

Dianne J DeMarco, Notary Public
My Commission Expires September 11, 2020

PAUL L. CHERNICK

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Jonathan Wallach), *1996 Summer Study on Energy Efficiency in Buildings*, Washington: American Council for an Energy-Efficient Economy 7(7.47–7.55). 1996.

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning*. Washington: National Association of Regulatory Utility Commissioners. May 1994.

"Environmental Externalities: Highways and Byways" (with Bruce Biewald and William Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning*. Washington: National Association of Regulatory Utility Commissioners. May 1994.

"The Transfer Loss is All Transfer, No Loss" (with Jonathan Wallach), The *Electricity Journal* 6:6 (July 1993).

"Benefit-Cost Ratios Ignore Interclass Equity" (with others), *DSM Quarterly*, Spring 1992.

"ESCos or Utility Programs: Which Are More Likely to Succeed?" (with Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

“Determining the Marginal Value of Greenhouse Gas Emissions” (with Jill Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II*, July 1991.

“Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs” (with Emily Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference*, April 1991.

“Accounting for Externalities” (with Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

“Methods of Valuing Environmental Externalities” (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

“The Valuation of Environmental Externalities in Energy Conservation Planning” (with Emily Caverhill), *Energy Efficiency and the Environment: Forging the Link*. American Council for an Energy-Efficient Economy; Washington: 1991.

“The Valuation of Environmental Externalities in Utility Regulation” (with Emily Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization*. Springer-Verlag; Berlin: 1991.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), *Gas Energy Review*, December 1990.

“Externalities and Your Electric Bill,” *The Electricity Journal*, October 1990, p. 64.

“Monetizing Externalities in Utility Regulations: The Role of Control Costs” (with Emily Caverhill), in *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

“Monetizing Environmental Externalities in Utility Planning” (with Emily Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment” (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

“Demand-Side Bidding: A Viable Least-Cost Resource Strategy” (with John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Incorporating Environmental Externalities in Evaluation of District Heating Options” (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment," (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference,* June 1990.

"Incorporating Environmental Externalities in Utility Planning" (with Emily Caverhill), *Canadian Electrical Association Demand Side Management Conference*, May 1990.

"Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?" in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10–13 1989.

"Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23 1989.

"The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal" (with John Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

"Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553–557.

"Capital Minimization: Salvation or Suicide?," in I. C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63–72.

"The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April 1987, pp. 36–42.

"Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 547–562.

"Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System" (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 2093–2110.

"Forensic Economics and Statistics: An Introduction to the Current State of the Art" (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1 1985, pp. 25–36.

"Power Plant Performance Standards: Some Introductory Principles," *Public Utilities Fortnightly*, April 18 1985, pp. 29–33.

"Opening the Utility Market to Conservation: A Competitive Approach," *Energy Industries in Transition, 1985–2000,* Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November 1984, pp. 1133–1145.

"Insurance Market Assessment of Technological Risks" (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York 1985.

"Revenue Stability Target Ratemaking," *Public Utilities Fortnightly*, February 17 1983, pp. 35–39.

"Capacity/Energy Classifications and Allocations for Generation and Transmission Plant" (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University 1982.

Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (with Fairley, W., Meyer, M., and Scharff, L.) (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December 1981.

Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September 1977.

REPORTS

"Comments on Nova Scotia Power Inc.'s Proposed Capital Expenditure Justification Criteria." Filed by the Nova Scotia Small Business Advocate in N.S. UARB Matter No. 05355.

"Avoided Energy Supply Costs in New England: 2013 Report" (with Rick Hornby, David White, John Rosenkranz, Ron Denhardt, Elizabeth Stanton, Jason Gifford, Bob Grace, Max Chang, Patrick Luckow, Thomas Vitolo, Patrick Knight, Ben Griffiths, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"Affordability of Pollution Control on the Apache Coal Units: Review of Arizona Electric Power Cooperative's Comments on Behalf of the Sierra Club" (with Ben Griffiths). 2012. Filed as part of comments in Docket EPA-R09-OAR-2012-0021 by National Parks Conservation Association, Sierra Club, et al.

"Audubon Arkansas Comments on Entergy's 2012 IRP." 2012. Prepared for and filed by Audubon Arkansas in Arkansas PUC Docket No. 07-016-U.

"Economic Benefits from Early Retirement of Reid Gardner" (with Jonathan Wallach). 2012. Prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

"Analysis of Via Verde Need and Economics." 2012. Appendix V-4 of public comments of the Sierra Club et al. in response to November 30 2011 draft of U.S. Army Corps of Engineers environmental assessment in Department of the Army Environmental Assessment and Statement of Finding for Permit Application SAJ-2010-02881.

"Comments for The Alliance for Affordable Energy on Staff's 'Proposed Integrated Resource Planning Rules for Electric Utilities in Louisiana.'" 2011. Filed by the Alliance for Affordable Energy in Louisiana PSC Docket R-30021.

"Avoided Energy Supply Costs in New England: 2011 Report" (with Rick Hornby, Carl Swanson, David White, Jason Gifford, Max Chang, Nicole Hughes, Matthew Wittenstein, Rachel Wilson, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"State of Ohio Energy-Efficiency Technical-Reference Manual Including Predetermined Savings Values and Protocols for Determining Energy and Demand Savings" (with others). 2010. Burlington, Vt.: Vermont Energy Investment Corporation.

"Avoided Energy Supply Costs in New England: 2011 Report" (with Rick Hornby, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Ben Warfield, Jason Gifford, and Max Chang). 2009. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"Green Resource Portfolios: Development, Integration, and Evaluation" (with Jonathan Wallach and Richard Mazzini). 2008. Report to the Green Energy Coalition presented as evidence in Ont. Energy Board EB 2007-0707.

"Risk Analysis of Procurement Strategies for Residential Standard Offer Service" (with Jonathan Wallach, David White, and Rick Hornby) report to Maryland Office of People's Counsel. 2008. Baltimore: Maryland Office of People's Counsel.

"Avoided Energy Supply Costs in New England: 2007 Final Report" (with Rick Hornby, Carl Swanson, Michael Drunsic, David White, Bruce Biewald, and Jenifer Callay). 2007. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"Integrated Portfolio Management in a Restructured Supply Market" (with Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers' Counsel.

"Natural Gas Efficiency Resource Development Potential in New York" (with Phillip Mosenthal, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak). 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

"Natural Gas Efficiency Resource Development Potential in Con Edison Service Territory" (with Phillip Mosenthal, Jonathan Kleinman, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak. 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

"Evaluation and Cost Effectiveness" (principal author), Ch. 14 of "California Evaluation Framework" Prepared for California utilities as required by the California Public Utilities Commission. 2004.

“Energy Plan for the City of New York” (with Jonathan Wallach, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

“Updated Avoided Energy Supply Costs for Demand-Side Screening in New England” (with Susan Geller, Bruce Biewald, and David White). 2001. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

“Review and Critique of the Western Division Load-Pocket Study of Orange and Rockland Utilities, Inc.” (with John Plunkett, Philip Mosenthal, Robert Wichert, and Robert Rose). 1999. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

“Avoided Energy Supply Costs for Demand-Side Management in Massachusetts” (with Rachel Brailove, Susan Geller, Bruce Biewald, and David White). 1999. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

“Performance-based Regulation in a Restructured Utility Industry” (with Bruce Biewald, Tim Woolf, Peter Bradford, Susan Geller, and Jerrold Oppenheim). 1997. Washington: NARUC.

“Distributed Integrated-Resource-Planning Guidelines.” 1997. Appendix 4 of “The Power to Save: A Plan to Transform Vermont’s Energy-Efficiency Markets,” submitted to the Vt. PSB in Docket No. 5854. Montpelier: Vermont DPS.

“Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests” (with Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People’s Counsel.

“Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire’s Electric-Utility Industry” (with Bruce Biewald and Jonathan Wallach). 1996. Concord, N.H.: NH OCA.

“Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities” (with Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

From Here to Efficiency: Securing Demand-Management Resources (with Emily Caverhill, James Peters, John Plunkett, and Jonathan Wallach). 1993. 5 vols. Harrisburg, Penn: Pennsylvania Energy Office.

“Analysis Findings, Conclusions, and Recommendations,” vol. 1 of “Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro” (with Plunkett, John, and Jonathan Wallach), December 1992.

“Estimation of the Costs Avoided by Potential Demand-Management Activities of Ontario Hydro,” December 1992.

“Review of the Elizabethtown Gas Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Jonathan Wallach, John Plunkett, James Peters, Susan Geller, Blair. Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

Environmental Externalities Valuation and Ontario Hydro’s Resource Planning (with E. Caverhill and R. Brailove), 3 vols.; prepared for the Coalition of Environmental Groups for a Sustainable Energy Future, October 1992.

“Review of Jersey Central Power & Light’s 1992 DSM Plan and the Demand-Side Management Rules” (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

“The AGREA Project Critique of Externality Valuation: A Brief Rebuttal,” March 1992.

“The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts,” March 1992.

“Initial Review of Ontario Hydro’s Demand-Supply Plan Update” (with David Argue et al.), February 1992.

“Report on the Adequacy of Ontario Hydro’s Estimates of Externality Costs Associated with Electricity Exports” (with Emily Caverhill), January 1991.

“Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities,” (with John Plunkett et al.), September 1990. Filed in NY PSC Case No. 28223 in re New York utilities’ DSM plans.

“Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica’s Power Needs,” (with Conservation Law Foundation, et al.), June 1990.

“Analysis of Fuel Substitution as an Electric Conservation Option,” (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

“The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company” (with Eric Espenhorst), Boston Gas Company, December 22 1989.

“The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update” (with Emily Caverhill), Boston Gas Company, December 22 1989.

“Conservation Potential in the State of Minnesota,” (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

“Review of NEPOOL Performance Incentive Program,” Massachusetts Energy Facilities Siting Council, April 12 1988.

“Application of the DPU’s Used-and-Useful Standard to Pilgrim 1” (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

“Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods,” Massachusetts Energy Facilities Siting Council, June 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

"Adding Transmission into New York City: Needs, Benefits, and Obstacles." Presentation to FERC and the New York ISO on behalf of the City of New York. October 2004.

"Plugging Into a Municipal Light Plant," With Peter Enrich and Ken Barna. Panel presentation as part of the 2004 Annual Meeting of the Massachusetts Municipal Association. January 2004.

"Distributed Utility Planning." With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative, November 1999.

"The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond." Presentation as part of the Ohio Office of Energy Efficiency's seminar, "Gas Utility Integrated Resource Planning," April 1994.

"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

"Comparing and Integrating DSM with Supply." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"DSM Cost Recovery and Rate Impacts." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Cost-Effectiveness Analysis." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling" (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference. June 1993.

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

"Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels (session leader), DSM Advocacy Workshop. April 15 1992.

"Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs," Energy Planning Workshops; Columbia, S.C. October 21 1991;

"Least Cost Planning and Gas Utilities." Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

"Least-Cost Planning in a Multi-Fuel Context," NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

"Accounting for Externalities: Why, Which and How?" Understanding Massachusetts' New Integrated Resource Management Rules; Needham, Massachusetts, November 9 1990.

"Increasing Market Share Through Energy Efficiency." New England Gas Association Gas Utility Managers' Conference; Woodstock, Vermont, September 10 1990.

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

"Conservation in the Future of Natural Gas Local Distribution Companies," District of Columbia Natural Gas Seminar; Washington, D.C., May 23 1989.

"Conservation and Load Management for Natural Gas Utilities," Massachusetts Natural Gas Council; Newton, Massachusetts, April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, New Hampshire, January 22–23 1989.

"Assessment and Valuation of External Environmental Damages," New England Utility Rate Forum; Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

"Reviewing Utility Supply Plans," Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30 1985.

"Power Plant Performance," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals. August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations. March 1988 to June 1989.

EXPERT TESTIMONY

1. **Mass. EFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **Mass. EFSC** 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General. September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **Mass. EFSC** 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General. November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **Mass. DPU** 19494; Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with Susan Geller.

5. **Mass. DPU** 19494; Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **U.S. ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts. June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with Susan Geller.

7. **Mass. DPU** 19845; Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 4 1979.

Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller. Testimony eventually withdrawn due to delay in case.

8. **Mass. DPU** 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General. January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **Mass. DPU** 20248; Petition of Massachusetts Municipal Wholesale Electric Company to purchase additional share of Seabrook Nuclear Plant; Massachusetts Attorney General. June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **Mass. DPU** 200; Massachusetts Electric Company rate case; Massachusetts Attorney General. June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **Mass. EFSC** 79-33; Eastern Utilities Associates 1979 forecast; Massachusetts Attorney General. July 16 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **Mass. DPU** 243; Eastern Edison Company rate case; Massachusetts Attorney General. August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298; Gulf States Utilities rate case; East Texas Legal Services. August 25 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **Mass. EFSC** 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 5 1980.

Cost comparison methodology; nuclear cost estimates; cost of conservation, co-generation, and solar.

15. **Mass.** **DPU** 472; Recovery of residential conservation-service expenses; Massachusetts Attorney General. December 12 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **Mass.** **DPU** 535; Regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 26 1981 and February 13 1981.

    Filing requirements, certification, qualifying-facility status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of qualifying facilities in specific areas; wheeling; standardization of fees and charges.

17. **Mass.** **EFSC** 80-17; Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 12 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **Mass.** **DPU** 558; Western Massachusetts Electric Company rate case; Massachusetts Attorney General. May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **Mass.** **DPU** 1048; Boston Edison plant performance standards; Massachusetts Attorney General. May 7 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **D.C.** **PSC** FC785; Potomac Electric Power rate case; D.C. People's Counsel. July 29 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **N.H.** **PSC** DE1-312; Public Service of New Hampshire—supply and demand; Conservation Law Foundation, et al. October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Mass. Division of Insurance;** Hearing to fix and establish 1983 automobile insurance rates; Massachusetts Attorney General. October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Ill. Commerce Commission** 82-0026; Commonwealth Edison rate case; Illinois Attorney General. October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **N.M. PSC** 1794; Public Service of New Mexico application for certification; New Mexico Attorney General. May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Conn. DPUC** 830301; United Illuminating rate case; Connecticut Consumers Counsel. June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **Mass. DPU** 1509; Boston Edison plant performance standards; Massachusetts Attorney General. July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Mass. Division of Insurance;** Hearing to fix and establish 1984 automobile-insurance rates; Massachusetts Attorney General. October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Conn. DPUC** 83-07-15; Connecticut Light and Power rate case; Alloy Foundry. October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **Mass. EFSC** 83-24; New England Electric System forecast of electric resources and requirements; Massachusetts Attorney General. November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Mich.** PSC U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan. February 21 1984.

Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **Mass.** DPU 84-25; Western Massachusetts Electric Company rate case; Massachusetts Attorney General. April 6 1984.

Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **Mass.** DPU 84-49 and 84-50; Fitchburg Gas & Electric financing case; Massachusetts Attorney General. April 13 1984.

Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Mich.** PSC U-7785; Consumers Power fuel-cost-recovery plan; Public Interest Research Group in Michigan. April 16 1984.

Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000; Montaup Electric rate cases; Massachusetts Attorney General. April 27 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine** PUC 84-113; Seabrook 1 investigation; Maine Public Advocate. September 13 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **Mass.** DPU 84-145; Fitchburg Gas and Electric rate case; Massachusetts Attorney General. November 6 1984.

Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Penn. PUC** R-842651; Pennsylvania Power and Light rate case; Pennsylvania Consumer Advocate. November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **N.H. PSC** 84-200; Seabrook Unit 1 investigation; New Hampshire Public Advocate. November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Mass. Division of Insurance;** Hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

    Profit margin calculations, including methodology and implementation.

40. **Mass. DPU** 84-152; Seabrook Unit 1 investigation; Massachusetts Attorney General. December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power rate case; Maine PUC Staff. December 11 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113; Seabrook 2 investigation; Maine PUC Staff. December 14 1984.

    Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **Mass.** **DPU** 1627; Massachusetts Municipal Wholesale Electric Company financing case; Massachusetts Executive Office of Energy Resources. January 14 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vt.** **PSB** 4936; Millstone 3 costs and in-service date; Vermont Department of Public Service. January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **Mass.** **DPU** 84-276; Rules governing rates for utility purchases of power from qualifying facilities; Massachusetts Attorney General. March 25 1985, and October 18 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **Mass.** **DPU** 85-121; Investigation of the Reading Municipal Light Department; Wilmington (Mass.) Chamber of Commerce. November 12 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Mass. Division of Insurance;** Hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **N.M.** **PSC** 1833, Phase II; El Paso Electric rate case; New Mexico Attorney General. December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Penn.** **PUC** R-850152; Philadelphia Electric rate case; Utility Users Committee and University of Pennsylvania. January 14 1986.

    Limerick-1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **Mass.** **DPU** 85-270; Western Massachusetts Electric rate case; Massachusetts Attorney General. March 19 1986.

Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Penn.** PUC R-850290; Philadelphia Electric auxiliary service rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK. March 24 1986.

Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **N.M.** PSC 2004; Public Service of New Mexico, Palo Verde issues; New Mexico Attorney General. May 7 1986.

Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

53. **Ill. Commerce Commission** 86-0325; Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 13 1986.

Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **N.M.** PSC 2009; El Paso Electric rate moderation program; New Mexico Attorney General. August 18 1986. (Not presented).

Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston Public Improvements Commission;** Transfer of Boston Edison district heating steam system to Boston Thermal Corporation; Boston Housing Authority. December 18 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Mass. Division of Insurance;** Hearing to fix and establish 1987 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. December 1986 and January 1987.

Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **Mass. DPU** 87-19; Petition for adjudication of development facilitation program; Hull (Mass.) Municipal Light Plant. January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **N.M. PSC** 2004; Public Service of New Mexico nuclear decommissioning fund; New Mexico Attorney General. February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **Mass. DPU** 86-280; Western Massachusetts Electric rate case; Massachusetts Energy Office. March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Mass. Division of Insurance** 87-9; 1987 Workers' Compensation rate filing; State Rating Bureau. May 1987.

    Profit-margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184; Economic viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief. August 17 1987.

    Nuclear plant operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. **Minn. PUC** ER-015/GR-87-223; Minnesota Power rate case; Minnesota Department of Public Service. August 17 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Mass. Division of Insurance** 87-27; 1988 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **Mass. DPU** 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric. November 4 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Mass. Division of Insurance** 87-53; 1987 Workers' Compensation rate refiling; State Rating Bureau. December 14 1987.

    Profit-margin calculations including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Mass. Division of Insurance;** 1987 and 1988 automobile insurance remand rates; Massachusetts Attorney General and State Rating Bureau. February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **Mass. DPU** 86-36; Investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities; Conservation Law Foundation. May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **Mass. DPU** 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company. May 18 1988, and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **Mass. DPU** 88-67; Boston Gas Company; Boston Housing Authority. June 17 1988.

    Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **R.I. PUC** Docket 1900; Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 24 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Mass. Division of Insurance** 88-22; 1989 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vt. PSB** 5270, Module 6; Investigation into least-cost investments, energy efficiency, conservation, and the management of demand for energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group. September 26 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vermont House of Representatives, Natural Resources Committee;** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group. February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **Mass. DPU** 88-67, Phase II; Boston Gas company conservation program and rate design; Boston Gas Company. March 6 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vt. PSB** 5270; Status conference on conservation and load management policy settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service. May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority. June 16 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **Mass. DPU** 89-100; Boston Edison rate case; Massachusetts Energy Office. June 30 1989.

Prudence of BECo's decision to spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **Mass.** **DPU** 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric. July 24 1989. Rebuttal, October 3 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **Mass.** **DPU** 89-72; Statewide Towing Association, police-ordered towing rates; Massachusetts Automobile Rating Bureau. September 13 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vt.** **PSB** 5330; Application of Vermont utilities for approval of a firm power and energy contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group. December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20-year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **Mass.** **DPU** 89-239; Inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. December 1989. April 1990. May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California** **PUC**; Incorporation of environmental externalities in utility planning and pricing; Coalition of Energy Efficient and Renewable Technologies. February 21 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Ill. Commerce Commission** Docket 90-0038; proceeding to adopt a least-cost electric-energy plan for Commonwealth Edison Company; City of Chicago. May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

    Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Md. PSC** 8278; Adequacy of Baltimore Gas & Electric's integrated resource plan; Maryland Office of People's Counsel. September 18 1990.

    Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Ind. Utility Regulatory Commission;** Integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1 1990.

    Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **Mass. DPU** 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 5 1990.

    Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **Mass. EFSC** 90-12/90-12A; Adequacy of Boston Edison proposal to build combined-cycle plant; Conservation Law Foundation. December 14 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** 90-286; Adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 19 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Va. SCC** PUE900070; Order establishing commission investigation; Southern Environmental Law Center. March 6 1991.

    Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **Mass. DPU** 90-261-A; Economics and role of fuel-switching in the DSM program of the Massachusetts Electric Company; Boston Gas Company. April 17 1991.

Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration;** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech. May 13 1991.

    NEPCo rates for power purchases from the New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. **Vt. PSB** 5491; Cost-effectiveness of Central Vermont's commitment to Hydro Quebec purchases; Conservation Law Foundation. July 19 1991.

    Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **S.C. PSC** 91-216-E; Cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. September 13 1991. Surrebuttal October 2 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Md. PSC** 8241, Phase II; Review of Baltimore Gas & Electric's avoided costs; Maryland Office of People's Counsel. September 19 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport (Maine) Planning Board;** AES/Harriman Cove shoreland zoning application; Conservation Law Foundation and Natural Resources Council of Maine. October 1 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **Mass. DPU** 91-131; Update of externalities values adopted in Docket 89-239; Boston Gas Company. October 4 1991. Rebuttal, December 13 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Fla. PSC** 910759; Petition of Florida Power Corporation for determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 21 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Fla.** **PSC** 910833-EI; Petition of Tampa Electric Company for a determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 31 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Penn.** **PUC** I-900005, R-901880; Investigation into Demand Side Management by electric utilities; Pennsylvania Energy Office. January 10 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **S.C.** **PSC** 91-606-E; Petition of South Carolina Electric and Gas for a certificate of public convenience and necessity for a coal-fired plant; South Carolina Department of Consumer Affairs. January 20 1992.

    Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **Mass.** **DPU** 92-92; Adequacy of Boston Edison's street-lighting options; Town of Lexington. June 22 1992.

    Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **S.C.** **PSC** 92-208-E; Integrated-resource plan of Duke Power Company; South Carolina Department of Consumer Affairs. August 4 1992.

    Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **N.C. Utilities Commission** E-100, Sub 64; Integrated-resource-planning docket; Southern Environmental Law Center. September 29 1992.

    General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ont.** **EAB** Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.). October 1992.

    Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas** **PUC** 110000; Application of Houston Lighting and Power company for a certificate of convenience and necessity for the DuPont Project; Destec Energy, Inc.. September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine BEP;** In the Matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Md. PSC** 8473; Review of the power sales agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel. November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **N.C. Utilities Commission** E-100, Sub 64; Analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **S.C. PSC** 92-209-E; In re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 24 1992.

Demand-side-management planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Fla. DER** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Md. PSC** 8487; Baltimore Gas and Electric Company electric rate case. Direct, January 13 1993; Rebuttal, February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Md. PSC** 8179; Approval of amendment no. 2 to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. **Mich. PSC** U-10102; Detroit Edison rate case; Michigan United Conservation Clubs. February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

DSM planning, program designs, potential savings, and avoided costs.

115. **Mich. PSC** U-10335; Consumers Power rate case; Michigan United Conservation Clubs. October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Ill. Commerce Commission** 92-0268, Electric-energy plan for Commonwealth Edison; City of Chicago. Direct testimony, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for licensing of hydro power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vt. PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service fuel-switching and DSM program design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Fla. PSC** 930548-EG–930551–EG, Conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vt. PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **Mass. DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Mich. PSC** U-10554, Consumers Power Company DSM program and incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Mich. PSC** U-10702, Detroit Edison Company cost recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **N.J. BRC** EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Mich. PSC** U-10671, Detroit Edison Company DSM programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Mich. PSC** U-10710, Power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **N.C. Utilities Commission** E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, Least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. **D.C. PSC** Formal 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ont. Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

DSM cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. **Mass. DPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Md. PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995

Rate design, cost-of-service study, and revenue allocation.

135. **N.C. Utilities Commission** E-2, Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

136. **Arizona Commerce Commission** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 **Vt. PSB** 5835; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. **Md. PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. **Mass.** **DPU** 96-100; Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. **Mass.** **DPU** 96-70; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. **Mass.** **DPU** 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. **Md.** **PSC** 8725; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **N.H.** **PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ont. Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

146. **New York** **PSC** Case 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. **Vt.** **PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. **Mass.** **DPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vt.** **PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. **Mass.** DPU 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. **Mass.** DTE 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. **N.H.** PUC Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Md.** PSC 8774; APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Power-supply arrangements between APS's operating subsidiaries; power-supply savings; market power.

154. **Vt.** PSB 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine** PUC 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **Mass.** DTE 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vt.** PSB 6107, Green Mountain Power rate increase, Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **Mass.** **DTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Md.** **PSC** 8794 and 8804; BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Md.** **PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Md.** **PSC** 8797; Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Conn.** **DPUC** 99-02-05; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. **Conn.** **DPUC** 99-03-04; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. **Wash.** **UTC** UE-981627; PacifiCorp–Scottish Power merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. **Utah** **PSC** 98-2035-04; PacifiCorp–Scottish Power merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. **Conn.** **DPUC** 99-03-35; United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. **Conn. DPUC** 99-03-36; Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; Supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. **W. Va. PSC** 98-0452-E-GI; electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. **Ont. Energy Board** RP-1999-0034; Ontario performance-based rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. **Conn. DPUC** 99-08-01; standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; Supplemental January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Conn. Superior Court** CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the Conn. DPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Conn. Superior Court** CV 99-049-7597; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the Conn. DPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ont. Energy Board** RP-1999-0044; Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03; PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Conn.** **DPUC** 99-09-12; Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ont. Energy Board** RP-1999-0017; Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **N.Y.** **PSC** 99-S-1621; Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine** **PUC** 99-666; Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **Mass.** **EFSB** 97-4; Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Conn.** **DPUC** 99-09-03; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Conn.** **DPUC** 99-09-12RE01; Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **Mass.** **DTE** 01-25; Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. Conn. DPUC 00-12-01 and 99-09-12RE03; Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. Vt. PSB 6460 & 6120; Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. N.J. BPU EM00020106; Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. N.J. BPU GM00080564; Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. Conn. DPUC 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; Supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. N.J. BPU EX01050303; New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. N.Y. PSC 00-E-1208; Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. Mass. DTE 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. **N.J. BPU** EM00020106; Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. **Vt. PSB** 6545; Vermont Yankee proposed sale; Vermont Department of Public Service. Direct, January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Conn. Siting Council** 217; Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vt. PSB** 6596; Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; Rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Conn. DPUC** 01-10-10; United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Conn. DPUC** 01-12-13RE01; Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ont. Energy Board** RP-2002-0120; Review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **N.J. BPU** ER02080507; Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Conn. DPUC** 03-07-02; CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Conn. DPUC** 03-07-01; CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vt. PSB** 6596; Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio PUC** Case 03-2144-EL-ATA; Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. Direct February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **N.Y. PSC** Cases 03-G-1671 & 03-S-1672; Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; Rebuttal April 2004; Settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **N.Y. PSC** 04-E-0572; Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ont. Energy Board** RP 2004-0188; cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **Mass. DTE** 04-65; Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; Supplemental January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **N.Y. PSC** 04-W-1221; Rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **N.Y. PSC** 05-M-0090; System-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Md. PSC** 9036; Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **B.C. Utilities Commission** Project No. 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. Direct, September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Conn. DPUC** 05-07-18; Financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. Direct September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Conn. DPUC** 03-07-01RE03 & 03-07-15RE02; Incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005. Additional Testimony, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Conn. DPUC** Docket 05-10-03; Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ont. Energy Board** Case EB-2005-0520; Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes: new break point, cost allocation, customer charges, commodity rate blocks.

215. **Ont. Energy Board** Case EB-2006-0021; Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Ind. Utility Regulatory Commission** Cause Nos. 42943 and 43046; Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn. PUC** Docket No. 00061346; Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Penn. PUC** Docket No. R-00061366, et al.; Rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Conn. DPUC** 06-01-08; Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Conn. DPUC** 06-01-08; United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since August 2006.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **N.Y. PSC** Case No. 06-M-1017; Policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Conn. DPUC** 06-01-08; Procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **Ohio PUC** PUCO Case No. 05-1444-GA-UNC; recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. Direct, February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **N.Y. PSC** Case 06-G-1332; Consolidated Edison Rates and Regulations; City of New York. Direct, March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alb. EUB** 1500878; ATCo Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. Direct, May 2007

Direct assignment of distribution costs to streetlighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Conn. DPUC** Docket 07-04-24; Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **N.Y. PSC** Case 07-E-0524; Consolidated Edison electric rates; City of New York. Direct, September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Man. PUB** 136-07; Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7; DPU 07-58 & -59; Proposed Brockton Power Company plant; Alliance Against Power Plant Location. Direct, March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **Conn. DPUC 08-01-01;** peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. Ont. Energy Board–2007-0905, Ontario Power Generation payments; Green Energy Coalition. Direct, April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. Utah PSC 07-035-93, Rocky Mountain Power Rates; Utah Committee of Consumer Services. Direct, July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. Ont. Energy Board-2007-0707; Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. N.Y. PSC Case 08-E-0596; Consolidated Edison electric rates; City of New York. Direct, September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. Conn. DPUC 08-07-01; Integrated resource plan; Connecticut Office of Consumer Counsel. Direct, September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. Man. PUB 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. Md. PSC 9036; Columbia Gas rates; Maryland Office of People's Counsel. Direct, January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. Vt. PSB 7440; extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **N. S. Review Board** Matter No. 01439 (P-884(2)); Nova Scotia Power DSM and cost recovery, Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **N. S. Review Board** Matter No. 0496 (P-172); proposed biomass project, Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Conn. Siting Council** 370A; Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. Direct, July 2009.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. **Mass. DPU** 09-39; NGrid rates, Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah PSC** Docket No. 09-035-23; Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009. Rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. **Utah PSC** Docket No. 09-035-15; Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; Surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. **Penn. PUC** Docket No. R-2009-2139884; Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. Direct, December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **Penn. PUC** Docket No. R-2009-2139884; Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. Direct, December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

247. **B.C. Utilities Commission** Project No. 3698573; British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct, February 2010.

Rate design and energy efficiency.

248. **Ark. PSC** Docket No. 09-084-U; Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; Surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

249. **Ark. PSC** Docket No. 10-010-U; Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; Reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

250. **Ark. PSC** Docket No. 08-137-U; Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; Supplemental, October 2010; Reply, October 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

251. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.); Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

252. **N.S. UARB** Matter No. 02961(P128.10); Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. Direct, June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

253. **Mass. DPU** 10-54; NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. Direct, July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

254. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, Direct, July 2010; Rebuttal, Surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

255. **Ont. Energy Board**-2010-0008; Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

256. **N.S. UARB** Matter No. 03454(NG-HG-R-10); Heritage Gas rates; N.S. Consumer Advocate. Direct, October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

257. **Man. PUB** Case No. 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, December 2010

Revenue-allocation and rate design. DSM program.

258. **N.S. UARB** Matter No. 03665(NSPI-P-891); Nova Scotia Power depreciation rates; N.S. Consumer Advocate. Direct, February 2011.

Depreciation and rates.

259. **New Orleans City Council** No. UD-08-02; Entergy IRP rules; Alliance for Affordable Energy. Direct, December 2010

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

260. **N.S. UARB** Docket Matter No. 03632 (BRD-E-R-10); Renewable-Energy Community-Based Feed-in Tariffs; N.S. Consumer Advocate. Direct, March 2011.

Cost of projects. Rate effects of feed-in tariffs. Consideration of community in computing costs.

261. **Mass. EFSB** 10-2/ DPU 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

262. **Utah PSC** Docket No. 10-035-124; Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

263. **N.S. UARB** Matter No. 04104 (NSPI P-892); Nova Scotia Power general rate application; N.S. Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

264. **N.S. UARB** Matter No. 04175 (NSPI P-202); Load-retention tariff; N.S. Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

265. Ark. PSC Docket No. 10-101-R; Rulemaking re self-directed energy efficiency for large customer; National Audubon Society and Audubon Arkansas. Testimony July 2011.

Energy efficiency.

266. Okla. Corporation Commission Cause No. PUD 201100077; Current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

267. Nevada PUC Docket No. 11-08019; Integrated analysis of resource acquisition; Sierra Club. Comments September 2011; Hearing October 2011

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

268. La. PSC Docket R-30021; Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

269. Nev. PUC Docket No. 11-08019; Integrated analysis of resource acquisition; Sierra Club. Comments September 2011; Hearing October 2011.

Demand-side management. Tests of cost-effectiveness. Resource screening. Risk.

270. Okla. Corporation Commission Cause No. PUD 201100087; Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

271. Ky. PSC Case No. 2011-00375; Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

272. N.S. UARB Docket NSUARB-E-ENSC-R-12; Demand-sidfe-management plan of Efficiency Nova Scotia; N.S. Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

273. N.S. UARB Docket NSUARB-NSPI-P-203; Utility-sponsored energy-efficiency programs; N.S. Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

274. **Utah PSC** Docket No. 11-035-200; Rocky Mountain Power Rates; Utah OCC. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** Docket No. 12-008-U; Environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012, Rebuttal, August 2012; Further, March 2013.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

276. **U.S. EPA** Docket EPA-R09-OAR-2012-0021; Air Quality Implementation Plan; Sierra Club, September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

277. **Arkansas PSC** Docket No. 07-016-U; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

278. **Vt. PSB** Docket No. 7862; Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation, October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

279. **Man. PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012

Estimation of marginal costs. Fuel switching.

280. **Kansas CC** Docket No. 12-GIMX-337-GIV, Utility energy-efficiency programs; The Climate and Energy Project, December 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

281. **N.S. UARB** Matter No. M05339; Capital Plan of Nova Scotia Power; N.S. Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

282. **N.S. UARB** Matter No. M05416; South Canoe wind project of Nova Scotia Power; N.S. Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

283. **N.S. UARB** Matter No. M0535; Capital plan of Nova Scotia Power; N.S. Small Business Advocate. February 2013.

Treatment of overheads and AFUDC in capital planning. Optimal timing of economic investment. Valuation of increased transmission capacity.

284. **N.S. UARB** Docket No. NSPI-P-892; Depreciation Rates of Nova Scotia Power; N.S. Consumer Advocate. April 2013.

Steam-plant lives and removal costs.

285. **N.S. UARB** Matter No. 05419; Maritime Link cost-recovery regulations; N.S. Consumer Advocate. April 2013.

Load Forecast. Cost effectiveness of proposed project.

286. **Ont. Energy Board** 2012-0451/0433/0074; Enbridge Gas GTA project; Green Energy Coalition. June 2013, revised August 2013.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

287. **N.S. UARB** Matter No. M05092; Tidal energy feed-in-tariff rate; N.S. Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

288. **B.C. Utilities Commission** Projects Nos. 3698715 & 3698719; Performance-based ratemaking plan for FortisBC companies, British Columbia Sustainable Energy Association and Sierra Club British Columbia. Joint testimony with John Plunkett, December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

ACRONYMS AND INITIALISMS

ASLRB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
DER	Department of Environmental Regulation
DPS	Department of Public Service
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURPA	Public Utility Regulatory Policy Act
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UTC	Utilities and Transportation Commission

PLC 2/14/2014

Kentucky Utilities Company

Incremental Connection Cost of Service Based on the Cost of Service Study
For the 12 Months Ended June 30, 2016

Rate RS

	Description	Distribution	Customer Service Expenses	Total
(1)	Rate Base	$ 54,468,341	$ 4,682,142	$ 59,150,482
(2)	Rate Base Adjustments	-	-	$ -
(3)	Rate Base as Adjusted	$ 54,468,341	$ 4,682,142	$ 59,150,482
(4)	Rate of Return	4.84%	4.84%	
(5)	Return	$ 2,634,624	$ 226,474	$ 2,861,099
(6)	Interest Expenses	$ 1,243,475	$ 106,890	$ 1,350,365
(7)	Net Income	$ 1,391,149	$ 119,584	$ 1,510,734
(8)	Income Taxes	$ 858,546	$ 73,801	$ 932,348
(9)	Operation and Maintenance Expenses	$ 6,749,731	$ 34,942,422	$ 41,692,153
(10)	Depreciation Expenses	$ 2,770,041	$ -	$ 2,770,041
(11)	Other Taxes	$ 512,719	$ -	$ 512,719
(12)	Curtailable Service Credit			$ -
(13)	Expense Adjustments - Prod. Demand	$ -	$ -	$ -
(14)	Expense Adjustments - Energy	$ -	$ -	$ -
(15)	Expense Adjustments - Trans. Demand	$ -	$ -	$ -
(16)	Expense Adjustments - Distribution	$ -	$ -	$ -
(17)	Expense Adjustments - Other	$ 25,845	$ 2,222	$ 28,067
(18)	Expense Adjustments - Total	$ 25,845	$ 2,222	$ 28,067
(19)	Total Cost of Service	$ 13,551,506	$ 35,244,920	$ 48,796,426
(20)	Less: Misc Revenue - Tran. Demand	$ -	$ -	$ -
(21)	Less: Misc Revenue - Energy	$ -	$ -	$ -
(22)	Less: Misc Revenue - Other	$ (215,229)	$ (18,501)	$ (233,730)
(23)	Less: Misc Revenue - Total	$ (215,229)	$ (18,501)	$ (233,730)
(24)	Net Cost of Service	$ 13,336,278	$ 35,226,419	$ 48,562,696
(25)	Billing Units	5,164,249	5,164,249	
(26)	Unit Costs	$ 2.58	$ 6.82	$ 9.40

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KY PSC Electronic Case Filing Receipt

Documents received for Case Number: 2014-00371
Joe F. Childers
On behalf of: Wallace McMullen and Sierra Club
at 3/6/2015 3:33:44 PM

Description: Direct Testimony of Paul Chernick on Behalf of Sierra Club

Received Items:

SC_read1st_030615__371.pdf	Read First File
2015.3.6_Direct_Testimony_of_Paul_Chernick_371.pdf	Direct Testimony of Paul Chernick on Behalf of Sierra Club
2015.3.6_Chernick_Affidavit_Case_No._2014-00371.pdf	Affidavit of Paul Chernick
2015.3.6_Exhibit_PLC-1_Case_No._2014-00371.pdf	Exhibit 1
2015.3.6_Exhibit_PLC-2_Case_No._2014-00371.pdf	Exhibit 2
2015.3.6_Exhibit_PLC-3_Case_No._2014-00371.pdf	Exhibit 3