BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas & Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M.)	Application 19-11-019 (filed November 22, 2019)

DIRECT TESTIMONY OF PAUL L. CHERNICK AND JOHN D. WILSON
ON BEHALF OF
SMALL BUSINESS UTILITY ADVOCATES

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SBUA
Small Business Utility Advocates

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ATTACHMENTS

I. Identification & Qualifications

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

A: My name is Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

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 electric generation plants and transmission lines, conservation program design, estimation of avoided costs, 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 summarized in Attachment 1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included planning and ratemaking for distributed resources, distributed resource planning, the benefits of load reduction on the distribution and transmission systems, utility planning, marginal costs, and related issues.

I have filed testimony in ten California PUC proceedings since 2014.

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

A: I am John D. Wilson. I am the research director of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a BA degree from Rice University in 1990, with majors in physics and history, and an MPP degree from the Harvard Kennedy School of Government with an emphasis in energy and environmental policy, and economic and analytic methods.

I was deputy director of regulatory policy at the Southern Alliance for Clean Energy for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Attachment 2.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than twenty times before utility regulators in California, the Southeast U.S. and Nova Scotia, and appeared numerous additional times before various regulatory and legislative bodies. I have testified before the California Public Utilities Commission twice.

II. Introduction

Q: On whose behalf are you testifying?

A: We are testifying on behalf of Small Business Utility Advocates (SBUA).

Q: What is the scope of your testimony?

A: We review the rate-design proposals of Pacific Gas & Electric (PG&E or the Company) for the small and medium commercial tariffs. We also review certain cost-allocation issues.

Q: What issues do you address?

A: We address the following aspects of PG&E's cost allocation and rate-design proposals:

- The method for determining Marginal Distribution Capacity Cost (MDCC).
- The method for determining Marginal Generation Capacity Cost (MGCC).

- The method for determining Marginal Transmission Capacity Cost (MTCC).
- The method for determining Marginal Customer Access Cost (MCAC).
- The rate design of optional Schedule B-6.
- The reliance on demand charges in most of the medium non-residential customers.
- The definition of the TOU periods.

Q: What are your conclusions regarding the PG&E proposals?

A: We make the following recommendations with respect to cost of service issues:

- The Commission should adopt Cal Advocates' recommendation to use 10 years of data, 5 historical and 5 forecast, when using the Discounted Total Investment Method (DTIM) to calculate MDCCs.
- The Commission should approve PG&E's use of costs driven by new capacity for system reliability in its calculation of MGCCs.
- The Commission should direct PG&E to file the results of the MTCC cost causation study and request that FERC approve rates consistent with its findings. Until such action is taken by FERC, the Commission should temporarily adjust PG&E's distribution rates so that the net effect is to appropriate allocate both transmission and distribution costs between system peak charges and non-capacity-related revenue requirements.
- The Commission should endorse Cal Advocates' recommendations for determining MCACs, including the New Customer Only method and the recovery of meter O&M costs through a lifetime O&M adder.

We make the following recommendations with respect to rate design issues:

- For optional rate schedule B-6, the Commission should adopt the full EPMC alternative.
- The Commission should direct PG&E to update its MTCCs using a backward- and forward-looking DTIM calculation.
- The Commission should take three steps to align PG&E's FERC jurisdictional transmission rates the findings of the Company's cost-causation study as follows:
  - Direct PG&E to file the results of the cost causation study and a request to modify its retail transmission rates with FERC.
  - Consider intervening in PG&E's Transmission Owner rate case to support the request.
  - Temporarily adjust PG&E's distribution rates so that the net effect is to appropriate allocate both transmission and distribution costs.
- The Commission should direct PG&E to replace all demand charges with TOU rates. Non-coincident demand charges should be collected through a general energy rate. Revenues currently collected through peak-period demand charges should be collected through the respective TOU period energy rates.
- The Commission should direct PG&E to created or revise tariffs to collect Marginal Energy Costs (MECs) through an RTP rate.
  - The revenue requirement for all other costs should remain unaffected.
  - An optional alternative to rate B-10 should be created to offer RTP rates.
  - Rates B-19 and B-20 should be revised to include RTP rates.
- The Commission should direct PG&E to change its TOU rate periods for the Super Off Peak (SOP) period as follows:

- The SOP period should be changed to 8 AM – 5 PM.
- The number of months in the SOP period definition should be re-evaluated by PG&E. The end of the SOP season should be aligned with the beginning of the summer season. The beginning of the SOP season should be selected in order to maximize the number of SOP months, while avoiding a significant potential for "false positive" hours with relatively high costs.
- The changes should be made at the earliest possible date in which PG&E would be able to roll out an effective customer education program.

- The Commission should authorize, but not direct, PG&E to shift the summer peak months to July – October and all peak period hours to 5 – 10 PM. PG&E should be authorized to make these changes via an Advice Letter prior to filing its 2023 GRC.

III. Cost of Service Issues

A. Marginal Distribution Capacity Cost (MDCC)

Q: Please discuss the positions of PG&E and Cal Advocates on calculating the Marginal Distribution Capacity Cost (MDCC).

A: PG&E and Cal Advocates both propose to use the Discounted Total Investment Method (DTIM) to compare load-growth related investments in dollars with annual incremental peak loads in kW in each division planning area.[1] MDCCs are calculated for circuit primary, substation primary, new

[1] Cal Advocates Testimony, Ch. 2, pp. 1, 9.

business primary, and secondary distribution categories. The main difference between their approaches is that Cal Advocates proposes to use 10 years of data, 5 historical and 5 forecast, while PG&E proposes to use only 5 forecast years.

Between the two approaches, we recommend the Commission adopt Cal Advocates' position. While forecast data is more theoretically sound, in our experience we have found that historical data is easier to interpret, as the costs and load growth are known.

Another reason for reducing reliance on the forecast data is that Cal Advocates identified "unexpected trends" in the forecast data: "decreasing amounts of annual distribution capacity load increases combined with stable or rising annual distribution capacity investments."[2] Since PG&E was unable to document the reason for these trends, this puts the exclusive reliance on forecast data on even shakier ground.

When considering whether to use historical or forecast data in a transmission or distribution cost study, utilities and regulators reasonably consider the impact of growing DERs on the system. There has, of course, been significant growth in DERs over the five-year historical period. Thus, even though that growth will be different in location and quantity over the five-year forecast period, the difference will not be so great as it would be if PG&E were on the verge of an initial wave of dramatic DER growth.

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[2] Cal Advocates Testimony, Ch. 2, p. 20, lines 1-8.

B. Marginal Generation Capacity Cost (MGCC)

Q: Please discuss the positions of PG&E and Cal Advocates on calculating the Marginal Generation Capacity Cost (MGCC).

A: PG&E and Cal Advocates each use a six-year time horizon, with PG&E's costs driven by new capacity for system reliability, while Cal Advocates favors an approach focused on load-growth driven capacity needs.[3] In this case, we recommend PG&E's method as reflecting actual marginal costs, and for reflecting the actual system benefit that customers are paying for: reliability.

Ironically, while Cal Advocates argues that its approach is the true marginal-cost method, it acknowledges that "there is no need for [the] capacity additions" valued by RA contract prices.[4] For other marginal costs, Cal Advocates places great emphasis on identifying actual marginal costs incurred. For example, as discussed above, Cal Advocates argues for historical costs to be utilized when calculating MDCCs.

MGCCs should not consider only load growth. Generation costs that will be allocated to customers also includes needs for system reliability. Cal Advocates recognizes this fact, stating that "Recent outages reflect the potential need for new capacity for system reliability, but again this potential need is not based on load growth."[5]

The relevance of reliability-driven costs is implicit in the use of adjusted net load, not gross load, to allocate generation costs. PG&E allocates MGCCs based on the generation Peak Capacity Allocation Factor (PCAF) method, which uses allocators for the top adjusted net load, defined as the gross load

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[3] Cal Advocates Testimony, Ch. 3, p. 7, lines 3-5, 9-11, and 12-13.

[4] Cal Advocates Testimony, Ch. 3, p. 10, line 9.

[5] Cal Advocates Testimony, Ch. 3, p. 7, lines 12-13.

minus the renewable, hydro, and nuclear generation resources.[6] Cal Advocates' testimony does not challenge PG&E's generation PCAF method. Since generation costs are allocated using a PCAF values that are based on adjusted net load, Cal Advocates proposal to limit those generation costs to only growth in gross load is inconsistent with the allocation method.

First, emphasizing load growth overlooks that MGCCs are allocated based on a reliability metric that considers *both* load growth *and* resource reliability. PG&E is absolutely correct to consider the marginal costs associated with procurement driven by operational and policy needs, including the adoption of renewable energy policies, retirement of once-through cooling units, the decrease in wind and solar ELCC, and the retirement of Diablo Canyon.[7] With the exception of hydro, each of the elements in the definition of adjusted net load are acknowledged by Cal Advocates as drivers of PG&E's capacity procurement need.

And second, Cal Advocates gets it exactly backwards when it states that using a system reliability driven capacity need "would lead to the incorrect allocation of capacity costs to customers with usage primarily during on-peak periods."[8] In fact, the TOU peak periods are established through the analysis of marginal generation and distribution costs, not peak demand.[9]

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[6] PG&E Testimony, Ch. 3, p. 3, lines 7-11 and footnote 5.

[7] Cal Advocates Testimony, Ch. 3, p. 6, lines 1-4.

[8] Cal Advocates Testimony, Ch. 3, p. 7, lines 10-11.

[9] PG&E Testimony, Exhibit 2, Ch. 11, p. 1-2.

C. Marginal Transmission Capacity Cost (MTCC)

Q: Please discuss the position of PG&E on transmission cost causation and its Marginal Transmission Capacity Cost (MTCC).

A: PG&E's transmission rates are FERC-regulated, and are not subject to Commission review. PG&E also estimated its MTCC for use in other proceedings at $12.46 per kW per year using a six-year forward-looking DTIM calculation.[10]

As directed by the Commission,[11] PG&E filed a transmission cost causation study. PG&E used generation PCAF to allocate capacity-related transmission costs on an hourly basis. PG&E identified the remaining transmission costs as not being related to system capacity. Since those remaining costs are not related to system capacity, they should be collected on some other basis, presumably as an energy charge.

The results of this study indicate that 27% of the transmission revenue requirement should be collected through peak or part-peak rates, with the remainder collected through a non-capacity related revenue requirement.[12]

Q: What is your opinion of the recommended MTCC charge?

A: Consistent with our testimony regarding the calculation of the MDCCs, we recommend the Commission support a forward- and backward-looking DTIM calculation instead of a forward-looking DTIM calculation. As discussed above, while forecast data is more theoretically sound, historical data is easier to interpret. Problems similar to the "unexpected trends" observed by Cal

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[10] PG&E Testimony, Exhibit 2, Ch. 5, pp. 1-2.

[11] D.18-08-013, p. 53.

[12] PG&E Testimony, Exhibit 2, Ch. 5, p. 7, Table 5-2.

Advocates in the MDCC forecast data could be present in the transmission forecast.

Since PG&E did not file any backward-looking DTIM calculations for the MTCC charge, we recommend that the Commission direct PG&E to file an Advice Letter with an updated MTCC charge using a backward- and forward-looking DTIM calculation.

Q: Are PG&E's FERC jurisdictional transmission rates consistent with the findings of its cost causation study?

A: No. As shown in Attachment 9, PG&E's FERC-filed retail transmission rates are \$0.02766 / kWh for Small Light & Power (Schedules B-1 and B-6) and \$9.01 / kW-mo for Medium Light and Power (Schedule B-10). Neither of these rates is consistent with the finding that 27% of the revenue requirement should be collected through peak or part-peak rates, and the remaining 83% collected through a non-capacity related revenue requirement.

Q: How should PG&E's FERC jurisdictional transmission rates be revised to be consistent with the findings of its cost causation study?

A: PG&E's FERC jurisdictional transmission rates should be revised to recover 27% of the revenue requirement through volumetric TOU rates during the peak and part-peak periods, and 83% of the revenue requirement recovered through a volumetric rate across all TOU periods.

In the case of Schedules B-1 and B-6, we recommend replacing the current uniform volumetric rate with a TOU volumetric rate design. The FERC-regulated rate for smaller customers is not consistent with the study findings because 27% of the revenue should be collected during peak periods.

In the case of Schedule B-10, we recommend replacing the current non-coincident volumetric rate with a TOU volumetric rate design. This rate is entirely inconsistent with the results of PG&E's study since it is a capacity-related revenue requirement that is not aligned with the PCAF hours.

The non-coincident demand charge used for Medium Light and Power rates (including B-10) and several other rates (for example, B-20) is inconsistent with current Commission policy. The Commission has recently found as a Conclusion of Law that, "Heavy reliance on non-coincident demand charges is generally disfavored by our historic rate design principles because non-coincident demand charges do not reflect cost causation for primary distribution, transmission, or generation capacity costs."[13]

Q: What is your recommendation to the Commission with respect to transmission costs?

A: We suggest that the Commission take three steps. First, the Commission should direct PG&E to file with the FERC (a) the results of the cost causation study and (b) a request to modify its retail transmission rates to a volumetric TOU rate design.[14] Second, the Commission should consider intervening in PG&E's Transmission Owner rate case to support the request. Because the Commission may choose to adjust its TOU periods from time to time, PG&E's request to FERC should identify a method for adjusting approved rates to align with any changes in the TOU periods that the Commission may approve.

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[13] D.18-08-013, Conclusion of Law 56.

[14] Our recommendation follows the approach adopted by the Commission for SDG&E. D.17-08-030, p. 47, Findings of Fact 18 and 19, and Ordering Paragraph 6.

Even better, the CPUC should work with the transmission owners and CAISO to develop a proposal to FERC that would return the cost allocation and rate design for transmission revenue requirements to the CPUC. In the other RTOs, FERC sets the transmission revenue requirement and the states determine the class allocation and rate design.

Third, the Commission should temporarily adjust PG&E's distribution rates so that the net effect is to appropriately allocate both transmission and distribution costs. For Schedules B-1 and B-6, all TOU distribution rates could be reduced by an amount equivalent to 27% of the transmission rate and the TOU distribution energy rates for peak periods could be increased to recover the required revenues. For Schedule B-10 (and potentially other periods with transmission demand charges), the non-coincident distribution demand charge could be reduced by an amount equivalent to the transmission rate and the TOU distribution energy rates for all periods could be increased to recover the required revenues consistent with the cost causation study findings. This adjustment should be temporary until FERC reaches a decision on the request for a change in rate design.

D. Marginal Customer Access Cost (MCAC).

Q: Please discuss the position of PG&E and Cal Advocates on Marginal Customer Access Cost (MCAC).

A: PG&E proposes to use the Real Economic Carrying Charge (RECC) Method to determine Transformer, Service Drop, and Meter (TSM) costs, and activity-based costing methodology to determine Marginal Revenue Cycle Services (RCS). Cal Advocates recommends that the Commission continue to rely on the New Customer Only (NCO) method for PG&E, as it has since 1996.

Cal Advocates also proposes three adjustments to the method as presented by PG&E testimony. Instead of the RCS method, Cal Advocates recommends recovery of meter O&M costs through a lifetime O&M adder. We compare the proposed MCAC from PG&E and Cal Advocates in Table 1Table 2.

Table 1: Proposed Small Business MCAC, PG&E vs Cal Advocates

Service	UNITS	PG&E	Cal Advocates
Small Commercial, Single-phase	$/Month	34.53	12.57
Small Commercial, Polyphase	$/Month	121.20	39.33
Medium Commercial, Secondary	$/Month	307.43	98.96

Source: Cal Advocates Testimony, Table 1-1, Ch. 1, p. 3.

Both these issues are cogently argued by Cal Advocates. We agree fully with the reasoning expressed in their testimony for continuing to use the NCO method to determine of marginal customer access costs, and recommend that the Commission explicitly endorse its method for this and future proceedings.

IV. Rate Design Issues

Q: What tariffs does your testimony concern?

A: SBUA is primarily concerned with two Small Power and Light tariffs, Rates B-1 and B-6. SBUA also believes that some higher demand small business customers may be on the B-10 rate, most likely receiving secondary service. We have summarized the current rates in Table 2.

Table 2: Summary of Existing Small Business Tariffs

Type	Description	UNITS	B-1	B-6	B-10 Secondary
Customer Charge	Single-phase	$/Month	10.00	10.00	
	Polyphase	$/Month	25.00	25.00	145.44
Energy	Summer				
	Peak	$/kWh	0.328	0.360	0.274
	Part-Peak	$/kWh	0.279	n/a	0.212
	Off-Peak	$/kWh	0.259	0.242	0.180
	Winter				
	Peak	$/kWh	0.253	0.253	0.198
	Off-Peak	$/kWh	0.237	0.233	0.162
	Super Off-Peak	$/kWh	0.220	0.217	0.126
Demand		$/kW			13.59

Source: PG&E July 2020 Errata Testimony, Exhibit 3, Ch. 4, Attachment B, pp. 1-2.

PG&E also classifies the B1-Storage tariff, which is not currently available, and streetlight and traffic control service tariffs as Small Power and Light tariffs.

A. Customer Charges

Q: How are the customer charges currently structured in PG&E's small and medium business tariffs?

A: Each of the Small Power and Light tariffs has two customer charges, depending on whether the customer connection is single-phase or polyphase, as summarized in Table 2. The B-10 tariff has a single customer charge.

Q: What is PG&E's proposal for the customer charges for small business customers?

A: PG&E proposes to retain customer charges at the same level, and does not testify as to the cost-based justification for retaining the customer charges at the same level.

Q: Do you agree with PG&E's recommendation to maintain the current customer charge?

A: Yes. PG&E's recommendation is supported by the similarity of the MCAC recommended by Cal Advocates (as discussed previously) to the current customer charges of $10 per month for single-phase and $25 per month for polyphase service. We do not find a specific recommendation on the current customer charge in Cal Advocates' testimony, but assume that they do not object to maintaining the current customer charge.

B. Meet and Confer, TOU Differential for Schedule B-6

Q: Please respond to the PG&E testimony regarding the 'meet and confer' with PG&E and Cal Advocates to discuss the Schedule B-6 rate.

A: We did not participate in the 'meet and confer' meetings, but we are advised by counsel that the description provided by PG&E is reasonably accurate.[15] The primary outcome of these discussions is the proposed increase in the summer TOU differential for Schedule B-6 from $0.12/kWh to about $0.21/kWh. In contrast, the current differential for Schedule B-1 is only $0.07/kWh.[16]

Upon further consideration, SBUA has decided that it no longer favors a demand charge tariff option, which was discussed PG&E's testimony. Instead, SBUA prefers that the Commission direct PG&E to establish an optional Real-Time Pricing (RTP) tariff as encouraged by the Commission in D.19-03-002.

TOU hours were also discussed during the meetings. We discuss our position regarding TOU hours below.

Q: What is your position regarding the proposed rates for Schedule B-6?

A: The proposed optional Schedule B-6 does not provide small business customers with an attractive alternative. We recommend that the Commission direct PG&E to adopt the full EMPC rate option, as presented in Appendix G, Table G-1 of PG&E's testimony.

While the summer TOU differentials are indeed significantly larger, the winter and Super Off-Peak (SOP) rates are virtually identical, as illustrated in Table 3. Furthermore, the summer TOU differential is widened mainly by

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[15] PG&E July 2020 Errata Testimony, Exhibit 3, Ch. 4, pp. 6-8.

[16] PG&E July 2020 Errata Testimony, Exhibit 3, Ch. 4, p. 5.

increasing the peak rate ($0.04/kWh), with very little discount in the off-peak rate ($0.01/kWh). Accordingly, nearly all of the benefit of this rate to a prospective customer would occur during the summer off-peak period.

In contrast, the alternative we recommend – full EPMC with current customer charges – would provide substantial discounts during the summer part-peak and SOP periods, as illustrated in Table 3. These rate differentials are large enough to incentivize significant load shifting.

Table 3: Summary of Proposed Small Business Tariffs, with Full EPMC Tariff B-6 Alternative

Type	Description	UNITS	B-1	B-6	B-6 Alt.
Customer Charge	Single-phase	$/Month	10.00	10.00	10.00
	Polyphase	$/Month	25.00	25.00	25.00
Energy	Summer				
	Peak	$/kWh	0.339	0.375	0.553
	Part-Peak	$/kWh	0.289	n/a	n/a
	Off-Peak	$/kWh	0.269	0.258	0.249
	Winter				
	Peak	$/kWh	0.263	0.268	0.273
	Off-Peak	$/kWh	0.247	0.248	0.222
	Super Off-Peak	$/kWh	0.230	0.232	0.179

Source: PG&E July 2020 Errata Testimony, Exhibit 3, Ch. 4, Att. B, p. 1; Exhibit 4, Appendix G, Table G-1, p. 3.

Adopting the full EMPC rate option would provide customers with a significantly different option. Furthermore, as it is the Commission's intent to move gradually towards fully cost-based rates, customer response to fully-cost-based rates would be clearly demonstrated by the level of voluntary adoption of these rates.

Q: What is your response to Cal Advocates' support for the more gradual transition proposed by PG&E?

A: Cal Advocates supports PG&E's proposed optional Schedule B-6 because they prefer "the gradual movement of the TOU differential … because customers will be transitioning to rates with new TOU periods." We agree with this rationale as it applies to the mandatory B-1 tariff, but with respect to the optional B-6 tariff, Cal Advocates' concern is misguided.

By overemphasizing concern with the transition to the new TOU periods, PG&E and Cal Advocates have essentially given small business customers two flavors of vanilla ice cream. While the transition to a more differentiated TOU rate may be a rocky road for customers at first, giving them a significantly different option will encourage some customers to taste the benefits of cost-based rates, to the eventual benefit of all customers.

C. Demand Charges

Q: How are demand charges used by PG&E?

A: Demand charges are included in the B1-Storage, B-10, B-19, and B-20 tariffs. The B1-Storage and B-10 tariffs are non-coincident demand charges, and some small businesses are likely served under these tariffs. The B-19 and B-20 tariffs are mixed coincident and non-coincident demand charges, and are not likely to serve small businesses.

Q: Are demand charges appropriate?

A: Generally, no. Demand charges usually do not reflect cost causation and may be counter-productive unless they relate to customer-specific equipment that is directly sized to demand.

Q: Do PG&E's costs of providing generation, transmission and distribution service vary with each customer's maximum demand?

A: No. The Commission has found that costs of generation, transmission and most of the distribution system are not caused by most individual customers' maximum demand. The only costs that vary with customer maximum demand, as opposed to customer contribution to a diversified demand, are those associated with facilities dedicated to that customer (meters, service drops, sometimes transformers) and—for very large customers—local facilities that experience their peak loads whenever the customer peaks.

Commission Rate Design Principle 5 states that "Rates should encourage reduction of both coincident and non-coincident peak demand." This has been interpreted by the Commission in its Conclusion of Law: "Heavy reliance on non-coincident demand charges is generally disfavored by our historic rate design principles because non-coincident demand charges do not reflect cost causation for primary distribution, transmission, or generation capacity costs."[17]

The Commission should encourage reduction of non-coincident peak demand through rates that are limited to proven demand-related cost drivers, namely meters, service drops, a portion of transformers and (for very large customers) feeder capacity. Otherwise, demand charges are generally inappropriate because they do not reflect the way that customers impose costs on the system. Recovery of costs related to overall system demand through a non-coincident demand charge dampens price signals for conservation, promotes inefficient customer behavior, and undermines customers' ability to control electricity costs.

[17] D.18-08-013, Conclusion of Law 56.

Q: Does PG&E use demand charges that differ substantially from the non-coincident demand charges whose shortcomings you describe above?

A: No, for two reasons. First, PG&E applies fully non-coincident demand charges, at the same rate every month of the year, in Rates B-10, B-19 and B-20. It is the only demand charge in Rate B-10. In Rates B-19 and B-20, the non-coincident charge is similar to the peak charge and much larger than the part-peak charge.

Second, Rates B-19 and B-20 also have demand charges that apply only in the peak period and the part-peak period, which are seasonally differentiated, with the winter peak rate similar to the summer part-peak rate. But these are still basically non-coincident demand charges. The peak period is five hours per day, which is 1,825 hours, or 21% of the year. Even though a peak demand charge may appear targeted at reducing system demand, a period that is one-fifth of the year is very broad target, leaving ample opportunities to shuffle loads within the peak period.

Q: What are the problems with peak period demand charges?

A: All the problems we discussed for fully non-coincident peaks also apply within a broad peak period demand charge. It is true that the peak-period demand charge does not encourage a customer who naturally peaks at 7 AM to shift load to 7 PM. However, consider a restaurant that peaks at 8 PM due to dishwashing, peak service, etc. The restaurant may be able to reduce that peak by pre-cooling until 7 PM. While this would reduce the restaurant's demand charge, it may increase total usage in the peak period and the probability of contributing to the highest-load and highest-price hours.

The peak demand charge does nothing to encourage energy efficiency; while it may have the effect of shifting some load out of the peak period, it may also just move it around within the peak. Each customer will be shaping its peak hours in different ways, with one moving operations into the 5 PM to 8 PM period to reduce a natural 9 PM peak and another moving load out of the 5 PM hour to the 6 PM to 9 PM period. All that reshuffling may do little to reduce load in the peak period overall.

The problem is exacerbated by the application of the demand charge to every day of the month, so that customers are wasting their time and money, and wasting storage and demand-response capabilities that could reduce loads on the feeder or the system.

Q: Why would a demand charge dampen price signals for conservation, promote inefficient customer behavior, and undermine customers' ability to control electricity costs?

A: In order to control monthly charges from a demand charge, customers need to have detailed information regarding their load profiles for each day of the coming month as well as an in-depth understanding of which combination of appliance- or equipment-usage gives rise to monthly maximum demands. Even with such information and knowledge, it would be difficult for many customers to reduce demand charges, since even a single failure to control load during the month would result in the same charge as if the customer had not attempted to control load at all.

A demand charge provides little or no incentive for most individual customers to take actions that reduce distribution-system costs. As discussed above, distribution equipment costs typically are driven by the diversified peak load for all customers sharing the equipment. An individual business is unlikely to reach its maximum demand at the same time as when the diversified peak on the distribution system occurs, unless it is a very large customer.

Thus, a demand charge would provide an incentive to a small business to control load at the time that customer reaches its individual maximum demand, which does not necessarily correspond to the time of peak load on the distribution system. In fact, some customers might respond to a demand charge by shifting loads from their own peak to the peak hour on the local distribution system, thereby increasing their contribution to maximum or critical loads on the local distribution system and further stressing the system during peak periods.

Demand charges also provide little or no incentive for most individual customers to take actions that reduce amount of capacity required to meet local or system resource adequacy requirements. As with the distribution system, an individual business is unlikely to reach its maximum demand at the same time as when the diversified net peak on the generation system occurs, and any load shifting that occurs could even increase the customer's contribution to net peak demand. This is particularly true today, when peak demand and the net peak demand (net of renewable generation) occurs at very different times.

Attachment 3 is a paper Mr. Chernick coauthored, entitled "Charge without a Cause," further explaining the shortcomings in demand charges.

Q: Do you have any information on the diversity of small-business customer load on the distribution system?

A: Yes. Demand charges for the customers' undiversified maximum loads are not giving strong signals to shift load away from the feeder peak. Most customers' maximum demands do not coincide with peak loads at the feeder level. The lack of coincidence is demonstrated by both system data and feeder-specific data.

In response to DR SBUA 001-Q06, PG&E provided for each of its 3,008 feeders the peak load on each feeder and the sum of the FLT non-coincident loads on the feeder (see Attachment 7). Most of the demand-billed load would have their own transformers, but some of the FLT loads would reflect the diversified loads of multiple demand-billed customers, or a demand-billed customer and some smaller customers without demand meters. The average ratio of the sum of the FLT peaks to the feeder peak is over 1.6, indicating that the peak loads at the feeder level does not coincide with the maximum demands of most of the customers on the feeder.

In response to DR SBUA 001-Q07, PG&E provided the time of the 2017 peak load on an unidentified feeder, as well as the following confidential data for each customer on the feeder: the rate schedule, maximum load, and the time and date of the maximum load (see Attachment 8). The feeder had a total of 105 customers on rates with demand charges, with maximum loads totaling 8.1 MW, out of the total 14.9 MW of transformer loads on the feeder. The feeder peaked at hour ending (HE) 15 on September 11, 2017.

- Only two of the demand-metered customers experienced their maximum loads, totaling 66 kW, in the peak hour.
- Nine customers, with 278 kW, peaked at other times on that day, one at HE 14 and the remainder at HE 12.
- The maximum loads of the remaining 94 demand-metered customers were spread over every month and over every hour from HE 8 to HE 23. Even among the 47 customers with their maximum loads in September, 45 peaked at times other than the feeder peak

Thus, only about 2% of the September demand-metered maximum loads occurred at the feeder peak.

Q: Is there any reasonable role for a distribution demand charge based on the customer's peak load, rather than some measure of coincident load, in any retail electric rate?

A: Only where the customer's undiversified non-coincidental peak affects the sizing, wear or stress on some equipment. For any customer with a dedicated service drop, their non-coincidental peak determines the sizing of that line. The same is true for the transformer serving the customer, if the customer does not share the transformer with anyone else, or dominates the transformer. As we travel up the distribution system, the customer's non-coincidental peak becomes less important: only a very large load will independently determine the peak hours on a feeder, let alone a substation.

Q: Is there any reasonable role for a generation demand charge based on the customer's peak load, rather than exclusively relying on TOU or RTP energy rates, in any retail electric rate?

A: No. Demand-related generation costs are related to system peak load, not to an individual customer's peak load. The need for generation is determined by the cumulative system load in the hours with high net load, not by the customer peaks in hours and days with varying loads and renewable generation. As noted above, a non-coincident generation demand charge is disfavored by California's rate design principles because it does not reflect cost causation. That would also apply to non-coincident generation demand charge leveled in four or five hours every day.

Q: Is the realization that non-coincident demand charges are inappropriate a new discovery?

A: No. The deficiencies of the demand charge have been known for at least 80 years:

> This conclusion [demand charges] was hailed as a great discovery, and made the basis of many tariffs. Unfortunately, it was based on a simple confusion. It is true that it costs a station more to supply 1,000 units if they are all to be taken in one minute than if they are to be spread over a longer period; but this applies to the aggregate output of the station, and not to supplies to the individual consumer. What is true of the individual consumer is that the cost of selling to him is greater if he buys during peak periods than if he buys during slack periods (unless there is excess capacity even at the peak). If therefore he takes 24 units all in one minute during the slack period it may cost less to supply him than if he takes 24 units at the rate of one unit per hour, because in the latter case he adds to capital costs at the peak. The maximum rate at which the individual consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak. (W. Arthur Lewis – The Two-Part Tariff Economica, 1941, See, Attachment 4.)

> [The] demand or capacity charge—is a charge for the utility's readiness to serve, on demand. This readiness to serve is made possible by the installation of capacity, the demand charge, therefore, distributes the costs of providing the capacity—the fixed, capital costs—on the basis of the respective causal responsibilities of various buyers for them. And the proper measure of that responsibility is the proportionate share of each customer in the total demand placed on the system at its peak…

> Unfortunately, the principle has usually been badly applied, in several important ways. First, if the demand charge were correctly to reflect peak responsibility it would impose on each customer a share of capacity costs equivalent to his share of total purchases at the time coinciding with the system's peak (a "coincident peak" demand charge). Instead, the typical two-part tariff bases that rate on each customer's own peak consumption over some measured time period, regardless of whether his peak coincides with that of the system (hence the designation "noncoincident" demand charge). That is, the peak (for example, half-hour) consumption of all customers, regardless of the time of day or year in which each falls, is added up, and each then is charged a. share of total system capital costs equivalent to the percentage share that his peak consumption constitutes of that total. The noncoincident demand method does have some virtue: it encourages customers to level out their consumption over time, in order to minimize their peak taking, hence their share of capacity costs. This, in turn, tends to improve the system's load factor—the ratio of average sales over the year to capacity—that is, the degree of capacity utilization. But it is basically illogical. It is each user's proportion of consumption at the system's peak that measures the share of capacity costs for which each is causally responsible: it is consumption at that time that determines how much capacity the utility must have available. The system's load factor might well be improved by inducing individual customers to cut down their consumption to a deep trough at the system, peak and enormously increase their peak utilization at the system's off-peak time: yet the noncoincident demand system would discourage them from doing so. (The Economics of Regulation, Alfred Kahn, Vol. I, pp. 95–96, 1970, See Attachment 6).

Indeed, the original purpose of the demand charge may have been to undercut the cost of self-generation based on the customer's load factor, rather than to reflect the utility's costs:

> The usefulness of demand-charge rate structures as an instrument of price discrimination in the face of competition from isolated plants [self-generation] was known within the industry and was accepted by early regulatory commissions as a justification for their use. Historical evidence shows the role of the demand-charge rate structure as an instrument of price discrimination was more important to its widespread adoption than was its role as an imperfect form of peak-load pricing. Other explanations for the popularity of demand-charge rate structures include the suggestion made by Arthur Lewis that their adoption was caused by inadequate metering technology and the suggestion made by I.C.R. Byatt that individuals in the industry favored them because they were unable to understand economic principles. These explanations are unsatisfactory in the light of available historical evidence. (John Neufeld, Price Discrimination and the Adoption of the Electricity Demand Charge, The Journal of Economic History, 1987, See Attachment 5).

Q: Would converting PG&E's demand charges to true coincident-peak charges on the PG&E or CAISO system peak, as Professor Kahn suggested, be appropriate?

A: That would be an improvement, from the perspective of 1970. However, while Kahn assumes that the need for capacity is created by one annual hour, PG&E's capacity requirements are driven by loads in many hours. The CAISO, CPUC, and other California entities rely on probabilistic measures such as loss-of-load expectation (LOLE), which are descended from the loss-of-load probability (LOLP) concept introduced for planning in 1966, just four years before Kahn's opus was published.[18]

Accordingly, well-designed time-of-use energy rates reflecting hourly contribution to capacity needs are better suited for collecting capacity-related costs than are demand charges. We will discuss PG&E's proposed time-of-use schedules below.

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[18] L.L. Garver, "Effective Load Carrying Capability of Generating Units", Paper 31 TP 66-51 Power System Engineering Committee of the IEEE Power Group, IEEE Winter Power Meeting, New York, N.Y., January 30-February 4, 1966.

Q: Given the problems with demand charges for all but the most local costs, does PG&E propose to phase them down or entirely phase them out?

A: No. PG&E charges the non-coincident demand rate based on the customer's maximum 15-minute load at any time in the month, regardless of the state of load on the distribution system at that hour. Similarly, the seasonal peak and part-peak demand charges are charged for the customer's maximum 15-minute load at any time in the defined period, even if that customer's maximum load occurs at a time of relatively low load on the feeder, substation, and system.

There are no such costs above the service drop for most customers.

Q: How should the Commission respond to PG&E's reliance on demand charges?

A: The Commission should order PG&E to reduce its use of demand charges and shift the revenue collection to TOU energy rates. Further shifting recovery of demand-related costs from demand charges to TOU rates would send a better energy price signal.

Retaining demand charges keeps energy rates lower and thereby perversely encourage increased energy consumption. Some of the increased energy consumption might occur at times of peak load on the distribution system – when energy conservation is most needed. Maintaining excessive demand charges could therefore increase distribution system costs, as well as more generally failing CPUC rate design principle 4, "Rates should encourage conservation and energy efficiency."

Q: How do you recommend the Commission eliminate demand charges?

A: We recommend that the Commission direct PG&E to revise TOU rates to replace all demand charges with TOU rates. For example, PG&E should convert Rate B-10 to a full TOU rate similar to Rate B-1. Non-coincident demand charges should be collected through a general energy rate. Revenues currently collected through peak-period demand charges should be collected through the respective TOU period energy rates.

D. Real-Time Pricing (RTP) Tariffs

Q: What are the benefits and tradeoffs inherent to Real-Time Pricing (RTP) tariffs?

A: RTP tariffs can perfectly align the collection of generation costs with the causation of those costs. However, it presents challenges for customers who lack the resources to implement and maintain systems to respond to rapidly changing prices.

Another challenge with RTP rates is that they are not a useful instrument for collecting embedded or distribution costs. Applying the EPMC method to a RTP rate will result in very high prices during peak periods, which would be uneconomic.

RTP rates are expected to result in changes in energy use. This is desirable, but as a result it will affect cost allocation, particularly over the long run. If customers on RTP rates respond to the rates and shift load to reduce generation costs, then those customer classes will be responsible for a smaller share of embedded costs in the equal percentage of marginal costs (EPMC) method. This will result in some intra-class cost shifts over the long run.

Because of these potential pitfalls, implementation of RTP rates should initially follow the following principles. RTP rates should be:

- Targeted to customers with the capability to implement and maintain systems to respond to rapidly changing prices;
- Limited to the recovery of marginal energy costs; and

- Implemented during the rate design process after the allocation of generation costs is determined using the existing methods (as discussed in our testimony above).

After experience with the mandatory TOU rates and the RTP rates we suggest below, it should be feasible for the Commission to consider whether to offer optional RTP tariffs to other customer classes.

Q: How do you recommend the Commission direct PG&E to implement RTP rates?

A: Because RTP rates should only recover marginal energy costs, we recommend the Commission direct a relatively limited application of RTP rates for bundled customers only. All distribution and transmission costs, as well as other generation costs, should be recovered through TOU rates.

The revenue requirement for RTP rates should be developed using the same method as TOU rates. After the full revenue allocation is completed, including EPMC allocation of non-marginal costs to customer classes (as discussed in PG&E's Exhibit 3, Chapter 2 testimony), the rate to collect the Marginal Energy Costs (MECs) revenue requirement in each RTP tariff should be collected through an RTP rate based on real-time CAISP prices for energy, and not include other costs.[19] The remaining portion of generation costs would be unaffected by this design, and should be collected through a TOU rate using current cost allocation and rate design methods (as discussed elsewhere in our testimony).

A potential concern with our simple method is that since RTPs cannot be known in advance, there would be a misalignment between the markup used

[19] Our position on this point is aligned with CLECA. *Dynamic Rate and Real Time Pricing Workshop Report,* October 15, 2019 (A.19-03-002), p. 17.

to recovery generation capacity costs and the EPMC scalar used to incorporate fixed costs into rates.[20] However, even under the current method, the markup and scalar are based on projected MECs, and do not reflect the actual costs experienced under the rates. Presently, no generation costs are perfectly aligned with causation by customer class due to the use of forecasts. The introduction of RTP rates will present a different, but not necessarily larger, misalignment.

RTP rates should be implemented for those customers who have the capacity to respond to market price signals. Because customers on Rates B-19 and B-20 are currently required to respond to a variety of demand charge signals, it is reasonable to assume that they have or can feasibly develop the capacity to respond to RTP rates. PG&E should convert Rates B-19 and B-20 to recover MECs through RTP rates.

Customers on Rate B-10 may also have this capacity, but many will not. Thus, PG&E should develop an optional version of Rate B-10 that collects actual generation costs through RTP rates.

As noted in ALJ Doherty's ruling of August 27, the Commission has indicated its support for RTP tariffs. In Decision 19-03-002, the Commission stated that a "focus on demand charge reform and RTP development is welcome." While a more complex approach to RTP tariff development could have advantages, our approach is very simple and should not require extensive analysis since it is limited to changing cost recovery for MECs in specific tariffs, leaving the rest of the cost allocation and rate design process intact.

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[20] Addressing a concern raised by Cal Advocates. *Dynamic Rate and Real Time Pricing Workshop Report,* October 15, 2019 (A.19-03-002), p. 5.

E. TOU Periods

Q: What periods does PG&E use for TOU pricing?

A: The time periods are shown in Table 4.

Table 4: PG&E TOU Periods

	Months	**Hours**
Summer Peak	June – September	4 – 9 PM
Summer Part-Peak		2 – 4 PM, 9 – 11 PM
Winter Peak	October – May	4 – 9 PM
Super Off Peak	March – May	9 – 2 PM

Source: PG&E July 2020 Errata Testimony, Exhibit 3, Ch. 4, Att. B, p. 1.

Q: Did PG&E select appropriate TOU periods?

A: Not entirely. PG&E reviewed its monthly and hourly TOU period decisions that were adopted in D.18-08-013. Although PG&E acknowledges that its analysis could support changing the definitions, PG&E recommends no changes to those decisions in order to avoid customer confusion so soon after adopting the current TOU periods.

PG&E acknowledges that its analysis justifies changes to the peak and super off peak (SOP) TOU periods, including:

- Shifting the summer months from the current June – September to July – October;
- Shifting the peak hours for both summer and winter months from the current 4 – 9 PM to 5 – 10 PM; and
- Shifting the SOP period from the current March – May, 9 AM – 2 PM period to March – May, 8 AM – 4 PM.

PG&E does not discuss the summer part-peak period.

We have reviewed PG&E's Dead Band Tolerance method and our opinion is that the method employed is reasonable and that it is effectively applied. However, for reasons discussed below, we suggest that the Commission take action in this proceeding to revise PG&E's TOU periods.

Q: What considerations suggest that PG&E's TOU periods should be revised in this proceeding?

A: One major consideration that PG&E does not discuss is the role of TOU periods, and the SOP rate in particular, in encouraging adoption of electric vehicles (EVs). This is a substantial topic of discussion in the draft Transportation Electrification Framework (TEF), under review in A.18.12.006.

While we agree that PG&E's concern about customer confusion is warranted, waiting until the 2023 GRC will result in a substantial delay in implementing TOU period revisions. It is likely that a decision on the question would not be issued until 2024, and then PG&E would need time to educate customers prior to making the TOU period revisions, so it is possible that the changes would not occur until late 2024 or even sometime in 2025.

The urgency of using all available policy tools to promote electric vehicles adoption and charging during more optimal periods warrants consideration of an earlier timeline to implement an evidence-based shift to a more expansive SOP TOU period.

Q: Please describe PG&E's analysis of the period for the Super Off Peak.

A: PG&E found that its current Super Off Peak rate is using a very poor TOU period definition. Of all the SOP period definitions tested using its goodness of separation (GOS) method, PG&E found that "The current SOP definition … actually has *the lowest GOS of all combinations tested*."[21] This is true for

[21] PG&E Testimony, Exhibit 2, Ch. 11, p. 20, lines 4-7.

the analysis with marginal generation costs only and is nearly true for the analysis that adds in marginal distribution costs.[22]

The highest GOS of all SOP period definitions tested is identified for the March – May, 8 AM – 5 PM combination,[23] with the March – June, 8 AM – 5 PM combination not very far behind. The only other month span tested by PG&E is November – June.

Even though PG&E identifies the 8 AM – 5 PM period as optimal, PG&E recommends that if a change is to be made, the SOP should be March – May, 8 AM – 4 PM. The 4 PM end time is recommended because it would be more "customer-friendly" by "align[ing] the end of the SOP with the start of the current peak period."[24] The GOS difference between the best option and the 4 PM end time option recommended by PG&E is 6.5% for MGCCs only, and 6.0% for MGCCs and MDCCs combined, which exceeds PG&E's dead band tolerance threshold of 5.0% for considering a change to the TOU period. Thus, by PG&E's definition, the March – May, 8 AM – 5 PM option has a significantly better GOS than the 4 PM end time alternative recommended by PG&E.

Not only is the 8 AM – 5 PM SOP TOU period optimal under PG&E's test, but it aligns best with PG&E's optimal peak period. As noted above, the optimal peak period begins at 5 PM, not 4 PM.

Q: What SOP TOU period do you recommend?

A: First, with respect to the hours, we recommend that the Commission direct PG&E to change the SOP period to 8 AM – 5 PM. PG&E's evidence demonstrates that this rate design is the optimal SOP period, performing more

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[22] PG&E Testimony, Exhibit 2, Ch. 11, pp. 20, 22, Figures 11-4 and 11-5.

[23] PG&E Testimony, Exhibit 2, Ch. 11, pp. 20, 22, Figures 11-4 and 11-5.

[24] PG&E Testimony, Exhibit 2, Ch. 11, p. 23, lines 9, 11-13.

than 5% better than PG&E's preferred change. In contrast, PG&E's preferred change is less well aligned with costs and does not align with the optimal peak rate, and thus is not necessarily customer-friendly in the long term.

With respect to the months, we recommend that PG&E offer the SOP rate from February to June. Increasing the number of SOP rate months from three to five would help promote EV adoption and charging during optimal periods. Small businesses, in particular, would be more likely to see a benefit from installing EV charging infrastructure if SOP period was available for more than just three months of the year.

We developed this recommendation in two steps. First, we reviewed PG&E's GOS analysis for November – June. It is evident that marginal costs are consistent with the intent of the SOP period quite often during this extended period. Compared with March – May, the number of true positives (hours with marginal costs at or below zero) is increased from 687 to 1,095. However, this is offset by the large number of false positives (SOP hours with marginal costs above zero).

Because there was evidence that encouraging power use during the SOP period for those additional months would be of some benefit, but also have some potential for cost, we conducted a monthly analysis. Our analysis considered both MGCCs and MDCCs.

First, we looked at the distribution of marginal costs by month during our recommended SOP hours of 8 AM – 5 PM. As shown in Table 5, the best months are indeed March – May, but more than half of the hours in February and June have a total MGCCs and MDCCs of less than $10 per MWh.

Table 5: Marginal Costs (MGCCs and MDCCs) During Super Off Peak Period (8 AM – 5 PM)

	Marginal Costs </= $0 /MWh	Marginal Costs $0 - $10 /MWh	Marginal Costs > $10 /MWh
November	16%	13%	71%
December	7%	7%	85%
January	18%	11%	71%
February	49%	9%	42%
March	72%	10%	18%
April	90%	5%	5%
May	87%	7%	6%
June	63%	15%	22%

Second, we looked at the average marginal costs by month and by TOU period, based on our recommended hours for SOP and Peak rate periods. As shown in Table 6, the average SOP marginal costs in February and June are $10.20 and $2.68 per MWh, respectively. While higher than the average marginal costs in March – May, SOP marginal costs in February and June are significantly lower than SOP marginal costs in other months of the year.

Perhaps more importantly, the differential between SOP and Off Peak marginal costs in February and June is not much lower than in May. The SOP in February does not compete for load with the SOP in March or May; the February SOP draws load away from the February Off Peak period, by giving customers a signal to charge their EVs and run their schedulable loads in the sunshine hours rather than overnight. In contrast, the months of November, December and January have both a higher frequency of hours with marginal costs greater than $10 per MWh as well as a much smaller differential between SOP and Off Peak marginal costs.

Table 6: Average Marginal Costs (MGCCs and MDCCs), by Rate Period ($ per MWh)

	Super Off Peak 8 AM – 5 PM	Off Peak 10 PM – 8 AM	Peak 5 PM – 10 PM	Off Peak / Super Off Peak Differential
November	23.22	49.60	109.13	26.37
December	32.65	55.00	114.22	22.35
January	24.99	55.97	81.09	30.98
February	10.20	52.77	71.33	42.57
March	- 2.02	46.99	55.64	49.01
April	- 9.88	41.63	45.61	51.50
May	- 8.01	37.12	50.98	45.13
June	2.68	38.59	148.47	35.91

Based on our analysis, we have two recommendations. First, the SOP start month should be February, rather than March.

Second, the existing evidence favors ending the SOP period in June. Nevertheless, we agree with PG&E that it makes sense to align the end of the SOP season with the beginning of the summer season. Currently, the summer season begins in June so the SOP rate should end in May. However, if the summer period is shifted to begin in July, the SOP rate should end in June.

Expanding the SOP season to five months has two advantages. First, it better aligns rates with costs, and will help shift load to high-solar hours in the late winter and spring. Second, an extended SOP season will align EV and storage charging with marginal costs over a larger period of the year. Our recommendation balances the concern about incentivizing uneconomic energy use with the Commission's interest in expanding low rate periods to incentivize EV and storage charging.

Q: When should PG&E make the change to the SOP rate period?

A: The Commission should direct PG&E to review its implementation schedule for the current TOU rate periods and identify the earliest possible date in which the Company would be able to roll out an effective customer education program for the change in the SOP rate period. PG&E should be directed to file a Tier 3 Advice Letter identifying the date at which it proposes to implement the change, along with its rationale for the selected date.

The Advice Letter should also provide PG&E's reconsideration of the starting and ending months, as discussed above. We have confidence that PG&E's review of this question can be fairly straightforward and thus will not require significant review by other parties. We recommend that it be included in the Advice Letter because the analysis will be of interest to parties for future proceedings.

If the only change made to the TOU periods is the expansion of the SOP rate period, we do not believe this will cause customer confusion that negatively affects rollout of mandatory TOU rates. In fact, it may assist with the marketing: PG&E can easily announce this change as an additional rate discount option. When have customers ever been confused because a sale price was extended?

Q: Should the Commission also direct PG&E to adjust its summer peak hours?

A: This is a closer call, but we also recommend that the Commission direct PG&E to make these changes as well. Firstly, both shifting the summer peak months to July – October and shifting all peak hours to 5 – 10 PM are merited by PG&E's analysis.

However, we would acknowledge that the benefit of making these changes is not as substantial as the SOP period definition changes discussed above. In addition to better aligning the peak periods with marginal costs, changing the peak period definitions would also support the SOP period definition changes discussed above. These benefits of making the changes, while less substantial than the SOP period definition changes, also appear fairly robust given the evidence provided by PG&E.

As discussed above, we agree that PG&E's concern about customer confusion is warranted, and is somewhat stronger for shifting the peak hours and summer peak months. Yet waiting until the 2023 GRC will result in a substantial delay in implementing TOU period revisions. If customer confusion concerns can be alleviated, we recommend that the Commission should direct PG&E to move forward with these changes to the definitions.

The Commission can provide a measured pace in the path forward by authorizing PG&E to:

- Make changes to the peak period definitions concurrent with the SOP period changes at its option in the same Advice Letter; or
- File a separate Advice Letter at any point prior to filing its 2023 GRC with changes to the peak period definitions, along with supporting evidence.

In either case, the Commission's authorization would be permissive, allowing the issue to be deferred to the 2023 GRC at PG&E's option.

Q: Does this conclude your testimony?

A: Yes.

ATTACHMENTS

ATTACHMENT – 1

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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

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"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.

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"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.

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"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." Demand-Side Management and the Global Environment Conference; Washington, D.C. April 22 1991.

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

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"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.

Austin City Council, Austin Energy Rates, March to June 2012.

Puerto Rico Energy Commission, Puerto Rico Electric Power Authority, rate design issues, September 2015 to present.

EXPERT TESTIMONY

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

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 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 1980.

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

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

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

13. **Texas PUC** 3298, Gulf States Utilities rates; East Texas Legal Services. August 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 1980.

Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **Mass. DPU** 472, recovery of residential conservation-service expenses; Massachusetts Attorney General. December 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 1981 and February 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 1981.

    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 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. **DC PSC** FC785, Potomac Electric Power rate case; DC Peoples Counsel. July 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** DE 81-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 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. CC** 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 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 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 Consumer Advocate. November 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 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 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 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 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 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 1985 and October 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 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 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 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 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 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 1986.

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

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

    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 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 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 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 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 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 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 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 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 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 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 1988.

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

68. **Mass. DPU** 88-123, petition of Riverside Steam & Electric; Riverside Steam and Electric Company. May 1988 and November 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 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** 1900, Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 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 1988, supplemented August 1988; Losses and Expenses, September 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 1988.

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

73. **Vt. House of Representatives, Natural Resources Committee,** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group. February 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 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 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 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 rates; Massachusetts Energy Office. June 1989.

    Prudence of decision to spend $400 million from 1986–88 to return Pilgrim nuclear 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 1989. Rebuttal, October 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 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 1989. Surrebuttal February 1990.

    Analysis of a proposed 20-year power purchase. Comparison to efficiency investment. Critique of conservation potential analysis. Analysis of Vermont electric energy supply. Planning risk of large supply additions. Valuation of environmental externalities. Identification of possible improvements to proposed contract.

81. **Mass. DPU** 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. Boston Gas Company. 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 1990.

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

83. **Ill. CC** 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 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 1990.

Rationale for demand-side management. 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. URC,** integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 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, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 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 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 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, commission investigation; Southern Environmental Law Center. March 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 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 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 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. Direct, September 13 1991; Surrebuttal October 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 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 1991.

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

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

    Obligation to pursue integrated resource planning, 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 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 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 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 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. UC** E-100 Sub 64, integrated-resource-planning docket; Southern Environmental Law Center. September 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.); Coalition of Environmental Groups. 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 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 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 1992.

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

108. **N.C. UC** E-100 Sub 64, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 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 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 1993; rebuttal February 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 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.

Demand-side-management 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. CC** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, 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. UC** 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** FC917 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.

Demand-side-management 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. UC** E-2 Sub 669. December 1995.

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

136. **Arizona CC** 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, Central Vermont Public Service Company rates; 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, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.

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

142. **Mass. DPU** 96-60, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.

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

143. **Md. PSC** 8725, Maryland electric-utilities merger; 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 incentive mechanisms in rates for the Consumers Gas Company.

146. **New York PSC** 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.

Proposed power-supply arrangements between APS's potential 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 street lighting; 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. 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** 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. 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** 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. UC** 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. 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. 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, 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** 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. URC** 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn. PUC** 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** 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 to October 2013.

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 August 2006 to October 2013.

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

221. **N.Y. PSC** 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 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. 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** 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. 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. May 2007.

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

226. **Conn. DPUC** 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), 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** 07-E-0524, Consolidated Edison electric rates; City of New York. 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. 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. 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. 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. 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** 08-E-0596, Consolidated Edison electric rates; City of New York. 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. 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. November 2008.

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

237. **Md. PSC** 9036, Columbia Gas rates; Maryland Office of People's Counsel. 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. UARB** M01439, 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. UARB** M01496, 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. July 2009. Also filed and presented in **MA EFSB** 08-02, February 2010.

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** 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** 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surre-buttal, January 2010.

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

245. **Penn. PUC** R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

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

246. **B.C. UC** 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. **Ark. PSC** 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.

248. **Ark. PSC** 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.

249. **Ark. PSC** 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.

250. **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.

251. **N.S. UARB** M02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

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

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

253. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. 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.

254. **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.

255. **N.S. UARB** 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

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

256. **Man. PUB** 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** M03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

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

259. **N.S. UARB** M03665, depreciation rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S. UARB M**03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

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** 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** M04104; Nova Scotia Power general rate application; Nova Scotia 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** M04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

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

265. **Ark. PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. **Okla. CC** 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** 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** 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. **Okla. CC** 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

270. **Ky. PSC** 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.

271. **N.S. UARB** M04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

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

272. **Kansas CC** 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

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

273. **N.S. UARB** M04862, Port Hawksbury load-retention mechanism; Nova Scotia 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** 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** 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** 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** 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. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area 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.

284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia 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.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. UC** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (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.

287. **Conn. PURA** Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

288. **Conn. PURA** Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

289. **Man. PUB** 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

290. **Utah PSC** 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

291. **Minn. PSC** E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

292. **Cal. PUC** Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of consumer price response. Benefits of minimizing customer charges.

293. **Md. PSC** 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

294. **N.S. UARB** M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

295. **Md. PSC** 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

296. **Québec Régie de L'énergie** R-3867-2013 phase 1, Gaz Métro cost allocation and rate structure; ROEÉ. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

297. **Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.

Proxy for review of bids. Oversight of procurement and selection process.

298. **Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.

Proxy for review of bids. Oversight of procurement and selection process.

299. **Ky. PSC** 2014-00371, Kentucky Utilities electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

300. **Ky. PSC** 2014-00372, Louisville Gas and Electric electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

301. **Mich. PSC** U-17767, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.

Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.

302. **N.S. UARB** M06733, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. June 2015.

Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.

303. **Penn. PUC** P-2014-2459362, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.

Avoided costs. Recovery of lost margin.

304. **Ont. Energy Board** EB-2015-0029/0049, 2015–2020 DSM Plans Of Enbridge Gas Distribution and Union Gas, Green Energy Coalition. Evidence July 31, 2015, Corrected August 12, 2015.

Avoided costs: price mitigation, carbon prices, marginal gas supply costs, avoidable distribution costs, avoidable upstream costs (including utility-owned pipeline facilities).

305. **PUC Ohio** 14-1693-EL-RDR, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.

Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.

306. **N.S. UARB** M06214, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.

Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.

307. **PUC Texas** Docket No. 44941, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.

Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

308. **N.S. UARB** M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

Economic evaluation of proposed projects, including replacement energy costs and modeling of equipment failures. Treatment of capitalized overheads and depreciation cash flow in computation of rate effects of spending plan.

309. **Md. PSC** 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; capacity load reductions and price mitigation; free riders and load shifting in peak-time rebate (PTR) program; cost of PTR participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

310. **City of Austin TX**, Austin Energy 2016 Rate Review, Sierra Club and Public Citizen. May 2016

Allocation of generation costs. Residential rate design. Geographical rate differentials. Recognition of coal-plant retirement costs.

311. **Manitoba PUB**, Manitoba Hydro Cost of Service Methodology Review, Green Action Centre. June 2016, reply August 2016.

Allocation of generation costs. Identifying generation-related transmission assets. Treatment of subtransmission. Classification of distribution lines. Allocation of distribution substations and lines. Customer allocators. Shared service drops.

312. **Md. PSC** 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; load reductions in dynamic-pricing (DP) program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

313. **Md. PSC** 9424, Delmarva P&L Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct September 2016, Rebuttal October 2016, Surrebuttal October 2016.

Estimation of effects of Smart Meter programs—dynamic pricing (DP), conservation voltage reduction and an informational program—on wholesale revenues, wholesale prices and avoided costs; estimating load reductions from the DP program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

314. **N.H. PUC** Docket No. DE 16-576, Alternative Net Metering Tariffs, Conservation Law Foundation. Direct October 2016, Reply December 2016.

Framework for evaluating rates for distributed generation. Costs avoided and imposed by distributed solar. Rate design for distributed generation.

315. **Puerto Rico Energy Commission** CEPR-AP-2015-0001, Puerto Rico Electric Power Authority rate proceeding, PR Energy Commission. Report December 2016.

Comprehensive review of structure of electric utility, cost causation, load data, cost allocation, revenue allocation, marginal costs, retail rate designs, identification and treatment of customer subsidies, structuring rate riders, and rates for distributed generation and net metering.

316. **N.S. UARB** M07745, NS Power 2017 Capital Expenditures Plan, Nova Scotia Consumer Advocate. January 2017.

Computation and presentation of rate effects. Consistency of assumed plant operation and replacement power costs. Control of total cost of small projects. Coordination of information-technology investments. Investments in biomass plant with uncertain future.

317. **N.S. UARB** M07746, NS Power Enterprise Resource Planning project, Nova Scotia Consumer Advocate. February 2017.

Estimated software project costs. Costs of internal and contractor labor. Affiliate cost allocation.

318. **N.S. UARB** M07767, NS Power Advanced Metering Infrastructure projects, Nova Scotia Consumer Advocate. February 2017.

Design and goals of the AMI pilot program. Procurement. Coordination with information-technology and software projects.

319. **Québec Régie de l'énergie** R-3867-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; ROEÉ. March 2017.

Estimation of one-time, continuing and periodic customer-related operating and maintenance cost. Costs related to loads and revenues. Dealing with lumpy costs.

320. **N.S. UARB** M07718, NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. April 2017.

Usefulness of transmission interconnection prior to operation of the associated power plant.

321. **Mass. DPU** 17-05, Eversource Rate Case, Cape Light Compact. Direct April 2017, Rebuttal May 2017.

Critique of proposed performance-based ratemaking mechanism. Proposal for improvements.

322. **PUCO** 16-1852, AEP Ohio Electric Security Plan, Natural Resources Defense Council. May 2017.

Residential customer charge. Cost causation. Effect of rate design on consumption.

323. **Iowa Utilities Board** RPU-2017-0001, Interstate Power and Light rate case, Natural Resources Defense Council. Direct August 2017, Reply September 2017.

Critique of proposed demand-charge pilot rates for residential and small commercial customers. Defects of demand rates and shortcomings of IPL experimental proposal design.

324. **N.S. UARB** M08087, NS Power 2017 Load Forecast, Nova Scotia Consumer Advocate. Direct August 2017.

Review of forecast methodology, including extrapolation of drivers of commercial load from US national data; treatment of non-firm and competitive loads; behind-the-meter generation and controlling peak-load growth.

325. **Québec Régie de l'énergie** R-3867-2013 phase 3B; Gaz Métro line-extension policy; ROEÉ. September 2017.

The costs of adding new load. Estimating the durability of revenues from line extensions.

326. **Mass. EFSB** 17-02; Eversource proposed Hudson-Sudbury transmission line; Town of Sudbury. Direct October 2017, Supplemental January 2018..

Accuracy of ISO New England regional load forecasts. Potential for distributed solar, storage and demand response.

327. **Manitoba PUB**, Manitoba 2017/18 & 2018/19 General Rate Application; Green Action Coalition. October 2017.

Marginal costs. Rate design. Affordability rate design for low-income and electric-heating customers. Design of residential inclining blocks. Problems with demand charges and demand ratchets. Cost-of-service study improvements.

328. **N.S. UARB** M08383, NS Power 2018 Annually Adjusted Rates; Consumer Advocate. January 2018.

Projection of incremental dispatch cost. Computing administrative charges. Methodological issues.

329. **N.S. UARB** M08349, NS Power's Advanced Metering Infrastructure Proposal; Consumer Advocate. January 2018.

Estimation of AMI benefits: load balancing among feeders, critical peak pricing, avoided costs of meters for distributed generation. NS Power's claims of benefits from accounting credits (AFUDC, overheads, and converting write-offs to reduced revenue) and shifting costs to customers (earlier billing, higher recorded usage). Realistic AMI meter life. Excessive charge for customers who opt out of AMI.

330. **N.S. UARB** M08350, NS Power 2018 Annual Capital Expenditures Plan; Consumer Advocate. February 2018.

Overlap between ACE projects and AMI project. Hydro project planning and valuation of lost hydro energy output.

331. **Conn. PURA** Docket No. 08-01-01RE05, Proposed Amendment to Peaker Contracts; Connecticut Consumers Counsel. May 2018.

Dividing increased revenues from ISO-NE's Pay-for-Performance mechanism between contract generators and ratepayers.

332. **Kansas CC** Docket No. 18-WSEE-328-RTS, Westar Rate Case; Sierra Club. Direct June 2018. Rebuttal June 2018. Supplement July 2018.

Costs and benefits of running Westar coal plants. Costs of renewables and other alternatives. Recommendation regarding planning, coal retirement schedule, and acquisition of leased capacity.

333. **Cal. PUC** Application 17-09-006; Pacific Gas and Electric Gas Cost Allocation Proceeding; Small Business Utility Advocates. Direct June 2018.

Allocation of gas distribution system costs. Allocation of costs of energy-efficiency programs.

334. **N.S. UARB** M08670, NS Power 2018 Load Forecast, Nova Scotia Consumer Advocate. Direct July 2018.

Review of forecast methodology, including treatment of future energy-efficiency programs, treatment of third-party supply and behind-the-meter generation.

335. **Iowa Utilities Board** RPU-2018-0003, MidAmerican Energy Request for Approval of Ratemaking Principles for Wind XII; Sierra Club. Direct August 2018.

Cost and benefits of continued operation of six MidAmerican coal-fired units.

336. Cal. PUC A.18-02-016, 03-001, 03-002; 2018 Energy Storage Plans; Small Business Utility Advocates. Direct, Rebuttal and Supplement, August 2018.

Reliance on substation-sited storage. Need for increased emphasis on customer-sited and shared storage. Maximizing benefits, total and for small business. Oversized SDG&E proposed projects. Cost recovery. Storage technology diversity.

337. La. PSC U-34794; Cleco Corp Purchase of NRG Assets and Contracts; Sierra Club. Direct, September 2018.

Economics of NRG generation resources, Cleco Power coal plants and wholesale sales contracts. Risks of the proposed transaction.

338. Cal. PUC A.18-11-005; Southern California Gas Demand-Response Proposal; Small Business Utility Advocates. Direct March 2019, Rebuttal April 2019.

Potential benefits of gas demand response and SoCalGas failure to identify potential benefits from its programs. Program design. Cost allocation.

339. Cal. PUC A.18-11-003; Pacific Gas & Electric Electric Vehicle Rate; Small Business Utility Advocates. Direct April 2019, Rebuttal May 2019.

Critique of subscription demand charge. Time-of-use periods. Outreach to small business. Time-of-use price differentials.

340. Cal. PUC A.18-07-024; Southern California Gas and San Diego Gas & Electric Triennial Cost Allocation Proceeding; Small Business Utility Advocates. Direct April 2019.

Core commercial declining blocks. Computation of customer charges. Embedded versus marginal cost allocation. Marginal cost computation. Allocation of self-generation incentives.

341. Vt. PUC 19-0397-PET; Screening Values for Energy-Efficiency Measures; Conservation Law Foundation. Direct May 2019.

Conceptual basis for including price-suppression benefits to consumers. Avoided T&D costs. Avoided externalities with a renewable energy standard. Risk mitigation.

342. N.S. UARB M09096; EfficiencyOne Application for 2020–2022 DSM Plan; Consumer Advocate. May 2019

Evaluate NS Power critique of EfficiencyOne proposal. Comparability of efficiency budgets. Affordability. Energy-efficiency programs and resource planning.

343. N.S. UARB M09191; NS Power 2019 Load Forecast Report; Consumer Advocate. July 2019.

Review load-forecast treatment of energy efficiency, fuel switching, electric vehicles, behind-the-meter solar, AMI-enabled programs, and the changing trend in lighting efficiency.

344. **Iowa Utilities Board** RPU-2019-001; Interstate Power and Light Rate Case; Sierra Club. Direct August 2019; Rebuttal September 2019.

Economics of continued operation of five coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of all units.

345. **Maine PUC** 2019-00101; Unitil Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019.

The role of fuel convserions in Unitil's load forecast. Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

346. **Maine PUC** 2019-00105; Bangor Natural Gas Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019.

Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

347. **Wisconsin PSC 6690-UR-126**; Wisconsin Public Service Corporation 2020 Rate Case, Sierra Club. Direct August 2019, Surrebuttal October 2019.

Economics of continued operation of four coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

348. **Wisconsin PSC 05-UR-109**; Wisconsin Electric Power Company2020 Rate Case; Sierra Club. Direct August 2019, Surrebuttal October 2019

Economics of continued operation of six coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

349 **N.S. UARB M09277**; NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. August 2019.

Benefits of the Maritime Link transmission line prior to operation of associated power supply and connecting transmission facilties.

350. **N.H. PUC** DG 17-198; Liberty Utilities Petition to Approve Firm Supply, Transportation Agreements, and the Granite Bridge Project; Conservation Law Foundation. September 2019.

Need for transportation contracts and new pipeline. Alternative of switching oil and propane to efficient electric end uses. Limited life of gas infrastructure and effect on ratepayer costs.

351. **Colorado PUC** 19AL-0268E; Public Service of Colorado Rate Case; Sierra Club. September 2019.

Prudence of management of superheater tube failures. Unfavorable economics of coal plants nationally. Need for continuing review of coal-plant economics and benefits of retirement.

352. **N.H. PUC** DG 17-152; Liberty Utilities Least Cost Integrated Resource Plan; Conservation Law Foundation. September 2019.
Integrated planning for gas utilities in an era of carbon constraints. Heat pump electrification versus gas conversion of oil-fired space and water heating.

353. **N.S. UARB** M09420; NS Power Application for an Extra-Large Industrial Active Demand Control Tariff; Nova Scotia Consumer Advocate. December 2019.

Estimating incremental costs, including lost wheeling revenues, variable O&M, and variable capital cost; updating and reconciliation of incremental costs.

354. **Cal. PUC** A.19-07-006; San Diego Gas & Electric Fast-Charging and Heavy-Duty Electric Vehicle Proposal; Small Business Utility Advocates. Direct January 2020, Rebuttal February 2020.

Interim rate proposal. Critique of subscription and demand charges. Time-of-use periods. Recovery of lost revenues.

355. **N.S. UARB** M09519; NS Power Smart Grid Application; Nova Scotia Consumer Advocate. February 2020. Joint testimony with John D. Wilson.

Differentiating capital costs from expenses. Inclusion of decommissioning costs in project plan. Selection of the Distributed Energy Resources Management System.

356. **N.S. UARB** M09499; NS Power 2020 Annual Capital Expenditure Plan; Nova Scotia Consumer Advocate. February 2020. Joint testimony with John D. Wilson.

Planning for hydro life extension or retirement. Appropriate levels of contingency in project budgets. Aggregation of multi-year capital programs. Cost-control efforts.

357. **Cal. PUC** A.19-03-002; San Diego Gas & Electric General Rate Application, Phase 2; Small Business Utility Advocates. Direct March 2020; Rebuttal May 2020.

Problems with proposed increases in the Monthly Service Fees and reliance on demand charges in for medium non-residential customers. Improving hours for the TOU periods.

358. **N.S. UARB** M09609; NS Power Authorization to Overspend on Gaspereau Dam Works; Nova Scotia Consumer Advocate. May 2020. Joint testimony with John D. Wilson.

Alternatives to the proposed project, including decommissioning the affected hydro system. Choice of project contingency factor. Estimation of archaeological costs. Replacement energy cost assumptions.

359. **N.S. UARB** M09609; NS Power Advanced Distribution Management System Upgrade; Nova Scotia Consumer Advocate. May 2020. Joint testimony with John D. Wilson.

Need for the ADMS. Integration with the Distributed Energy Resources Management System.

360. **Cal. PUC** A.19-10-012; San Diego Gas & Electric Power Your Drive Electric Vehicle Charging Program; Small Business Utility Advocates. Direct May 2020; Rebuttal June 2020. Joint testimony with John D. Wilson.

Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

361. **N.S. UARB** M09499; Authorization to Overspend for Various Distribution Routines; Nova Scotia Consumer Advocate. June 2020.

Guidelines for reporting cost overruns due to extreme weather. Documentation of drivers of equipment deterioration and replacement. Tracking costs of connecting new customers.

362. **N.S. UARB** M09499; NS Power 2020 Load Forecast Report; Nova Scotia Consumer Advocate. July 2020. Joint testimony with John D. Wilson.

Impacts of the COVID-19 recession on load. Additional appropriate end-use studies. Improvements to modelling of electrification and factors. Effects of AMI and time-varying pricing on data availability and load.

363. **Cal. PUC** A.20-03-002, et al; Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric 2020 Energy Storage Procurement and Investment Plans; Small Business Utility Advocates. Direct and Rebuttal September 2020.

Adequacy of transmission, distribution and customer-side storage acquisition. Extending residential smart water-heater and new-home storage programs to small commercial customers.

ACRONYMS AND INITIALISMS

APS	Alleghany Power System
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CC	Corporation Commission
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
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
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURA	Public Utility Regulatory Authority
PURPA	Public Utility Regulatory Policy Act
ROEÉ	Regroupement des organismes environnementaux en énergie
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UC	Utilities Commission
URC	Utility Regulatory Commission
UTC	Utilities and Transportation Commission

ATTACHMENT – 2

Attachment - 2

JOHN D. WILSON

Resource Insight, Inc.
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SUMMARY OF PROFESSIONAL EXPERIENCE

2019–Present **Research Director, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, and regulation. Reviews electric-utility rate design. Designs and evaluates conservation programs for electric utilities, including conservation cost recovery mechanisms and performance incentives. Evaluates performance of renewable resources and designs performance evaluation systems for procurement. Designs and assesses resource planning and procurement strategies for regulated and competitive markets.

2007-19 **Deputy Director for Regulatory Policy, Southern Alliance for Clean Energy.** Managed regulatory policy, including supervision of experts in areas of energy efficiency, renewable energy, and market data. Provided expert witness testimony on topics of resource planning, renewable energy, energy efficiency to utility regulators. Directed litigation activities, including support of expert witnesses in the areas of rate design, resource planning, renewable energy, energy efficiency, and resource procurement. Conducted supporting research and policy development. Represented SACE on numerous legislative, utility, and private committees across a wide range of climate and energy related topics.

2001–06 **Executive Director, Galveston-Houston Association for Smog Prevention.** Directed advocacy and regulatory policy related to air pollution reduction, including ozone, air toxics, and other related pollutants in the industrial, utility, and transportation sectors. Served on the Regional Air Quality Planning Committee, Transportation Policy Technical Advisory Committee, and Steering Committee of the TCEQ Interim Science Committee.

2000–01 **Senior Associate, The Goodman Corporation.** Provided transportation and urban planning consultant services to cities and business districts across Texas.

1997–99 **Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Florida Legislature.** Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures. Edited statewide government accountability newsletter and coordinated online and internal technical projects.

1997 **Environmental Management Consultant, Florida State University.** Project staff for Florida Assessment of Coastal Trends.

1992-96 **Research Associate, Center for Global Studies, Houston Advanced Research Center.** Coordinated and led research for projects assessing environmental and resource issues in the Rio Grande / Rio Bravo river basin and across the Greater Houston region. Coordinated task force and edited book on climate change in Texas.

EDUCATION

BA, Physics (with honors) and history, Rice University, 1990.

MPP, John F. Kennedy School of Government, Harvard University, 1992. Concentration areas: Environment, negotiation, economic and analytic methods.

PUBLICATIONS

"Urban Areas," with Judith Clarkson and Wolfgang Roeseler, in Gerald R. North, Jurgen Schmandt and Judith Clarkson, *The Impact of Global Warming on Texas: A Report of the Task Force on Climate Change in Texas*, 1995.

"Quality of Life and Comparative Risk in Houston," with Janet E. Kohlhase and Sabrina Strawn, *Urban Ecosystems*, Vol. 3, Issue 2, July 1999.

"Seeking Consistency in Performance Incentives for Utility Energy Efficiency Programs," with Tom Franks and J. Richard Hornby, *2010 American Council for an Energy-Efficient Economy Summer Study on Energy Efficiency in Buildings*, August 2010.

"Monopsony Behavior in the Power Generation Market," with Mike O'Boyle and Ron Lehr, *Electricity Journal*, August-September 2020.

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"Policy Options: Responding to Climate Change in Texas," Houston Advanced Research Center, US EPA and Texas Water Commission, October 1993.

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Houston Environmental Foresight Committee, *Seeking Environmental Improvement*, Houston Advanced Research Center, January 1996.

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Office of Program Policy Analysis and Government Accountability, *Best Financial Management Practices for Florida School Districts*, Report No. 97-08, October 1997.

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Office of Program Policy Analysis and Government Accountability, *Review of the Expedited Permitting Process Coordinated by the Governor's Office of Tourism, Trade, and Economic Development,* Report No. 98-17, October 1998.

Office of Program Policy Analysis and Government Accountability, *Florida Water Policy: Discouraging Competing Applications for Water Permits; Encouraging Cost-Effective Water Development,* Report No. 99-06, August 1999.

"Smoke in the Water: Air Pollution Hidden in the Water Vapor from Cooling Towers – Agencies Fail to Enforce Against Polluters," Galveston Houston Association for Smog Prevention, February 2004.

"Reducing Air Pollution from Houston-Area School Buses," Galveston Houston Association for Smog Prevention, March 2004.

"Who's Counting: The Systematic Underreporting of Toxic Air Emissions," Environmental Integrity Project and Galveston Houston Association for Smog Prevention, June 2004.

"Mercury in Galveston and Houston Fish: Contamination by Neurotoxin Places Children at Risk," Galveston Houston Association for Smog Prevention, October 2004.

"Exceeding the Limit: Industry Violations of New Rule Almost Slid Under State's Radar," Galveston Houston Association for Smog Prevention, January 2006.

"Whiners Matter! Citizen Complaints Lead to Improved Regional Air Quality Control," Galveston Houston Association for Smog Prevention, June 2006.

"Bringing Clean Energy to the Southeastern United States: Achieving the Federal Renewable Energy Standard," Southern Alliance for Clean Energy, February 2008.

"Cornerstones: Building a Secure Foundation for North Carolina's Energy Future," Southern Alliance for Clean Energy, May 2008.

"Yes We Can: Southern Solutions for a National Renewable Energy Standard," Southern Alliance for Clean Energy, February 2009.

"Green in the Grid: Renewable Electricity Opportunities in the Southeast United States," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Local Clean Power," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

"Recommendations for Feed-In-Tariff Program Implementation In The Southeast Region To Accelerate Renewable Energy Development," Southern Alliance for Clean Energy, March 2011.

"Renewable Energy Standard Offer: A Tennessee Valley Authority Case Study," Southern Alliance for Clean Energy, November 2012.

"Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast," Southern Alliance for Clean Energy, November 2014.

"Cleaner Energy for Southern Company: Finding a Low Cost Path to Clean Power Plan Compliance," Southern Alliance for Clean Energy, July 2015.

"Analysis of Solar Capacity Equivalent Values for Duke Energy Carolinas and Duke Energy Progress Systems," prepared for and filed by Southern Alliance for Clean Energy, Natural Resources Defense Council, and Sierra Club in North Carolina NCUC Docket No. E-100, Sub 147, February 17, 2017.

"Seasonal Electric Demand in the Southeastern United States," Southern Alliance for Clean Energy, March 2017.

"Analysis of Solar Capacity Equivalent Values for the South Carolina Electric and Gas System," Southern Alliance for Clean Energy, March 2017.

"Solar in the Southeast, 2017 Annual Report," with Bryan Jacob, Southern Alliance for Clean Energy, February 2018.

"Energy Efficiency in the Southeast, 2018 Annual Report," with Forest Bradley-Wright, Southern Alliance for Clean Energy, December 2018.

"Solar in the Southeast, 2018 Annual Report," with Bryan Jacob, Southern Alliance for Clean Energy, April 2018.

"Tracking Decarbonization in the Southeast, 2019 Generation and CO_2 Emissions Report," with Heather Pohnan and Maggie Shober, Southern Alliance for Clean Energy, August 2019.

"Seasonal Electric Demand in the Southeastern United States," with Maggie Shober, Southern Alliance for Clean Energy, April 2020.

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2016 **Georgia PSC** Docket No. 40161, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in Georgia Power's 2016 integrated resource plan, including portfolio diversity, operational and implementation risk, analysis of project-specific costs and benefits (including location and technology considerations), and methods for calculating dependable capacity credit for renewable resources.

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Nova Scotia UARB Matter No. M09579, direct testimony with Paul Chernick in Nova Scotia Power's application for the Gaspereau Dam Safety Remedial Works on behalf of the Nova Scotia Consumer Advocate. Alternatives to proposed project, project contingency factor, estimation of archaeological costs, and replacement energy cost calculation.

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California PUC Docket A.19-08-012, direct testimony in Southern California Edison's 2021 general rate case (track 2) on behalf of the Small Business Utility Advocates. Reasonableness of remedial software costs to be included in authorized revenue requirement.

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ATTACHMENT – 3

Charge Without a Cause?

Assessing Electric Utility Demand Charges on Small Consumers

Electricity Rate Design Review Paper No. 1

July 18, 2016

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Mark LeBel

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Introduction & Overview

There has been significant recent attention to the possibility of including demand charges in the electricity rates charged to residents and small businesses. Electric utilities have historically served these 'small customers' under a two-part rate structure comprised of a fixed monthly customer charge that recovers the cost of connecting to the grid and an energy charge (or charges) that recover all other costs. Much of this attention to the issue of demand charges for small customers has been initiated by electric utilities reacting to actual or potential reductions in sales, revenue and cost recovery.

Demand charges are widely familiar to large, commercial and industrial customers, where they are used to base some portion of these customers' bills on their maximum rate of consumption. While a customer charge imposes the same monthly cost for every customer in a rate class, and an energy charge usually imposes the same cost per unit of energy used over a long period of time (e.g. the entire year, a month, or all weekday summer afternoons), most demand charges impose a cost based on usage in a very short period of time, such as 15 minutes or one hour per month. The timing of the specific single maximum demand event in a month that will result in demand charges is generally not known in advance.

The goal of this document is to unpack the key elements of demand charges and explore their effect on fairness, efficiency, customer acceptability and the certainty of utility cost recovery. As will be evident, most applications of demand charges for small customers perform poorly in all categories. Following are five key takeaways:

- Residents and small businesses are very diverse in their use of electricity across the day, month and year — most small consumers' individual peak usage does not actually occur during peak system usage overall. This means that traditional demand charges tend to overcharge the individual small consumer.
- Apartment residents are particularly disadvantaged by demand charges because a particular apartment resident's peak usage isn't actually served by the utility. Utilities only serve the combined diverse demand of multiple apartments in a building or complex rather than the individual apartment unit.
- Demand charges are complex, difficult for small consumers to understand, and not likely to be widely accepted by the small customer groups.
- Very little of utility capacity costs are associated with the demands of individual small consumers. Nearly all capacity is sized to the combined and diverse demand of the entire system, the costs of which are not captured by traditional demand charges. If consumers actually were able to respond to a demand charge by levelizing their electricity usage across broader peak periods, then utilities would incur revenue shortages without any corresponding reduction in system costs.
- Demand charges do not offer actionable price signals to small consumers without investment in demand control technologies or very challenging household routine changes. This results in effectively adding another mandatory fixed fee to residential and small consumer electric bills.

About the Authors

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Legacy Demand Charges

While there are a large number of variants on the basic theme, the standard demand charge is a fee in dollars per kW times the customer's highest usage in a short (e.g. one-hour) period during the billing month. These charges are nearly universal for industrial and larger commercial customers.

This rate design is a legacy of the 19th century, when utilities imposed demand charges to differentiate between customers with fairly stable loads over the month (mostly industrial loads) from those who used lots of energy in a few hours, but much less the rest of the month. Utilities recognized that the latter customers with peaky loads were more expensive to serve per kWh, and monthly maximum demand was the only other measurement available given existing meter technology at the time.

Beyond the standard design, variants include:

- Billing demand computed as the highest load over 15 or 30 minutes, rather than an hour;
- Charges per kVA rather than per kW, thereby incorporating power factor;
- Charges that are higher in some months and/or some daily periods than in others;
- Ratchets, in which the demand charge can be set by the highest load in the preceding year or peak season, as well as the current month; and
- Hours-use or load-factor rates, where the price per kWh declines as monthly kWh/kW increases, thereby incorporating an effective demand charge within an energy charge framework. For example:

First 200 kWh/kW	$0.15
Next 200 kWh/kW	$0.12
Over 400 kWh/kW	$0.10

For a high load factor customer (e.g. over 400 kWh/kW, or 60%), this works out to a $14/kW demand charge. But, for a low load factor customer with high peak demand at some times but otherwise low usage, like a school stadium lighting system with only 20 hours/month of usage, this rate design example works out to $1/kW (20 hours x .05/kWh built into the first 200 kWh/kW).

Demand-Charge Design Elements

As noted above, the standard demand charge uses the billing demand at the time of the customer's greatest consumption, integrated over a short period such as one hour, measured monthly. Thus, the charge is based on a single hour out of the 720 hours of a 30-day month, with each customer charged for load in whichever hour their maximum demand occurs, regardless of coincidence with the peak demand of the system. Because a customer's individual peak demand can occur at any time of day and not necessarily during the hour when system costs are greatest, the standard demand charge does not generally reflect cost causation. There are three categories of design options for demand charges: the time at which demand is measured, the period over which demand is averaged, and the frequency of its measurement.

Timing of billing demand measurement

The term "peak demand" is used in many different ways in utility jargon. These peaks include the following:

- **Customer peak:** Each customer experiences a non-coincident[1] maximum demand (NCP) at some point in the month. That value is typically used in legacy demand charges. Each customer also experiences a maximum non-coincident demand for the year (i.e. the highest of 12 monthly maximum non-coincident demands). This value is used for demand charges with ratchets.[2]
- **Equipment peak:** Each piece of utility transmission and distribution equipment experiences a maximum load each month and each year. Utilities often have detailed data on the timing of loads on substations, transmission lines, and distribution feeders. They use those data for system planning, but usually not in setting rates. The capacity of equipment varies with weather; when temperatures are cooler, equipment dissipates heat better and has more capacity.
- **Class peak:** Utilities generally estimate a class peak load for each customer class (e.g. residential, small commercial, large commercial), which may occur at different hours, months and seasons. Aggregated class peaks are often used in allocating some distribution costs to classes.
- **System peak:** The entire system experiences a maximum peak in each month, one of which will be the annual maximum peak. Loads of customers or customer classes measured at the time of the maximum monthly or annual system peak are said to be coincident demands for that month or year.
- **Designated or seasonal peak:** Utilities often designate a "peak period" for one or more months, when there is a high probability that the system's highest peak demands will occur, such as 3-7 p.m. from June through September. However, these designated peak times are based on expectations and do not necessarily coincide with actual system peak. Demand charges may measure each customer's highest one-hour demand during these periods. This is sometimes incorrectly referred to as a 'coincident peak demand charge,' or a 'demand time of use rate.'

Because of their diversity in energy usage, customers' individual non-coincident maximum loads usually do not occur at the same time as the peaks on the system as a whole — or even at the same time as peaks on the local distribution system. Thus, in addition to not reflecting the customer's contribution to utility costs, billing on the customer maximum demand does not effectively encourage customers to reduce their contribution to costs, and may actually encourage customers to move load from the times of their individual maximum demands to times of high system loads and costs. Unlike attempting to capture customer coincident demands, billing parameters for customer non-coincident load is relatively easy to measure. However, these loads are difficult to control, and a single brief unusual event (e.g. simultaneous operation of multiple end uses or equipment failure) can set the billing demand for the month and year.

With modern utility metering, utilities have the option of charging for customer loads at times that more closely correspond to cost causation — times when the system (or its various parts) is experiencing its maximum demand. A range of approaches are available:

- **Actual coincident peaks**. Because many cost allocation systems assign at least a portion of generation and transmission costs to customer classes on the basis of customer class contributions to the system peak(s) — the coincident peak or "CP" method — there is some logic behind billing on the basis of the individual customer's contribution to the system peak. A significant challenge with CP billing is there is no way to know that a particular hour will be the system peak, even as it is occurring, since a higher load may occur later in the day, month, season or year. The utility could provide customers with information on current and forecast loads, and each customer could try to respond to the *possibility* of a system peak, spreading out their response across many high load hours,

[1] The term "non-coincident" means not *intentionally* coincident with, i.e. at the same time as, the systempeak. Coincidence with the systempeak would only be by happenstance.

[2] The sum over customers by class of maximum non-coincident annual peak demands is used by some utilities in allocating some distribution costs.

only one of which will actually be used in computing billing demand. Like Russian Roulette, it is likely to be difficult for many residential and small commercial customers to understand and respond to this type of system.

- **Designated peak hours**. Rather than computing the billing demand for the actual system peak hours, the utility could, on relatively short notice, designate particular hours as potential peak (or potentially critical) hours and compute the billing demand as the average of the customer's load in those hours. This approach is similar to the designation of critical peak periods in some time-of-use rates or peak-time rebates in some load-management programs. Provided that the potential peak hour information can be effectively communicated to all customers subject to the structure, the ability to respond should be somewhat improved over the NCP and CP approaches.
- **Forecast peak periods**. Rather than designating individual hours for computation of billing demand, a utility could designate a peak window, such as noon to 4 p.m., when the system is likely to experience a peak or other critical condition, and set the billing demand as the customer's average consumption during that window. The hours around the system peak hour also tend to experience loads close to the actual peak load and contribute to reliability risk. Shifting load from the peak hour to one hour earlier or later may create a worse situation in that new hour. Here too, customers may be better able to respond to forecast peak periods than to individual hours, even if the period is only designated the day before or a few hours before the event.
- **Standard peak-exposure periods**. In the above examples, customers may only learn about peak periods after-the-fact or just a day or hours before they are set, but utilities could set time periods farther in advance, for instance in a rate case as part of the tariff itself. Especially for small customers, establishing a fixed period in which peaks and resource insufficiency are most likely, such as July and August weekdays or even more narrowly non-holiday summer weekday periods between noon and 4 p.m., may be more acceptable and effective than declaring the demand-charge hours on short notice. This approach trades improved predictability for customers for a diminished relationship to system costs. Customer response, such as limiting their maximum energy demands during the known peak periods, would be similar to the response to time of use rates, but with the consequences of not responding potentially more dire.

Period of billing demand measurement

Measurement of the customer's billing demand can occur over a wide variety of time frames. An instantaneous or short-duration measure of billing demand is possible but would penalize customers with overlapping loads of standard behind the meter technologies. Many residential customers have limited choice or control over when they use appliances. For example, electric furnaces and water heaters can consume significant levels of electricity, with common models drawing 10.5 kW and 4.5 kW, respectively. Air conditioners draw from 2 kW for a one-ton capacity model to 9 kW for a five-ton model. In addition, common hair dryers typically draw 1 kW and often more; the average microwave or toaster oven can draw 1 kW; and an electric kettle can draw 1 kW.

It is easy to see how the typical morning routine for a family would result in an instantaneous peak demand of as much as 18 kW and demand over a one-hour period in excess of 10 kW. A billed demand of 10 kW or more would result in high and hard-to-avoid charges, in addition to a fixed monthly charge, meaning that this household would have little to no control over the bulk of its monthly bill.

While families may be able to understand how this peak demand occurs, school schedules and work schedules may allow little flexibility to do anything about it. Further, many of these devices are designed to be automatically controlled by thermostats that would be difficult to override on a short-term basis to avoid demand charges. Moreover, these overlapping appliance demands do not drive costs on the system.

This example shows the electric demand of a morning schedule, while peak system demands are often later in the day. In addition, customer diversity can spread these demands out, diluting any effect on peak system demand.

At the other extreme, the billing demand measure could be 720 hours, for a 30-day month. This billing period would capture all the loads imposed by the customer to the utility system and requires no new metering. In fact, this billing approach is in common practice today and is known as the two-part rate, which charges customers for demand during each hour of each day of the billing period (a.k.a. energy) on top of the basic flat monthly customer charge.

Within this spectrum, the most common billing demand periods in practice today for commercial and industrial customers (outside of the two-part rate) range from 15 minutes to 60 minutes.[3] Short periods of measured billing demand are more difficult for customers to manage. For example, an apartment dweller who takes a shower and dries their hair while something is in the oven can run up demand of 10 kW or more, even though the average contribution to the system peak across units in the same apartment building is typically no more than 2 or 3 kW. Longer periods of measurement, such as 60 minutes or the average demand over several hours, tend to dilute the impacts of very short-term events.

There is great diversity in maximum loads among residential consumers. As mentioned above, demand charges have historically only been applied to large commercial and industrial customers, with a multitude of loads served through a single meter, and generally a dedicated transformer or transformer bank. For very large industrial customers, there is typically a dedicated distribution circuit or even distribution substation. So for these customers, diversity occurs on the customer's side of the meter, such as when copiers, fans, compressors, and other equipment cycles on and off in a large office building.

For residential consumers, there is also diversity — but it occurs on the utility's side of the meter as customers in different homes and apartments connected to the same transformers and circuits use power at different moments in time. The point is that the type of rate design that is appropriate for industrial customers, who may have a dedicated substation or circuit, is not necessarily appropriate for residential customers who share distribution components down to and including the final line transformer.

Indeed, in the example in the previous section regarding measurement of peak demand during a window designed to capture higher-cost hours (i.e. standard peak-exposure periods), one can envision a peak demand period that covers the entire window. Such an approach may be more closely tied to cost causation, but it would be difficult for the customer to respond unless measurement occurred each day and was averaged for the full billing period.

Frequency of billing demand measurement

By far the most common frequency of measurement is once per month. However, this is not the result of careful study and analysis, but is rather a matter of convenience related to the selection of billing periods approximating one month. Months and billing periods are arbitrary creations, whereas cost variation tends to be more seasonal in nature at the macro-scale, weekly at a mid-scale (workdays vs. weekends and holidays), and daily at a micro-scale.

However, actual generation capacity requirements are driven by many high-load hours, which collectively account for most of the risk of insufficient capacity following a major generation or transmission outage,

[3] A related decision point is specifying whether the billing demand period to be measured is random or clock-based. For example, can a 60-minute billing demand period begin at any time, or should it be restricted to clock hours?

so any single peak customer load is unlikely to provide optimal price signals. Pragmatically, loads of very short duration — the highest 50 hours per year or so — are best served with demand response measures that require no investment whatsoever in generation, transmission, or distribution capacity.

Some commercial and industrial customers are subject to what are called "demand ratchets" which set the minimum billing demand for each month based on a percentage (typically 50% to 100%) of the maximum billing demand for any month in the previous peak season (summer or winter) or previous 11 or 12 months. While ratchets smooth revenue recovery for the utility, they are the antithesis of cost causation in a utility system with diversified loads, and can severely penalize seasonal loads. The resulting unavoidable fixed charges impair the energy conservation price signal to customers. Therefore, billing demands could reflect cost causation more closely by having seasonal elements, and also weekly and daily elements, but this increases the complexity. Alternatively, demands could be measured and averaged over the 100 hours each month that contribute most to system peak loads.[4]

Finally, as discussed relative to the period of measurement, if kW of demand were to be measured in every hour of the month and summed, the result would be the current two part rate with no additional more expensive metering required.

Evaluation of Demand Charges

Loads, load management and load diversity

The costs that utilities typically recover in existing demand charges applied to large customers include those that are usually assigned to customer classes on the basis of a demand allocator.[5] These costs tend to be fixed for a period of more than one year, and usually include one or more of the following:

- Generation capacity costs (cost of peaking generators and all or a portion of the cost of baseload[6] units)
- Transmission costs (all or a portion)
- Distribution costs (all or a portion of distribution circuits and transformer costs)

Some utilities utilize separate demand charges for each major function, or sometimes group functions together, such as generation and transmission, that are allocated to customer classes on similar bases.

Because billing demand is a function of the total load of a customer's on-site electrical equipment operating simultaneously for a relatively short period of time, the demand charge may act as an incentive to levelize demand across the day. The types of large commercial and industrial customers that are currently subject to demand charges are usually sophisticated enough to understand the sources and timing of their electrical equipment and its consequent energy consumption.[7] Many, i.e. over half,[8] have

[4] Such a system would be more likely to capture high loads and peak demands on the system sub-functions, e.g. transformers, feeders, substations, transmission, and generation.

[5] It should be noted that some jurisdictions allocate a portion of fixed costs on average demand, or energy.

[6] Because baseload units serve all hours, many regulators have used the Peak Credit or Equivalent Peaker method to classify baseload plant costs between Demand and Energy. For example, in Washington, it's about 25% demand, 75% energy. In marginal cost studies, only the cost of a peaker is typically considered demand-related.

[7] Most utilities do not apply demand charges to small commercial customers under 20-50 kW demand.

energy managers whose job in part is to manage that energy consumption in light of the rates and rate structure of their local utility. Monitoring and load management equipment can be employed to maximize profitable industrial processes while avoiding new, higher peak demand charges. In other words, sophisticated large commercial and industrial customers may use energy management systems to restrain demand by scheduling or controlling when different pieces of equipment are used like fans, compressors, electrolytic processes, and other major equipment, in order to levelize the load over the day. Because these large customers have a diversity of uses on their premises, they may be able to manage that diversity to present a relatively stable load to the utility.[9] However, because individual customer demand often does not coincide with system demand, much of the demand management activity by the more sophisticated large customers is essentially pointless and wasteful from a system cost perspective.

Moreover, while it appears utilities believe demand-charge revenues are more stable than energy revenues, the stability of demand charge revenue even for large customers is highly dependent on the size, load factor and weather sensitivity of the large customers.

The sophistication of large customer energy management does not currently exist for most small commercial and residential customers. These customers have a great deal of load diversity, but that diversity is not within a single customer but between different customers using power at different times (see Appendix B). In these classes, because each customer is served through a separate meter, it is unlikely that individual constituents will have much ability to reduce the overall system demand or their own maximum billing demand in any significant way without acquisition and effective use of advanced load monitoring and management technologies. Residential demand controllers are marketed to all-electric customers (e.g. at some rural utilities with limited circuit capacity) that have implemented demand charges. These do enable customers with electric cooking, water heating, clothes dryers, space conditioning, and swimming pools to levelize their demand. But for urban apartment dwellers and other low-usage customers, the natural diversity between customers is much greater than the potential control over the diversity of uses within a household.

Technologies to manage and control this diversity of small customer usage are best deployed as demand response measures, targeted at hours that are key to the system, not to the individual consumer usage pattern. As a result of the small customers' lack of ability to control individual peak demands, a demand charge on small customers acts effectively as a fixed charge and generally provides a more stable and consistent revenue collection vehicle for the utility than volumetric energy charges.

Cost drivers and load alignment

Evidence shows that small residential customers are less likely to have their individual high usage occur at the time of the system peak demand, whereas large residential users are more likely. This is simply because large residential users are more likely to have significant air conditioning and other peak-oriented loads. Large residential users' loads tend to be more coincident with system peak periods and thus more expensive to serve. As a result of these load patterns, on an individual customer basis large residential users have higher individual load factors, meaning they will pay lower average rates if a non-coincident demand charge is imposed.

The figure below shows this relationship, in the context of residential customers:

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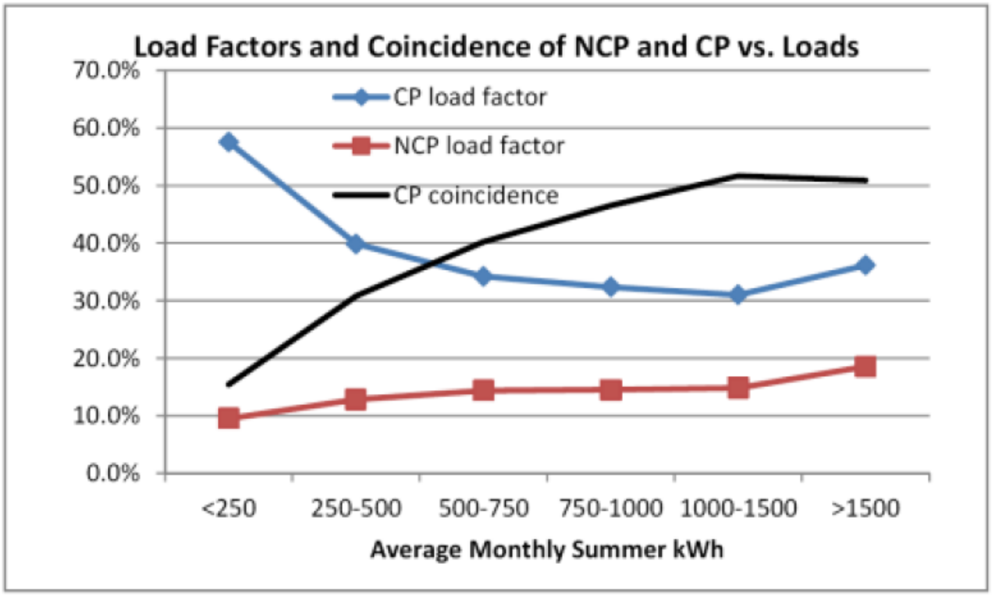
[8] A Review Of Alternative Rate Designs Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers; Rocky Mountain Institute, p. 76, May 2016 download at: www.rmi.org/alternative_rate_designs

[9] That stable load may not be less expensive to serve than the customer's most efficient load.

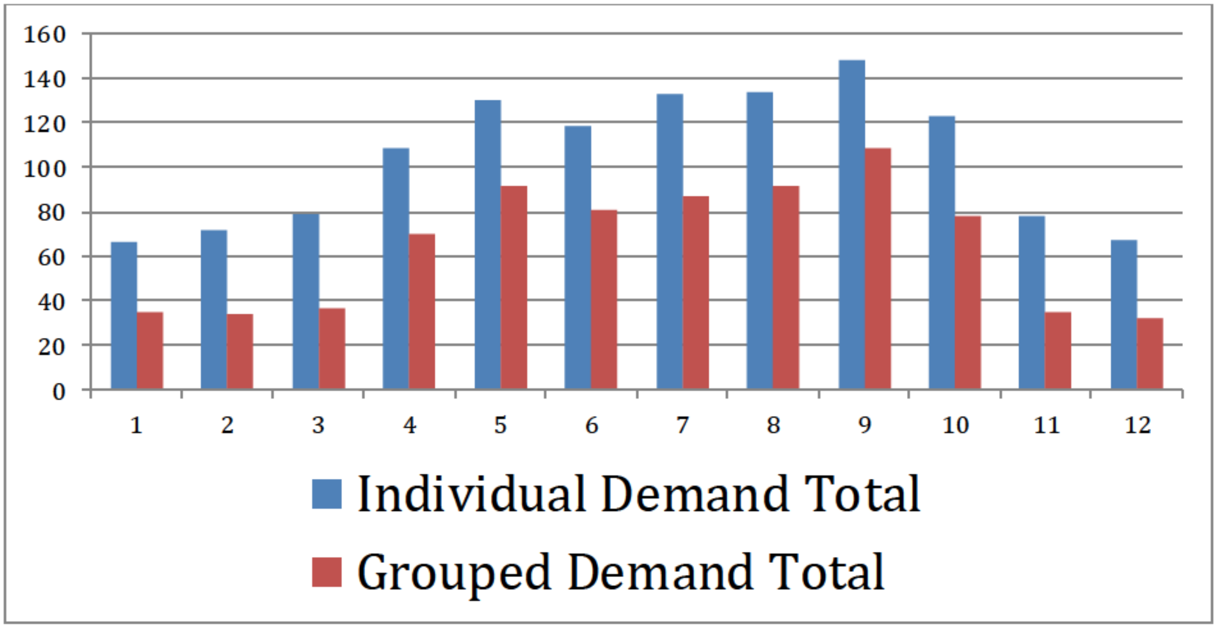


Source: Marcus Presentation to WCPSC, June 2015

The black line shows customers whose individual peak demand coincides with system peak tend to have both higher monthly energy use (kWh) and higher metered individual load factors. The red line shows that larger-use customers have higher individual metered non-coincident load factors. The blue line shows that smaller-use customers have higher "group" collective load factors, measured relative to the system coincident peak.

As described above, the breadth of equipment on a large commercial or industrial customer's site results in load diversity behind the meter allowing for a fairly smooth load pattern for these larger customers. Smaller customers without the same degree of behind the meter load diversity have many small appliances that often operate for short periods of time. It takes but a few operating simultaneously to establish a peak demand. For a large group of 100,000 to one million customers or so, there is a general pattern for the class load and in many cases it tends to drive the utility's peak demand towards later in the day, but on an individual customer basis, peak loads can occur at any time during the month depending on the lifestyle, ages of family members, work situation, and other factors.

Apartments are particularly affected. About three-quarters of apartments in the US have electric water heaters. An electric water heater draws 4.4 kW when charging, but only operates about two hours per day, for a total of about 9 kWh of consumption per day. But each apartment has its own water-heating unit. Combined with hair dryer, range, clothes dryer, and other appliances, an apartment unit may draw 10-15 kW for short periods, but only about 0.5 to 1.0 kW on average (360-720 kWh per apartment per month). Because many apartments are served through a single transformer and meter bank, what actually matters to system design is not the individual demands of apartments, but the combined (diverse) demand of the building or complex. The illustration below shows how the sum of individual apartments' maximum hourly demands in one apartment building (in the Los Angeles area) compares to the combined maximum hourly demand for the complex:



Source: RAP Demand Charge Webinar, December 2015

The equity of rates and bills for apartment residents, where each household has few residents, but the entire building is connected to the utility through a single transformer bank, must also be addressed because the utility does not actually serve the consumption of individual customers, but only their collective needs. Finally, if customers do respond and levelize their consumption across the day or across the peak hours to minimize their demand charges, then the rates designed will not produce the revenue expected but any impacts on system costs (e.g. avoided upgrades or expansions) would likely not occur for years.

Appendix B contains residential load curves for customers in New Mexico and Colorado covering the four summer peak days for the utility providing service. It is clear from these charts that individual residential customer load is volatile, and not subject to consistent patterns that the customer would be in a position to manage. Each customer experienced its individual peak at a unique time. The collective group peak was not at the time of each individual customer's peak in any of the months. The bottom line is no discernible cost causation relationship with individual customers' peak demand.

Metering costs and allocation

Finally, demand charges also require more complex, and expensive, metering technologies than conventional two-part tariffs. The cost-effectiveness of these upgrades should be analyzed on their own merits, and where the costs are justified by energy savings or peak load reduction, they should be treated in the same fashion as the costs that are avoided, with only the portion justified by customer-related benefits (e.g. reduced meter reading expense) treated as customer-related. The remainder would be attributed to such drivers as energy costs and coincident peaks. For more information, see Smart Rate Design for a Smart Future for a discussion of how Smart Grid costs should be classified and allocated in the rate design process.[10]

[10] Regulatory Assistance Project, Smart Rate Design for a Smart Future, 2015.

Demand charges as a price signal

Imposition of demand charges runs counter to the ratemaking principles of simplicity, understandability, public acceptability, and feasibility of application. It's a formidable task to try to train millions of customers in the meaning of billing demand, the factors driving it, and how to control and manage it. Indeed, RMI (2016, p. 76) notes "[w]hile it's possible that, if customers are sufficiently educated about a demand charge rate, they will reduce peak demand in response, no reliable studies have evaluated the potential for peak reduction as a result of demand charges." The same RMI report indicates that time-varying energy charges are more effective at reducing peak demands than are demand charges.[11] Additionally, the Brattle Group reported a peak load reduction of less than **2%** for residential demand charges, compared with reductions as great as **40%** for critical peak pricing energy rates.[12]

The examples given in Appendix B show no pattern that a customer might be able to manage in advance — which is the knowledge required in order to control a peak demand occurrence. In part this is due to a mix of appliances that are set to turn on and off automatically as needed (e.g. air conditioning, hot water heaters, refrigerator) and others that are under the control of the home or small business owner (e.g. lighting, hair dryers, kitchen appliances, television). Without sophisticated load control and automation devices, it is unclear how small customers could manage peak loads. Without installation of such load control technology, a demand charge is not an effective price signal. Importantly, a charge like a demand charge is only a price signal if the customer can respond to it. If not, it becomes an unmanageable fixed charge with a substantially random character.

Indeed, large residential customers with many appliances (e.g. swimming pool heaters and pumps) that have higher load factors may benefit from demand charges as cost recovery is shifted to a charge based on a single peak demand from demand-related costs being applied against every kWh. This has been true with the larger commercial and industrial class as well. Conversely, low usage customers — including low-income customers — would likely pay more on average.

The Bonbright Criteria

Professor Bonbright's famous 1961 work, Principles of Public Utility Rates, outlined eight criteria of a sound rate structure. It is useful to consider how demand charges fare under these criteria and the following summary addresses each criteria.

1. **The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.**

   Simplicity: While the demand rate itself can be viewed as simple — a single charge applied to a single parameter — the concept of demand integrated over a short time frame (e.g. 15 minutes or one hour) is not simple and requires customer education.

   Understandability: The application and management of demand rates is likely to be difficult because customers cannot easily manage the demand in the short time intervals typically applied to demand charge rate design.

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[11] A Review Of Alternative Rate Designs Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers; Rocky Mountain Institute, May 2016 download at: www.rmi.org/alternative_rate_designs

[12] Presentations of Ahmad Faruqui and Ryan Hledik, EUCI Residential Demand Charge Summit, 2015.

Public acceptability: Demand charges are not likely to be readily accepted by small customers for the reasons outlined above. Indeed, for most consumers they will just seem like another fixed charge. (See Arizona Public Service Company case study below.)

Feasibility of application: While technically feasible, new metering is required. The likely metering technology is smart meters that can also be used for more appropriate time-varying rates (although some claim the smart meter only estimates the peak demand). As noted above, it is not clear that customers can respond to demand charges; for many utilities, the attraction of demand charges for small customers may be that customers will not be able to avoid them.

2. **Freedom from controversies as to proper interpretation.**

   Proper interpretation of demand charges will be difficult for customers who don't have the behavioral or technological ability to understand, prepare for and manage peak demands in advance. This may result in misunderstandings, frustration and increasing complaints. A utility should be able to demonstrate that the smallest customers currently on demand rates understand their bills, before applying demand charges to still smaller customers.

3. **Effectiveness in yielding total revenue requirements under the fair-return standard.**

   Rate structures that establish an effective relationship between billing parameters and cost causation are reasonably likely to yield total revenue requirements following implementation. However, it is clear that individual maximum demands for small customers are very diverse and rarely occur at the time of maximum system demand. To the extent small customers are able to respond to the demand price signal, they may move their peak load from a less costly time of day to a more costly time of day, and their measured demand (and the associated revenue) may vary sharply from month to month as different appliances happen to be used simultaneously generating the measured demand upon which the charge is based. Thus the link with cost causation is weak, and achieving total revenue requirements is more at risk.

4. **Revenue stability from year to year.**

   Similarly, the weak cost causation link can cause instability as a significant portion (often 60% or more) of a small customer's revenue is dependent on the relative stability of a single 15 minute or one hour period during the entire month. Customer peak demand, particularly for air conditioning customers, is highly temperature sensitive, so mild summers may result in severe undercollection of revenues.

5. **Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")**

   Here, too, it is unclear whether demand charges for small customers will be stable over time, but given the volatility of small customer loads, bills may lack stability. If small customers are unable to respond to the demand charge price signal, then the demand charge will act as a fixed charge and the *rate* would likely be stable. If over time small customers are able to use technologies or behavioral changes to reduce maximum demands, utility revenue may drop significantly and the rate will need to be increased to recover allowed revenues, and thus will be less stable. This paradoxical situation results in the shifting of costs from those able to manage peak loads to those who are unable.

6. **Fairness of the specific rates in the apportionment of total costs of service among the different customers.**

   As pointed out above in comparing customers of different sizes (see for example the apartment dwellers discussion), small customers tend to have lower individual load factors, i.e. higher peak demands relative to their energy consumption, but higher collective group load factors (which drive utility capacity needs). In fact, lower use customers tend to have less coincidence of their individual peak demands with the system peak demand. As a result, demand charges paid by these customers would be associated with a time period that is not correlated with cost causation. This would place an unfair burden on small customers.

7. **Avoidance of "undue discrimination" in rate relationships.**

   As above, the lower coincidence of individual peak demands of lower use customers with system peak loads should lead to lower charges or bills, but applying the same demand charges to the customer's peak demand whenever it occurs would generate high charges and bills, thus discriminating against low use customers.

8. **Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:**

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on peak versus off peak electricity, Pullman travel versus coach travel, single party telephone service versus service from a multi party line, etc.).

As noted in the body of this paper, in addition to a lack of coincidence with cost-causing system peak loads, demand charges (particularly NCP demand charges) are generally not actionable for small customers. Thus the small customer cannot respond to this "signal" in any meaningful way that might result in lower utility costs.

More importantly, there is evidence that small customers can and do respond to price signals based on energy charges that vary by time or usage. Shifting cost recovery from energy charges to demand charges reduces the customer's incentive to reduce consumption, and results in an inefficient use of resources.

Finally, the authors of this paper support the concept of **customer agency.** In other words, the customer should have choice, control, and the right of energy self-determination. Demand charges without associated technology to control demand tend to act as fixed and unavoidable charges, and will have the effect of reducing the variable energy rate. These rate changes can significantly diminish the incentive for customers to reduce energy consumption through behavioral changes, energy efficiency technologies, or distributed generation resources and result in increased fossil fuel emissions.

Arizona Case Study

While no regulatory Commission has approved mandatory demand charges for residential customers in recent memory, this has not always been the case. A real world example is Arizona Public Service Company's (APS) residential demand rate. APS has an optional demand charge residential rate, which has been in effect since the 1980s and currently has about 10% enrollment. The customers who self-select onto this rate design are those whose usage patterns benefit from this rate option; others choose a TOU rate or an inclining block rate. The Company assists customers in identifying the lowest cost rate option for their individual usage patterns.

In a 2015 case study performed by APS, the utility explains that its optional residential demand rate "helps customers select the best rate at time of new service through [its] website rate comparison tool."[13] An examination of the relative size of residential customers that have self-selected onto the demand rate reveals that they have an average monthly consumption nearly three times the average monthly consumption of customers on the default rate.[14]

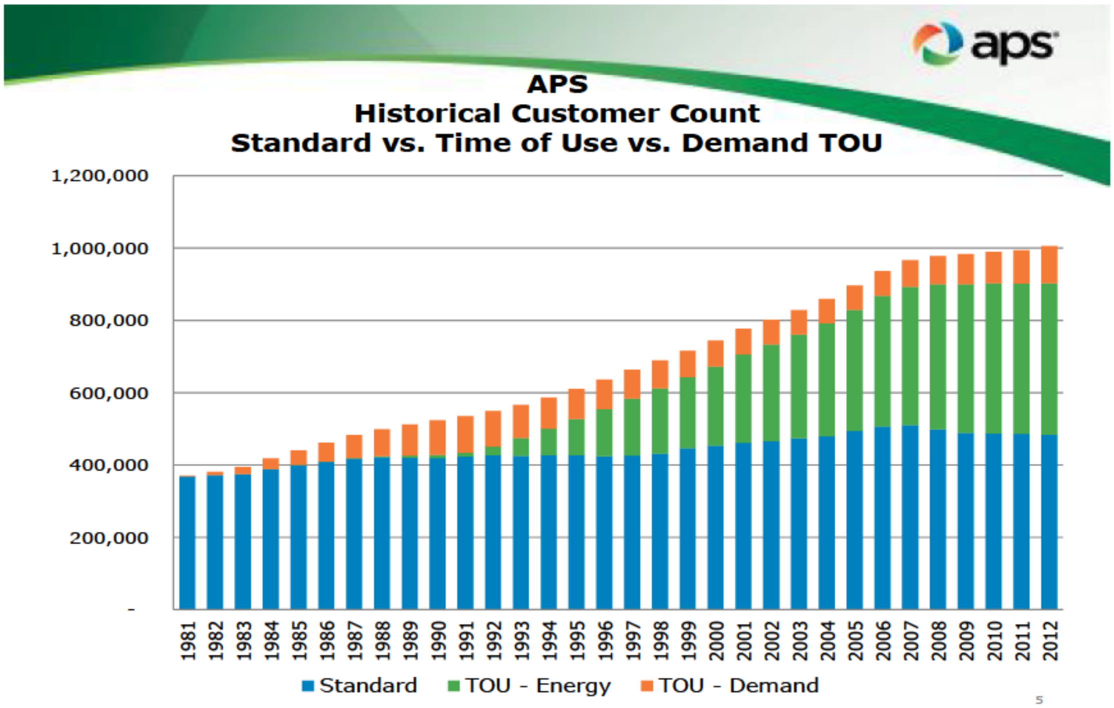
There is important history here. In the late 1980's, as the Palo Verde nuclear plants came into service and APS rates increased sharply, the ACC implemented inclining block default rates. The company opposed this at the time, but found a work-around for large-use customers, the demand and TOU rates. The demand and TOU rates have no inclining blocks (there are no barriers to implementing both together, but Arizona has not done so), so it is a way for large-use customers to avoid the higher per-unit price for higher unit that the Arizona Corporation Commission (ACC) created in with the inclining block rate design. The Company markets the demand rate only to large-use customers who they think will benefit. Many of these customers have diverse loads behind the meter, and can benefit from a demand charge if they have (or can shape) load to take advantage of the rate design, and evade the inclining block rate. Some install demand controllers to ensure their water heaters or swimming pool pumps turn off when the air conditioning turns on.[15] So it is a self-selected subclass of customers with above-average usage, and above-average diversity. Results from this subset should not be presumed to reflect behavior or experience of other subclasses.

Use of the rate comparison tool for self-selection infers that those APS residential customers who have chosen to take service on the demand rate did so because it would lower their bills without any modification in consumption patterns. Current enrollment in APS's optional demand rate does not imply that customers in APS's territory have the ability to respond to the price signal set by demand charges. Indeed, since the customer has no way of knowing when they have hit their peak demand, it is unclear if there is even a price signal being sent. To the contrary, the fact that APS has marketed its optional demand charge rates for upwards of three decades with only 10% current enrollment demonstrates that 90% of APS's customers have either not gained an understanding of how the demand charge rate would impact them, or they have decided that the demand charge rate is not the best option for them.

[13] Meghan Grabel, APS, *Residential Demand Rates: APS Case Study* 3 (June 25, 2015), *available at* http://www.ksg.harvard.edu/hepg/Papers/2015/June%202015/Grabel%20Panel%201.pdf.

[14] *Id*. at 7.

[15] See, for example, http://www.apsloadcontroller.com/ or www.energysentry.com for examples of devices that cost



In a recent rate proceeding, APS revealed that as many as 40% of its customers that recently switched from a two part rate to the optional demand charge rate actually increased their maximum on-peak demand. This means that even among the customers that self-selected onto the demand charge rate (mostly to save money relative to the inclining block standard rate), 40% did not respond to the demand charge price signal in their optional tariff.

It should be noted that APS's current optional residential demand charge tariff was originally approved by the ACC in October 1980 as a mandatory tariff for new residential customers with refrigerated air-conditioning. However, the Commission removed the mandatory requirement less than three years later, noting the change was "in response to complaints that the mandatory nature of the EC-l rate produced unfair results for low volume users." In addition, the Commission stated that removal of the mandatory demand charge would "alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-l rate."

Appendix A: Additional References

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Regulatory Assistance Project
- Smart Rate Design for a Smart Future: https://www.raponline.org/document/download/id/7680
- Designing DG Tariffs Well: http://www.raponline.org/document/download/id/6898
- Use Great Caution in the Design of Residential Demand Charges: http://www.raponline.org/document/download/id/7844
- *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs: http://www.raponline.org/document/download/id/7361*
- *Time-Varying and Dynamic Rate Design: http://www.raponline.org/document/download/id/5131*

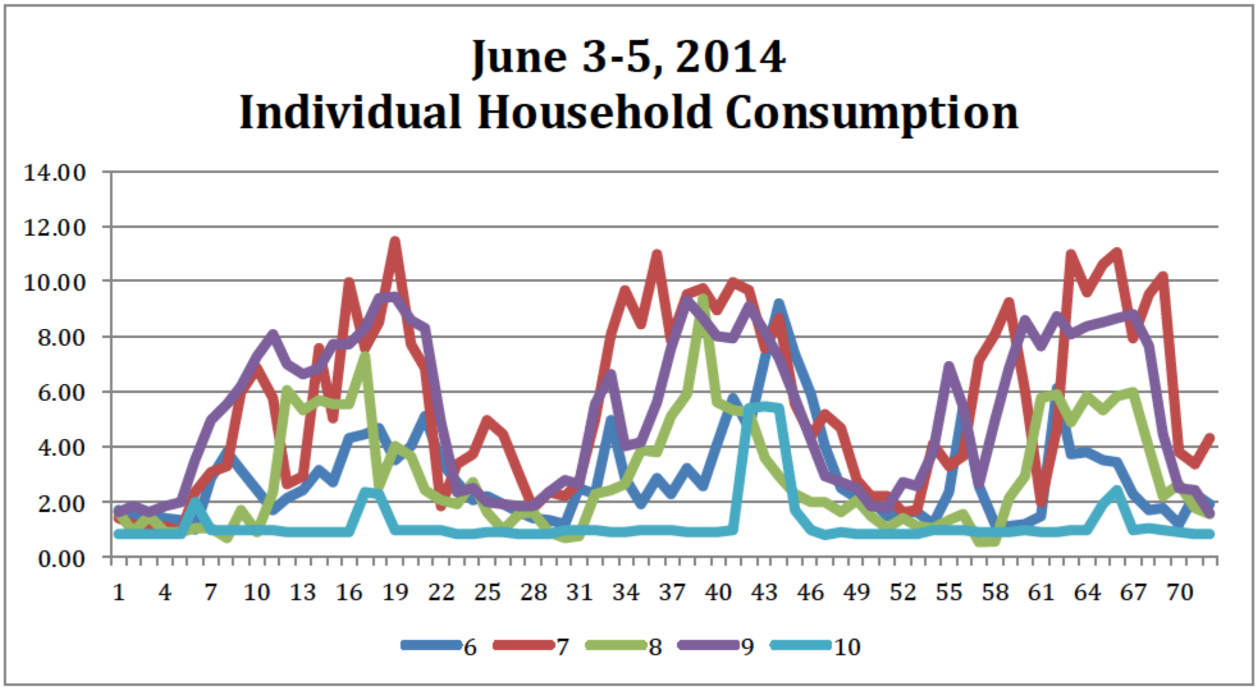
Rocky Mountain Institute
- A Review of Rate Design Alternatives: http://www.rmi.org/alternative_rate_designs

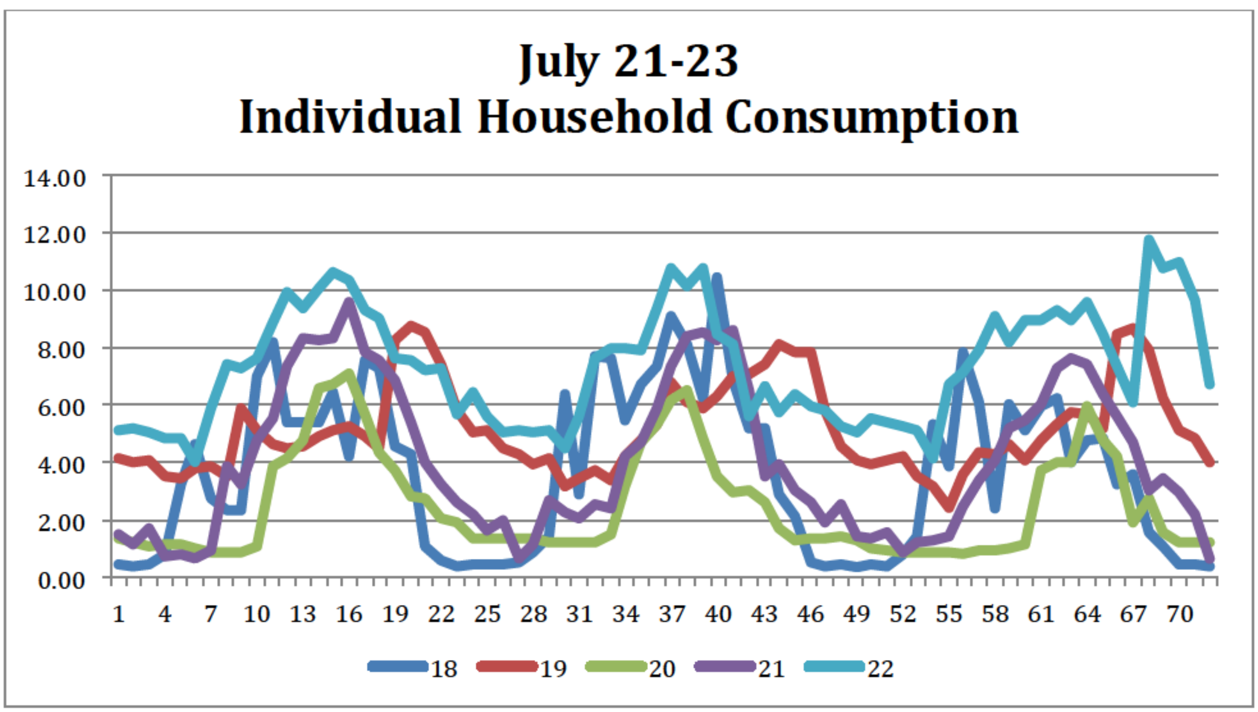
Appendix B: Sample Individual Residential Customer Loads

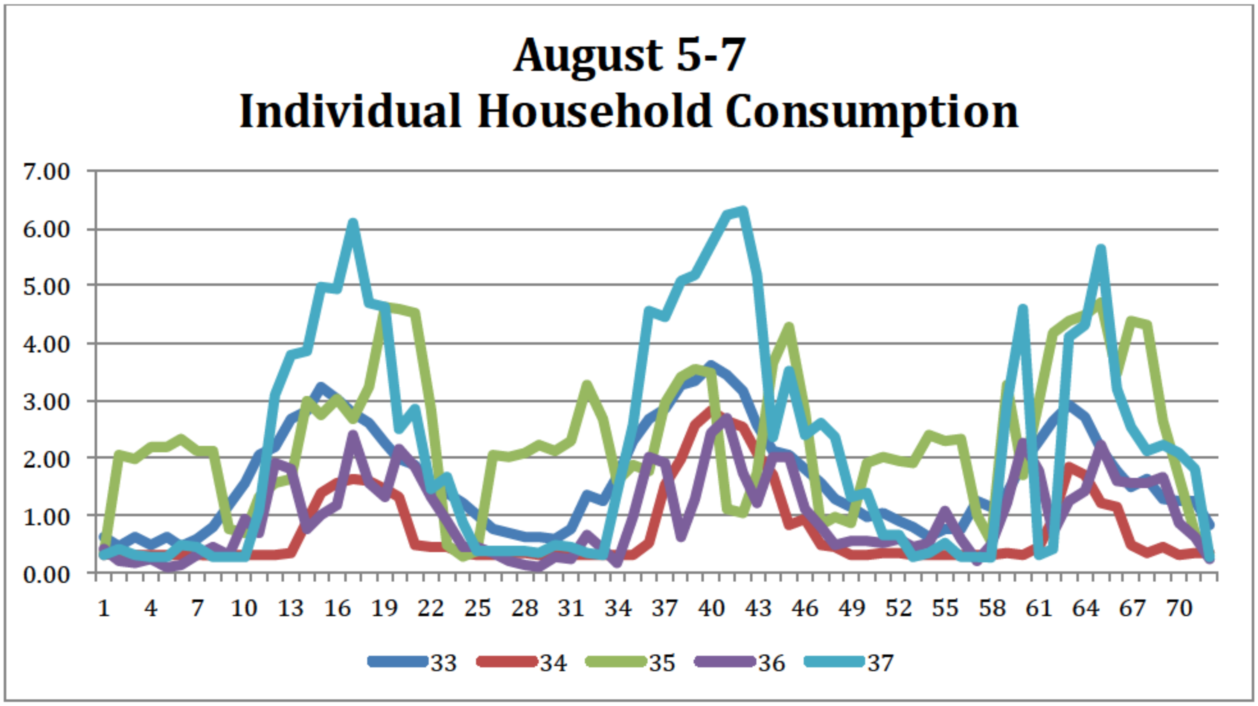
<u>New Mexico</u>

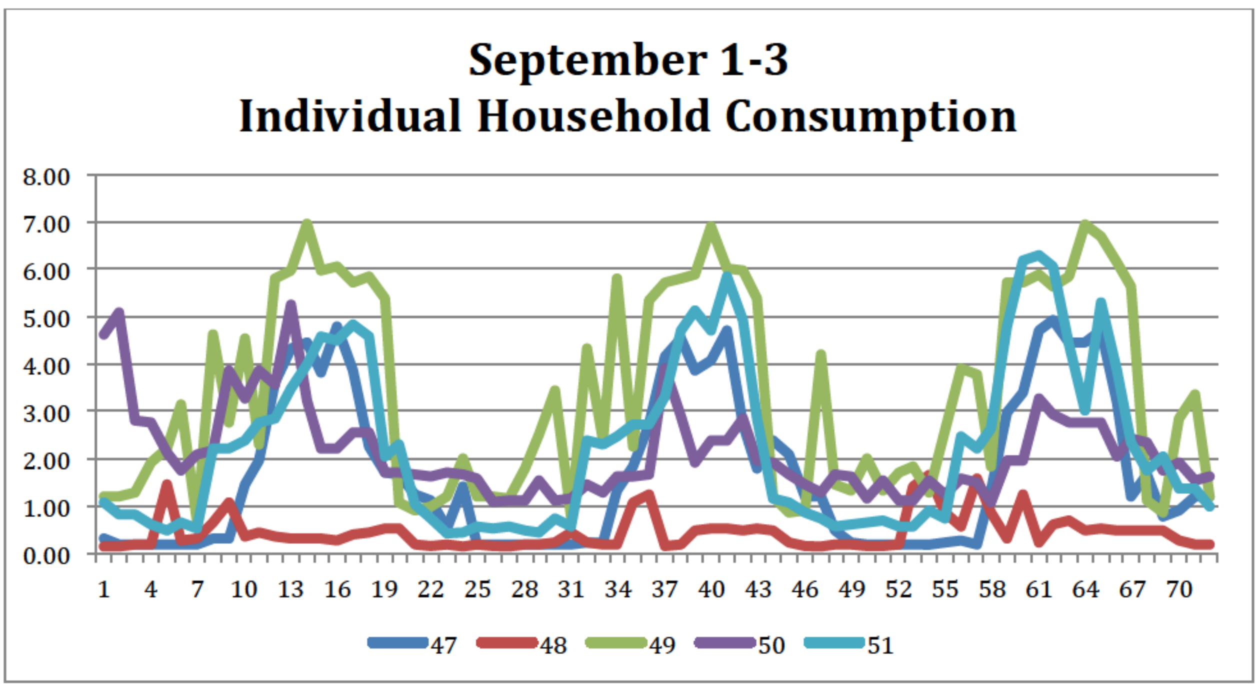
Four summer peak periods; three days and five customers per chart

(middle day is system peak day)





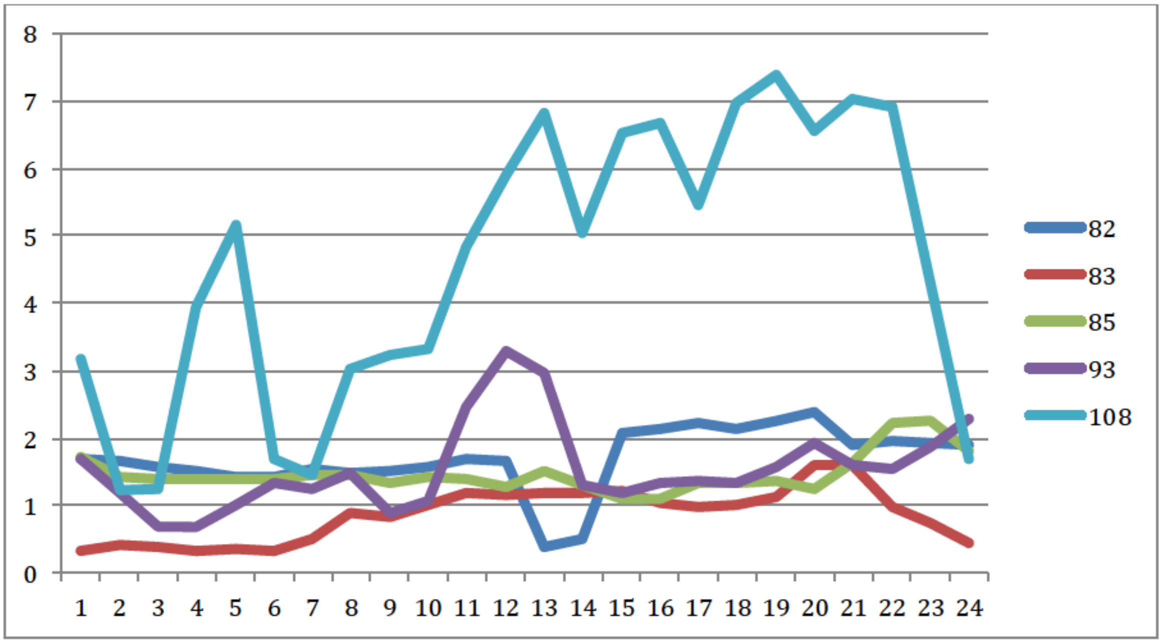

August 5-7
Individual Household Consumption
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
33 34 35 36 37


September 1-3
Individual Household Consumption
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
47 48 49 50 51

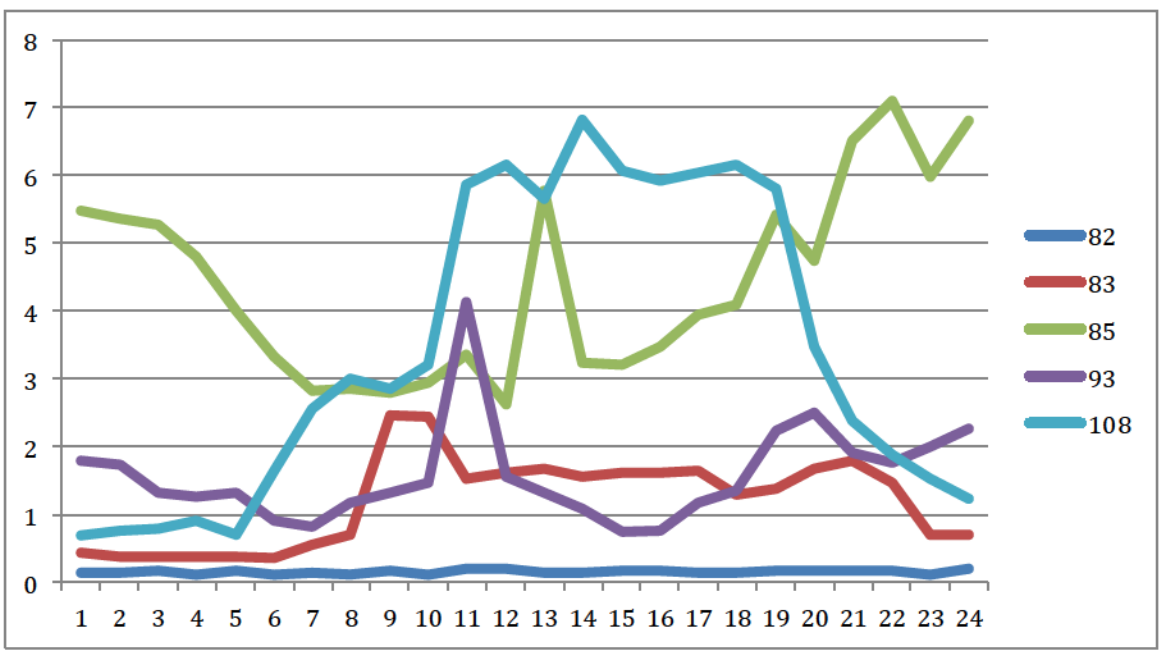
Colorado

Four summer peak days; five customers per chart

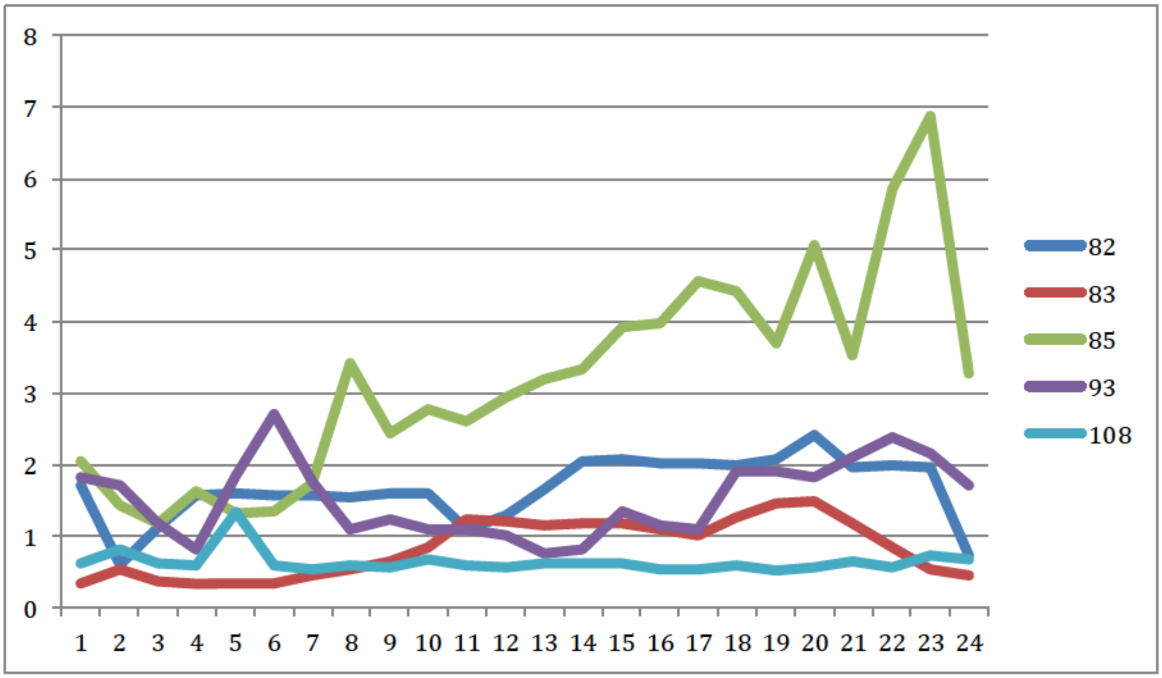
June 27, 2013



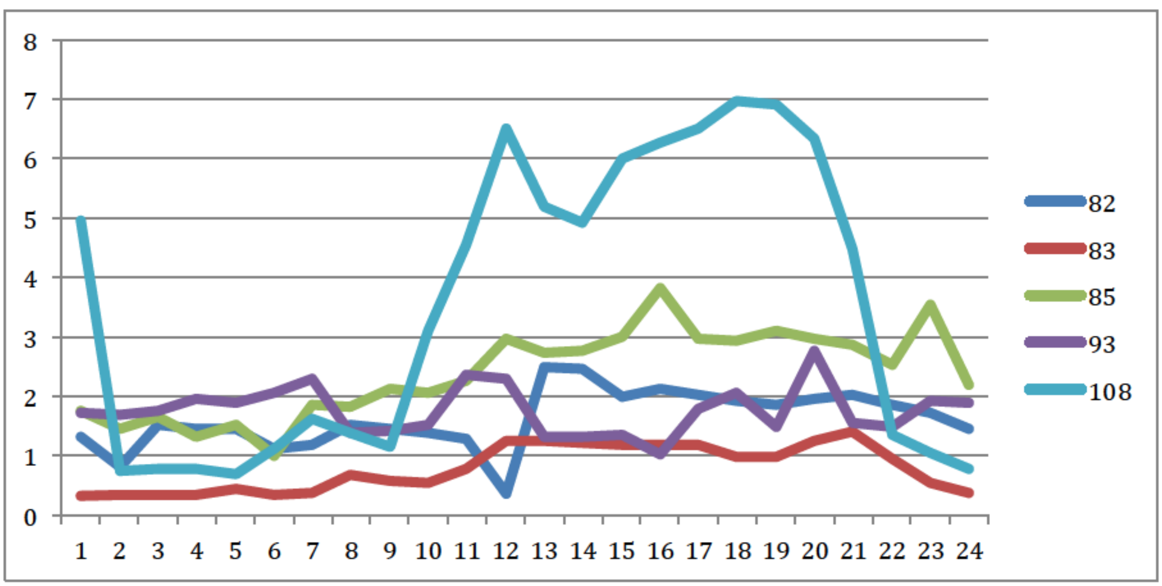
July 11, 2013



August 20, 2013



September 6, 2013



ATTACHMENT – 4

The Two-Part Tariff

Author(s): W. Arthur Lewis
Source: *Economica*, New Series, Vol. 8, No. 31 (Aug., 1941), pp. 249-270
Published by: Wiley on behalf of The London School of Economics and Political Science and The Suntory and Toyota International Centres for Economics and Related Disciplines
Stable URL: https://www.jstor.org/stable/2549332
Accessed: 05-03-2020 19:39 UTC

The Two-Part Tariff

By W. Arthur Lewis

Two-part charging has made steady progress in this country since it was first suggested in the later years of the nineteenth century. In the electricity industry, where it was first adopted, the system is now almost universal; it has been adopted by the Central Electricity Board, which controls wholesale distribution, and strongly recommended to retail distributors by two committees reporting to the Electricity Commissioners. In 1921 it was applied to the telephone system, where it is now the principal method of pricing. Gas legislation has been specially altered to permit undertakings to use the system, and they were adopting it with some zeal in the years immediately preceding the outbreak of war. In industry at least one concern has been using the system for some forty years. Yet despite this progress the principles of two-part charging are not widely known or understood. Much of the literature is obscure, some aspects of the subject have never been fully treated, and even where there is agreement among the better writers, their conclusions have not yet seeped through to all the persons responsible for drawing up these tariffs. A further survey of the subject does not therefore seem inappropriate.

The essence of two-part charging is that the consumer is called on to pay two charges, one which varies directly with the amount of the commodity that he consumes, and another which does not. Thus the Post Office charges for the use of the telephone (1) a quarterly rental, payable whether any calls are made or not, plus (2) a charge for each call. Similarly for electricity one may be asked to pay a fixed charge depending on e.g. the size or rateable value of one's house, plus a charge per unit of actual consumption. Let us first examine the incentives to two-part charging, and then enquire how it serves the public interest.

I

The first incentive to the use of a two-part tariff is the existence of standing charges which continue whether a firm is operating or not. First, where in consequence of periodical fluctuations in demand, there are regular periods when equipment is standing idle, it is often suggested that the only "scientific" way to allocate costs to consumers is to use a two-part tariff. And secondly, even where there are no such regular fluctuations, an entrepreneur may find it profitable to use a two-part tariff in order to escape the risks of unforeseen change. Let us take first the regular fluctuations.

Most industries are subject to some degree of regular fluctuation in the demand for their products: at some times business is brisk, at others it is slack. The cycle may be diurnal—restaurants, buses and shops have regularly each day hours of peak demand and hours of almost idleness—or it may be weekly, or seasonal, or like the trade cycle it may extend over several years. Where the product can easily be stored, these fluctuations in demand need not induce similar fluctuations in production; the plant can work continuously throughout the year, storing in the slack period the excess output which will be required at the peak. If the product cannot be stored, or the cost of storing it is prohibitive, the result is different; the plant must be large enough to meet the maximum demand, and when demand slackens, equipment lies idle. It is then necessary, in computing marginal cost, to distinguish between supplies produced at the peak, and those produced at other times. If the plant is of equilibrium size, it is necessary, in order to produce additional supplies at the peak, to provide additional equipment; marginal cost at the peak is high, and may be nearly equal to, or even greater than, average cost. But in the slack period no additional equipment is necessary, and marginal cost is correspondingly less.[1] If the cost of storing the commodity were less than the difference between these two different marginal costs, it would pay to store, and production would be continuous; cost of storage is prohibitive when it exceeds this difference.

The conclusion that the whole of the standing charges

[1] Undertakings frequently rely on their slack periods for overhauling equipment, making new plans, or just resting. Compensation for this must be included in computing marginal cost in slack periods. In the limiting case, where all the slack time and equipment are taken up in this way, marginal cost is the same as at the peak.

is to be allocated to peak output may seem at first to conflict with the doctrine that such charges are a joint cost of peak and slack periods which cannot accurately be divided between them. But this is not so. Let us take the analogous case of growing cotton to produce seed and lint. If there is a good demand for both these commodities it is impossible to allocate the cost between them: demand alone will decide what part is to be contributed by each. But suppose that there is a very strong demand for lint and only a very small demand for seed, such that in the equilibrium situation more seed is produced than the market will take at any price above zero; then the whole cost will be contributed by, and is attributable to the production of lint. Similarly with production in peak and slack periods. If a mere lowering of price in slack periods stimulates demand sufficiently to keep equipment fully occupied at a price greater than zero, no exact allocation of costs is possible as between peak and slack. But when some equipment must lie idle in the slack period, the whole cost becomes attributable to peak output.[1]

The suggestion that under these conditions the appropriate method of charging is to use a two-part tariff we owe to an English engineer, Dr. John Hopkinson, who became consulting engineer to the first Edison electric power stations in this country, and subsequently Professor of Electrical Engineering at King's College, London. For his presidential address to the Junior Engineering Society in 1892 he chose as subject "The Cost of Electric Supply".[2] The paper begins by stressing the fact that costs are determined by peak demand, goes on to analyse the various elements of fixed and variable cost, and concludes:

> "The ideal method of charge then is a fixed charge per quarter proportioned to the greatest rate of supply the consumer will ever take, and a charge by meter for the actual consumption."[3]

According to this principle it is necessary to discover for each consumer not only how much he consumes during the

[1] The standing charges to which we are referring in this section are not overheads in the sense of costs which do not vary with output. They are costs which increase if peak output increases, and which in the long run can be reduced if peak output is reduced; i.e., they are part of long run marginal cost. True overheads, which do not vary with peak output, are joint costs which cannot be allocated. But such costs are rare.

[2] First published in the *Transactions* of the Society, Vol. III. Reprinted with other papers by Hopkinson in his *Original Papers*, Vol. I.

[3] *Original Papers*, p. 261.

quarter, but also what is his maximum rate of consumption, defined as the largest amount taken in any small period, e.g. half an hour. Since the equipment of the concern depends on its maximum output in a short period, the consumer is made to pay a fixed charge depending on his maximum in a short period. A similar idea underlies the "Wright" rates offered by some concerns—a type of quantity discount whose gradations depend upon the maximum rate of consumption of the individual consumer.

This conclusion was hailed as a great discovery, and made the basis of many tariffs. Unfortunately it was based on a simple confusion. It is true that it costs a station more to supply 1,000 units if they are all to be taken in one minute than if they are to be spread over a longer period; but this applies to the aggregate output of the station, and not to supplies to the individual consumer. What is true of the individual consumer is that the cost of selling to him is greater if he buys during peak periods than if he buys during slack periods (unless there is excess capacity even at the peak). If therefore he takes 24 units all in one minute during the slack period it may cost less to supply him than if he takes 24 units at the rate of one unit per hour, because in the latter case he adds to capital costs at the peak. The maximum rate at which the individual consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak.

This point is now generally accepted among the better writers on the subject, but the persons actually engaged in framing tariffs (they are usually engineers) do not seem to have mastered it yet. A recent survey of the tariffs of the larger electricity undertakings show 34 per cent. offering to industrial consumers two-part tariffs based on individual maximum demand, and a smaller percentage offering such tariffs to domestic consumers.[1] They have also been recommended by a committee reporting to the Electricity Commissioners,[2] and adopted by the Central Electricity Board. Gas engineers, indeed, have gone so far as to suggest for their product two fixed charges based on individual maximum demand, one to take account of the production peak, and one for the distribution peak. Since gas can be stored, the two peaks do not coincide. The

[1] D. J. Bolton, *Costs and Tariffs in Electricity Supply* (1938), pp. 117 and 136.

[2] *Report on Uniformity of Electricity Charges and Tariffs* by a Committee appointed by the Electricity Commissioners (1930), paras. 119, 136.

volume of output produced varies not from hour to hour, but from season to season, the size of the plant being determined by the greatest demand in any twenty-four hours. But the calls on the distribution system vary from hour to hour. Two fixed charges to cover the standing costs of production and distribution, a third to cover " customer " costs (discussed in Section IV of this paper), and a variable to cover prime costs, would give the industry a four-part tariff—such are the heights to which this sort of analysis leads!

Hopkinson himself seems to have been a little uneasy about all this, for he added:

> " In fixing the rates of fixed charge it must not be forgotten that it is improbable that all consumers will demand the maximum supply at the same moment, and consequently the fixed charge named might be reduced or some profit be obtained from it."[1]

This however merely added to the confusion. For subsequent writers professed to meet the difficulty by introducing the concept of the " diversity factor ". Since all consumers are not taking at their maximum rates at the same time, the sum of the individual maximum demands is greater than the total demand on the station at the time of its peak. The diversity factor is defined as the ratio of the sum of the individual demands to the total demand at the time of the peak. There are many theories as to the way in which this diversity factor should be used to " correct " cost allocations based on individual maximum demand; the subject has a vast literature. The latest English work on the subject, D. J. Bolton's *Costs and Tariffs in Electricity Supply* (1938), contains a thirty-page chapter on the diversity factor, full of mathematical symbols, curves and principles deduced from the laws of probability, though from the tentativeness with which he puts them forward, the author himself does not seem to have much faith in them. This is as well, for no amount of correction can alter the fact that the standing costs of the undertaking are related not to the maximum rate at which the individual consumer takes, but to the amount he takes at the time of the station peak. Both the Hopkinson two-part tariff and the Wright quantity discount, based on the maximum demand of the individual consumer, are fallacious in so far as they claim to be exactly allocating to each consumer the costs he causes the undertaking to incur.

[1] *Original Papers*, p. 261.

As we have already seen, the true essence of the problem is that marginal costs are greater at the peak than at other times. To put the matter loosely, capital costs are to be allocated exclusively to consumers taking at the peak, and in proportion to the amount each takes at that time. It is not uncommon to find cases where prices are for this reason higher at the peak than in slack times. Thus transport undertakings frequently offer cheap tickets in the middle of the day, the telephone system has its cheap night rates, and there are seasonal fluctuations in shipping freights and in hotel charges . Such price differentiation is not price discrimination, or charging what the traffic will bear, for those terms in their proper meaning relate to differentiation based on differences in elasticity of demand, while the differentiation here is due to differences in marginal cost, and is just as likely, if not more so, in perfectly competitive conditions as in cases of monopoly.

Nevertheless, while we may say that the " normal " way to allocate standing charges where there are peaks is simply to charge different prices at the peak and in slack periods, it is theoretically possible to achieve the same result with a two-part tariff. If the fixed charge is based not on individual maximum demand but on individual consumption at the time of the station peak, the total charge to any consumer will be the same as it would be if he were charged different prices at different times for a consumption with the same time pattern. This method of allocating standing charges need not be confined to electricity. The season tickets offered by transport undertakings are of the same kind ; the holder is expected to travel to and from work at the peak, and makes his contribution to expenses in a lump sum ; he is then allowed to travel free at all other times, since the cost of carrying the marginal traveller at other times is negligible. Even the long fluctuations associated with the business cycle could be dealt with in this way, the consumer paying at the beginning of say every ten years a fixed sum based on his consumption during the boom. In the case of electricity the indices at present used by various undertakings on which to base their fixed charges—rateable value of the consumer's house, size of the house, capacity of apparatus installed (even individual maximum demand)—may be more or less fair bases for estimating the proportions in which different consumers take at the time of the peak; but they cannot claim to be allocating the standing charges as exactly as would a charge varying directly with consumption at the time of the peak.[1]

Yet the two-part tariff may be the best method available. Charging different prices at different times is only possible if the time of consumption can be recorded. In the early days of electricity such differentiation seems to have been out of the question because of the cost involved in installing special meters to time the consumption of the individual consumer and charge him accordingly. In these circumstances some early concerns were content to make a charge which did not vary with the hour, and which was clearly inappropriate not only because it allocated part of the standing charges to units consumed in slack periods, but also because the result of so doing was to discourage consumption in the period when marginal costs are low. Where there are regular fluctuations in marginal cost, and the timing of consumption is impracticable, two-part charging is superior to making only an undifferentiated variable charge, because off-peak consumption does not make any contribution to the fixed charge and is stimulated by the low variable. It is true that when the two-part tariff is first introduced, the low variable will also tend to stimulate peak consumption, but if there is a general increase in peak consumption, the fixed charge will be increased to meet the heavier standing charges, and will allocate them more or less correctly according as the index chosen truly reflects the proportions in which different consumers take at the time of the peak.

We must therefore conclude that as a method of cost allocation where there are peaks in demand and supply, the two-part tariff is superior to having a single undifferentiated price which discourages off-peak consumption, but inferior to charging different prices at different times, though it may sometimes be more convenient than the latter if the measurement and timing of consumption are costly. This may have been the case when electricity was first being developed, but does not seem to be so any longer. According to Bolton:

> "If one were starting *de novo* it would be an easy matter to invent a much more scientific tariff on the costs side,

[1] In addition each of these bases has its own disadvantage. E.g., rateable value is a much more arbitrary index of consumption than is even the size of the house; and charging according to capacity installed tends to discourage installations. For a discussion of this see *Report on Uniformity of Electricity Charges*, paras. 70–99.

and moreover a perfectly practical one.[1] Undertakings usually know when their peaks will occur, both locally and on the bulk supply. Tariffs would be framed to avoid these times, and for domestic loads they might be, say, 4d. a unit from 4 to 6 p.m. and ½d. all other times. A combined single-phase meter and synchronous clock could be mass produced for about 30s. to 35s., and for another 5s. the makers could probably extend the hands and put it in a bakelite case. It could then hang in the hall and show the time of day (and, incidentally, the rate of charge). An alternative method of changing the timing could be by 'ripple control', referred to at the end of Chapter VII.

"Such a tariff would require no alternatives and would save all individual assessments and charges whatsoever. It is perfectly easy to understand, particularly after all the publicity recently given to the 'shilling trunk calls' based on exactly the same principle. It represents real costs and at the same time it gives endless scope for heating, cooking, etc., at competitive figures for all times outside the narrow high price zone. However, such ideals (if ideal they are) must be reserved for some brave new world, since the timid old one has chosen other methods and is too fearful of change to be likely to give them up."[2]

II

To conclude that two-part charging, using any of the usual bases for calculating the fixed charge, is an inferior method of cost allocation, is not, however, to conclude that it is either an undesirable or an unprofitable method of recovering the standard charges. It may be a method by which a firm protects itself against the risks of unforeseen change.

Let us suppose that an entrepreneur is deciding to invest capital in the form of durable equipment in a certain industry. In doing this he runs the risk that his expectations of the future may be frustrated; if there are new products, new rivals, new inventions, or other unfavourable changes, he may be unable fully to recover the money he is investing.

[1] The author adds the cryptic footnote: "I.e. it would work, and in fact has worked. But this is not to say that it would be more satisfactory, in practice, than our present schemes. Experience in Paris suggests that it might not, and anyhow it is far too large a question to be discussed in a sentence."

[2] *Op. cit.*, pp. 208–9.

How is he to protect himself against the risk of such changes? From his point of view, the most satisfactory arrangement might be to avoid all risk by getting each potential consumer to pay in advance some proportion of the sum invested. If in the aggregate consumers contributed sums sufficient to cover the capital invested, the entrepreneur would be relieved of all risk of loss. Nevertheless, much as this arrangement might please the entrepreneur, it would be unlikely to please the consumer, who is reluctant to pay in advance for services which he may never use. If this method proved impracticable, the entrepreneur might try as his next best course to get each user to contract to take a minimum quantity of the product, or if payment is by monthly subscription, to subscribe for a minimum number of months—this is a common feature of telephone, gas, electricity and other undertakings. Failing this, the entrepreneur may try to protect himself by securing exclusive contracts, the customer promising not to use the services of any rival undertaking. The list of concerns using such contracts is large; it includes the railway companies, who offer special "agreed charges" to clients who send all their traffic by rail, liner conferences who offer a "deferred rebate", brewers, film distributors, iron and steel concerns, a manufacturer of shoe machinery, and others. Or he may simply offer quantity discounts. All these are methods of tying the consumer to the undertaking, relieving the entrepreneur of the risk of loss due to miscalculations or to changes in demand or supply conditions.

Such devices run counter to the spirit of private enterprise. The essence of that system is that entrepreneurs are the specialists in risk-bearing. It is therefore very difficult to introduce such devices into an industry where entry is unrestricted and easy. There is usually some entrepreneur who is willing to charge the consumer per unit consumed, and to assume himself the risk that over a number of years demand will be large enough for him to recoup all his costs[1]; and where there are such entrepreneurs,

[1] Sometimes it is suggested that in very risky industries no entrepreneur will come forward unless protected either by a monopoly or by special contracts. For instance, the patent system receives some support on the ground that entrepreneurs would be unwilling to try out new inventions unless protected by a monopoly. Similarly combinations in liner shipping are said to be necessary since shipowners would be unwilling to send their ships on regular voyages unless protected against intermittent competition. There seems to be little ground for this view. In the liner case the combinations emerged because there were too many regular sailings, not because there were too few, and their effect was to reduce, not to increase the number. But this is too large an issue to be developed here.

consumers are unwilling to be tied by payment in advance or by any exclusive contract. Competitive private enterprise demands that overhead costs shall be recouped not through any fixed charge, as the theory of the two-part tariff suggests, but by inclusion in the variable charge.[1]

The monopolist, too, may meet his overhead costs simply by having a sufficiently high variable charge. But he may choose between doing so and making a fixed charge. He may have a fixed and no variable charge, or a variable and no fixed charge, or some combination of both. The risk of unforeseen change is a strong argument in favour of a fixed charge, which will throw upon the consumer any loss resulting from unfavourable change. Hence unless the entrepreneur is willing himself to bear this risk—and with it the possibility that there may be *favourable* changes—he may seek to impose such a charge. His incentive to insure himself in this way will be particularly great if his product has to face strong competition from other products. For the imposition of a fixed charge in a sense ties the customer to the undertaking, making it worth his while to buy as much as possible from that concern, rather than to divide his purchases, so that his average price may fall as low as possible.

However, the power of the entrepreneur to secure himself in this way depends on the attitude of consumers and on the strength of his monopoly position. It may well be that if a fixed payment is demanded some consumers who are not certain how large their consumption will be will refrain from buying at all. Thus a recent survey of gas undertakings in Great Britain which offer consumers the alternatives of a two-part tariff and a single variable charge shows that a large percentage of those who would benefit by switching over to the two-part tariff fail to do so. Ignorance of the advantages of the two-part tariff may account for this to some extent, but it is also probable that some consumers prefer to remain on the ordinary tariff because they are uncertain how large their consumption is likely to be, and unwilling to commit themselves to the payment of a

[1] Sometimes part of the "overheads" can be traced to some particular consumer. For instance, a firm may generate its own electricity, but may also connect itself to the public service as an insurance against breakdowns. Where the public station has to instal extra plant as a reserve against this contingency it will make a fixed charge to the firm whether it takes any electricity or not. But in these cases the "overhead" is not an overhead at all; it is a cost directly attributable to the particular consumer, and would not be incurred but for the undertaking to serve him; it is a "customer" cost, as defined in section IV of this paper.

fixed charge.[1] Where this is an important element, there must be no fixed charge or only a low one, or alternatively consumers must be permitted to choose between a two-part tariff and an ordinary one. Note however that in some cases the element of risk may work the other way. A potential customer may say, "I am unwilling to take this commodity on the basis of so much per unit because I am uncertain how much my family and I will take from time to time, and I may find at the end of the year that we have run up a tremendous bill; I would prefer you to quote me one lump sum charge, and then let us take as much as we like." If the commodity is a new one, or subject to large and unpredictable variations in demand (e.g. one's demand for medical services) the risk element may well favour the imposition of a high fixed charge with a very low or no variable.

In sum, we can see that there is much more in the analysis of standing charges than meets the eye. To the economist, brought up on the analysis of competitive markets, what to do about such costs presents little problem; they go into a variable charge, fluctuating with demand. To the public utility engineer, impressed by the fact that these are fixed costs not diminishing with output, the ideal charge is a fixed charge. Either of these may be the more profitable solution in any given case, but each case must be considered on its own merits.

III

So much for standing charges and their relevance to two-part charging. In the literature of the subject this is the topic most often mentioned, but there are other incentives to two-part charging which we must now examine.

The first point to be considered is that it may not be worth while making a variable charge if the cost of measuring the amount taken by each consumer is high. In the early days of electricity and of the telephone, before simple recording devices were invented, consumers were for this reason charged a lump sum independent of use. Similarly in some countries it is considered that the cost of installing water meters in each house, and reading them periodically, would not be justified. This argument is most forceful

[1] See P. Chantler, *The British Gas Industry*, pp. 127–130.

where elasticity of demand is not very high, so that consumption is not much greater if unmeasured than it would be if it were measured and charged for. If elasticity of demand is high, and marginal cost high, the argument loses its force.

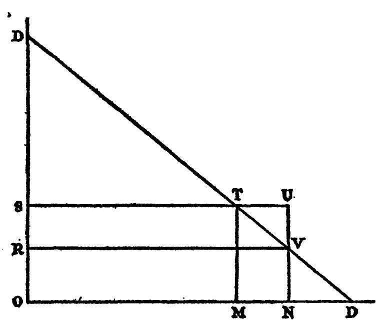
Another point in favour of having a fixed charge is that it may make it possible for the firm to extract some of the "consumer's surplus". The extent to which this is possible depends on the income elasticity of demand for the commodity. If income elasticity is zero, then when a fixed charge is imposed, so long as it is not so high that the consumer ceases to buy altogether, he will buy the same amount at any given marginal price as he would have bought if there were no fixed charge; he will therefore be paying a higher average price for any given quantity than he would be prepared to pay if there were only a variable charge. The effect of the two-part tariff is as it were to shift his demand curve to the right.[1] But this is only so where income elasticity of demand is low. What it boils down to in practice is that the firm will gain from the two-part tariff if customers keep their eyes on the cost of the marginal unit rather than on the total amount spent on the commodity. If the customer watches the size of his bill rather than the marginal price the demand curve facing the firm will be substantially the same whatever system of charging it may use. This point is not always understood. Thus it is sometimes suggested that the success of the two-part tariff is proved by the fact that sales expand when a firm adopts it.[2] But this view is fallacious. If the fixed charge is small, the effect of adopting a two-part tariff is to lower the average price at which the commodity is sold. But if the firm lowered its average price without adopting a two-part tariff sales would similarly expand. The only relevant question is, if the average price had been lowered to the same extent without adopting a two-part tariff, would sales have expanded to the same or a lesser extent? For the two-part tariff is superior only in so far as it enables the firm to sell more at any given average price than it would if average and marginal prices coincided. In some cases

[1] The two-part tariff shares this characteristic with quantity discounts of the "block" type. Wherever the average charge differs from the marginal charge, the demand curve tends to be shifted to the right.

[2] E.g. J. T. Haynes, giving the results of a two-part tariff at Rotherham, makes this claim. *The Two-Part Tariff as an Aid to Gas Sales*, pp. 23–35.

this will be so, in others where the customer concentrates on the size of his bill rather than on the marginal price the two-part tariff has not this advantage.

The fact that two different elasticities are relevant when the two-part tariff is used, income elasticity and elasticity of substitution at the margin, is important where two products are highly competitive with each other, as in the case of gas and electricity. The point is not important if one product is a substitute for the other in all uses, for then even if one industry is offering a two-part tariff with a very low variable charge, the consumer will carefully compare his probable total expenditures in using the one product or the other before he commits himself to the payment of the fixed charge. Here competition is determined not just by the marginal price, but also by the amount of the fixed charge; it is average price that counts.[1] But the position is different if each product has a use in which it is essential, and competition is limited to certain additional uses, e.g. if electricity is considered essential for lighting, and gas for cooking, but they compete for heating and other purposes. Here since the fixed charge has to be paid anyway, only the marginal price is relevant. Each industry may find it profitable so to reduce its variable charge that it only just covers marginal cost. It is easily shown that it will not pay to go below marginal cost. Thus in the following diagram, if *DD* is the demand curve, *OS* the marginal cost,



and income elasticity is assumed zero, the maximum consumer's surplus which can be extracted from this particular consumer by way of fixed charge is the area *DST*. If the

[1] If after making the comparison the consumer chooses the product using the two-part tariff, he will become tied to the firm, which will then profit if there should be unforeseen change unfavourable to him. But this is a separate point which we have already discussed in the preceding section of this paper.

firm made a variable charge less than OS, say OR, the consumer would demand ON, and the firm's net revenue would be a maximum of DST minus TUV, the fixed charge being increased to DRV. If the variable charge is to go below marginal cost, it must be for some reason other than consumer's surplus, such as the reasons already mentioned. Now marginal cost is not the same as prime cost; it includes all costs which vary with output. In the long run most costs, including equipment and expenses of management, vary with output, and this must be remembered in appropriate circumstances. In the limiting case all the firm's costs are marginal costs, to be recouped through the variable charge, and if it is subject to strong competition the firm will be unable to tap consumer's surplus by levying a fixed charge. In general a fixed charge can only be levied if the firm is in a strong monopoly position, or if marginal cost is less than average cost and firms take account of this in their oligopolistic competition with each other.

Next we come to two-part charging as a form of price discrimination. The effect of making the same fixed charge to all consumers is to discriminate against the small ones. This will pay only if their demands are on the average less elastic than those of large consumers. This is not usually the case, but may be found in special conditions. Thus the small consumer of electricity may be small because he is using it only for lighting, while the large may be using it for heating, power, or other purposes for which the demand is much more elastic than for lighting. One way of meeting this situation would be not to use a two-part tariff, but to charge different prices for current used for different purposes. The two-part tariff, however, serves the same purpose; it is an alternative to rate classification.

Nevertheless it is unlikely that the ability to bear a fixed charge will be the same among all consumers. To avoid discriminating heavily against small consumers, undertakings sometimes have a different fixed charge for each consumer, varying according to the rateable value of his house, the number of rooms, or some similar index. This has indeed the advantage that the fixed charge can be made to increase so rapidly that in effect larger consumers are made to pay higher average prices per unit than smaller consumers, if the smaller are thought to have the more elastic demands.

To avoid frightening off the smaller consumers it is also customary to offer as an alternative to the two-part tariff a single variable charge, somewhat higher than the variable charge of the two-part tariff; the latter is then used only by larger consumers. Or the firm may offer not a two-part tariff but a "block" quantity discount; e.g. it may say, "for the first 20 units, 6d. per unit, additional units at 1d. per unit". This is not so hard on the small consumer, while for the consumer of more than 20 units it has the same effect as a two-part tariff in that the average price differs from the marginal. Here too the size of the first block may vary from consumer to consumer.[1]

Finally, the whole of this discussion so far has been based on the tacit assumption that price discrimination is practicable. This is of course only the case if the commodity cannot easily be transferred from those who pay a low price to those who pay a high price. Suppose, for example, that a department store tried to recoup its overhead costs by using a two-part tariff: it might for instance offer a 10 per cent. discount to any customer who pays a "quarterly subscription" of £2. It would be unlikely to continue the scheme long, because it would soon find that some people were getting goods through subscribing members without themselves paying a subscription. Unless buyers can be isolated from each other, the two-part tariff is an unprofitable method of pricing.[2]

There is, however, one exception to this rule. If a firm is selling to middlemen, a two-part tariff will enable the large middleman to produce more cheaply than the small,

[1] It has sometimes been suggested that when a firm first introduces the block quantity discount each consumer should have as his first block an amount equal to his previous consumption. But this is not an easy policy to put into effect. J. T. Haynes, who contemplated introducing it in one undertaking he controlled, explains why it was rejected: "It was then proposed that every consumer should be charged a greatly reduced price for all gas used in excess of his normal consumption. This sounded attractive, but examination revealed a number of difficulties. What was a consumer's normal consumption? A large number of typical meter cards were examined, and adjacent houses were found to have widely different consumptions, affected by the number in the family, periods of sickness, inclination or disinclination to use gas, etc. The application of the proposal in such cases would quickly create a sense of unequal treatment between neighbours, and could not be defended by the undertaking in the light of the equal conditions clauses in the Corporation's Gas Acts." See *The Two-Part Tariff as an Aid to Gas Sales*, p. 13. C. L. Paine's proposal (see his article "Some Economic Consequences of Discrimination by Public Utilities," ECONOMICA, 1937) would be even more difficult to apply than this, because it involves raising the upper price above the level of the previous price and estimating how much each consumer would have bought if this were the only price.

[2] The department store might meet this difficulty by putting a limit on the amount bought on any one subscription, say £30. But then "membership" ceases to correspond to the true two-part tariff, and becomes a means of charging a special price to those who purchase between £20 and £30.

if the fixed charge is the same to both, and perhaps to capture his business. The firm may prefer to have only a few large customers, for it may wish them to be able to form a combine to increase their own charges to the public, so that it in turn may be able to share part of their monopoly gains. Trade unionists sometimes for a similar reason urge their employers to combine. In such circumstances the firm will discriminate heavily against small customers, having a fixed charge which is very high relatively to the variable, or even dispensing entirely with the variable and allowing any customer who pays the fixed charge to take as many units as he likes. On the other hand, it is equally likely that the firm may fear that a reduction in the number of its customers might be harmful, since they may be able to combine to force down its charges. In this case it will pursue the opposite policy, discriminating not against the small middleman but against the large. Or again it may particularly want to discriminate against large purchases if the commodity is trade marked and perishable, and it wishes to maintain a reputation for freshness; or to discriminate against small purchases if it wishes to create a reputation of exclusiveness for its products (e.g. cosmetics). Any argument for reducing the number of one's retail outlets is an argument supporting the use of a two-part tariff; any argument in favour of increasing their number is an argument against having a fixed charge.

IV

We have left to the last the case for two-part charging based on the existence of "customer" costs, because, though it seems the most obvious case, to analyse it is to get a summary of the whole problem. "Customer" costs are those costs which have to be incurred if any given customer is to be served, but which do not vary directly with his consumption; such costs as equipping his house with electric wires and fittings, installing a meter and reading it periodically, keeping his account and so on; costs which vary with the number of customers rather than with output.

Suppose, for example, that an electricity concern is supplying electric current, and undertakes to wire premises and instal all necessary fittings. The cost of the installation is an indivisible item which does not vary directly with the amount of current consumed. At first sight it seems quite reasonable to make a separate charge for this, or to use a two-part tariff, basing the fixed charge on the cost of installation, or at least to offer quantity discounts for current. But this is not necessarily the most profitable policy. In suitable circumstances the firm may prefer to make only a fixed charge, supplying the consumer with as much current as he likes without any additional charge. Or on the other hand it may prefer to instal "free of charge", recouping itself for the cost of installation by having a high variable charge. Its fixed charge may be high, low, zero, or even negative (that is to say, instead of asking the consumer to pay for installation, the firm may actually pay him a "rent" for the privilege of installing its equipment on his premises). Similarly, its variable charge may be high or negative; the firm may not merely supply current free, but it may also undertake to repair the equipment free of charge (this being the equivalent of a variable negative) or pay a refund to the consumer if his consumption is large.

This problem is not confined to public utilities; it appears wherever there are complementary goods like gramophones and gramophone records, razors and razor blades, motor cars and tyres, telephone instruments and a telephone service, or other twin commodities one of which is a durable instrument which must be installed before the other can be used. If conditions were suitable a company might give away gramophones to stimulate the sale of records, or give away records to stimulate the sale of gramophones. This poses the question, what is a commodity? In the former case the company would say that it was selling records, the gramophone being only part of the cost of production; in the latter it would be the record that was part of the cost of selling gramophones. The enjoyment of any satisfaction involves a number of separate costs, some of which are indivisible, and it is a problem to decide how many of these indivisible costs are to be treated as different commodities and charged separately, and how many to be merged into a single variable charge. Nor is the problem confined to cases where all costs are undertaken by the same firm. Even if the gramophone companies are separate from the record companies, it may pay one set of companies to subsidise the other; so also it might pay motor car manufacturers to subsidise the sale of petrol, and so on. Given the complementarity it is always the same problem : how high should the fixed charge be relatively to the variable ?

We can also fit into the same category another problem which is really only a limiting case of the first. This is the case where the only cost is an indivisible customer cost. An example of this is a case where a firm leases machinery to manufacturers. There is only an installation cost, the cost of the machine. Yet the firm may charge either a fixed monthly rent, or a monthly rent plus a royalty varying with the output of the machine, or a royalty alone with no fixed rental.[1] Wherever a firm is leasing some durable commodity, the use of which is measurable, it can adopt, if it wishes, a two-part tariff as its charge. How high should the fixed charge be ?

In competitive conditions the solution is simple : the fixed charge is no more and no less than the cost of installation. But in an imperfect market this is not necessarily the most profitable policy ; then all the arguments for and against a fixed charge which we have discussed in the previous sections are once more relevant. The difference now is that we must take as our base for the fixed charge the amount of the installation cost. Arguments in favour of a fixed charge are to be interpreted as supporting a fixed charge greater than the amount of the installation cost ; arguments against a fixed charge are arguments for reducing the fixed charge below installation cost, even to zero or a negative price.

Thus the element of risk may serve to reduce the fixed charge below installation cost : consumers may hesitate to wire their premises because they are not sure that their consumption of electricity will justify the initial sum involved, so the firm may assume that risk for them. Or on the other hand it may be the variable charge which they fear, and so the firm may quote a single fixed charge, allowing them to consume as much as they please. Similarly, if potential purchasers of motor cars are deterred by the high initial cost involved, the gasolene companies might profitably subsidise the motor manufacturers, and raise the price of petrol ; but if it is the running cost which deters the pur-

[1] A well known case is that of the United Shoe Machinery Company, which leases machinery to shoe manufacturers on a two-part basis.

chaser, it will be the motor manufacturer who will profitably subsidise the gasolene company, the tyre company, the repair companies, and so on.

Similarly, where marginal costs are low and the cost of measuring consumption is high, there will be no variable charge. If the cost of producing petrol becomes small enough, car owners will be allowed all they want in return for an annual tax on their cars.

The relevance of the two elasticities is as great here as to the allocation of overhead costs. Sometimes by reducing the variable charge one can increase the amount of consumer's surplus to be obtained through the installation charge. At other times, free installation is justified, because it leads to such a terrific increase in demand for the subsidiary commodity. Discrimination, too, may justify either a high installation and low variable charge, if for instance demand is less elastic in some uses than in others ; or a fixed charge less than installation cost and high variable charge, if the firm is selling to middlemen and particularly wants to have a large number of outlets, for example if it is leasing machinery and fears the consequence of a buyers' monopoly. With customer costs, as with standing charges, there is no simple solution ; each case must be weighed on its own merits.

V

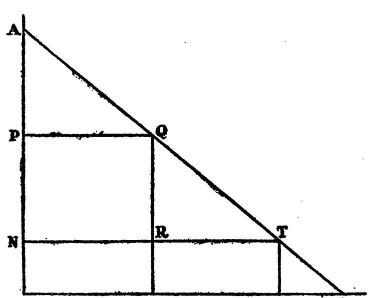
It remains to consider two-part charging from the standpoint of the public interest. We have seen that from the point of view of the entrepreneur the two-part tariff may frequently be the most profitable method of charging. Can we say that the public interest requires that the fixed charge should be exactly equal to customer cost and that anything more or less is undesirable ?

To answer this we must re-examine the incentives to making a fixed charge greater or less than customer cost. The first was that the tariff may be used as a means of allocating overheads where there are peaks in production due to peaks in demand ; we saw that it is an inferior method of doing this, even from the standpoint of the entrepreneur, but there is no substantial reason why it should not be adopted if it prove the most convenient. Secondly, a two-part tariff may be a means by which either the entrepreneur

D

or the consumer relieves himself of risk. There is nothing in this inherently contrary to the public interest; but there is some danger of abuse if the consumer is "tied" to one undertaking in competition with others. Especially is this so if the variable charge is reduced below marginal cost, for competition between undertakings must be based on marginal cost if there is to be an "ideal" allocation of resources. Or thirdly, two-part charging may be adopted where the cost of measuring individual consumptions is disproportionately great; this too does not necessarily run counter to the public interest.

When we come to the two-part tariff as a means of stimulating consumption at the margin the matter is not so simple. It is now generally agreed that the "ideal" output of a concern is such that every consumer is getting every unit for which he is prepared to pay marginal cost.[1] If marginal cost is equal to or greater than average cost, there is no case for a fixed charge; a variable charge equal to marginal cost will cover the total costs of the firm. But if marginal cost is less than average cost, a variable charge equal to marginal cost will not cover total costs. If total costs are to be covered, either the variable charge must be greater than marginal cost, or a fixed charge levied in addition to the variable. It is easily shown that it is better to recoup the difference between average and marginal cost by a fixed charge than to add it to the variable. Consider the following diagram where *AD* is the demand curve (for convenience a straight line) of a consumer whose income



elasticity is assumed to be zero, and *ON* the marginal cost on the assumption that the cost of supplying this consumer

[1] There are difficulties in applying this principle to the use of a two-part tariff by public utilities because marginal cost to the undertaking is not necessarily equal to marginal social cost; on this problem see C. L. Paine, *loc. cit.*, pp. 428–431.

is constant and there is no customer cost. Suppose that the firm was formerly charging a single price *OP* (average cost), and that it now adopts a two-part tariff with a variable charge *ON*. This consumer's purchases will then increase from *OM* to *OS*, income elasticity being assumed zero. If the amount of the fixed charge is equal to the area *PQRN*, the consumer will be better off than he was under the previous system since *QRT* will be added to his consumer's surplus. He will in fact be better off than before so long as the fixed charge is less than $PQRN + QRT$. This means that two-part charging can benefit both the buyer and the seller better than having a single variable charge, equal to average cost. The danger is that the firm may try to take the whole of the consumer's surplus, *ANT*, in which case two-part charging becomes the most perfect form of discrimination, and capable of the gravest exploitation. But provided that this danger is guarded against, two-part charging is clearly better than having only a variable equal to average cost, in cases where marginal cost is less than average cost.[1]

Next, an objection raised against two-part charging is that small consumers may have to go without the commodity because they cannot afford to pay the fixed charge. In so far as the fixed charge is being levied as a contribution to overhead costs, this is easily met by an appropriate adjustment of the fixed charge; it is not in the interest of the undertaking, any more than of the public, that the charge should be so high as to exclude anybody. But where the fixed charge is levied to cover customer costs, the objection is equivalent to suggesting that some consumers should get the commodity for less than it costs. Thus, in 1933 the Parliamentary Secretary to the Board of Trade explained to representatives of the gas industry why he would oppose any clause permitting a two-part tariff in a forthcoming Bill:

> "I am not attempting to justify the exclusion of the minimum charge from the Bill on any ground of logic or technicality. I am doing it entirely on the political

[1] Note that in these cases where marginal cost is less than average cost some writers have favoured an alternative solution, viz.: to charge only a variable equal to marginal cost, and to meet the difference by a subsidy out of general taxation. The points at issue between this solution and two-part charging involve questions of social justice rather than economics. For a discussion see, for example, C. L. Paine, *loc. cit.*, and H. Hotelling, "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates", *Econometrica*, 1938 and discussion with Ragnar Frisch in *Econometrica*, 1939.

argument that the Government are not prepared to face the opposition that would necessarily come from people in scattered places amounting to millions in total who would never understand the reasons behind a clause of this kind."[1]

An argument like this for compelling the gas industry to supply gas below cost to some consumers and to recover the loss from others does not seem to be strictly within the province of the economist.

Again, two-part charging may be used as a means of increasing or reducing the number of one's retail outlets. For example, it is sometimes alleged that one consequence of two-part charging by the United Shoe Machinery Company has been to maintain an excessive number of small shoe manufacturers. In general we may assume that it is not in the public interest to have a larger or smaller number of outlets than would emerge in conditions of perfect competition. But there is seldom perfect competition either in manufacturing industry or in retail trade. Hence the most that we can say is that the usefulness of two-part charging depends on whether or not it tends to bring about the results which would emerge under perfect competition. For example, if it is used in order to counteract monopolistic tendencies in the outlets it is in the public interest; if it is used to reduce the number of outlets in order to create an illusion of "exclusiveness", it is harmful.

The public's principal safeguard against the abuses of two-part charging is competition, which makes exploitation impossible. Where there is little competition, the abuse of two-part charging merges itself into the general problem of the control of monopoly. We cannot take up this subject here in all its ramifications. It is sufficient to point out that in the cases where the two-part tariff is most common there is already some machinery of control. In industry the outstanding case of two-part charging, the shoe machinery case, is based on patent rights; and there already exists under the patent legislation provision for the control of abuses which might well be tightened up. Elsewhere two-part charging is most common in public utilities, the price policies of which are usually subject to regulation in one way or another. Two-part charging can be of great benefit to the public; all that is needed is control adequate to prevent abuse of the power it confers on those who use it.

[1] *Joint Committee of the House of Lords and House of Commons on Gas Prices* (H.L. 24, 91, H.C. 110), 1937, para. 16.

ATTACHMENT – 5

Price Discrimination and the Adoption of the Electricity Demand Charge

JOHN L. NEUFELD

Between 1905 and 1915, as state price regulation became widespread, electric utilities in the United States faced severe competition. The primary source of electricity for industry then was not utilities but self-generation by the user in an "isolated plant." The demand-charge rate structure first became widespread during this period. The demand-charge rate structure has been interpreted as a misapplication of the peak-load pricing principle, a view which has made its popularity a puzzle. Instead it was adopted as a sophisticated mechanism which institutionalized profit-maximizing price discrimination given the competition from isolated plants.

The development of the U.S. electric power industry and its pricing policies have often been shaped by the structure of the markets in which it operated. Electric power companies historically faced stiff competition from substitutes for centrally generated electricity. For example, the market for artificial lighting was originally served by gas companies, and Edison's initial pricing policies were based not on his production costs but on the cost to his potential customers of gas lighting.[1] Another competitor to electric utilities, whose importance eclipsed that of gas lighting, was the self-production of energy by an electricity user through the operation of an "isolated plant" on his premises. Isolated plants were long the dominant source of electricity for the industrial class of consumers, whose use of electricity significantly altered American manufacturing.[2] As the movement for state regulation of utility rates developed, from roughly 1905 to 1915, the U.S. electric utility industry organized itself to institutionalize the demand-

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[1] Charles E. Neil, "Entering the Seventh Decade of Electric Power," Edison Electric Institute (1912), unpaged. Material discussed here appears on the 12th page.

[2] As the electrification of industry increased, more energy was purchased from utilities. The enormous impact of electrification on American industry has been shown by Warren D. Devine, "From Shafts to Wires: Historical Perspective on Electrification," this JOURNAL, 43 (June 1983), pp. 347–72; Richard B. DuBoff, "The Introduction of Electric Power in American Manufacturing," *Economic History Review*, 2nd ser., 20 (Dec. 1967), pp. 509–18; and Arthur G. Woolf, "Electricity, Productivity, and Labor Saving in American Manufacturing, 1900–1929," *Explorations in Economic History*, 21 (Apr. 1984), pp. 176–91.

charge rate structure. Although this rate structure (explained below) had been conceived much earlier, it was only in this period that it came to be widely adopted.

Events surrounding the adoption of the electricity demand-charge rate structure shed light onto the conditions facing the electric power industry in the early part of this century and the way in which it rediscovered and applied principles of price discrimination. The issue is also of interest to economists for another reason. American economists have long advocated time-of-day or other peak-load pricing rate structures for electric utilities, but until very recently such structures have seldom been used.[3] In contrast, demand-charge rate structures became universal for industrial and large commercial customers. A demand-charge rate structure bases a user's bill on his maximum power consumption (known in the early industry as "demand") and on his total energy consumption.[4] Thus this rate structure bases a user's bill on

[3] The first publication by an American economist in this tradition probably was J. M. Clark, "Rates for Public Utilities," *American Economic Review*, 1 (Sept. 1911), pp. 473–87. The usually cited seminal works in the modern literature include M. Boiteux, "La Tarification des Demands en Point: Application de la Theorie de la Vente au Cout Marginal," *Revue Generale de l'Electricite*, 58 (Aug. 1949), pp. 321–40, translated as "Peak-Load Pricing" in *Journal of Business*, 33 (Apr. 1960), pp. 157–79; and P. Steiner, "Peak Loads and Efficient Pricing," *Quarterly Journal of Economics*, 71 (Nov. 1957), pp. 585–610. Econometricians have recently become involved with estimating the benefits from time-of-day rates. See Dennis J. Aigner, "The Welfare Econometrics of Peak-Load Pricing for Electricity," *Journal of Econometrics: Annals 1984–3*, 26 (Sept./Oct. 1984), pp. 1–15.

[4] Energy has a time dimension and is now commonly measured in kilowatt-hours. Power has no time dimension and is measured in kilowatts. One kilowatt-hour of energy can be consumed by using one kilowatt of power for one hour or by using two kilowatts of power for one-half hour. "Demand" is (and was) usually measured not as the maximum instantaneous power used but as the maximum average power used in any 15-minute (or other short time) period. The specific way in which "demand" is charged usually falls into one of two categories: Hopkinson rates and Wright rates. A Hopkinson rate contains an explicit demand charge, for example: demand charge = \$2.50 per month per kilowatt of the maximum demand in the month, plus an energy charge of 5 cents per kilowatt-hour used in the month. A Wright rate achieves the same objective through the use of a declining block structure with the size of the high-priced block a function of "demand": 10 cents per kilowatt-hour for electricity used equivalent to or less than 50 hours use per month of the maximum demand; 5 cents per kilowatt-hour for electricity used in excess of the equivalent of 50 hours use per month of the maximum demand. Consider an electricity user whose maximum power consumption in one month is 1 kw and whose energy consumption is 300 kwh. Under a Hopkinson rate, the bill would be calculated as: 1 kw × \$2.50 per month (= \$2.50) + 300 kwh × \$0.05 per kwh (= \$15.00) = a total charge of \$17.50. Under a Wright rate the calculation would be: (1 kw demand × 50 hours) × \$0.10 (= \$5.00) + (300 kwh − 50 figured above) × \$0.05 (= \$12.50) = a total charge of \$17.50. Given any Hopkinson rate structure, one can always develop a Wright rate structure which will produce identical bills except in the case of an electricity user whose consumption of energy is so low relative to his maximum power usage that it remains wholly in the initial high-priced block. Actual rate structures sometimes combine features of Hopkinson and Wright rate structures and frequently add other complicating features, such as block pricing. The term "demand-charge rate structure" will be used to refer to any rate structure in which a user's bill is partially a function of his maximum power consumption independent of the time in which the maximum power consumption occurred. The term "demand charge" will be used either interchangeably with "demand-charge rate structure," or, more specifically, to refer to the component of an electricity user's bill which is determined by maximum power consumption. The term

the size of his individual peak instead of his level of consumption during the system peak, as would peak-load pricing. This feature has caused it to be interpreted as a misapplication of the principle of peak-load pricing—an interpretation which makes its popularity over time-of-day pricing quite mysterious.[5]

During the last decade of the nineteenth century and the first five years of the twentieth century, a wide-ranging discussion occurred among electric engineers and utility executives concerning the proper basis for pricing electricity. The discussion was international in scope, and most of the original ideas came from Britain. Many, if not all, of the electricity pricing structures which continue to be used and considered today were explored then, and lively exchanges occurred between advocates of demand-charge rate structures and advocates of time-of-day structures.[6] In an address delivered in 1892, the British engineer John Hopkinson became the first of a number of engineers to characterize the electricity demand charge as the correct device to divide a utility's fixed costs among its customers.[7] Hopkinson's analysis demonstrates the importance of the peak load on the total costs of running a power plant, but he made the inferential leap of concluding that it was therefore proper to charge electricity users on the basis of their individual peaks rather than on their consumption during system peaks.

Although modern economic theorists would find flaws in his analysis, as did some of his contemporary colleagues, Hopkinson's proposals suited the industry of his time. In Hopkinson's day artificial lighting consumed almost all of the output of electric utilities.[8] Its relatively high cost led electric lighting to be used almost exclusively in the evening, especially during winter when sunset was early. Under these condi-

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"demand," especially in quoted material, will often refer to the engineering concept of maximum power consumption rather than the usual economic concept. The meaning should be clear from the context.

[5] See, for example Alfred E. Kahn, *The Economics of Regulation* (New York, 1970), vol. 1, pp. 95–96; Ralph K. Davidson, *Price Discrimination in Selling Gas and Electricity* (Baltimore, 1954), pp. 85–86; and W. Arthur Lewis, "The Two-Part Tariff," *Economica*, 8 (Aug. 1941), p. 252.

[6] For more on these early discussions see W. J. Hausman and J. L. Neufeld, "Time-of-Day Pricing in the U.S. Electric Power Industry at the Turn of the Century," *Rand Journal of Economics*, 15 (Spring 1984), pp. 116–26; John L. Neufeld, "The Origin of Electricity Rate Structures—1882 to 1905" (unpublished manuscript, University of North Carolina at Greensboro, 1985).

[7] John Hopkinson, "The Cost of Electric Supply," *Transactions of the Junior Engineering Society*, 3 (1892–1893), pp. 33–46.

[8] In 1897 and 1898 the Commissioner of Labor surveyed electric power companies and received responses from about 31 percent, responsible for 45 percent of the value of all electricity generation. Of those reporting income by type of service (93 percent of respondents), arc lighting accounted for 39 percent of total income and incandescent lighting accounted for 49 percent. A relatively small number of large stations were responsible for much of the non-lighting income. Lighting was the source of over 90 percent of total income for 75 percent of respondents. *Fourteenth Annual Report of the Commissioner of Labor 1899*, House of Representatives, 56th Cong., Document No. 713 (Washington, D.C., 1900).

tions, peaks of individual users were likely to occur simultaneously, making the measure of an individual's maximum power consumption an excellent proxy for his consumption during the system peak. In addition, when Hopkinson gave his address, metering technology was not well developed, and a customer's maximum power consumption was likely to be estimated from the number of connected light bulbs rather than measured with a meter. Indeed, it was common for such estimates to be the sole basis on which electricity was priced. These conditions are consistent with the thesis that the demand-charge rate structure was a second-best form of peak-load pricing, adopted when there was little difference between the time of a system's peak and the time of individual users' peaks, an argument recently put forth by Michael Crew and Paul Kleindorfer.[9] Although plausible, their interpretation is at odds with subsequent events in the industry's history.

Technological progress proceeded rapidly in the early electric industry. Meters capable of measuring maximum power consumption, as well as time-of-day meters, soon became available. The manager of an electric utility in Brighton, England, Arthur Wright, developed the first practical demand meter capable of measuring a user's maximum power consumption. Before the turn of the century he became quite active in promoting Hopkinson's logic, his own version of the demand-charge rate structure, and his meter among U.S. utilities.[10] Those in the United States converted by Arthur Wright include Samuel Insull, the president of Chicago's Commonwealth Edison and one of the most influential executives in the industry. Insull acquired a financial interest in the American rights to Wright's meter patents, and his stature insured that discussions on the demand-charge rate structure were prominent in industry trade meetings.[11]

Despite the prominence of Samuel Insull, demand-charge rate structures did not become widespread until later, after 1906 and before 1917. Thus the adoption of demand-charge rate structures followed their conception by some thirty years, after the industry had altered significantly from the turn of the century. Industrial electricity use, which was largely consumed off the system peak, had become quite important to electric utilities. Although individual peaks of industrial users were the least likely to coincide with the system peak, they were the users most

[9] Michael A. Crew and Paul R. Kleindorfer, *The Economics of Public Utility Regulation* (Cambridge, Mass., 1986), pp. 185–93.

[10] Arthur Wright, "Cost of Electricity Supply," *Municipal Electrical Association Proceedings* (London, 1896), pp. 44–67; and Arthur Wright, "Profitable Extensions of Electricity Supply Stations," *Proceedings of the National Electric Light Association, Twentieth Convention* (New York, 1897), pp. 159–89.

[11] Insull mentioned his financial involvement in the Wright patents in a discussion over the relative merits of demand-charge and time-of-day rate structures, *Minutes of the Fourteenth Annual Meeting (19th Convention) of the Association of Edison Illuminating Companies* (Sault Sainte Marie, Michigan, 1898), p. 133.

likely to face demand-charge rate structures. It would be far easier to accept the thesis that demand-charge rate structures were an imperfect form of peak-load pricing had they become widespread earlier or had they been used primarily for residential electricity users, whose peaks coincided with the system peak as late as 1921.[12]

A more satisfactory explanation for the widespread adoption of the demand-charge rate structure can be found in the historical record of discussions occurring within the industry between 1905 and 1915. The onset of state price regulation helped stimulate these discussions because it placed (or threatened to place) the utility industry's operations within a legalistic framework open to public scrutiny and debate, and industry leaders wanted their interests protected from the possible adverse actions of regulatory commissions.[13] Many of the discussions concerned rate structures in general and the demand-charge rate structures in particular. Although the off-peak consumption (and the level of consumption) of industrial users of electricity made them very important to the utility industry, the possibility that these customers would turn to isolated plants for their electricity supply was a serious concern. Under certain conditions, the most profitable way for a utility to price its product for industrial users was to structure rates not on the basis of the utility's cost of production, as peak-load pricing would, but on the basis of factors which would determine the customer's cost of operating an isolated plant, namely his energy consumption and the size of his individual peak.

The usefulness of demand-charge rate structures as an instrument of price discrimination in the face of competition from isolated plants was known within the industry and was accepted by early regulatory commissions as a justification for their use. Historical evidence shows the role of the demand-charge rate structure as an instrument of price discrimination was more important to its widespread adoption than was its role as an imperfect form of peak-load pricing. Other explanations for the popularity of demand-charge rate structures include the suggestion made by Arthur Lewis that their adoption was caused by inadequate metering technology and the suggestion made by I.C.R. Byatt that individuals in the industry favored them because they were unable to understand economic principles.[14] These explanations are unsatisfactory in the light of available historical evidence.

[12] H. E. Eisenmenger, *Central Station Rates in Theory and Practice* (Chicago, 1921), p. 262.

[13] The first commission was established in Massachusetts in 1887. The next commissions were not established until 1907. By 1915, 33 states had established such commissions with 21 established during the period 1911–1913. George J. Stigler and Claire Friedland, "What Can Regulators Regulate? The Case of Electricity," *Journal of Law and Economics*, 5 (Oct. 1962), p. 13.

[14] Lewis, "The Two-Part Tariff"; I. C. R. Byatt, "The Genesis of the Present Pricing System in Electricity Supply," *Oxford Economic Papers*, 15 (1963), pp. 8–18.

ISOLATED PLANTS AND THE STRUCTURE OF UTILITY RATES

Many of the factors affecting the economics of electricity production from isolated plants and from central utilities were similar. The capacity of capital equipment required for generation and distribution was determined by the maximum power, rather than the total energy, the equipment handled. The cost of capital was the major expense of electricity production. The cost of fuel required by the prime mover to generate electricity, however, was directly related to the total electrical energy generated. Although some expenses were related to factors other than total energy generation and maximum power production, most expenses were determined by one or both of these measures of output.

There were also important differences between the two. An isolated plant did not have many of the administrative costs, such as metering and billing, which a utility bore. Isolated plants were usually located near the place of consumption, eliminating transmission costs. Perhaps most importantly, if steam were produced for use in production processes or space heating, an isolated plant could produce electricity as a byproduct. On the other hand, central utilities had two important advantages over isolated plants. First, by using larger generators than any single user could, they benefited from economies of scale. Second, as long as the individual peaks of their customers were not simultaneous, the total generating capacity which the utility required was less than the sum of the generating capacities each user would have required in an isolated plant. Termed "diversity," this advantage was well known to the early electric utility industry. The factors working to the advantage of utilities became more important over time as the size of utilities increased. In the industry's early days, the advantages of isolated plants may have overshadowed those of central utilities, but as growth in the optimal scale of generation led to larger utilities, their advantages came to dominate.[15]

An industrial electricity user choosing between making or buying electricity would certainly compare costs. At an isolated plant costs were a function of the user's total expected energy production and maximum power use. The cost of utility-supplied electricity depended on the utility's rate schedule. Utilities should have responded by offering industrial users a rate structure which maximized the utility's profits. Monopoly power caused profit-maximizing prices to exceed marginal costs, although this does not imply supranormal profits, especially if scale economies caused marginal costs to be below average costs. The profit-maximizing prices quoted to a customer depended on

[15] A table showing maximum available generator size by year is given by Neil, "Entering the Seventh Decade," 5th page. During the period 1879 to 1903 the annual growth rate in maximum generator size was 24.6 percent. From 1904 to 1929 the growth rate was 11.2 percent.

two factors: the marginal cost of serving the customer and the customer's demand elasticity for electricity from the utility, which was in turn affected by the viability of an isolated plant.

To determine the profit-maximizing rate structure a utility considered the marginal cost to the utility of supplying service, the total cost to the customer of owning and operating an isolated plant, and the average prices the utility was charging all customers. Three possibilities existed. For some electricity users, the total cost of an isolated plant was less than the utility's marginal cost. A utility could have attracted such users only by the offer of unprofitable rates; no rate structure would have been profit maximizing. This situation was probably common in the very early days of electric power when (as I show later) the majority of all electricity used by industry came from isolated plants. For a second category of electricity user, the high cost of an isolated plant precluded it from consideration. A rate structure of Ramsey prices would have maximized utility profits from them.[16] Peak-load pricing with rates closely tracking (above) marginal cost would have been optimal.

Demand-charge rate structures were the preferred form of rate structure for electricity users in the third category. For them, the cost of operating an isolated plant was greater than the marginal cost to the utility of supply. For customers in this category, however, the cost of operating an isolated plant fell in the gap between the marginal cost to the utility of providing service and the (above-marginal cost) prices the utility generally was charging its customers for such service. Thus in setting prices for these customers, the utility had to take into account competition from isolated plants. Because the marginal cost of supplying them was less than the cost of self-supply, the utility was able to set a price which was high enough to cover marginal cost, thus contributing to profits, yet low enough to make electricity from the utility more attractive than electricity from an isolated plant. The profit-maximizing rate structure had to track the costs of the competition, that is, the costs of operating an isolated plant, not the utility's marginal cost of supply (although prices had to cover marginal cost).

The onset of state rate regulation made it difficult for utilities to determine prices through individual negotiation. Regulation required published rate schedules. A rate schedule which automatically offered lower prices to those for whom the operation of isolated plants was cheaper had to be structured on the factors which determined the cost of isolated plant operation. Those factors are energy consumption and maximum power use, and the demand-charge rate structure is based precisely on them. The individual peaks of these users probably did not

[16] The classic review of Ramsey pricing can be found in William J. Baumol and David Bradford, "Optimal Departures from Marginal Cost Pricing," *American Economic Review*, 60 (June 1970), pp. 265–83.

coincide with the system peak, but this was less important to rate setting than was their cost of using isolated plants. For them demand-charge rates were not a second-best form of peak-load pricing, rather they were the best mechanism for price discrimination.

THE HISTORICAL RECORD

The early power industry operated on a small scale and originally faced competition from isolated plants even for lighting. Edison's original Pearl Street Station in New York City served an area about a mile square, and in 1904 only fifteen and a half square miles were served by the Edison distribution system, which was still much larger than the Edison systems in other major cities.[17] Detroit's Edison system served only three squares miles, as did Philadelphia's, while other cities had still smaller systems. In addition to his central station business, Edison also operated an Isolated Plant Company which installed as much lighting in the 1880s as did his central station operation.[18] Isolated plants were not only attractive to industrial electricity users, but were also likely to receive serious consideration from hotels and large office buildings. In 1902 the Bureau of the Census conducted a census of central electric light and power stations. Although isolated plants were not canvassed, the report had some interesting comments on them which show the continued access of isolated plants to available scale economies:

> In fact, no statistics of isolated plants are included in this report, which to that extent, therefore falls short of embracing the entire electric light and power industry of the United States. Many of these isolated plants are of a very extensive and important character, being supplied with the most improved apparatus and giving facilities equal to those furnished to populous communities. It is estimated that there are 50,000 of these plants, and that they consume at least half the product in some lines of electric apparatus.[19]

Further evidence on the importance of self-generation can be found by comparing the electrical generation of the entire U.S. electric utility industry with the generation of electricity by industrial, mine, and railway electric power plants (Table 1). This latter group comprised only a portion of all isolated power plants since it excluded isolated plants in institutions, hotels, apartment houses, office buildings, and amusement parks. Nevertheless, the combined output of this subset of isolated power plants exceeded the combined output of the entire utility industry (private and public) as late as 1912 and remained important for many

[17] Neil, "Entering the Seventh Decade," 2nd page.

[18] Harold C. Passer, *The Electrical Manufacturers 1875–1900* (Cambridge, Mass., 1953), pp. 117–21.

[19] U.S. Bureau of the Census, Special Reports, *Central Electric Light and Power-Stations 1902* (Washington, D.C., 1905), p. 3.

TABLE 1
ELECTRICITY PRODUCTION IN THE UNITED STATES BY OWNERSHIP OF GENERATORS FOR SELECTED YEARS
(in gigawatt-hours)

	(1) Total Electric Utility Industry	(2) Total Industrial, Mine and Railway Electrical Power Plants	(3) Percent of Total 100 × (2) / [(1) + (2)]
1902	2,507 gwh	3,462 gwh	58%
1907	5,862	8,259	58
1912	11,569	13,183	53
1917	25,438	17,991	41
1920	39,405	17,154	30
1925	61,451	23,215	27
1930	91,112	23,525	21
1940	141,837	38,070	21
1950	329,141	59,533	15
1960	755,374	88,814	11
1970	1,531,609	108,162	7

Source: Edison Electric Institute, *Historical Statistics of the Electric Utility Industry* (New York, 1974), p. 21.

years after. The significance of self-generation to the important industrial class of electricity users can be seen from the proportion of total electric horsepower powered from self-generation (Table 2). Again, self-generated power dominated utility-generated power until after 1914 and remained as much as half of utility-generated power in 1929.

Interest in the relative advantages of electricity provided by utilities and by isolated plants stimulated considerable discussion in trade journals and at professional meetings. Both American and British

TABLE 2
ELECTRIC MOTOR POWER USED IN U.S. MANUFACTURING BY SOURCE OF ELECTRICITY
(horsepower)

	(1) Purchased Energy	(2) Self-Generated Energy	(3) Percent of Total 100 × (2) / [(1) + (2)]
1899	182,562 hp	310,374 hp	63%
1904	441,589	1,150,886	72
1909	1,749,031	3,068,109	64
1914	3,884,724	4,938,530	56
1919	9,284,499	6,969,203	43
1923	13,365,663	8,821,551	40
1925	15,868,828	10,254,745	39
1927	19,132,310	11,219,979	37
1929	22,775,664	12,376,376	35

Source: U.S. Census of Manufactures: 1929 (Washington, D.C., 1933), p. 112.

journals published articles discussing which was the more economical.[20] Interesting isolated plant installations were described in some detail.[21] Back-to-back papers advocating each source of supply were presented at engineering meetings attended by industrial electricity users.[22]

The connections among price discrimination, utility rate structures, and the use of isolated plants were realized quite early. In 1900 an important leader of the early electric utility industry characterized the competition in a way that shows the frustration it occasioned: "Isolated plants have proved active competitors and a thorn in the flesh for more reasons than one. Of all forms of competition I like this one least. Bad methods of charging have cultivated the isolated plant to an appalling extent.[23] The role of the demand-charge rate structure as a tool of price discrimination which tracked the cost to a customer of using an isolated plant was clearly recognized in an editorial in *Electrical World* in 1915:

> [Demand-charge rate structures] make it extremely easy, by a combination of a demand charge with an energy charge, to arrange a discount curve possessing almost any characteristic required to meet the exigencies of local service. If, for example, there are in any territory a considerable number of large consumers—isolated plants let us say—who can be served only at a rate which would be ruinous if extended to all customers, it is perfectly possible to devise a combination demand and service rate which shall meet the requirement of charging what the traffic will bear with respect to this particular group without extending unjustifiably great discounts to others. The same general device, in one form or another, has therefore become very widely used as giving rise to perhaps the maximum flexibility in producing a general discount curve suitable for meeting the conditions that may arise under almost any circumstances.[24]

As the movement for state rate regulation grew, political attention focussed on the operation of electric power companies, and state legislatures moved to strip power companies of the ability to engage in price discrimination at all.[25] Those whose interests lay in the use of isolated plants were most likely to favor such restrictions. In 1913 an association of manufacturers of machinery for isolated plants formed

[20] Two of many are: R. S. Hale, "Isolated Plant vs. Central Stations Supply of Electricity: A Suggestion for Obtaining Estimates of Costs on a Competitive Basis," *Electrical World and Engineer*, 42 (Sept. 5, 1903), pp. 383–84; H. S. Knowlton, "The Central Station and the Isolated Plant," *Cassier's Magazine*, 32 (Aug. 1907), pp. 359–63.

[21] "Electrical Plant in the Newark Free Public Library," *Electrical World and Engineer*, 42 (Aug. 15, 1903), pp. 271–72.

[22] Charles T. Main, "Central Stations versus Isolated Plants for Textile Mills," pp. 205–17; and R. S. Hale, "The Supply of Electrical Power for Industrial Establishments from Central Stations," pp. 219–27; also discussion, pp. 977–1009, all from *Proceedings of the Joint Meeting of the American Institute of Electrical Engineers and the American Society of Mechanical Engineers* (Feb. 16, 1910).

[23] Henry L. Doherty, "Equitable, Uniform, and Competitive Rates," *Proceedings of the National Electric Light Association, Twenty-third Convention* (New York, 1900), p. 305.

[24] "Principles of Rate-Making," an editorial, *Electrical World*, 65 (Apr. 17, 1915), p. 971.

[25] "Central-Station Rates Discussed at Boston," *Electrical World*, 57 (Mar. 9, 1911), p. 604; William H. Winslow, "Rate Making for Central Stations," *Electrical World*, 63 (Jan. 3, 1914), pp. 12–13.

under the name "Uniform Electric Rate Association" for the apparent purpose of preventing or ending the practice by central stations of granting lower prices to those who might otherwise have used isolated plants. The association obtained and published as a pamphlet an opinion by Louis D. Brandeis on the legality of that practice.[26] Brandeis took the position that rate differentials were justifiable if they could be shown to be cost based, but that differentials based solely on differences in the characteristics of demand (including the feasibility of using isolated plants) were not legal. The publication of Brandeis's opinion was followed in *Electrical World* by a series of over twenty letters to the editor on the issue of uniform rates.[27]

Responsibility for defending the industry's interests in the rate structure controversy was taken by the leading industry trade group, the National Electric Light Association (NELA), forerunner of the modern Edison Electric Institute. The NELA aimed to forge a common methodology among utilities for structuring rates. In 1910 the NELA formed a special committee on "Rate Research" so that the various companies could have "far more uniform methods of making rates and more uniform rates than exist in the country to-day."[28] In its first report, the committee argued that it was important for the NELA, rather than regulatory commissions or the courts, to take the initiative in formulating rate structures. The committee noted then and later, with satisfaction, that commissions and courts had avoided dealing with the issue of rate structures. The committee opened an office in Chicago and published (for several decades) a weekly periodical, *Rate Research*, which reprinted many of the most important papers on demand-charge rate structures written before the turn of the century, and reported on and abstracted all news which affected electric rates and regulation, especially regulatory commission opinions. In its second annual report, issued in 1912, the committee provided standard forms for utilities to use in presenting their rates to customers and regulators. In addition, the committee unanimously recommended that demand-charge rates be used for large business users of electricity but reported disagreement over whether such rates were appropriate for those with lower consumption.[29] No justifications for these positions were provided in the report.

The controversy over rates centered on the issue of price discrimina-

[26] Louis D. Brandeis, "Central Station Rates, Legal Opinion of Louis D. Brandeis," abstracted and quoted in *Rate Research*, 4 (Oct. 15, 1913), pp. 35–38, and (Oct. 22, 1913), pp. 51–54.

[27] These letters appeared in the letters to the editor section of *Electrical World* from October 25, 1913 to July 31, 1915.

[28] *Proceedings of the National Electric Light Association, Thirty-Fourth Convention* (New York, 1911), p. 290.

[29] "Report of the Rate Research Committee," *Proceedings of the National Electric Light Association, Thirty-Fifth Convention* (New York, 1912), pp. 184–229.

tion. Could different rates be justified only when the costs of serving customers varied (the "cost-of-service" basis), or was it also desirable or acceptable to charge different rates to customers varying only in demand characteristics (the "value-of-service" basis)?[30] The opponents of value of service were concerned about the exploitation of monopoly power in the pursuit of profit maximization and criticized the practice of customers being charged different rates when there were no apparent differences in the conditions of supply. Proponents of the value-of-service approach came to the position that cost of service was the appropriate basis for setting a utility's total earnings, but that value of service was appropriate in determining the share of those earnings to be borne by each customer. They argued that it was better for all of the utility's customers if new customers could be induced to take central station supply, rather than self-generate, as long as the price charged those customers exceeded marginal costs, permitting some contribution to overhead costs. Thus the objective of rate design was to provide the largest possible service at the lowest possible cost to all, a position consistent with social welfare given the existence of large economies of scale within the utility industry.

In its 1914 report to the National Electric Light Association, the Rate Research Committee strongly advocated value of service as the primary basis for structuring rates.[31] The committee specifically defined value of service as the amount which an electricity user would have to pay to obtain an equivalent or substitute means of service, and noted that the concept had proven most acceptable to regulatory commissions when used to meet the competition from isolated plants.[32] The committee's comments regarding the use of demand-charge rate structures are revealing:

> In the case of large customers, the value of the service to the customer clearly depends on the amount for which he could make the same service for himself, because if the rate asked is notably higher than this amount, the customer may put in his own plant. The value of the service to the customer depends on what it would cost him to make it himself, and this cost clearly depends in part on the size of plant that he would need. The size of plant that he would need is determined by his maximum demand and necessary reserve. . . .
>
> The demand is at least a rough measure of this cost, and is therefore a test of the value to the buyer.[33]

The committee also considered and expressed its disapproval of

[30] These discussions paralleled to a remarkable extent earlier discussions on rate structures within the railway industry, although surprisingly little reference was made to the case of railways by those in the electric power industry. D. Phillip Locklin, "The Literature on Railway Rate Theory," *Quarterly Journal of Economics*, 47 (Feb. 1933), pp. 167–230.

[31] "Report of the Rate Research Committee and Discussion," *Proceedings of the National Electric Light Association, Thirty-Seventh Convention* (New York, 1914), pp. 59–116.

[32] Ibid., pp. 63, 70.

[33] Ibid., p. 88.

time-differentiated rates. Although such rates, according to the committee, did reflect differences in the costs of providing service, "unless this happens to coincide with a difference of value to the buyer, they are undesirable."[34] Despite the concern felt by some members of the NELA, regulatory commissions proved to be sympathetic to the value-of-service principle and to the demand-charge rate structure. L. R. Nash, in a book written in 1933, discussed the role of cost of service and value of service in terms which are virtually the same as those advocated by the Rate Research Committee in its 1914 report. Rates for large customers, according to Nash, were commonly based on value of service, defined as the cost to the user of providing such service to himself.[35] Nash cited several rulings from state commissions in support of this position. An interesting example of an early (1909) Massachusetts regulatory commission ruling which dealt with the issues of value of service and demand-charge rate structures was published in *Rate Research* in 1912:

> . . . there is a considerable number [of customers], both actual and possible, who may readily supply themselves with light or obtain power from some other source. . . . If the company is to supply them, it is subject to the ordinary rules of business competition—it must meet prices established by conditions which it does not create and cannot control, or not do the business. . . .
>
> . . . The demand system, whatever its faults in determining the individual's cost to the company, has at least the merit of recognizing the most essential elements determining the probable cost to the individual of supplying himself, and therefore operates to fit the price which the company must make to get his business, to his actual condition.[36]

Discussions within the industry between 1905 and 1915 show an appreciation for the use of the demand-charge rate structure as a tool of price discrimination in the face of competition from isolated plants. To accept price discrimination in the face of isolated plants as the cause of the widespread use of demand-charge rate structures requires evidence that their use first became widespread during that time period.

DATING THE ADOPTION OF DEMAND-CHARGE RATE STRUCTURES

Completely satisfactory data on the form of rate structures used by utilities in the United States are not available for years prior to 1917. In 1917 the NELA Rate Research Committee began publication of an annual series of reports giving detailed information on the rates and rate structures used by electric utilities in all major cities in the United States. Before 1917, tables showing the rates charged by different utilities were occasionally constructed. Unfortunately, the primary

[34] Ibid., pp. 86–87.
[35] L. R. Nash, *Public Utility Rate Structures* (New York, 1933), p. 321.
[36] "Electric Rates—Massachusetts," *Rate Research*, 2 (Oct. 23, 1912), pp. 52–53.

purpose of those tables was to permit comparisons of the average level of rates among utilities rather than to provide details on the structure of rates. Indeed, until the work of the NELA Rate Research Committee, the terms used to describe features of electricity rate structures lacked uniformity. Despite these shortcomings, evidence for the years 1897 and 1906 strongly suggests that demand-charge rate structures were not widely used in those years. By contrast, the demand-charge rate structure was ubiquitous by 1917.

One of the earliest sources of information about rates charged by electric utilities in the United States was a paper presented by J. W. Lieb at a convention of the Association of Edison Illuminating Companies in 1897.[37] Lieb discussed extensively the variety of rate structures then known, including a number of demand-charge structures. His examples of actual utility rate structures were all European. He described one form of demand-charge rate structure as "being extensively used in Europe and America," in which the price per kilowatt-hour was discounted as a function of total energy consumption and maximum power consumption.[38] Lieb also provided a set of tables, however, showing the rates charged by Edison companies in twelve major American cities for incandescent, arc, and power service. The demand-charge feature was present in only five of the twelve cities' incandescent contracts, and in only three of the cities' power contracts. If his table reflects a greater use of demand-charge rate structures for lighting, that is consistent with the use of demand-charge rates as a form of peak-load pricing. Their use, however, did not dominate other rate structures.

In 1906, the National Electric Light Association published a confidential report on rates for electric service.[39] The report gives a table listing rates by city for 1,183 American cities and a small number of foreign cities. The table devotes columns for each city to business incandescent lights, residence lights, arc lights, and power service. For the three types of lighting service, there are separate entries for each city for flat rate (non-metered) service and metered service. For power service there are separate entries for rates based on horsepower and rates based on kilowatt-hours. Remarks for each city are also given which occasionally provide detailed information about rate structures. Despite the detail of this table, significant information may have been lost. In a number of cases, the table entries clearly describe demand-charge rate structures. In many cases, however the table entries indicate that charges or discounts were based on a "sliding scale," an

[37] J. W. Lieb, Jr., "Methods of Charging for Current," *Minutes of the Thirteenth Meeting of the Association of Edison Illuminating Companies* (Niagara Falls, 1897), pp. 59–79.

[38] Ibid., p. 68.

[39] *The National Electric Light Association's Report of Rates for Commercial Lighting and Power Service* (New York, 1906).

ambiguous term which may indicate that a demand-charge rate structure was used.[40] In many other cases, several prices are given for a kilowatt-hour without explanation. It is likely that the rate structure granted discounts for large energy consumption alone, but the possibility that "demand" was a factor cannot be dismissed.

A number of cities were described in the 1906 report as having "Wright" demand rates, but no cities were described as having "Hopkinson" rates, a ubiquitous rate structure designation in 1917. Publication of the 1906 report preceded the creation of the NELA Rate Research Committee and the publication of *Rate Research*. The greater use of the Hopkinson structure in 1917 may well reflect the success of the committee's efforts to reeducate the industry about the theoretical rate structure work which had been performed before the turn of the century.

Despite the shortcomings of the 1906 report, it gives the clear impression that demand-charge rate structures were not widely used. Indeed, had utilities offered the number of complex rate structures in 1906 which they were to have in 1917 and later, it is doubtful such a simple table could have been constructed. Of all the U.S. cities in the report, over 95 percent had residential lighting rates, and 91 percent used metered rates for residential lighting. Of those using metered rates, only about 9 percent of the cities reported use of "sliding scales" or demand charges. Similarly, 98 percent reported business incandescent rates, and 92 percent used metered rates. Only about 10 percent of the metered rates were clearly demand-charge rates or "sliding scale" rates. Rates for power were less common; only 69 percent of the cities in the report had such rates listed. Of those with power rates, only about 11 percent had structures which contained demand charges or "sliding scales." Although in use, the demand-charge rate structure was not dominant, and it was not primarily being used for industrial customers.

In 1917 the Rate Research Committee published the first volume in an annual survey of electricity rates. The volume contained information for 161 U.S. cities with populations above 40,000.[41] Each rate structure for each utility is described in detail, making it possible to reliably determine the extent to which demand-charge rate structures were used. Most utilities used several rate structures, up to sixteen, and the average was approximately seven. Rate structures were quite idiosyncratic, and many customers were given the option of choosing among several rate structures.

In a number of cities more than one utility provided electric service,

[40] Generally the term sliding scale indicated that discounts on energy costs were given those with larger consumption, as would be the case under a declining block rate schedule. Presumably this term might also have been used for a "Wright" demand-charge rate structure, or a similar rate structure. See fn. 4 for an explanation of the Wright rate structure.

[41] Rate Research Committee, *NELA Rate Book and Supplement* (Chicago, 1917).

TABLE 3
PERCENT OF U.S. CITIES USING CERTAIN ELECTRICITY RATE STRUCTURES

	User Class			
	Residential Lighting	Business or Commercial Lighting	Power	Industrial, Wholesale or Primary Service
Percent of cities with rates for this class	98.1%	97.5%	93.8%	75.2%
Of cities with rates for this class, percent using				
Demand charge rate structures only	26.6	35.7	35.1	73.6
Nondemand charge structures only	60.8	51.0	15.9	8.3
Both demand charge and other rate structures	12.7	13.4	49.0	18.2

Note: Cities are those with populations above 40,000.
Source: Compiled by the author from Rate Research Committee, National Electric Light Association, *NELA Rate Book and Supplements: 1917* (Chicago, 1917).

but competing utilities usually offered identical rates. Twenty-one cities had multiple utilities with different rates. I have taken the rates of the utility first listed as representative.

Table 3 categorizes rate structures based on title and listed applicability as given in the 1917 report and abbreviates the information given in that report. Some rate structures were placed in two categories; for example, "wholesale power" was placed in both the power and the industrial categories and "general lighting" was categorized as both residential and commercial lighting. Rate structures apparently intended for restricted use, such as heating and cooking and electric-car battery charging, were not categorized.

Demand-charge rate structures appear to have been more common for all classes of service in 1917 than they were in 1906 or in 1897, owing, perhaps, to improved metering technology, although this difference could merely reflect inadequacies of the earlier data. By 1917, however, demand-charge rates structures were least used for residential lighting and were most used for power and industrial service. Demand-charge rate structures were used for power service in 84 percent of the cities with that rate class; nearly 92 percent of cities with industrial rates used demand-charge rate structures for that service. This pattern is consistent with the hypothesis that demand-charge rate structures were most likely to be offered those for whom self-generation of electricity was most attractive, rather than those for whom maximum power consumption was a good proxy for consumption during the system peak.

CONCLUSION

Despite long advocacy by economists, time-of-day or other forms of peak-load pricing have not been widely used by American electric utilities. Instead, utilities have traditionally used demand-charge rate structures for large industrial users of electricity. These rate structures have often been viewed as a misapplication of the principles of peak-load pricing, which has made their popularity puzzling. Rationales for their widespread use have explained them as a "second-best" form of peak-load pricing, adopted when an individual electricity user's peak was likely to occur at the same time as the system peak and when metering technology was in its infancy. These explanations are plausible descriptions of the electric power industry before the turn of the century, when time-of-day and demand-charge rate structures were developed. The evidence indicates, however, that demand-charge rate structures did not become widespread until after 1906, and they were used primarily for industrial electricity users, whose maximum power consumption was least likely to coincide with system peaks.

A better explanation is found in the historical record of the industry. In the period roughly between 1906 and 1915, the industry faced the onset of state price regulation. Anxious to protect rate structures from outside legal challenge, the leading industry trade group organized to develop unanimity on the form of and justification for electricity rate structures. It was during this period that the demand-charge rate structure became widespread, and it was justified not as a form of peak-load pricing but as an instrument of price discrimination designed to reduce the price of electricity for those for whom the self-generation of electricity in isolated plants was an alternative to the purchase of electricity from electric utilities. Utilities responded to the serious competitive threat posed by isolated plants by using a rate structure which based prices not on the factors determining the utility's production costs but on the factors which would determine the cost of alternative supply. The cost of electricity from an isolated plant depended on the user's maximum power consumption and total energy consumption, and the demand-charge rate structure made the cost of electricity from a utility also dependent on these same factors. The persistence of the demand-charge rate structure after isolated plants ceased to pose a competitive threat to utilities is interesting, and makes it a modern relic of the economic conditions faced by electric utilities in an earlier time.

ATTACHMENT – 6

The Economics of Regulation
Principles and Institutions

Volume I Economic Principles
Volume II Institutional Issues

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Public utility companies do employ peak-responsibility pricing to some degree. The telephone companies charge lower rates for night than for daytime long-distance calls; electric companies frequently have low night rates for hot-water heating; both they and natural gas companies—local distributors and interstate pipelines alike—offer at lower rates service that the customer will agree may be interrupted if capacity is being taxed by other users and try to promote off-peak sales in numerous ways;[16] railroads charge lower rates for return-hauls of freight, when the greater flow is in the opposite direction; airlines offer special discount fares—family plans, youth fares, and so forth—for travel on unfilled planes or in slack seasons or days of the week.[17]

The two-part tariff, generally credited to John Hopkinson, an English engineer, and almost universally used by electric and gas utilities for large-volume sales at wholesale and to industrial users, represents an effort to apply just such a principle. The first part—the energy, commodity or "running" charge—embodies the variable costs, properly charged to all customers, and is levied on a per unit of consumption basis (per kwh or per MCF of gas). The second part—the demand or capacity charge—is a charge for the utility's readiness to serve, on demand. This readiness to serve is made possible by the installation of *capacity*: the demand charge, therefore, distributes the costs of providing the capacity—the fixed, capital costs—on the basis of the respective causal responsibilities of various buyers for them. And the proper measure of that responsibility is the proportionate share of each customer in the total demand placed on the system at its peak. (Sometimes the tariff will have three instead of two parts—the third, "customer" charge reflecting the costs of services such as meter-reading and billing that vary on a per customer basis instead of with different amounts purchased.)[18]

Unfortunately, the principle has usually been badly applied, in several important ways. First, if the demand charge were correctly to reflect peak responsibility it would impose on each customer a share of capacity costs equivalent to his share of total purchases at the time coinciding with the

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16 A particularly illuminating example is provided by the case of a combination company—that is, one distributing both electricity and gas—the two major portions of whose business had noncoincident peaks. The Chairman of the Board of Directors of the Public Service Electric and Gas Co. reported to his stockholders:

"In our sales promotion programs we are stressing the selling of 'off-peak loads', such as electric heating, to increase the winter use of electricity, thus helping to offset the summer air-conditioning peak; and gas air-conditioning and interruptible gas service to induce greater use of gas in the off-peak summer period." Annual Meeting of Stockholders, April 18, 1966.

Note that the company was competing with itself—pushing the off-peak sales of each product in competition with the other in periods of the latter's peak demand.

Our discussion of peak-responsibility has run entirely in terms of pricing policies. As the Public Service example suggests, the same considerations would justify public utility companies using various other sales promotional devices, such as intensive advertising or the sale of the relevant appliances at cost, or less, to increase off-peak sales. On the general question of the proper treatment of selective promotional expenditures, see pp. 149 and 164, note 10.

17 For a decision sustaining reduced railroad rates for coal shipped during the slack season, provided those rates were available nondiscriminatorily to all shippers, see *ICC v. Louisville & N.R. Co.*, 73 F. 409 (1896) and another disallowing a similar seasonal reduction by a motor carrier on household goods because it did not meet the condition of nondiscrimination, ICC, *Reduced Seasonal Household Goods Rates*, Report and Order, 332 ICC 512 (1968).

18 More often the customer costs will be recovered by specifying a minimum bill, or in sufficiently high per unit charges for the first block of electricity or gas purchased.

system's peak (a "coincident peak" demand charge). Instead, the typical two-part tariff bases that rate on each customer's *own* peak consumption over some measured time period, regardless of whether *his* peak coincides with that of the system (hence the designation "noncoincident" demand charge). That is, the peak (for example, half-hour) consumption of all customers, regardless of the time of day or year in which each falls, is added up, and each then is charged a share of total system capital costs equivalent to the percentage share that his peak consumption constitutes of that total. The noncoincident demand method does have some virtue: it encourages customers to level out their consumption over time, in order to minimize their peak taking, hence their share of capacity costs. This, in turn, tends to improve the system's load factor—the ratio of average sales over the year to capacity—that is, the degree of capacity utilization. But it is basically illogical. It is each user's proportion of consumption at the *system's* peak that measures the share of capacity costs for which each is causally responsible:[19] it is consumption at *that* time that determines how much capacity the utility must have available. The system's load factor might well be improved by inducing individual customers to cut down their consumption to a deep trough at the *system* peak and enormously increase *their* peak utilization at the system's off-peak time: yet the noncoincident demand system would discourage them from doing so.[20]

Second, the charges have typically been based on average instead of marginal costs. Therefore, the energy charge has generally ignored the fact that electricity is produced under conditions of short-run increasing cost; and the demand charge has tended to embody the opposite error.

Third, the two-part tariff has applied only to bulk sales. Retail sales of gas and electricity to households typically contain no such differentials based on time of consumption (with specific exceptions such as special night rates for water-heating). Instead, they usually carry block rates, with diminishing charges for larger blocks of consumption: for instance, 6¢ for the first 30 kwh, 4¢ for the next 50, 3¢ for the next 100, 2¢ for the next 570 and 1½¢ for anything above 750 kwh—regardless of the time of taking.[21] Since household utilization typically has a marked peak that coincides roughly with that of the system (whether because of air-conditioning on hot summer days, or for home heating, lighting, and cooking in the early evenings of short and cold winter days), the use of diminishing block rates has a strong perverse tendency to underprice marginal sales at the peak.[22] Against this distortion, however, one must weigh the tendency of such declining block rates correctly to reflect the declining unit costs of electricity and gas distribution with increased intensity of use.

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[19] This entire discussion continues under the assumption that capacity costs are constant, so that *average* capacity costs (which is what are measured by both coincident and noncoincident demand methods) are the same as marginal capacity costs. If instead the system is subject to decreasing costs (see Chapter 5), each user will be *marginally* responsible for less than his percentage of coincident peak demands multiplied by total capacity costs, because marginal cost is less than average.

[20] See W. Arthur Lewis, *op. cit.*, 50–53; Ralph K. Davidson, *Price Discrimination in Selling Gas and Electricity* (Baltimore: Johns Hopkins Press, 1955), 84–88, 133–134, 192–193.

[21] This schedule is taken from C. F. Phillips, *op. cit.*, 352, who identifies the preponderant uses of the successive blocks as lighting; refrigeration, washer, and dryer; cooking; water-heating and air-conditioning; and electric house heating, respectively.

[22] See Shepherd, "Marginal-Cost Pricing in American Utilities," *South. Econ. Jour.* (July 1966), XXXIII: 62.

In recent years, both England and France have taken important steps toward remedying some of these deficiencies of the Hopkinson tariff. The famous French "Tarif Vert," put into effect in 1956 (only for bulk and industrial sales), instituted rates varying with the time of day and season of the year in order to base demand charges on the system peak. The change recognized that energy charges too should vary with the level of demand because variable costs are not constant.[23] The British Central Electricity Generating Board (CEGB) went over in 1962–63 to the coincident peak for determining demand charges on its (wholesale) sales to the regional Area Boards and introduced a differential day-night "running" (that is, energy) charge.[24] In 1967–68, explicitly recognizing that the latter charges were erroneously based on average (day and night) instead of marginal operating costs, it introduced differential time-of-day, -week and -year energy charges reflecting the increasing SRMC function.[25]

The 1967–68 reforms reacted to another, even more interesting problem already alluded to briefly above: how should the principle of peak responsibility be applied if the same capacity does not serve all users? If capacity is not interchangeable, so that the same type of plant or equipment does not necessarily serve both peak and off-peak users, it is no longer true that peak consumption alone should bear all capacity costs. In electricity generation, it is economical for short periods of time to use gas turbine generating units, which have low capital costs but high operating costs. These are inefficient for continuous utilization, but are less costly than installing regular capacity for just the extreme peak demands.[26] In consequence, when the CEGB tried to incorporate the entire capacity costs in the demand charges, at about £10 a year per kw, it found that some of its Area Board customers began to install their own gas turbines, at a cost of about £4 per kw, and therefore cut down their peak purchases. The Board correctly recognized that the true incremental or avoidable costs of supplying capacity that would be used for peaks of comparatively short duration (it estimated this type of capacity would be economic if operated no longer than 250 hours of the year) were not £10 but £4 per kw, and that the £11 now estimated to be the capital costs per kw of basic capacity, such as would be economic for longer periods of operation (because of its far lower variable costs) should therefore be borne by

[23] The demand charge to industrial customers in the Paris region provides discounts ranging from 0% in winter peak hours to 98% in summer "empty" hours. Eli W. Clemens, "Marginal Cost Pricing: A Comparison of French and American Industrial Power Rates," *Land Econ.* (November 1964), XL: 391. See also Meek, *op. cit.*, Part II, *Jour. Ind. Econ.* (November 1963), XII: 45–63, and the articles by Marcel Boiteux and Pierre Massé in J. R. Nelson, *Marginal Cost Pricing in Practice*, 134–156.

[24] R. L. Meek, "The Bulk Supply for Electricity," *Oxford Econ. Papers* (July 1963), n.s. XV: 107–123.

[25] The Board settled for three running or energy rates:

". . . one for *peak units*—now defined as those used between 8 and 12 A.M. and for 4:30 and 6:30 P.M. from Mondays to Fridays in December and January, except for Christmas and Boxing Days . . .;

". . . a second rate for *day units* used between 7:30 A.M. and 11 P.M. daily, but outside the peak . . .;

". . . a third rate for *night units* used between 11 P.M. and 7.30 A.M. . . ." "Puncturing the Power Peak," *The Economist*, May 14, 1966, 734.

The consequence of moving to increasing marginal charges for operating costs was to cause the operating charges to make some contribution to capacity costs as in our model, p. 94, above; the French Green Tariff has the same effect.

[26] For a general, diagrammatic statement of the conditions for such a choice, see M. A. Crew, "Peak Load Pricing and Optimal Capacity: Comment," *Amer. Econ. Rev.* (March 1968), LVIII: 168–170.

consumption during the longer-period, "winter plateau" of demand.[27] Similar qualifications of simple-minded peak responsibility pricing would clearly be appropriate to the extent storage capacity instead of basic pipeline capacity served the peak needs of natural gas consumers.[28]

Although most public utility executives and regulators recognize that peak responsibility pricing has some validity, probably most would also vigorously resist its wholehearted acceptance. William G. Shepherd's survey disclosed that the majority of American electric utilities practice little or no explicit marginal cost pricing, and among those that do, the main emphasis is on raising off-peak sales, by charging them something less than average capacity costs, instead of purposefully imposing all the capacity charges on the peak users.[29] He found, moreover, that publicly-owned companies, if anything, follow marginalist and peak responsibility principles even less than private;[30] and that electric utilities in states with "tough" regulatory commissions, such as New York and California, similarly incorporate little marginalism in their rate structures.

An outstanding illustration of the resistance of strong regulatory commissions is provided by the Federal Power Commission's formula for natural gas pipeline rate-making specified in its famous *Atlantic Seaboard* decision of 1952.[31] The distinctive feature of the Atlantic Seaboard formula is that it requires that capacity costs be distributed 50–50 between the demand and commodity charges instead of incorporated exclusively in the former. Since the demand costs are distributed among customers in proportion to their shares in the volume of sales at the system's (three-day) peak, while the commodity costs are borne in proportion to their annual volume of purchases, the consequence of the 50–50 formula is to shift a large proportion[32] of capacity costs to off-peak users. This produces an uneconomic encouragement to sales at the peak (whose price falls short of the true marginal costs of peak

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[27] Accordingly, it introduced two demand rates: an £11 "basic capacity charge" for consumption during the winter plateau, when it estimated that demand would be on the average no more than 90% of the maximum system demand, and a "peaking capacity charge" of £4 for the period, estimated not to exceed 250 hours a year, when demand would exceed the 90% plateau. See R. L. Meek, "The New Bulk Supply Tariff for Electricity," *Econ. Jour.* (March 1968), LXXVIII: 48–53 and *passim;* "Puncturing the Power Peak," *The Economist,* May 14, 1966, 734.

This complicating factor in peak responsibility pricing was pointed out by Melvin G. de Chazeau, "Reply," *Q. Jour. Econ.* (February 1938), LII: 357 and recognized—along with most other problems—by Bonbright, *op. cit.,* 354 note.

[28] For an analysis of the ways in which the introduction of gas storage requires a modification of the simple charging of all capacity costs to peak users, see R. K. Davidson, *op. cit.,* 138–147.

[29] *Op. cit., South Econ. Jour.* (July 1966), XXXIII: 61–65. Effective earlier critics of the failure of electricity as well as gas distribution companies to employ marginal costing, in particular with respect to the allocation of capacity costs, were I. M. D. Little, *The Price of Fuel* (Oxford: Clarendon Press, 1953), 54–76 and R. K. Davidson, *op. cit.,* especially 81–97, 111–147.

[30] See also Richard L. Wallace, "Cost and Revenue Associated with Increased Sales of TVA Power," *South. Econ. Jour.* (April 1967), XXIII: 526–534; and, for an Australian example, H. M. Kolsen, "The Economics of Electricity Pricing in N. S. W.," *Economic Record* (December 1966), XLII: 564–565.

[31] *In the Matters of Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation,* Opinion No. 225, 11 FPC 43 (1952).

[32] This is not wholly 50%, because peak users also pay their proportionate share of the commodity charge, which includes half of the capacity costs. But the point is that in deciding to what extent to cut their purchases at the peak relative to off-peak, peak customers are influenced by only the 50% of capacity costs incorporated in the demand charge; the other 50% does not affect that calculation because they pay it equally whenever they take the gas.

ATTACHMENT – 7

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	SBUA_001-Q06		
PG&E File Name:	GRC-2020-PhII_DR_SBUA_001-Q06		
Request Date:	October 30, 2020	Requester DR No.:	001
Date Sent:	November 13, 2020	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Trevor Bergero	Requester:	Jennifer Weberski

QUESTION 06

Please provide the following information for each feeder on PG&E's system for 2019, or the most recent year for which PG&E has such data:

a. The capacity of the feeder.

b. The peak load observed on the feeder

c. PG&E's current estimate of the sum of the maximum demand of the customers on the feeder.

d. Documentation of PG&E's method for estimating the maximum demand of customers on each feeder.

ANSWER 06

PG&E has based its responses on 2017 data to remain consistent with the information supporting its Exhibit 2 Chapter 8 testimony.

Attachment 01, "GRC-2020-PhII_DR_SBUA_001-Q06Atch01_Feeder_Cpcty_Dmd.xlsx" provides capacity, feeder-level peak load, and total final line transformer (FLT) peak load for 3,008 distribution feeders. The feeder peak load and total FLT load for each feeder are sourced from the PCAF and FLT analyses presented in PG&E's Exhibit 2 Chapter 8 testimony. The feeder capacities are sourced from PG&E's Distribution Planning Department. For confidentiality purposes, feeder identifiers have been anonymized and geographic identification of the data is not provided.

PG&E notes that the feeder-level PCAF analysis and transformer-level FLT analysis are performed separately and rely on some subtly different assumptions for data aggregation and data exclusion criteria. While PG&E has compared the information from the two analyses for this data response, the comparison may not reflect a perfectly mapped relationship between feeder and FLT loads—though PG&E does believe the data to be generally correct. Particularly, there are a small number of cases where feeder-level peak load is greater than the total FLT load on that feeder. PG&E attributes these instances to the underlying differences in the two data sources.

ATTACHMENT – 8

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	SBUA_001-Q07		
PG&E File Name:	GRC-2020-PhII_DR_SBUA_001-Q07		
Request Date:	October 30, 2020	Requester DR No.:	001
Date Sent:	November 13, 2020	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Trevor Bergero	Requester:	Jennifer Weberski

QUESTION 07

Please select a PG&E feeder with a mix of residential, small non-residential and large non-residential customers and provide the following for 2019, or the most recent year for which PG&E has such data:

a. The date, time and megawatt (or MVA) value of the feeder's peak load.

b. The date, time and megawatt (or MVA) value of the maximum demand of each customer on the feeder, and the rate that the customer is served on, without identifying the customers. If necessary to preserve customer anonymity, rates may be consolidated.

ANSWER 07

THIS DATA RESPONSE INCLUDES ATTACHMENTS MARKED CONFIDENTIAL AND IS SUBJECT TO PROTECTION UNDER THE NONDISCLUSRE AGREEMENT BETWEEN PG&E AND SBUA

PG&E has based its responses on 2017 data to remain consistent with the information supporting its Exhibit 2 Chapter 8 testimony.

a. The sample feeder selected by PG&E has a peak load of 8.671 MW which occurs at Hour Ending (HE) 15 (3:00 pm) on September 11th, 2017.

b. See Attachment 01, "GRC-2020-PhII_DR_SBUA_001-Q07Atch01_FLT_DMD_CONF.xlsx"

   Attachment 01 provides the peak final line transformer (FLT) loads for each transformer on the sample feeder, as well as each customer's net delivered and/or net received load which occurs during their respective FLT peak load hour. For confidentiality proposes, customer and transformer identifiers have been anonymized and no geographic identification of the data is provided.

   PG&E notes that the transformer peak load values contain both positive and negative values. Positive values are indicative of a transformer peak load occurring in the "delivered" direction (i.e. energy flowing from PG&E to customers), whereas negative values are indicative of a transformer peak load occurring in the "received" direction (i.e. energy flowing from customers back to PG&E.)

Likewise, the customer net-delivered and net-received load values contain both positive and negative values as well. For these loads, a positive value represents customer load which contributes to the FLT peak load, whereas a negative value represents customer load which offsets and therefore reduces the FLT peak load.

Details on net delivered and net received loads relative to FLT load are discussed in PG&E’s Opening Testimony, Exhibit 2 Chapter 8.

ATTACHMENT – 9

97 FERC ¶ 63, 014

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company — Docket Nos. ER99-2326-000, EL99-68-000

INITIAL DECISION

(Issued October 31, 2001)

APPEARANCES

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Wallace L. Duncan, Esq., Michael Postar, Esq. and *Lisa Gast, Esq.* on behalf of Modesto Irrigation District

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Jennifer L. Key, Esq. and *Michael P. Mackness, Esq.* on behalf of Southern California Edison Company

Ronald N. Carroll, Esq. and *Michael G. Henry, Esq.* on behalf of Enron Power Marketing, Inc.

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H. Peter Young, Presiding Administrative Law Judge

TABLE OF CONTENTS

A. FACTUAL BACKGROUND/ PROCEDURAL HISTORY

The instant proceeding arises out of the functional unbundling of Pacific Gas and Electric Company ("PG&E" or "Company") services in connection with electric industry restructuring mandated by the Public Utilities Commission of the State of California ("CPUC"). In accordance with the CPUC mandate, PG&E and two other utilities[1] filed three joint applications with this Commission. The joint applications sought: (1) a declaratory order for PG&E, SDG&E and SCE to categorize certain jurisdictional assets as either "transmission" or "distribution" facilities; (2) authority for PG&E, SDG&E and SCE to convey operational control of any facilities categorized as "transmission" to a state-wide independent system operator; and (3) authority for PG&E, SDG&E and SCE to sell energy at market-based rates through a state-wide independent power exchange. The Commission conditionally granted the joint applications by order issued November 26, 1996. *Pacific Gas and Electric Company, et al.,* 77 FERC ¶ 61,204 (1996). *Inter alia*, the Commission' s November 26, 1996 order required PG&E, SDG&E and SCE to submit more detailed filings concerning their respective transmission owner ("TO") rates by March 31, 1997. *Id.* at pp. 61,826, 61,837.

PG&E made its first TO rate filing in accordance with the Commission' s order on March 31, 1997 in Docket No. ER97-2358-000 ("TO-1"). On December 17, 1997, the Commission issued an order accepting the Company's proposed TO-1 rates for filing, making the rates effective subject to refund and setting them for hearing. PG&E made a second TO rate filing on March 30, 1998 in Docket No. ER98-2351-000 ("TO-2"). On May 28, 1998, the Commission issued an order accepting the Company's proposed TO-2 rates for filing, making the rates effective subject to refund and setting them for consolidated hearing with TO-1. The parties filed a formal offer of settlement resolving all TO-1/TO-2 issues on April 14, 1999, and the presiding judge certified that offer of settlement to the Commission as contested on May 20, 1999. The Commission has not yet made a determination with respect to the contested TO-1/ TO-2 offer of settlement.

PG&E made a third TO rate filing establishing charges for transmission service provided under the California Independent System Operator Corporation ("ISO") Open Access Transmission Tariff ("OATT") on March 31, 1999 in the instant Docket No. ER99-2326-000 ("TO-3"). On May 27, 1999, the Commission issued an order accepting the Company's proposed TO-3 rates for filing, making the rates effective subject to refund and setting them for hearing. The parties filed a formal offer of partial settlement

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1 San Diego Gas & Electric Company ("SDG&E") and Southern California Edison Company ("SCE").

resolving all TO-3 wholesale transmission revenue requirement and base wholesale transmission rate issues on November 8, 1999. The presiding judge certified the TO-3 offer of partial settlement to the Commission on December 9, 1999. The Commission approved the November 8, 1999 offer of partial settlement by letter order issued January 31, 2000 in Docket Nos. ER99-2326-002 and EL99-68-002. The parties subsequently filed a second offer of partial settlement in TO-3 which resolved all but two of the remaining retail rate issues.[2] The presiding judge certified that offer of partial settlement to the Commission on March 31, 2000, and the Commission approved it by letter order issued April 26, 2000.

PG&E made a fourth TO rate filing on September 1, 1999 in Docket No. ER99-4323-000 ("TO-4"). On October 27, 1999, the Commission issued an order accepting the Company's proposed TO-4 rates for filing, making the rates effective April 1, 2000 (subject to refund) and setting them for hearing. The parties filed a formal offer of settlement resolving all TO-4 issues on May 30, 2000, and the presiding judge certified that offer of settlement to the Commission on July 7, 2000. The Commission approved the TO-4 offer of settlement by letter order issued September 15, 2000. As a consequence, the TO-3 rate design/rates at issue in the instant proceeding will have an effective period of only ten months.[3]

PG&E filed direct testimony and exhibits in support of its position on March 31, 1999, and filed supplemental direct testimony and exhibits specifically addressing retail rate design on August 6, 1999. Various parties filed answering testimony and exhibits on October 29, 1999, November 5, 1999 and December 3, 1999; cross-answering testimony and exhibits were filed on January 13, 2000. PG&E filed rebuttal testimony and exhibits on February 10, 2000.

The parties filed a joint stipulation of contested issues on February 22, 2000. An evidentiary hearing on the stipulated issues was conducted from March 7, 2000 through March 16, 2000. The evidentiary record closed March 31, 2000. Initial briefs were filed April 24, 2000; reply briefs were filed May 22, 2000.

B. ISSUE ANALYSES

I. What is the Proper Retail Rate Design?

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2 Those two retail rate issues are the subject of this Initial Decision.

3 From May 31, 1999 through March 31, 2000.

PG&E historically has allocated its retail transmission revenue requirement among retail transmission customer classes using the CPUC-approved Equal Percentage of Marginal Cost ("EPMC") methodology. Under this methodology, PG&E: (1) determines a test year embedded cost of service; (2) calculates unit marginal costs on a functional (*e.g.,* generation, transmission, distribution) basis; (3) calculates the functional revenues that would be collected from each customer class if the customers within each class were charged the unit marginal cost of a particular function; (4) determines system-wide marginal cost revenues by summing the functional marginal cost revenues that would be collected from each customer class; and (5) allocates the test year embedded cost of service revenue requirement (from step # 2) among customer classes according to each class's proportional share of system-wide marginal cost revenues. The unbundling of retail transmission in California, however, transferred jurisdiction over retail transmission from the CPUC to this Commission. The Commission' s May 27, 1999 TO-3 hearing order expressly declined to grant a PG&E request for deference to the CPUC-approved EPMC methodology, instead requiring the Company to demonstrate at hearing "that the [CPUC] methodologies are consistent with the open access requirements of Order No. 888." 87 FERC ¶ 61,218, at p. 61,862 (1999).

a. *Party Positions*

1. <u>PG&E</u>

PG&E emphasizes that it proposes to use the very same retail rate design it has used over the past ten years. The Company maintains that this design not only is CPUC tested and approved, but also is consistent with Order No. 888 because it satisfies the five prescriptive transmission pricing principles reflected in the Commission' s October 26, 1994 Transmission Pricing Policy Statement, 69 FERC ¶ 61,086 (1994) (the "Transmission Pricing Policy Statement"). According to PG&E, the EPMC methodology satisfies the Transmission Pricing Policy Statement's: (1) *revenue requirement principle* because it merely allocates a previously established revenue requirement among retail customer classes; (2) *comparability principle* because PG&E charges itself and others for retail transmission service on the same basis; (3) *economic efficiency principle* because the EPMC methodology is based on marginal cost of service; (4) *fairness principle* because EPMC neither produces subsidies between existing and new transmission customers nor impedes new retail users under California' s "direct access" market structure; and (5) *practicality principle* because changing the retail transmission rate design under which PG&E (and other investor-owned California utilities) has operated for many years presents numerous administrative, logistical and engineering problems. PG&E also maintains that alternate rate designs suggested by Staff and Enron have no demonstrated advantage over the EPMC approach. Moreover, while PG&E acknowledges that it could accommodate application of the Staff-endorsed alternative, the Company maintains that the Staff proposal would require two modifications [4] and also carries a hefty administrative burden unless applied only on a prospective basis.

2. Commission Staff

Staff contends that PG&E simply has not satisfied its burden of proof with respect to the EPMC methodology. Staff essentially dismisses PG&E's reliance on prior CPUC approval as immaterial, asserting that in the context of this proceeding the Company has neither adequately explained the EPMC methodology nor established that it is consistent with the open access requirements of Order No. 888. Staff consequently maintains that PG&E has completely disregarded the express requirements of the Commission' s TO-3 hearing order, and that the Company's proposed rate design must be rejected on that basis alone. This position notwithstanding, Staff also asserts that the EPMC methodology is patently inconsistent with the open access requirements of Order No. 888 because EPMC violates three of the five principles reflected in the Transmission Pricing Policy Statement: fairness, economic efficiency and practicality. Staff argues that using the EPMC methodology to design retail rates would be unfair/inequitable because PG&E applies a different methodology to wholesale transmission customers taking similar service—whose costs are allocated based on their proportionate contributions to system-wide load. Staff also claims that PG&E's proposed EPMC methodology fails to reflect true marginal costs, thereby undermining economic efficiency with respect to transmission system investment by producing inaccurate price signals and subsidies. Finally, Staff submits that PG&E's proposed EPMC methodology fails the practicality test because it is overly complex and inadequately explained. Staff therefore contends that EPMC is inconsistent with the open access requirements of Order No. 888, and proposes instead that PG&E be required to design retail transmission rates the same way the Company designs rates for wholesale transmission customers taking similar service.

3. Enron[5]

Enron argues that PG&E has neither demonstrated that EPMC is consistent with Order No. 888's open access requirements nor that the methodology achieves the

4 On conditions that: (1) loss-adjusted retail demands are utilized; and (2) the standby charge is adjusted.

5 Enron Power Marketing, Inc.

fundamental objective of implementing non-discriminatory/ pro-competitive conditions on PG&E's transmission system. According to Enron, the transmission service which PG&E provides to retail customers is indistinguishable from the transmission service provided to wholesale customers. Enron therefore concludes that PG&E's retail rate design should match the Company's wholesale rate design. Enron emphasizes that the "12 coincident peak" methodology [6] under which PG&E designs wholesale rates is this Commission' s standard methodology, and that requiring the Company to apply this methodology to retail rates ensures that PG&E's wholesale and retail customers pay similar rates for similar services.

4. CPUC

CPUC does not oppose PG&E's proposed EPMC retail rate design, noting that EPMC is the rate design methodology currently used in California. CPUC nevertheless declines to argue for Commission deference to EPMC in this case, stating that it does not want to appear to prejudge pending CPUC proceedings in which EPMC and policies related to the methodology remain at issue. Commenting on PG&E's suggestion that it could accept a 12 CP methodology on conditions that loss-adjusted retail demands are utilized and the standby charge is adjusted, CPUC observes that PG&E's proposed standby charge adjustment would increase by 63% over the charge the Company's preferred EPMC methodology would produce. CPUC takes the position that PG&E's 12 CP standby charge should not exceed the EPMC standby charge. CPUC also takes issue with any suggestion that this Commission should prescribe the CPUC-authorized account to which any refunds arising out of this proceeding should be allocated.

b. *Discussion*

No party disputes the fact that PG&E's initial filing in these dockets employs the same retail rate design the Company has used to develop retail rates before the CPUC for more than ten years. Neither does any party dispute that the CPUC consistently has approved PG&E's use of this [EPMC] retail rate design to allocate the Company's retail transmission revenue requirement among customer classes. These facts notwithstanding, the TO-3 hearing order expressly declined to grant PG&E's request for deference to the California Commission with respect to retail rate design, reiterating instead that "PG&E must make a showing in the ordered hearing that the California Commission' s methodologies are consistent with the open access requirements of Order

6 The 12 coincident peak ("12 CP") methodology allocates costs among customer classes based on customers' average transmission system demands at 12 monthly points coincident with peak system use.

No. 888." 87 FERC ¶ 61,218, at p. 61,862 (1999) (footnote citing prior statement of requirement omitted). CPUC, moreover, expressly declined to argue for deference in this case. I therefore find and conclude that any PG&E reliance on prior CPUC approval of the EPMC methodology is immaterial in the context of this proceeding.

Order No. 888 clearly endorses well-supported alternative rate methodologies. *FERC Statutes and Regulations, Regulations Preambles* January 1991-June 1996 ¶ 31,036, at p. 31,668 (1996). Alternative rate methodology support is primarily evaluated in accordance with principles articulated in the Transmission Pricing Policy Statement. The Transmission Pricing Policy Statement expressly states that different customers may pay different rates if they use the transmission system in different ways. *FERC Statutes and Regulations, Regulations Preambles* January 1991-June 1996 ¶ 31,005, at p. 31,141 (1996). In addition, it expressly states that revenue requirement, comparability, economic efficiency, fairness and practicality must be considered. *Id.*, at pp. 31,141-44. An acceptable alternative rate methodology *must* satisfy the revenue requirement [7] and comparability principles; it also *should* satisfy the economic efficiency, fairness and practicality principles, but these may be balanced against one another in appropriate circumstances. *Id.*, at p. 31,141.

Staff contends as a threshold matter that PG&E has failed adequately to explain EPMC on the record in this proceeding, arguing that this deficiency alone compels the methodology' s rejection under both Order No. 888 and the TO-3 hearing order. This argument has substantial merit. The record establishes that a good deal of PG&E's ostensible support for EPMC derives from the Company's 1993 general rate case (the "1993 GRC") before the CPUC. Exh. PGE-29, at pp. 3-4; Tr. 601-02, 609-13; Exh. S-31, at pp. 12-13; Exh. S-36, at pp. 1-14. None of the original 1993 GRC supporting material, however, was offered into evidence in this proceeding. And while PG&E characterizes EPMC as "a fairly involved process" (Tr. 611), the record fails to reflect much of that process or its underlying support.[8] Tr. 601-13. These deficiencies are exacerbated by the facts that the TO-3 hearing order expressly declined to grant PG&E's request for deference to CPUC concerning retail rate design and CPUC expressly declined to argue for such deference. I therefore find and conclude that PG&E has not satisfied the Order No. 888 requirement that alternative rate methodologies be well- supported in the context of this proceeding.

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7 "Non-conforming" proposals need not satisfy this principle.

8 In addition, the record indicates that some of the EPMC support on which PG&E implicitly relies was developed in 1991 and, as a consequence, might now be unreliable. Tr. 597-98.

Neither has PG&E presented any persuasive evidence that it provides transmission service to retail customers which differs from the transmission service provided to wholesale customers. PG&E maintains that its wholesale and retail transmission customers are dissimilarly situated in that wholesale service is provided to larger loads at more and higher-voltage delivery points than retail service is provided. Exh. PGE-29, at p. 7; Tr. 567-69. This distinction, however, confuses the nature of the service at issue. The record establishes that both PG&E's wholesale and retail customers take their transmission service under the same TO tariff and over the same high-voltage lines. Exh. EPM-1, at p. 6; Tr. 618. The record also establishes that PG&E's retail customers are assigned a portion of the costs for bulk transmission facilities providing 230 kV and 500 kV service under the EPMC methodology. Tr. 618-19. These facts confirm that similar *transmission* service is provided to both wholesale and retail customers. It is immaterial that retail customers may require a lower-voltage *distribution* service in addition to the transmission service at issue. Accordingly, I find and conclude that PG&E has not established that it provides different transmission services to its wholesale and retail customers. It follows that EPMC would violate Order No. 888's fundamental non-discrimination principle if it were used to design retail transmission rates at the same time wholesale transmission rates were designed using the 12 CP methodology.

Whether EPMC is consistent with the open access requirements of Order No. 888 depends on its consistency with Transmission Pricing Policy Statement principles. As previously stated, an acceptable alternative rate methodology *must* satisfy the revenue requirement and comparability principles, and also *should* satisfy the economic efficiency, fairness and practicality principles— though these may be balanced against one another to determine whether the rate proposal at issue is just and reasonable. No party alleges that EPMC would violate either the revenue requirement or comparability [9] principles in this instance, and the record contains substantial evidence that it would not. Applying EPMC as proposed could not over-collect PG&E's retail transmission revenue requirement because it would merely *allocate* the appropriate revenue requirement among retail customer classes. Exh. PGE-28, at pp. 2-3; Tr. 553. Similarly, designing retail rates in accordance with EPMC would not violate comparability because PG&E imposes the same charges for retail transmission service on both itself and other customers irrespective of rate design methodology. Tr. 565.

Staff and Enron contend that EPMC fails to satisfy Order No. 888's open access

9 Although Enron presents some of its objections in "comparability" terms, I find that those objections more appropriately should be considered in the context of the fairness principle, *infra*.

requirement because it violates Transmission Pricing Policy Statement economic efficiency, fairness and practicality principles. PG&E counters that EPMC: (1) satisfies the economic efficiency principle because the methodology is based on marginal cost of service; (2) satisfies the fairness principle because EPMC neither produces subsidies between existing and new transmission customers nor impedes new retail users under California' s "direct access" market structure; and (3) satisfies the practicality principle because changing the retail transmission rate design under which PG&E has operated for many years presents numerous administrative, logistical and engineering problems. PG&E also argues that the alternate rate designs suggested by Staff and Enron have no demonstrated advantage over EPMC.

I find and conclude that whether the Staff/Enron-proposed rate designs have any demonstrated advantage(s) over EPMC is immaterial. Staff and Enron do not bear the burden of persuasion in this proceeding. Turning to the principles at issue, the record compels me to find and conclude that PG&E's proposed use of the EPMC methodology to design retail transmission rates would—at a minimum—violate the fairness and practicality principles, and might violate the economic efficiency principle as well. I previously determined that PG&E failed to establish it provides different transmission services to wholesale and retail customers. I consequently concluded EPMC would violate Order No. 888's fundamental non-discrimination principle if it were used to design retail transmission rates at the same time wholesale transmission rates were designed using the 12 CP methodology. Discrimination is by definition unfair and inequitable.[10] Moreover, conceding *arguendo* PG&E's claim that changing the retail transmission rate design under which the Company has operated for many years presents numerous administrative, logistical and engineering problems, the record before me compels conclusions that EPMC is a complicated and inadequately explained methodology. It does not satisfy the practicality principle for those reasons. And while the record indicates that EPMC promotes economic efficiency in certain respects (Exh. PGE-28, at p.4), it conversely suggests that EPMC could subvert economic efficiency by obscuring the market signals marginal pricing is intended to send (Exh. S-31, at pp. 16-17).

I find and conclude that PG&E's retail rate design proposal is consistent with the Transmission Pricing Policy Statement's revenue requirement and comparability principles, but is inconsistent with the fairness, practicality and economic efficiency principles. On balance, I find and conclude that PG&E's proposed retail rate design fails to satisfy the Transmission Pricing Policy Statement. The Company logically should use

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10 So, too, is basing wholesale transmission rates on *actual loads* while basing similar retail service rates on *marginal cost estimates*. Exh. S-31, at p. 18.

the same (12 CP) methodology to design retail transmission rates that it uses to design wholesale transmission rates. PG&E concedes it could accommodate a 12 CP methodology, provided the methodology is applied prospectively and subject to two (2) conditions: loss-adjusted retail demands are utilized and the standby charge is adjusted to reflect a reasonable share of stand-by customer[11] contract demands. Exh. PGE-29, at pp. 4-6.

No party disputes that the 12 CP methodology should be applied on a prospective basis. Such application, moreover, would be consistent with general Commission policy. *See, e.g., Consumers Energy Company,* 89 FERC ¶ 61,138 (1999). I therefore find and conclude that the 12 CP methodology should be applied to PG&E's retail transmission rates on a prospective basis. And since no party challenges PG&E's position that loss-adjusted retail demands should be utilized, I find and conclude it is appropriate to adopt this modification as well. The record, however, indicates that PG&E's proposed demand loss-adjustments are outdated. Exh. S-49; Tr. 602-04. PG&E therefore must support any demand loss-adjustments with current data.

No party opposes PG&E's standby charge adjustment in principle. Staff and CPUC nevertheless object to the magnitude of PG&E's proposed adjustment, which the record indicates would increase stand-by customer rates by approximately 63%. Exh. PUC-58. PG&E presented evidence at hearing that the stand-by rate increase is consistent with the increase(s) a shift to 12 CP would impose on other transmission voltage retail customers because stand-by customer system demand is comparable to large customer retail demand. Tr. 522-23, 526-27. The Company also presented evidence that a 63% stand-by customer rate increase is a function of applying the same 38% reservation factor to 12 CP that currently is applied under EPMC (Exh. PGE-31, at pp. 6, 12; Tr. 524), and that an unadjusted switch to 12 CP would reduce the stand-by customer allocation from approximately 0.75% of total transmission revenue requirement to approximately 0.02% (Tr. 521-22). In the absence of any contradictory record evidence, I am compelled to find and conclude that PG&E's evidence on this point is adequate to support the Company's proposed standby charge adjustment.

PG&E's retail rate design proposal recommends this Commission to order any over-collected retail transmission revenues to be credited through the Company's CPUC-jurisdictional Transmission Revenue Account ("TRA"). Exh. PGE-25, at p. 9. The Company bases this recommendation on the presumption that such over-collections only

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11 Stand-by customers operate their own merchant power plants/cogeneration facilities on the PG&E system.

would affect CPUC's calculation of PG&E's competitive transition charges ("CTCs").[12]

Id. The Commission previously has stated that it "will defer to the California Commission and California legislature with respect to the design of the CTC"—adding that "recovery of retail stranded costs is a matter in the first instance for the states to address and resolve." *Pacific Gas and Electric Company, et al.,* 77 FERC ¶ 61,265, at p. 62,093 (1996). As a consequence, I find and conclude it would be inappropriate to address CTCs or the TRA in the context of this proceeding.

II. Are Certain Facilities Which Formerly Were Classified as Generation Ties and Generator Step-Up Transformers Properly Included in the Network Transmission Rate Base?

PG&E proposes to re-classify as "network transmission" facilities approximately $132 million worth of gross plant previously designated "generation ties" or "generator step-up transformers." The Company's Diablo Loop, Morro Bay Loop and Moss Landing Loop comprise approximately $89 million worth of these facilities; the remaining $43 million is spread among 41 separate transmission lines/transformers which PG&E characterizes as performing network transmission functions.

a. *Party Positions*

1. <u>PG&E</u>

PG&E maintains that the network transmission classification of the Diablo Loop, Morro Bay Loop and Moss Landing Loop is beyond dispute. According to the Company, each of these facilities: (1) unambiguously performs a critical network transmission function; (2) was properly color-coded on the transmission system maps filed with the Commission in support of its initial FPA Section 203 filing for permission to turn operational control over to the California Independent System Operator ("ISO"); (3) was in fact turned over to ISO operational control at commencement of ISO operations; and (4) always has been reflected in PG&E's transmission rates. PG&E argues that under these circumstances there can be no doubt that the Diablo Loop, Morro Bay Loop and Moss Landing Loop properly are included in PG&E's transmission rate base or that the revenue requirement associated with them properly should be recovered in TO-3 transmission rates. PG&E emphasizes that with respect to the other 41 facilities at issue, 39 of them are listed on the ISO's Transmission Register, indicating that they also were under ISO operational control at commencement of ISO operations and therefore should have been included in transmission rate base. The Company dismisses any challenge to such inclusion based on its failure to make a supplemental FPA Section 203 filing to

12 PG&E uses CTCs to recover stranded costs.

correct inaccurate color-coding on transmission system maps submitted in support of the initial filing as unnecessary, also noting that some of these facilities were mis-classified despite being properly color-coded on the maps. In addition, PG&E stresses that the bulk of facilities at issue no longer has any associated generation and therefore must exclusively be performing transmission functions. PG&E characterizes the balance as "dual function" facilities which should be included in transmission rate base because they serve a discrete transmission function in addition to any generation function they may serve.

2. Commission Staff

Staff maintains the record in this proceeding does not support allocating any of the costs associated with the facilities at issue to PG&E's network transmission rate base. Staff argues that costs charged to captive transmission customers under the TO-3 tariff must reflect facilities which: (1) properly have been turned over to the ISO's operational control; and (2) predominantly perform a network transmission function. According to Staff, the facilities at issue satisfy neither of these criteria.

Staff takes the position that none of the re-classified facilities properly has been turned over to ISO operational control through the requisite FPA Section 203 filing with the Commission, arguing that this deficiency alone compels exclusion from network transmission rate base under the TO-3 tariff. Similarly, while Staff concedes that PG&E always has included the Diablo, Morro Bay and Moss Landing Loops in transmission rate base, it claims the Company did not always recover the costs associated with those facilities from *all* transmission customers as it would under the TO-3 tariff. Instead, because PG&E previously classified the Diablo, Morro Bay and Moss Landing Loops as "generation tie" facilities, the Company charged customers based on a sub-functional methodology intended to reflect only those portions of the transmission system used to serve them. Any transmission customer not using the generation tie sub-function did not pay for generation tie facilities— including the Diablo, Morro Bay and Moss Landing Loops—under that methodology. Staff underscores that the record in this proceeding does not show whether any non-PG&E transmission customers used/paid for the Diablo, Morro Bay and Moss Landing Loops prior to the electric industry restructuring which transferred operational control over these facilities to the ISO.

In addition, Staff emphasizes that while the Diablo, Morro Bay and Moss Landing Loops indisputably perform a network contingency function, these facilities' active *generation- related* functions far outweigh their network contingency functions. Staff contends it would be egregiously inconsistent with the Commission' s fundamental ratemaking policy that costs be allocated according to use for PG&E to charge 100% of the costs associated with these facilities to captive *transmission* customers. According to Staff, the only arguable basis for PG&E's proposed inclusion of any of the facilities at issue in network transmission rates is the Company's tortured re-definition of "generation ties" and "generator step-up transformers" as any transmission line or transformer that is used *exclusively* to step-up or transmit power from a generator to the grid (the "exclusive use" definition). Staff disputes the "exclusive use" definition's legitimacy and, as a consequence, endorses retaining the "primary use" definition for assigning costs to generation that PG&E used for approximately twenty (20) years prior to this filing.

3. CPUC[13]

CPUC raises the same legal issue as Staff concerning PG&E's failure to transfer operational control of the facilities at issue to the ISO through the requisite FPA Section 203 filing. It argues that PG&E cannot recover costs associated with such facilities under the TO-3 tariff because transfer of operational control to the ISO is a condition precedent to recovery under that tariff. And like Staff, CPUC acknowledges that some of the facilities at issue perform a network contingency function, but challenges the "exclusive use" definition's legitimacy for cost allocation purposes. CPUC vigorously disputes any PG&E assertion that CPUC ever reviewed, accepted or adopted PG&E's "exclusive use" definition in the context of a CPUC proceeding. To the contrary, CPUC maintains that the "exclusive use" definition undermines the fundamental objective of California's energy industry restructuring because it effectively re-bundles generation and transmission costs and, additionally, creates a "free rider" problem with respect to generators using the facilities at issue. CPUC also criticizes PG&E's attempt to justify the "exclusive use" definition on the basis that dual-function facilities present cost allocation difficulties, noting that such difficulties do not excuse inappropriate cost allocation— particularly when appropriate allocation may be achieved contractually. CPUC therefore advocates a "primary function" test analogous to that applied to natural gas facilities. CPUC submits it is far more reasonable to allocate costs according to primary function than to do so in accordance with PG&E's "exclusive use" proposal. CPUC also states it would not oppose proportionate cost allocation for dual-function facilities, but notes that such allocation has no record support in this proceeding.

4. CDWR[14]

CDWR maintains that PG&E has not satisfied the burden of proof concerning its

13 Public Utilities Commission of the State of California

14 Department of Water Resources of the State of California

proposed re-classification of the facilities at issue as "network transmission." CDWR submits that any such re-classification is exclusively attributable to PG&E's unjustified "exclusive use" re-definition of generation ties/generator step-up transformers, adding that the "exclusive use" definition itself fails to comply with Commission and CPUC unbundling mandates. CDWR also echoes the argument that PG&E cannot recover costs associated with facilities improperly transferred to ISO operational control under the TO-3 tariff because proper transfer of such operational control is a condition precedent to recovery under that tariff.

5. LADWP[15]

LADWP, in contrast to Staff, CPUC and CDWR, argues there is no legal or evidentiary basis for deviating from the traditional Commission policy of rolling into network transmission rate base the costs of any transmission line(s) which benefit/are integrated with the network transmission grid. Accordingly, LADWP supports PG&E's proposed recovery of costs associated with the facilities at issue under the TO-3 tariff. LADWP additionally argues that electric industry restructuring requires the Commission

15 Los Angeles Department of Water and Power

to adopt a "bright-line" test to distinguish between facilities which perform a network transmission function and those which do not. To this end, LADWP enumerates seven (7) characteristics intended to identify facilities which perform no network transmission function whatsoever. LADWP submits that such facilities typically: (1) will be connected to an integrated transmission network at a single station; (2) will not exhibit power flow when the connected station is off line; (3) will exhibit power flow in a single direction—away from the connected station—when the station is on line; (4) will not commingle the connected station's power with power from a resource owned or controlled by another company/entity; (5) will not have its power flow affected by alternate transmission path constraints; (6) will not be connected in parallel to a network transmission facility; and (7) will not be directly connected to wholesale or retail customers. LADWP suggests the Commission should endorse this test as a matter of general policy.

6. Southern Cities[16]

Southern Cities emphasize there is no dispute that the facilities at issue perform a network transmission function. They maintain that this fact, coupled with the traditional Commission principle that transmission revenue requirement should include the costs of all facilities supporting the integrated transmission network, necessarily leads to the conclusion that PG&E should recover all costs at issue under the TO-3 tariff.

b. *Discussion*

As a threshold matter, I find and conclude that any consideration of LADWP's proposed "bright-line" test to distinguish between facilities which perform a network transmission function and those which do not is beyond the scope of this proceeding. It is not within my authority to establish Commission policy. Neither is LADWP's proposed test necessary to decide the issue presented.[17]

The record is conclusive that each of the facilities at issue performs at least *some* network transmission function. Exh. PGE-13, at pp. 4-9; Exh. DWR-1, at p. 29; Tr. 661-62, 847-48. No party disputes this fact. It follows that the issue to be decided is not whether the facilities at issue perform network transmission functions, but whether—and to what degree—it is appropriate for PG&E to recover the costs associated with those

16 Cities of Anaheim, Banning, Colton and Riverside, California
17 This Initial Decision does not address the merits/deficiencies of PG&E's proposed "exclusive use" definition for the same reason.

facilities under the TO-3 tariff.[18]

It has long been Commission policy to require all costs associated with a particular facility to be rolled-in to network transmission rate base insofar as any degree of integration with the transmission grid could be demonstrated. *See, e.g., American Electric Power Service Corp.*, 44 FERC ¶ 61,206, at p. 61,748 (1988) (*"American Electric")*. PG&E, LADWP and Southern Cities maintain that this policy supports PG&E cost recovery for the facilities at issue under the TO-3 tariff. I disagree.

The line of cases which *American Electric* represents was decided in a pre-Order No. 888/California restructuring environment. A fundamental characteristic of that environment was bundled service. But as the Commission more recently observed:

> Much has changed since we decided these cases. Most importantly, in Order No. 888, we required the unbundling of transmission and wholesale generation services. We believe it is appropriate to reexamine our policy on the functionalization and the recovery of costs associated with [generator step-up transformers] to ensure that unbundled service customers are paying only their appropriate share of the cost of services which they use. In this regard, we said in *Northern States* that:
>
>> . . . in designing a rate for a transmission- only customer, a utility must unbundle the components of its cost of service in order to identify specifically those costs which relate to the provision of transmission service. [64 FERC at p. 63,379]
>
> In *Northern States* we went on to say that under the old approach where utilities were selling primarily a bundled generation and transmission service, the precise functionalization of generation and transmission costs was not critical. However, we found that this approach "may need to be reexamined in light of changes taking place in the electric industry—particularly the increase in transmission- only service." (*Id.*, footnote omitted) Furthermore, we stated that "[t]he *fundamental* theory of Commission ratemaking is that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the costs to be incurred." (*Id.*, emphasis in original)

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18 The parties jointly stipulated that the factor to be used in converting any costs excluded from TO-3 tariff recovery to a reduction in PG&E's annual retail transmission revenue requirement shall be 13.5%. JS-1; Tr. 65.

Kentucky Utilities Company, 85 FERC ¶ 61,274, at p. 62,111 (1998) ("*Kentucky*") (quoting *Northern States Power Company*, 64 FERC ¶ 61,324 (1993) ("*Northern States*"), *reh'g denied*, 74 FERC ¶ 61,106 (1996)). The Commission went on expressly to state that it was reversing its earlier policy of allowing such costs to be included in transmission rate base because that treatment ignored the role the facilities at issue performed in supporting generation and ancillary services. *Id*., at p. 62,112.

The same reasoning logically applies to the facilities at issue here. The record establishes that while the Diablo, Morro Bay and Moss Landing Loops each indisputably performs a critical network transmission function, each facility's generation- tie function far outweighs its network contingency function. For example, the record confirms that the various generating units connected by these three (3) facilities transmitted power over them to the grid between 81% and 100% of the time throughout 1997, 1998 and 1999. Exh. S-42; Exh. S-43; Exh. S-44; Exh. S-45; Exh. S-46; Exh. S-47; Exh. S-48; Tr. 482, 489-92. Allocating 100% of the costs associated with these facilities to their network contingency functions therefore would accomplish precisely the opposite of ensuring that unbundled service customers pay their appropriate shares of the cost of services which they use, and clearly would be inconsistent with the "fundamental" theory of Commission ratemaking articulated in *Kentucky* and *Northern States*: that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the costs to be incurred.[19] I therefore find and conclude it is unjust and unreasonable for PG&E to recover 100% of the costs associated with the Diablo, Morro Bay and Moss Landing Loops under the TO-3 tariff. And since the record in this proceeding does not establish what proportional use of these facilities legitimately may be allocated to network transmission, there is no option but to exclude Diablo, Morro Bay and Moss Landing Loop costs from TO-3 tariff recovery in their entirety—at least until PG&E quantifies these facilities' network transmission components in a compliance filing. On this record, the only way to ensure that network transmission customers not utilizing the Diablo, Morro Bay and Moss Landing Loops' generation- tie function do not pay costs associated with that function is for PG&E to continue to allocate those costs under the current sub- functional methodology.

This does not hold true for the entirety of the facilities at issue. The record indicates that $17 million worth of these facilities are dual-function. As such, they must be treated in the same manner as the Diablo, Morro Bay and Moss Landing Loops. In contrast, the record confirms that while the remaining $26 million worth of facilities at

19 The inconsistency would be even more pronounced under PG&E's proposed "exclusive use" definition. That standard would allocate to network transmission 100% of costs associated with any facility demonstrating the slightest *scintilla* of network support.

issue once performed generation connection functions in addition to their network transmission functions, the previously connected generation is no longer in service. Exh. PGE-10, at p. 12; Tr. 383; Exh. PGE-13, at pp. 6-7; Tr. 661-62. It follows that these facilities must now be dedicated exclusively to network transmission. Accordingly, 100% of their associated costs should be recoverable under the TO-3 tariff.

Staff, CPUC and CDWR argue that even these limited costs cannot be recovered under the TO-3 tariff because PG&E failed properly to transfer operational control over *any* of the facilities at issue to the ISO through the requisite FPA Section 203 filing. PG&E counters that a supplemental FPA Section 203 filing might be desirable to eliminate any confusion over precisely which facilities were in fact transferred to the ISO's operational control, but such a filing is not a condition precedent to the actual transfer of operational control over those facilities.

I find and conclude that Staff, CPUC and CDWR are technically correct in their assertion that transfer of operational control to the ISO presupposes an FPA Section 203 filing. Strict adherence to that principle insofar as this $26 million worth of facilities is concerned, however, unnecessarily elevates form over substance. The record indicates that at least some of these facilities were simply overlooked/ mistakenly color-coded in the initial Section 203 filing. Tr. 496-98. More important, the record indicates that most (if not all) of these $26 million worth of facilities were at all relevant times properly reflected in the ISO Transmission Register—which serves as the *operational* indicator of whether facilities are in fact under ISO control. Exh. PGE-30, at p. 1; Exh. S-30, at p. 2; Exh. DWR-11, at p. 138; Exh. DWR-12, at p. 7. It clearly was contemplated that the Transmission Register would track interim facility changes that rendered serial FPA Section 203 filings administratively impractical. Exh. DWR-15, at p. 39. On the record before me, I find and conclude that PG&E's failure to transfer operational control over this $26 million worth of facilities through a supplemental FPA Section 203 filing does not preclude the Company from recovering the costs associated with those facilities under the TO-3 tariff.

C. MATTERS NOT DISCUSSED

This Initial Decision's failure to discuss any matter raised by the parties, or any portion of the record, does not indicate that it has not been considered. Rather, any such matter(s) or portion(s) of the record has/have been determined to be meritless, immaterial or irrelevant. Arguments made on brief which were unsupported by record evidence or legal precedent have been accorded no weight.

D. ORDER

Wherefore, it is ordered, subject to review by the Commission on exceptions or on its own motion, as provided by the Commission' s Rules of Practice and Procedure, that within thirty (30) days of the issuance of the Final Order of the Commission in this proceeding, PG&E shall comply with the findings and conclusions contained in this Initial Decision, as adopted or modified by the Commission. Such compliance shall include a filing with the Commission adopting a 12 CP methodology for the Company's retail transmission rate design, with the modifications/ supplementation specified herein, as well as a supplemental FPA Section 203 filing which accurately reflects all facilities transferred to the ISO's operational control.

H. Peter Young
Presiding Administrative Law Judge

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company   Docket Nos. ER99-2326-000
EL99-68-000

INITIAL DECISION

(Issued October 31, 2001)

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H. Peter Young, Presiding Administrative Law Judge

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A. FACTUAL BACKGROUND/PROCEDURAL HISTORY

The instant proceeding arises out of the functional unbundling of Pacific Gas and Electric Company ("PG&E" or "Company") services in connection with electric industry restructuring mandated by the Public Utilities Commission of the State of California ("CPUC"). In accordance with the CPUC mandate, PG&E and two other utilities[1] filed three joint applications with this Commission. The joint applications sought: (1) a declaratory order for PG&E, SDG&E and SCE to categorize certain jurisdictional assets as either "transmission" or "distribution" facilities; (2) authority for PG&E, SDG&E and SCE to convey operational control of any facilities categorized as "transmission" to a state-wide independent system operator; and (3) authority for PG&E, SDG&E and SCE to sell energy at market-based rates through a state-wide independent power exchange. The Commission conditionally granted the joint applications by order issued November 26, 1996. Pacific Gas and Electric Company, et al., 77 FERC • 61,204 (1996). Inter alia, the Commission's November 26, 1996 order required PG&E, SDG&E and SCE to submit more detailed filings concerning their respective transmission owner ("TO") rates by March 31, 1997. Id. at pp. 61,826, 61,837.

PG&E made its first TO rate filing in accordance with the Commission's order on March 31, 1997 in Docket No. ER97-2358-000 ("TO-1"). On December 17, 1997, the Commission issued an order accepting the Company's proposed TO-1 rates for filing, making the rates effective subject to refund and setting them for hearing. PG&E made a second TO rate filing on March 30, 1998 in Docket No. ER98-2351-000 ("TO-2"). On May 28, 1998, the Commission issued an order accepting the Company's proposed TO-2 rates for filing, making the rates effective subject to refund and setting them for consolidated hearing with TO-1. The parties filed a formal offer of settlement resolving all TO-1/TO-2 issues on April 14, 1999, and the presiding judge certified that offer of settlement to the Commission as contested on May 20, 1999. The Commission has not yet made a determination with respect to the contested TO-1/ TO-2 offer of settlement.

PG&E made a third TO rate filing establishing charges for transmission service provided under the California Independent System Operator Corporation ("ISO") Open Access Transmission Tariff ("OATT") on March 31, 1999 in the instant Docket No. ER99-2326-000 ("TO-3"). On May 27, 1999, the Commission issued an order accepting the Company's proposed TO-3 rates for filing, making the rates effective subject to refund and setting them for

[1] San Diego Gas & Electric Company ("SDG&E") and Southern California Edison Company ("SCE").

hearing. The parties filed a formal offer of partial settlement resolving all TO-3 wholesale transmission revenue requirement and base wholesale transmission rate issues on November 8, 1999. The presiding judge certified the TO-3 offer of partial settlement to the Commission on December 9, 1999. The Commission approved the November 8, 1999 offer of partial settlement by letter order issued January 31, 2000 in Docket Nos. ER99-2326-002 and EL99-68-002. The parties subsequently filed a second offer of partial settlement in TO-3 which resolved all but two of the remaining retail rate issues.[2] The presiding judge certified that offer of partial settlement to the Commission on March 31, 2000, and the Commission approved it by letter order issued April 26, 2000.

PG&E made a fourth TO rate filing on September 1, 1999 in Docket No. ER99-4323-000 ("TO-4"). On October 27, 1999, the Commission issued an order accepting the Company's proposed TO-4 rates for filing, making the rates effective April 1, 2000 (subject to refund) and setting them for hearing. The parties filed a formal offer of settlement resolving all TO-4 issues on May 30, 2000, and the presiding judge certified that offer of settlement to the Commission on July 7, 2000. The Commission approved the TO-4 offer of settlement by letter order issued September 15, 2000. As a consequence, the TO-3 rate design/rates at issue in the instant proceeding will have an effective period of only ten months.[3]

PG&E filed direct testimony and exhibits in support of its position on March 31, 1999, and filed supplemental direct testimony and exhibits specifically addressing retail rate design on August 6, 1999. Various parties filed answering testimony and exhibits on October 29, 1999, November 5, 1999 and December 3, 1999; cross-answering testimony and exhibits were filed on January 13, 2000. PG&E filed rebuttal testimony and exhibits on February 10, 2000.

The parties filed a joint stipulation of contested issues on February 22, 2000. An evidentiary hearing on the stipulated issues was conducted from March 7, 2000 through March 16, 2000. The evidentiary record closed March 31, 2000. Initial briefs were filed April 24, 2000; reply briefs were filed May 22, 2000.

B. ISSUE ANALYSES

I. What is the Proper Retail Rate Design?

[2] Those two retail rate issues are the subject of this Initial Decision.

[3] From May 31, 1999 through March 31, 2000.

PG&E historically has allocated its retail transmission revenue requirement among retail transmission customer classes using the CPUC-approved Equal Percentage of Marginal Cost ("EPMC") methodology. Under this methodology, PG&E: (1) determines a test year embedded cost of service; (2) calculates unit marginal costs on a functional (e.g., generation, transmission, distribution) basis; (3) calculates the functional revenues that would be collected from each customer class if the customers within each class were charged the unit marginal cost of a particular function; (4) determines system-wide marginal cost revenues by summing the functional marginal cost revenues that would be collected from each customer class; and (5) allocates the test year embedded cost of service revenue requirement (from step # 2) among customer classes according to each class's proportional share of system-wide marginal cost revenues. The unbundling of retail transmission in California, however, transferred jurisdiction over retail transmission from the CPUC to this Commission. The Commission's May 27, 1999 TO-3 hearing order expressly declined to grant a PG&E request for deference to the CPUC-approved EPMC methodology, instead requiring the Company to demonstrate at hearing "that the [CPUC] methodologies are consistent with the open access requirements of Order No. 888." 87 FERC • 61,218, at p. 61,862 (1999).

a. Party Positions

1. PG&E

PG&E emphasizes that it proposes to use the very same retail rate design it has used over the past ten years. The Company maintains that this design not only is CPUC tested and approved, but also is consistent with Order No. 888 because it satisfies the five prescriptive transmission pricing principles reflected in the Commission's October 26, 1994 Transmission Pricing Policy Statement, 69 FERC • 61,086 (1994) (the "Transmission Pricing Policy Statement"). According to PG&E, the EPMC methodology satisfies the Transmission Pricing Policy Statement's: (1) revenue requirement principle because it merely allocates a previously established revenue requirement among retail customer classes; (2) comparability principle because PG&E charges itself and others for retail transmission service on the same basis; (3) economic efficiency principle because the EPMC methodology is based on marginal cost of service; (4) fairness principle because EPMC neither produces subsidies between existing and new transmission customers nor impedes new retail users under California's "direct access" market structure; and (5) practicality principle because changing the retail transmission rate design under which PG&E (and other investor-owned California utilities) has operated for many years presents numerous administrative, logistical and engineering problems. PG&E also maintains that alternate rate designs suggested by Staff and Enron have no demonstrated advantage over the EPMC approach. Moreover, while PG&E acknowledges that it could accommodate application of the Staff-endorsed alternative, the Company maintains that the Staff proposal would require two modifications[4] and also carries a hefty administrative burden unless applied only on a prospective basis.

2. Commission Staff

Staff contends that PG&E simply has not satisfied its burden of proof with respect to the EPMC methodology. Staff essentially dismisses PG&E's reliance on prior CPUC approval as immaterial, asserting that in the context of this proceeding the Company has neither adequately explained the EPMC methodology nor established that it is consistent with the open access requirements of Order No. 888. Staff consequently maintains that PG&E has completely disregarded the express requirements of the Commission's TO-3 hearing order, and that the Company's proposed rate design must be rejected on that basis alone. This position notwithstanding, Staff also asserts that the EPMC methodology is patently inconsistent with the open access requirements of Order No. 888 because EPMC violates three of the five principles reflected in the Transmission Pricing Policy Statement: fairness, economic efficiency and practicality. Staff argues that using the EPMC methodology to design retail rates would be unfair/inequitable because PG&E applies a different methodology to wholesale transmission customers taking similar service whose costs are allocated based on their proportionate contributions to system-wide load. Staff also claims that PG&E's proposed EPMC methodology fails to reflect true marginal costs, thereby undermining economic efficiency with respect to transmission system investment by producing inaccurate price signals and subsidies. Finally, Staff submits that PG&E's proposed EPMC methodology fails the practicality test because it is overly complex and inadequately explained. Staff therefore contends that EPMC is inconsistent with the open access requirements of Order No. 888, and proposes instead that PG&E be required to design retail transmission rates the same way the Company designs rates for wholesale transmission customers taking similar service.

[4] On conditions that: (1) loss-adjusted retail demands are utilized; and (2) the standby charge is adjusted.

3. Enron[5]

Enron argues that PG&E has neither demonstrated that EPMC is consistent with Order No. 888's open access requirements nor that the methodology achieves the fundamental objective of implementing non-discriminatory/pro-competitive conditions on PG&E's transmission system. According to Enron, the transmission service which PG&E provides to retail customers is indistinguishable from the transmission service provided to wholesale customers. Enron therefore concludes that PG&E's retail rate design should match the Company's wholesale rate design. Enron emphasizes that the "12 coincident peak" methodology[6] under which PG&E designs wholesale rates is this Commission's standard methodology, and that requiring the Company to apply this methodology to retail rates ensures that PG&E's wholesale and retail customers pay similar rates for similar services.

4. CPUC

CPUC does not oppose PG&E's proposed EPMC retail rate design, noting that EPMC is the rate design methodology currently used in California. CPUC nevertheless declines to argue for Commission deference to EPMC in this case, stating that it does not want to appear to prejudge pending CPUC proceedings in which EPMC and policies related to the methodology remain at issue. Commenting on PG&E's suggestion that it could accept a 12 CP methodology on conditions that loss-adjusted retail demands are utilized and the standby charge is adjusted, CPUC observes that PG&E's proposed standby charge adjustment would increase by 63% over the charge the Company's preferred EPMC methodology would produce. CPUC takes the position that PG&E's 12 CP standby charge should not exceed the EPMC standby charge. CPUC also takes issue with any suggestion that this Commission should prescribe the CPUC-authorized account to which any refunds arising out of this proceeding should be allocated.

b. Discussion

No party disputes the fact that PG&E's initial filing in these dockets employs the same retail rate design the Company has used to develop retail rates before the CPUC for more than ten years. Neither does any party dispute that the CPUC consistently

[5] Enron Power Marketing, Inc.

[6] The 12 coincident peak ("12 CP") methodology allocates costs among customer classes based on customers' average transmission system demands at 12 monthly points coincident with peak system use.

has approved PG&E's use of this [EPMC] retail rate design to allocate the Company's retail transmission revenue requirement among customer classes. These facts notwithstanding, the TO-3 hearing order expressly declined to grant PG&E's request for deference to the California Commission with respect to retail rate design, reiterating instead that "PG&E must make a showing in the ordered hearing that the California Commission's methodologies are consistent with the open access requirements of Order No. 888." 87 FERC • 61,218, at p. 61,862 (1999) (footnote citing prior statement of requirement omitted). CPUC, moreover, expressly declined to argue for deference in this case. I therefore find and conclude that any PG&E reliance on prior CPUC approval of the EPMC methodology is immaterial in the context of this proceeding.

Order No. 888 clearly endorses well-supported alternative rate methodologies. FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996 • 31,036, at p. 31,668 (1996). Alternative rate methodology support is primarily evaluated in accordance with principles articulated in the Transmission Pricing Policy Statement. The Transmission Pricing Policy Statement expressly states that different customers may pay different rates if they use the transmission system in different ways. FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996 • 31,005, at p. 31,141 (1996). In addition, it expressly states that revenue requirement, comparability, economic efficiency, fairness and practicality must be considered. Id., at pp. 31,141-44. An acceptable alternative rate methodology must satisfy the revenue requirement[7] and comparability principles; it also should satisfy the economic efficiency, fairness and practicality principles, but these may be balanced against one another in appropriate circumstances. Id., at p. 31,141.

Staff contends as a threshold matter that PG&E has failed adequately to explain EPMC on the record in this proceeding, arguing that this deficiency alone compels the methodology's rejection under both Order No. 888 and the TO-3 hearing order. This argument has substantial merit. The record establishes that a good deal of PG&E's ostensible support for EPMC derives from the Company's 1993 general rate case (the "1993 GRC") before the CPUC. Exh. PGE-29, at pp. 3-4; Tr. 601-02, 609-13; Exh. S-31, at pp. 12-13; Exh. S-36, at pp. 1-14. None of the original 1993 GRC supporting material, however, was offered into evidence in this proceeding. And while PG&E characterizes EPMC as "a fairly involved process" (Tr. 611), the record fails to reflect much of

[7] "Non-conforming" proposals need not satisfy this principle.

[8]
that process or its underlying support. Tr. 601-13. These deficiencies are exacerbated by the facts that the TO-3 hearing order expressly declined to grant PG&E's request for deference to CPUC concerning retail rate design and CPUC expressly declined to argue for such deference. I therefore find and conclude that PG&E has not satisfied the Order No. 888 requirement that alternative rate methodologies be well-supported in the context of this proceeding.

Neither has PG&E presented any persuasive evidence that it provides transmission service to retail customers which differs from the transmission service provided to wholesale customers. PG&E maintains that its wholesale and retail transmission customers are dissimilarly situated in that wholesale service is provided to larger loads at more and higher-voltage delivery points than retail service is provided. Exh. PGE-29, at p. 7; Tr. 567-69. This distinction, however, confuses the nature of the service at issue. The record establishes that both PG&E's wholesale and retail customers take their transmission service under the same TO tariff and over the same high-voltage lines. Exh. EPM-1, at p. 6; Tr. 618. The record also establishes that PG&E's retail customers are assigned a portion of the costs for bulk transmission facilities providing 230 kV and 500 kV service under the EPMC methodology. Tr. 618-19. These facts confirm that similar transmission service is provided to both wholesale and retail customers. It is immaterial that retail customers may require a lower-voltage distribution service in addition to the transmission service at issue. Accordingly, I find and conclude that PG&E has not established that it provides different transmission services to its wholesale and retail customers. It follows that EPMC would violate Order No. 888's fundamental non-discrimination principle if it were used to design retail transmission rates at the same time wholesale transmission rates were designed using the 12 CP methodology.

Whether EPMC is consistent with the open access requirements of Order No. 888 depends on its consistency with Transmission Pricing Policy Statement principles. As previously stated, an acceptable alternative rate methodology must satisfy the revenue requirement and comparability principles, and also should satisfy the economic efficiency, fairness and practicality principles though these may be balanced against one another to determine whether the rate proposal at issue is just and reasonable. No party alleges that EPMC would violate either the

[8] In addition, the record indicates that some of the EPMC support on which PG&E implicitly relies was developed in 1991 and, as a consequence, might now be unreliable. Tr. 597-98.

revenue requirement or comparability[9] principles in this instance, and the record contains substantial evidence that it would not. Applying EPMC as proposed could not over-collect PG&E's retail transmission revenue requirement because it would merely allocate the appropriate revenue requirement among retail customer classes. Exh. PGE-28, at pp. 2-3; Tr. 553. Similarly, designing retail rates in accordance with EPMC would not violate comparability because PG&E imposes the same charges for retail transmission service on both itself and other customers irrespective of rate design methodology. Tr. 565.

Staff and Enron contend that EPMC fails to satisfy Order No. 888's open access requirement because it violates Transmission Pricing Policy Statement economic efficiency, fairness and practicality principles. PG&E counters that EPMC: (1) satisfies the economic efficiency principle because the methodology is based on marginal cost of service; (2) satisfies the fairness principle because EPMC neither produces subsidies between existing and new transmission customers nor impedes new retail users under California's "direct access" market structure; and (3) satisfies the practicality principle because changing the retail transmission rate design under which PG&E has operated for many years presents numerous administrative, logistical and engineering problems. PG&E also argues that the alternate rate designs suggested by Staff and Enron have no demonstrated advantage over EPMC.

I find and conclude that whether the Staff/Enron-proposed rate designs have any demonstrated advantage(s) over EPMC is immaterial. Staff and Enron do not bear the burden of persuasion in this proceeding. Turning to the principles at issue, the record compels me to find and conclude that PG&E's proposed use of the EPMC methodology to design retail transmission rates would at a minimum violate the fairness and practicality principles, and might violate the economic efficiency principle as well. I previously determined that PG&E failed to establish it provides different transmission services to wholesale and retail customers. I consequently concluded EPMC would violate Order No. 888's fundamental non-discrimination principle if it were used to design retail transmission rates at the same time wholesale transmission rates were designed using the 12 CP methodology. Discrimination is by definition unfair and

[9] Although Enron presents some of its objections in "comparability" terms, I find that those objections more appropriately should be considered in the context of the fairness principle, infra.

inequitable.[10] Moreover, conceding arguendo PG&E's claim that changing the retail transmission rate design under which the Company has operated for many years presents numerous administrative, logistical and engineering problems, the record before me compels conclusions that EPMC is a complicated and inadequately explained methodology. It does not satisfy the practicality principle for those reasons. And while the record indicates that EPMC promotes economic efficiency in certain respects (Exh. PGE-28, at p.4), it conversely suggests that EPMC could subvert economic efficiency by obscuring the market signals marginal pricing is intended to send (Exh. S-31, at pp. 16-17).

I find and conclude that PG&E's retail rate design proposal is consistent with the Transmission Pricing Policy Statement's revenue requirement and comparability principles, but is inconsistent with the fairness, practicality and economic efficiency principles. On balance, I find and conclude that PG&E's proposed retail rate design fails to satisfy the Transmission Pricing Policy Statement. The Company logically should use the same (12 CP) methodology to design retail transmission rates that it uses to design wholesale transmission rates. PG&E concedes it could accommodate a 12 CP methodology, provided the methodology is applied prospectively and subject to two (2) conditions: loss-adjusted retail demands are utilized and the standby charge is adjusted to reflect a reasonable share of stand-by customer[11] contract demands. Exh. PGE-29, at pp. 4-6.

No party disputes that the 12 CP methodology should be applied on a prospective basis. Such application, moreover, would be consistent with general Commission policy. See, e.g., Consumers Energy Company, 89 FERC • 61,138 (1999). I therefore find and conclude that the 12 CP methodology should be applied to PG&E's retail transmission rates on a prospective basis. And since no party challenges PG&E's position that loss-adjusted retail demands should be utilized, I find and conclude it is appropriate to adopt this modification as well. The record, however, indicates that PG&E's proposed demand loss-adjustments are outdated. Exh. S-49; Tr. 602-04. PG&E therefore must support any demand loss-adjustments with current data.

No party opposes PG&E's standby charge adjustment in principle. Staff and CPUC nevertheless object to the magnitude

[10] So, too, is basing wholesale transmission rates on actual loads while basing similar retail service rates on marginal cost estimates. Exh. S-31, at p. 18.

[11] Stand-by customers operate their own merchant power plants/cogeneration facilities on the PG&E system.

of PG&E's proposed adjustment, which the record indicates would increase stand-by customer rates by approximately 63%. Exh. PUC-58. PG&E presented evidence at hearing that the stand-by rate increase is consistent with the increase(s) a shift to 12 CP would impose on other transmission voltage retail customers because stand-by customer system demand is comparable to large customer retail demand. Tr. 522-23, 526-27. The Company also presented evidence that a 63% stand-by customer rate increase is a function of applying the same 38% reservation factor to 12 CP that currently is applied under EPMC (Exh. PGE-31, at pp. 6, 12; Tr. 524), and that an unadjusted switch to 12 CP would reduce the stand-by customer allocation from approximately 0.75% of total transmission revenue requirement to approximately 0.02% (Tr. 521-22). In the absence of any contradictory record evidence, I am compelled to find and conclude that PG&E's evidence on this point is adequate to support the Company's proposed standby charge adjustment.

PG&E's retail rate design proposal recommends this Commission to order any over-collected retail transmission revenues to be credited through the Company's CPUC-jurisdictional Transmission Revenue Account ("TRA"). Exh. PGE-25, at p. 9. The Company bases this recommendation on the presumption that such over-collections only would affect CPUC's calculation of PG&E's competitive transition charges ("CTCs").[12] Id. The Commission previously has stated that it "will defer to the California Commission and California legislature with respect to the design of the CTC" adding that "recovery of retail stranded costs is a matter in the first instance for the states to address and resolve." Pacific Gas and Electric Company, et al., 77 FERC • 61,265, at p. 62,093 (1996). As a consequence, I find and conclude it would be inappropriate to address CTCs or the TRA in the context of this proceeding.

II. Are Certain Facilities Which Formerly Were Classified as Generation Ties and Generator Step-Up Transformers Properly Included in the Network Transmission Rate Base?

PG&E proposes to re-classify as "network transmission" facilities approximately $132 million worth of gross plant previously designated "generation ties" or "generator step-up transformers." The Company's Diablo Loop, Morro Bay Loop and Moss Landing Loop comprise approximately $89 million worth of these facilities; the remaining $43 million is spread among 41 separate transmission lines/transformers which PG&E characterizes as performing network transmission functions.

[12] PG&E uses CTCs to recover stranded costs.

a. Party Positions

1. PG&E

PG&E maintains that the network transmission classification of the Diablo Loop, Morro Bay Loop and Moss Landing Loop is beyond dispute. According to the Company, each of these facilities: (1) unambiguously performs a critical network transmission function; (2) was properly color-coded on the transmission system maps filed with the Commission in support of its initial FPA Section 203 filing for permission to turn operational control over to the California Independent System Operator ("ISO"); (3) was in fact turned over to ISO operational control at commencement of ISO operations; and (4) always has been reflected in PG&E's transmission rates. PG&E argues that under these circumstances there can be no doubt that the Diablo Loop, Morro Bay Loop and Moss Landing Loop properly are included in PG&E's transmission rate base or that the revenue requirement associated with them properly should be recovered in TO-3 transmission rates. PG&E emphasizes that with respect to the other 41 facilities at issue, 39 of them are listed on the ISO's Transmission Register, indicating that they also were under ISO operational control at commencement of ISO operations and therefore should have been included in transmission rate base. The Company dismisses any challenge to such inclusion based on its failure to make a supplemental FPA Section 203 filing to correct inaccurate color-coding on transmission system maps submitted in support of the initial filing as unnecessary, also noting that some of these facilities were mis-classified despite being properly color-coded on the maps. In addition, PG&E stresses that the bulk of facilities at issue no longer has any associated generation and therefore must exclusively be performing transmission functions. PG&E characterizes the balance as "dual function" facilities which should be included in transmission rate base because they serve a discrete transmission function in addition to any generation function they may serve.

2. Commission Staff

Staff maintains the record in this proceeding does not support allocating any of the costs associated with the facilities at issue to PG&E's network transmission rate base. Staff argues that costs charged to captive transmission customers under the TO-3 tariff must reflect facilities which: (1) properly have been turned over to the ISO's operational control; and (2) predominantly perform a network transmission function. According to Staff, the facilities at issue satisfy neither of these criteria.

Staff takes the position that none of the re-classified facilities properly has been turned over to ISO operational control through the requisite FPA Section 203 filing with the Commission, arguing that this deficiency alone compels exclusion from network transmission rate base under the TO-3 tariff. Similarly, while Staff concedes that PG&E always has included the Diablo, Morro Bay and Moss Landing Loops in transmission rate base, it claims the Company did not always recover the costs associated with those facilities from all transmission customers as it would under the TO-3 tariff. Instead, because PG&E previously classified the Diablo, Morro Bay and Moss Landing Loops as "generation tie" facilities, the Company charged customers based on a sub-functional methodology intended to reflect only those portions of the transmission system used to serve them. Any transmission customer not using the generation tie sub-function did not pay for generation tie facilities including the Diablo, Morro Bay and Moss Landing Loops under that methodology. Staff underscores that the record in this proceeding does not show whether any non-PG&E transmission customers used/paid for the Diablo, Morro Bay and Moss Landing Loops prior to the electric industry restructuring which transferred operational control over these facilities to the ISO.

In addition, Staff emphasizes that while the Diablo, Morro Bay and Moss Landing Loops indisputably perform a network contingency function, these facilities' active generation-related functions far outweigh their network contingency functions. Staff contends it would be egregiously inconsistent with the Commission's fundamental ratemaking policy that costs be allocated according to use for PG&E to charge 100% of the costs associated with these facilities to captive transmission customers. According to Staff, the only arguable basis for PG&E's proposed inclusion of any of the facilities at issue in network transmission rates is the Company's tortured re-definition of "generation ties" and "generator step-up transformers" as any transmission line or transformer that is used exclusively to step-up or transmit power from a generator to the grid (the "exclusive use" definition). Staff disputes the "exclusive use" definition's legitimacy and, as a consequence, endorses retaining the "primary use" definition for assigning costs to generation that PG&E used for approximately twenty (20) years prior to this filing.

3. CPUC[13]

CPUC raises the same legal issue as Staff concerning PG&E's failure to transfer operational control of the facilities at issue to the ISO through the requisite FPA Section 203 filing. It argues that PG&E cannot recover costs associated with such

[13] Public Utilities Commission of the State of California

facilities under the TO-3 tariff because transfer of operational control to the ISO is a condition precedent to recovery under that tariff. And like Staff, CPUC acknowledges that some of the facilities at issue perform a network contingency function, but challenges the "exclusive use" definition's legitimacy for cost allocation purposes. CPUC vigorously disputes any PG&E assertion that CPUC ever reviewed, accepted or adopted PG&E's "exclusive use" definition in the context of a CPUC proceeding. To the contrary, CPUC maintains that the "exclusive use" definition undermines the fundamental objective of California's energy industry restructuring because it effectively re-bundles generation and transmission costs and, additionally, creates a "free rider" problem with respect to generators using the facilities at issue. CPUC also criticizes PG&E's attempt to justify the "exclusive use" definition on the basis that dual-function facilities present cost allocation difficulties, noting that such difficulties do not excuse inappropriate cost allocation particularly when appropriate allocation may be achieved contractually. CPUC therefore advocates a "primary function" test analogous to that applied to natural gas facilities. CPUC submits it is far more reasonable to allocate costs according to primary function than to do so in accordance with PG&E's "exclusive use" proposal. CPUC also states it would not oppose proportionate cost allocation for dual-function facilities, but notes that such allocation has no record support in this proceeding.

4. CDWR[14]

CDWR maintains that PG&E has not satisfied the burden of proof concerning its proposed re-classification of the facilities at issue as "network transmission." CDWR submits that any such re-classification is exclusively attributable to PG&E's unjustified "exclusive use" re-definition of generation ties/generator step-up transformers, adding that the "exclusive use" definition itself fails to comply with Commission and CPUC unbundling mandates. CDWR also echoes the argument that PG&E cannot recover costs associated with facilities improperly transferred to ISO operational control under the TO-3 tariff because proper transfer of such operational control is a condition precedent to recovery under that tariff.

5. LADWP[15]

LADWP, in contrast to Staff, CPUC and CDWR, argues there is no legal or evidentiary basis for deviating from the traditional Commission policy of rolling into network transmission rate base

[14] Department of Water Resources of the State of California

[15] Los Angeles Department of Water and Power

the costs of any transmission line(s) which benefit/are integrated with the network transmission grid. Accordingly, LADWP supports PG&E's proposed recovery of costs associated with the facilities at issue under the TO-3 tariff. LADWP additionally argues that electric industry restructuring requires the Commission to adopt a "bright-line" test to distinguish between facilities which perform a network transmission function and those which do not. To this end, LADWP enumerates seven (7) characteristics intended to identify facilities which perform no network transmission function whatsoever. LADWP submits that such facilities typically: (1) will be connected to an integrated transmission network at a single station; (2) will not exhibit power flow when the connected station is off line; (3) will exhibit power flow in a single direction away from the connected station when the station is on line; (4) will not commingle the connected station's power with power from a resource owned or controlled by another company/entity; (5) will not have its power flow affected by alternate transmission path constraints; (6) will not be connected in parallel to a network transmission facility; and (7) will not be directly connected to wholesale or retail customers. LADWP suggests the Commission should endorse this test as a matter of general policy.

6. Southern Cities[16]

Southern Cities emphasize there is no dispute that the facilities at issue perform a network transmission function. They maintain that this fact, coupled with the traditional Commission principle that transmission revenue requirement should include the costs of all facilities supporting the integrated transmission network, necessarily leads to the conclusion that PG&E should recover all costs at issue under the TO-3 tariff.

b. Discussion

As a threshold matter, I find and conclude that any consideration of LADWP's proposed "bright-line" test to distinguish between facilities which perform a network transmission function and those which do not is beyond the scope of this proceeding. It is not within my authority to establish Commission policy. Neither is LADWP's proposed test necessary to decide the issue presented.[17]

[16] Cities of Anaheim, Banning, Colton and Riverside, California

[17] This Initial Decision does not address the merits/deficiencies of PG&E's proposed "exclusive use" definition for the same reason.

The record is conclusive that each of the facilities at issue performs at least some network transmission function. Exh. PGE-13, at pp. 4-9; Exh. DWR-1, at p. 29; Tr. 661-62, 847-48. No party disputes this fact. It follows that the issue to be decided is not whether the facilities at issue perform network transmission functions, but whether and to what degree it is appropriate for PG&E to recover the costs associated with those facilities under the TO-3 tariff.[18]

It has long been Commission policy to require all costs associated with a particular facility to be rolled-in to network transmission rate base insofar as any degree of integration with the transmission grid could be demonstrated. See, e.g., American Electric Power Service Corp., 44 FERC • 61,206, at p. 61,748 (1988) ("American Electric"). PG&E, LADWP and Southern Cities maintain that this policy supports PG&E cost recovery for the facilities at issue under the TO-3 tariff. I disagree.

The line of cases which American Electric represents was decided in a pre-Order No. 888/California restructuring environment. A fundamental characteristic of that environment was bundled service. But as the Commission more recently observed:

> Much has changed since we decided these cases. Most importantly, in Order No. 888, we required the unbundling of transmission and wholesale generation services. We believe it is appropriate to reexamine our policy on the functionalization and the recovery of costs associated with [generator step-up transformers] to ensure that unbundled service customers are paying only their appropriate share of the cost of services which they use. In this regard, we said in Northern States that:
>
> > . . . in designing a rate for a transmission-only customer, a utility must unbundle the components of its cost of service in order to identify specifically those costs which relate to the provision of transmission service. [64 FERC at p. 63,379]
>
> In Northern States we went on to say that under the old approach where utilities were selling primarily a bundled generation and transmission service, the

[18] The parties jointly stipulated that the factor to be used in converting any costs excluded from TO-3 tariff recovery to a reduction in PG&E's annual retail transmission revenue requirement shall be 13.5%. JS-1; Tr. 65.

> precise functionalization of generation and transmission costs was not critical. However, we found that this approach "may need to be reexamined in light of changes taking place in the electric industry particularly the increase in transmission-only service." (Id., footnote omitted) Furthermore, we stated that "[t]he fundamental theory of Commission ratemaking is that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the costs to be incurred." (Id., emphasis in original)

Kentucky Utilities Company, 85 FERC • 61,274, at p. 62,111 (1998) ("Kentucky") (quoting Northern States Power Company, 64 FERC • 61,324 (1993) ("Northern States"), reh'g denied, 74 FERC • 61,106 (1996)). The Commission went on expressly to state that it was reversing its earlier policy of allowing such costs to be included in transmission rate base because that treatment ignored the role the facilities at issue performed in supporting generation and ancillary services. Id., at p. 62,112.

The same reasoning logically applies to the facilities at issue here. The record establishes that while the Diablo, Morro Bay and Moss Landing Loops each indisputably performs a critical network transmission function, each facility's generation-tie function far outweighs its network contingency function. For example, the record confirms that the various generating units connected by these three (3) facilities transmitted power over them to the grid between 81% and 100% of the time throughout 1997, 1998 and 1999. Exh. S-42; Exh. S-43; Exh. S-44; Exh. S-45; Exh. S-46; Exh. S-47; Exh. S-48; Tr. 482, 489-92. Allocating 100% of the costs associated with these facilities to their network contingency functions therefore would accomplish precisely the opposite of ensuring that unbundled service customers pay their appropriate shares of the cost of services which they use, and clearly would be inconsistent with the "fundamental" theory of Commission ratemaking articulated in Kentucky and Northern States: that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the costs to be incurred.[19] I therefore find and conclude it is unjust and unreasonable for PG&E to recover 100% of the costs associated with the Diablo, Morro Bay and Moss Landing Loops under the TO-3 tariff. And since the record in this proceeding does not establish what proportional use of these

[19] The inconsistency would be even more pronounced under PG&E's proposed "exclusive use" definition. That standard would allocate to network transmission 100% of costs associated with any facility demonstrating the slightest scintilla of network support.

facilities legitimately may be allocated to network transmission, there is no option but to exclude Diablo, Morro Bay and Moss Landing Loop costs from TO-3 tariff recovery in their entirety at least until PG&E quantifies these facilities' network transmission components in a compliance filing. On this record, the only way to ensure that network transmission customers not utilizing the Diablo, Morro Bay and Moss Landing Loops' generation-tie function do not pay costs associated with that function is for PG&E to continue to allocate those costs under the current sub-functional methodology.

This does not hold true for the entirety of the facilities at issue. The record indicates that $17 million worth of these facilities are dual-function. As such, they must be treated in the same manner as the Diablo, Morro Bay and Moss Landing Loops. In contrast, the record confirms that while the remaining $26 million worth of facilities at issue once performed generation connection functions in addition to their network transmission functions, the previously connected generation is no longer in service. Exh. PGE-10, at p. 12; Tr. 383; Exh. PGE-13, at pp. 6-7; Tr. 661-62. It follows that these facilities must now be dedicated exclusively to network transmission. Accordingly, 100% of their associated costs should be recoverable under the TO-3 tariff.

Staff, CPUC and CDWR argue that even these limited costs cannot be recovered under the TO-3 tariff because PG&E failed properly to transfer operational control over any of the facilities at issue to the ISO through the requisite FPA Section 203 filing. PG&E counters that a supplemental FPA Section 203 filing might be desirable to eliminate any confusion over precisely which facilities were in fact transferred to the ISO's operational control, but such a filing is not a condition precedent to the actual transfer of operational control over those facilities.

I find and conclude that Staff, CPUC and CDWR are technically correct in their assertion that transfer of operational control to the ISO presupposes an FPA Section 203 filing. Strict adherence to that principle insofar as this $26 million worth of facilities is concerned, however, unnecessarily elevates form over substance. The record indicates that at least some of these facilities were simply overlooked/mistakenly color-coded in the initial Section 203 filing. Tr. 496-98. More important, the record indicates that most (if not all) of these $26 million worth of facilities were at all relevant times properly reflected in the ISO Transmission Register which serves as the operational indicator of whether facilities are in fact under ISO control. Exh. PGE-30, at p. 1; Exh. S-30, at p. 2; Exh. DWR-11, at p. 138; Exh. DWR-12, at p. 7. It clearly was contemplated that the Transmission Register would track interim facility changes that rendered serial FPA Section 203 filings administratively impractical. Exh. DWR-15, at p. 39. On the record before me, I find and conclude that PG&E's failure to transfer operational control over this $26 million worth of facilities through a supplemental FPA Section 203 filing does not preclude the Company from recovering the costs associated with those facilities under the TO-3 tariff.

C. MATTERS NOT DISCUSSED

This Initial Decision's failure to discuss any matter raised by the parties, or any portion of the record, does not indicate that it has not been considered. Rather, any such matter(s) or portion(s) of the record has/have been determined to be meritless, immaterial or irrelevant. Arguments made on brief which were unsupported by record evidence or legal precedent have been accorded no weight.

D. ORDER

Wherefore, it is ordered, subject to review by the Commission on exceptions or on its own motion, as provided by the Commission's Rules of Practice and Procedure, that within thirty (30) days of the issuance of the Final Order of the Commission in this proceeding, PG&E shall comply with the findings and conclusions contained in this Initial Decision, as adopted or modified by the Commission. Such compliance shall include a filing with the Commission adopting a 12 CP methodology for the Company's retail transmission rate design, with the modifications/supplementation specified herein, as well as a supplemental FPA Section 203 filing which accurately reflects all facilities transferred to the ISO's operational control.

H. Peter Young
Presiding Administrative Law Judge

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