BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 20-10-012 (filed October 23, 2020)

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

TABLE OF CONTENTS

TABLE OF 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, where I 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 twelve 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 thirty 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 in six proceedings.

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 SCE's Phase 2 2020 General Rate Case Application, addressing issues of marginal costs and revenue allocation, rate design, and TOU periods. Our discussion of rate design recommends that the Commission establish a Track 2 in this proceeding to consider proposals for Real Time Pricing pilot tariffs. We also recommend that the Commission consolidate the GS-1 and GS-2 classes, as examined in SCE-04, Appendix J.

III. Marginal Costs and Revenue Allocation

A. Marginal Generation Capacity Costs (MGCCs)

Q: Please summarize SCE's method for calculating MGCCs.

A: SCE calculates the long-term MGCC based on the expectation that "future capacity needs will most likely be met by 4-hour lithium-ion batteries."[1] Next, as Cal

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[1] SCE, Exhibit 2, p. 16, lines 15-16.

Advocates describes it, "SCE then assumes separate batteries are used to serve both peak and flex or ramping needs, which essentially doubles SCE's proposed MGCC for revenue allocation."[2] These costs are then assigned to time periods using SCE's Capacity Allocation Tool.[3]

Q: What is your opinion of SCE's method for calculating MGCCs?

A: We generally agree with the use of 4-hour battery storage as the cost basis for MGCCs. Cal Advocates concurs with the use of the 4-hour batteries but disagrees with SCE's cost inputs and time horizon.4 We take no position on the MGCC cost inputs or time-horizon issues.

With respect to the spreading of costs between peak capacity needs and ramping capacity needs, we disagree with methods proposed by SCE and Cal Advocates. Instead, we recommend that all MGCC costs be allocated to peak capacity needs as proposed by PG&E in its most recent Phase 2 GRC.

Regarding the Capacity Allocation Tool, we also disagree with the methods proposed by SCE and recommend the use of the methods proposed by PG&E.

Finally, we did not identify any concerns with SCE's method for allocating MGCCs to customer classes but take issue with Cal Advocates' recommendation to change the assignment method for distributed generation (DG) related costs to match the method for renewable portfolio standard (RPS) costs.

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[2] Cal Advocates, Ch. 4, p. 2, lines 13-15.

[3] SCE-02, p. 19, line 5 through p. 20, line 12.

[4] Cal Advocates, Ch. 4, p. 4.

1. Allocation of MGCCs between peak and ramp

Q: Why do you recommend against using SCE's method for spreading MGCCs between peak and ramp?

A: We agree with Cal Advocates that SCE's proposal to assign capacity costs to both the peak and flex functions, doubling the MGCC from $90.85 to $181.70 per kW-year, is inappropriate. Cal Advocates' testimony demonstrates that SCE has failed to provide any support for its proposal to treat peak and ramp generation requirements separately.[5] Essentially all of the critical ramping demands are winter months with no contribution to peak-load reliability risk. Peaking and ramping would not compete for the energy stored in the batteries, since SCE's capacity allocation heat maps show that 93% of the ramping demands are on the weekends, when only 3% of the peak contribution occurs.[6] No hour has non-zero peak and ramping.

SCE compounds this excessive MGCC by then splitting that $181.70 per kW-year between peak-related capacity (65 percent) and flexible generation capacity (35 percent).[7] We were unable to locate any justification for this 65/35 split in SCE's testimony or workpapers, and Cal Advocates does not discuss this split. If $91 is required by a kilowatt of peak load, we do not see why SCE would allocate 65% of $182, or $113, to that peak load.

Q: Why do you also disagree with Cal Advocate's method for spreading MGCCs between peak and ramp?

A: While we agree with Cal Advocates that the cost of MGCCs should not be doubled, Cal Advocates argues for splitting the MGCC costs on a 75/25 basis between ramp

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[5] Cal Advocates, Ch. 4, pp. 14-18.

[6] SCE-02, pp. 22-23, Tables I-5 and I-6.

[7] SCE-03, p. 11, lines 11-13. Also verified in SCE's workpaper "GRC Tool.xlsx", tab "Heat Maps," cells AC20:AF22.

and peak, "based on the concept that a 4-hour lithium-ion battery … would theoretically provide 3 hours of ramping capacity and 1 hour of peaking capacity."[8]

There are two fundamental flaws with Cal Advocates arguments: peaking does not compete with ramping, so no division of the hours of storage is necessary; and the metric for allocating storage between ramping and peaking should not be Cal Advocates' ratio of three hours to one hour.

Cal Advocates' argument that storage should be treated as supporting a three-hour load and then contributing to peak for one hour is refuted by its own evidence. Cal Advocates notes that "there was only a single instance…where a top 100 ramp period coincided with the same month as a top peak hour…even this single ramp period does not fall on the same day...as any of the top peak hours in the same month."[9] Cal Advocates then concludes, "Clearly, it does not make sense to model peak and flex functions as if each function requires its own dedicated battery."[10] Equally, it does not make sense to model peak and flex functions as if the functions used storage on the same day. All four hours of capacity are available to serve either peaking or ramping functions, as justified by conditions in different seasons.

Furthermore, even if any incremental storage capacity were driven by to ramping, Cal Advocates' approach to allocating the majority of costs to the ramping function is invalid. It is incorrect to identify ramping events as lasting three hours and peaking events as lasting just one hour. Ramping events are defined by a three-hour metric, but they may be shorter or longer than three hours.

Similarly, periods of net-load peak exposure can definitely last longer than one hour. Even same-day demand response events are called for more than one hour.

[8] Cal Advocates, Ch. 4, p. 18, lines 16-18.

[9] Cal Advocates, Ch. 4, p. 16, lines 5-8.

[10] Cal Advocates, Ch. 4, p. 17, lines 2-3.

There is ample evidence throughout the Commission's review of TOU and CPP event periods, RTP rate design, demand response program design, and countless other proceedings to prove that peaking events often last several hours. In SCE's 2024 peak demand forecast, the peak day includes a seven-hour peak event.[11]

A single-peak-hour focus also overlooks operational flexibilities available from energy-limited resources. Hydro resources can be shifted among hours to some extent, output from a battery in the hours around the peak may allow CAISO to use more of the hydro energy in the hour of maximum need. Transmission lines can be loaded to higher levels in the peak hour, if their load can be decreased by using the batteries in near-load hours.

In summary, rather than competing services, ramping and peak capacity are joint products of battery storage. Just as raising one steer produces both meat and a hide for leather, building a megawatt of storage produces both ramping and peaking services. It has long been known that efficient pricing of joint products requires allocation of common costs (such as the battery) to the product that requires the most of the common resource and creates the binding constraint on output.[12] Rather than looking at the duration of ramping and peaking events, allocation of the capacity costs, should take into consideration the magnitude of the needs.[13]

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[11] SCE, Generation Capacity Revenue Allocation Model, workpaper SCE-03 – I.C.3.a – Generation Capacity Retail Net Load and Revenue Allocation.xlsx, tab Peak (Net), rows 5905-5911.

[12] If putting all the common cost on one product would result in decreasing the demand for that product and increasing the demand for the other product, so that the second product now causes the binding constraint, prices should be set so that the two products require the same amount of the common input.

[13] Those needs may be measured in megawatts or megawatt-hours.

SCE's allocation of ramp capacity is driven by a forecasted daily maximum ramp of about 8,400 MW.[14] The 8,400 MW ramping capacity need is concentrated during hour 18 in November and hour 19 in March (which represents 52% of the ramping need), and 93% is on weekends.[15] Based on this finding, SCE allocates a portion of the MGCCs to the winter mid-peak period.[16] In SCE's revenue allocation process, the 6-7 pm weekend hour receives somewhat somewhat smaller allocation. Still, as shown in Table 1, SCE allocates about half of the ramp-related revenue to the weekend.

Table 1: Ramp Generation Capacity Allocation by Time and Type of Day[17]

Type of Day	Hour	Net Ramp Capacity (Sum of MWs)	Percent
Weekday	5 pm – 6 pm	7,519	10 %
	6 pm – 7 pm	31,086	40 %
Weekend	5 pm – 6 pm	8,372	11 %
	6 pm – 7 pm	30,242	39 %
Total		**77,219**	**100 %**

This is significant because SCE's gross load at the end of these ramping events is on the order of 10,000 MW, and the maximum three-hour ramp is under 8,500 MW, less than half the forecast peak for summer weekday net peak capacity requirement of about 17,900 MW.[18] At first blush, the summer peak requirement seems to be the more important driver of total resource needs.

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[14] SCE, Generation Capacity Revenue Allocation Model, workpaper SCE-03 – I.C.3.a – Generation Capacity Retail Net Load and Revenue Allocation.xlsx, tab Ramp, cell T123.

[15] SCE-02, p. 23, Table I-6.

[16] SCE-02, p. D-2.

[17] Calculated from SCE, Generation Capacity Revenue Allocation Model, workpaper SCE-03 – I.C.3.a – Generation Capacity Retail Net Load and Revenue Allocation.xlsx.

[18] SCE-02, p. 22, Table I-5; Generation Capacity Revenue Allocation Model, workpaper SCE-03 – I.C.3.a – Generation Capacity Retail Net Load and Revenue Allocation.xlsx, tab Peak, cell S5908. This

Indeed, in the Extreme Weather Reliability proceeding (R.20-11-003), summer peak events prompted the Commission to increase near-term procurements. For the foreseeable future, the winter ramping capacity requirement is likely to be more than adequately supplied with capacity procured to meet peaking requirements. Cal Advocates proposal to collect 75 percent of MGCCs during winter ramping periods is at odds with the demonstrated capacity requirements of the CAISO system.

SCE does not clearly state why the capacity available to meet the summer peak capacity requirement is not adequate for meeting ramping capacity.

Q: Why do you recommend zero MGCC allocation to the ramping function?

A: In theory, we agree that if both peaking and ramping requirements were to require additional storage, then the unit marginal cost of battery storage should be allocated to reflect the costs of maintaining reliability and balancing the relative frequency of loss of load events (LOLE, a measure of peak capacity risk) and loss of ramp events (LORE).[19]

Furthermore, even if ramping capacity requirements were a binding constraint, battery storage is not necessarily the least expensive means of meeting those requirements. The issue of whether peak and ramp capacity should be considered joint costs or separate costs was explored in a workshop convened by SCE in August 2019 to explore revenue allocation for flexible generation.[20] In that meeting, PG&E made a persuasive argument that, since virtually all high-ramp events occur in non-summer

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17,900 MW net peak capacity requirement is forecast during an hour with a forecast gross load of about 18,500 MW. Some hours with lower net peak capacity requirements have forecast gross loads of over 22,100 MW.

[19] SCE-03, Appendix B, Flexible Generation Capacity (August 22, 2019), p. 9.

[20] SCE-03, Appendix B, Flexible Generation Capacity Revenue Allocation Workshop (August 22, 2019).

months, the least-cost solution for the system is curtailment of renewables at the beginning of the ramp.[21]

Following that workshop, in its Phase 2 GRC application, PG&E adopted the position that "the least-cost way to meet flexible capacity constraints … turned out to be curtailment of contracted solar resources during the first hour of the maximum ramp on Flex need days." PG&E also discussed the uncertainty created by CAISO's 2019 RA Enhancements proposal, and for both reasons, set ramp (or Flex) capacity costs to zero.[22]

Furthermore, curtailment to resolve ramps is not costly: PG&E estimates that curtailment represents less than 0.5% of forecasted utility-scale solar generation.[23] Because such curtailment costs are captured through MECs and are not related to generation capacity investments, it is not reasonable to allocate any MGCC costs to ramp. PG&E's argument leaves the question of whether there is any marginal capacity requirement during the ramp period as a moot point.

2. SCE's method for allocation of MGCCs across hours

Q: What are the problems with SCE's Capacity Allocation Tool?

A: While SCE's Capacity Allocation Tool "is intended to be a relative distribution of risk used to allocate capacity value across hours based on a 1-in-10 planning scenario,"[24] the planning scenario is improperly constructed to achieve that goal.

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[21] SCE-03, Appendix B, Jan Grygier, PG&E Discussion Points on Developing and Allocating Flexible Capacity Costs (August 22, 2019), pp. 4-5.

[22] PG&E, Exhibit PGE-2 (A.19-11-019), p. 2-6, line 18 through p. 2-7, line 3.

[23] SCE-03, Appendix B, Jan Grygier, PG&E Discussion Points on Developing and Allocating Flexible Capacity Costs (August 22, 2019), p. 6.

[24] SCE-02, p. 20, FN 34.

Specifically, SCE's Capacity Allocation Tool relies on load, wind, solar, and transportation electrification load shapes that are not properly aligned. According to SCE's *Capacity Allocation Tool User Guide*:

> The Net Load input file ("CAT STEP 1 – 2024 Master File.xlsm") contains the hourly load, wind, and solar shapes. The hourly load is 30 unique system level load shapes based on 30 years of historical weather data that are scaled such that the average annual energy represents the internal energy forecasted by SCE minus distributed generation photo voltaic (DG PV) plus a shape for transportation electrification (TE). DG PV is treated as supply side resources and in the total solar profile input as an annual shape. Wind and solar shapes are the total expected contracted RPS plus forecasted DG PV.[25]

The hourly load shapes represent 30 unique weather years, but the transportation electrification load shape and the solar and wind generation profiles are deterministic, and do not vary from year to year.[26]

The 1-in-10 planning scenario is improperly constructed because it does not correlate system load with its solar and wind generation profiles, as naturally occurs. On a cloudy day, solar generation is reduced and system load also tends to be lower. The relationship of wind generation to system load is less straightforward, but generally sunny, calm conditions are associated with higher loads than sunny, breezy conditions. Of course, the relationships are complicated by the varying weather conditions across the CAISO system.

A better practice is to develop system load and renewable energy generation profiles that are based on the same weather years, either using actual historical data or a model. Because of the important role that hydroelectric generation plays on the CAISO system, it is also important to include hydro profiles that are based on those same weather years as well.

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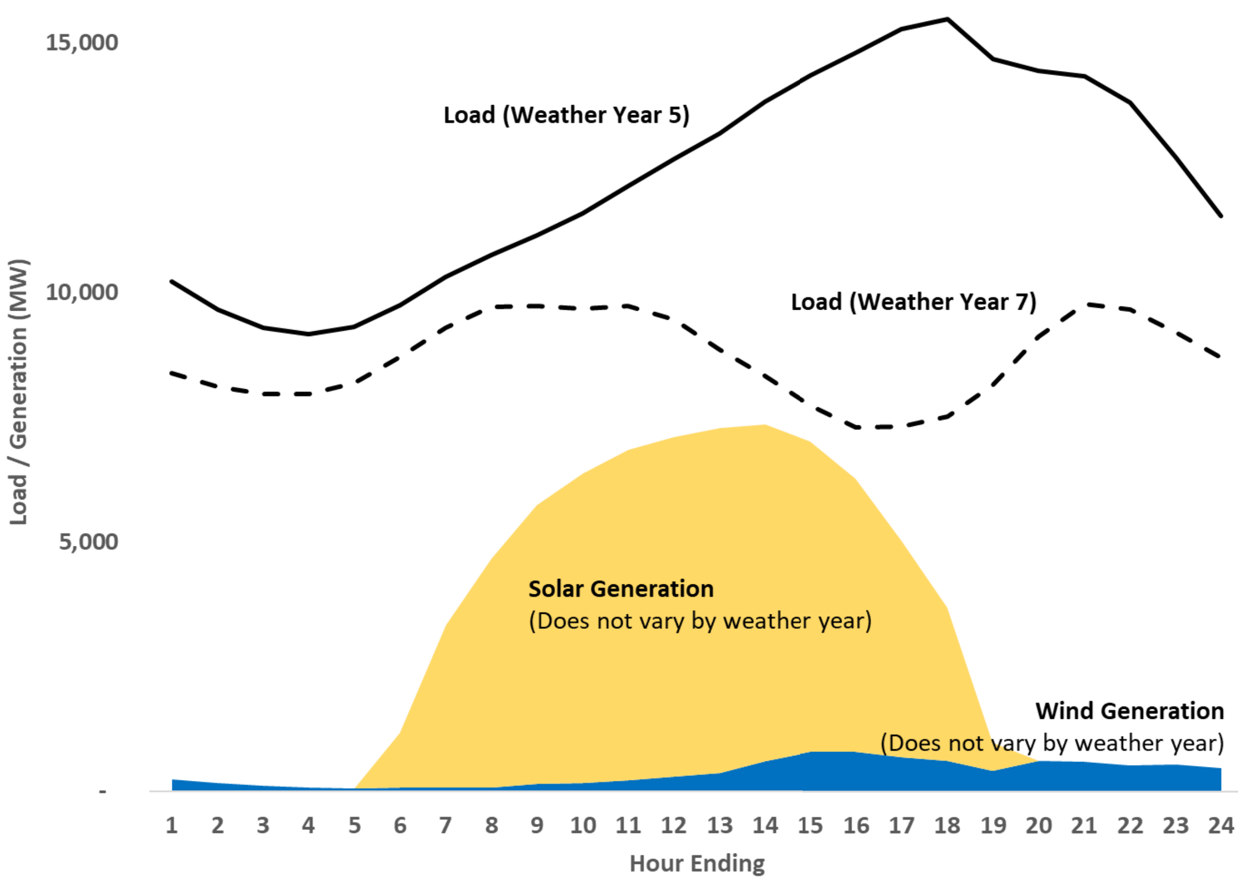
[25] SCE, *Capacity Allocation Tool User Guide*, Attachment 3 (attachment to data request CalAdv-SCE-011-NC, Question 01), p. 2.

[26] SCE-02, p. 21, lines 1-27.

Q: Can you give some examples of how SCE's Capacity Allocation Tool fails to properly relate system load to renewable energy generation profiles?

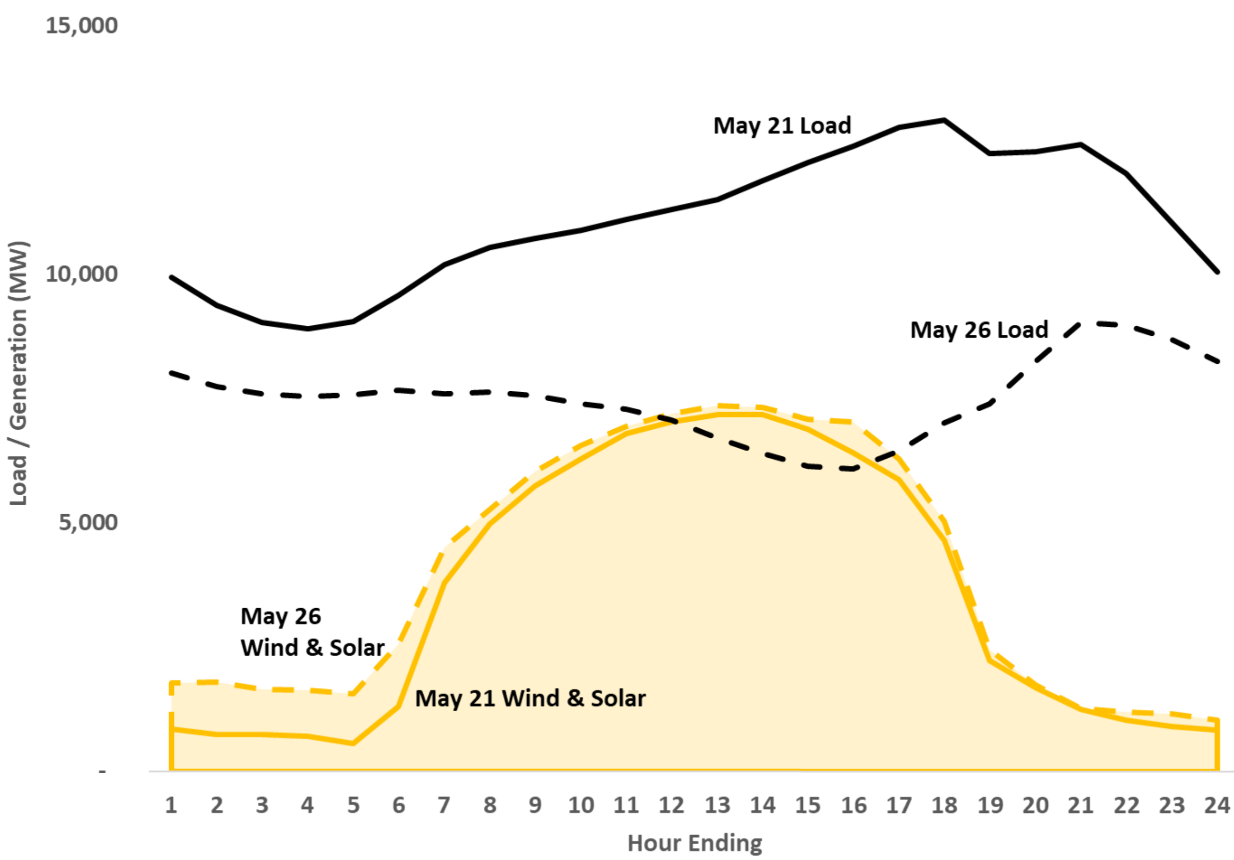
A: Yes. In Figure 1, we show hourly loads for June 14 for two of the thirty weather-year scenarios; those are gross loads, before any reduction for distributed solar. The wind and solar (distributed + utility-scale) generation profiles are uniform across both load scenarios. While we do not have access to the underlying weather data, it is likely that WY 5 is a hot, sunny day since demand rises sharply, while WY 7 appears to be more consistent with a cooler, possibly cloudier and breezier day. Pairing these two load shapes with the same June 14 solar and wind profiles is improper.

Figure 1: Net Load for Two Weather-Year Scenarios Compared to Renewable Generation, June 14 Model Forecast



In Figure 2, we illustrate that even within the same weather-year scenario, SCE's load forecast varies significantly from day to day, while the renewable energy generation profile changes very little. Using WY 20, we see that May 21 appears to be a hot, sunny day, while May 26 appears to be a cooler, possibly cloudy day. The small variation in renewable energy generation (aggregated in this figure to allow for comparison) is almost entirely attributable to wind generation. We surmise that it is unlikely that renewable energy generation would exceed load on May 26 since solar production would be reduced by cloud cover. That same cloud cover would also dampen the ramping requirement on May 26. Modeling a typical solar day on a cool, cloudy day would overestimate the ramping requirement.

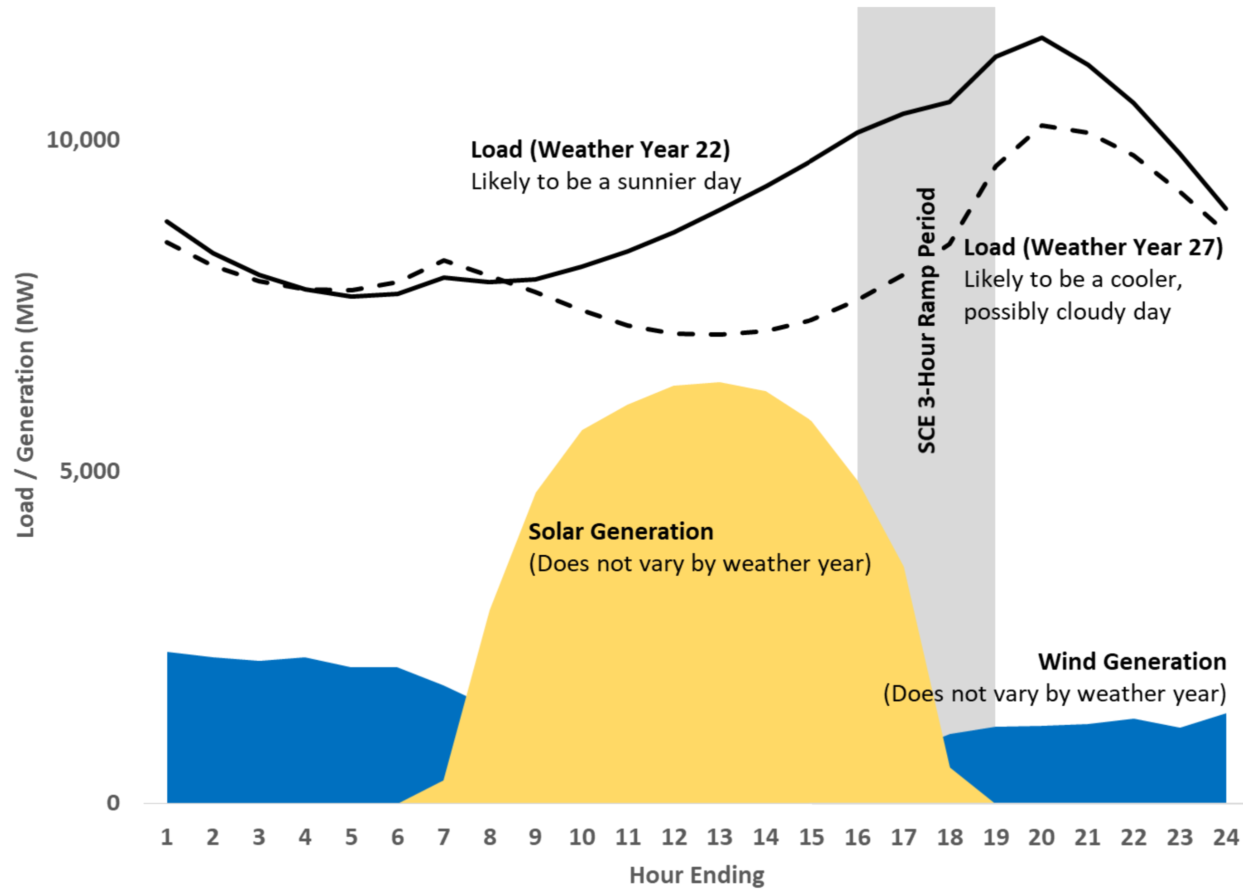
Figure 2: Net Load for Two Forecast Days in a Single Weather-Year Scenarios Compared to Renewable Generation



In Figure 3, we focus on the use of the Capacity Allocation Tool to model ramping events by illustrating a March 10, a weekend day. Again, the load curves exclude distributed solar, and the wind and solar (distributed + utility-scale) generation profiles are uniform across both load scenarios. While we do not have access to the underlying weather data, it is likely that WY 22 is a hot, sunny day since demand rises sharply, while WY 27 appears to be more consistent with a cooler, possibly cloudy day. Yet because the solar generation profile is identical for both scenarios, WY 27 has a higher 3-hour ramp of 8,102 MW compared to 6,446 MW for WY 22.[27] This might be the opposite of what would likely occur if WY 22 is the sunnier day: Adjusting the scenarios to appropriate levels of solar (more for WY 22, less for WY 27) could result in a larger ramp on the sunny WY 22 day than on the cooler WY 27 day.

[27] These illustrative ramp calculations include only load, solar, and wind generation. SCE's ramp calculations include other considerations.

Figure 3: Net Load for Two Weather-Year Scenarios Compared to Renewable Generation, March 10 Model Forecast



While March 10 was not identified by SCE even among its top fifty highest ramping days, the ramp for WY 27 would have ranked in the top three. It is impossible to determine whether pairing solar and wind generation profiles to the weather-year load data would reshuffle the ramping forecast. What is evident is that SCE's use of the Capacity Allocation Tool to identify days and hours with high ramping capacity requirements is flawed.

We recommend against allocating MGCCs to ramping capacity, so it is not necessary to develop a method for allocating capacity to ramping events. If the Commission decides that some MGCCs should be allocated to ramping capacity, our investigation of the Capacity Allocation Tool demonstrates that it should not be used to allocate those costs to specific hours, which is a required step prior to allocating those costs to classes. We do not have the necessary data to develop an alternative.

3. *Recommended method for allocation of MGCCs across hours*

Q: Is it feasible to develop system load and renewable energy generation profiles using the same weather years?

A: Yes, and this is necessary to allocate MGCCs to hours with net peaking conditions. PG&E's Adjusted Net Load (ANL) method uses system load and renewable generation profiles using the same weather-year scenarios, as well as aligning those data with nuclear generation and curtailment of renewable resources. PG&E's ANL method involves applying the historical relationship between the ANL, effective market heat rate (EMHR), and energy price drivers such as the price of natural gas and greenhouse gas emission costs to drive forecast values.[28] The ANL method can be summarized as follows.[29]

- The solar and wind generation profiles and system load shapes for the most recent ten weather years are obtained from the SERVM dataset used in the integrated resource plan (IRP).
- The annual totals for load and non-hydro renewables are taken from the IRP reference system plan for forecast years.
- The profiles and load shapes are scaled match the annual totals for load and non-hydro renewables.

[28] PG&E, Phase 2 2020 General Rate Case, Exhibit 2, A.19-11-019, pp. 2-11 – 2-36.

[29] PG&E, Phase 2 2020 General Rate Case, Exhibit 2, A.19-11-019, pp. 2-36 – 2-40.

- A more complex method for hydro, nuclear, and curtailment of renewable resources completes the development of ten unique weather scenarios of ANL data.

PG&E uses these ten scenarios to forecast ANL, effective market heat rate (EMHR), and energy price data. PG&E calculates an hourly price forecast of wholesale market energy prices in northern California as equal to the average hourly price over all ten scenarios. From those hourly prices, PG&E calculates MECs at the transmission voltage level as a load weighted average value. PG&E made a final adjustment to MECs to account for the impact of increasing amounts of energy storage on MECs relative to the calibration period.

Q: How does PG&E assign MGCC to appropriate time periods?

A: PG&E assigns MGCC using a formula that assigns zero MGCCs to all hours with ANL less than 80 percent of the forecast peak, and then using a MGCC price that increases linearly with ANL such that the full MGCC is assigned.[30] Then, the total MGCCs for each TOU period (e.g., summer on-peak) are summed and divided by forecast load to derive a period-specific MGCC rate.

Q: How do you recommend that SCE assign MGCC to appropriate time periods?

A: We recommend that SCE assign MGCC using PG&E's ANL method. Since PG&E's method is publicly available and, for the most part, uses CAISO system data, SCE may be able to apply PG&E's hourly ANL values without any modification.

There are some aspects of PG&E's method that we have not closely examined, such as the use of a six-year levelized MGCC value. We do not take a specific position on such details. However, since MGCCs are the basis for certain demand response prices, there may be a benefit to maximizing the alignment between the IOUs'

[30] PG&E, Phase 2 2020 General Rate Case, Exhibit 2, A.19-11-019, p. 3-3, lines 9-16.

methods for calculating MGCCs to enable a more consistent statewide response to critical peak events.

4. Assignment of MGCC costs to customer classes

Q: Do you have any concerns with SCE's method for assigning MGCC costs to customer classes?

A: Not at this time, but we will review other parties' testimony on this topic.

Q: Do you support Cal Advocates' proposal to assign hourly costs related to renewable portfolio standard (RPS) and distributed generation (DG) resources on the same basis?

A: No. SCE assign DG costs based on distribution marginal cost revenues as with other costs. Cal Advocates proposes to assign DG costs based on each class' share of system-level annual sales. Cal Advocates states that, "RPS and DG are similar resources in the sense that they are both renewable resources and [therefore] should be treated similarly in the revenue allocation process."[31] This is a fundamentally flawed argument.

First of all, Cal Advocates concurs that SCE is correct to allocate hourly RPS generation based on sales but overlooks the regulatory design that drives that allocation. Cal Advocates points to the fact that RPS procurement is driven by policy directives and that customers have no control over which resources are procured. This is true of many, many aspects of generation, distribution, and transmission costs. In fact, one could opine that all utility procurements are driven by policy directives at some level.

[31] Cal Advocates, Ch. 4, p. 23, lines 7-9.

The reason that the cost responsibility surcharge (CRS) allocates RPS costs based on sales is that there is no requirement to procure RPS resources or credits to serve any particular load. The above-market costs of SCE's RPS costs are collected from both bundled and unbundled customers, and the market costs are collected from bundled customers on the same basis, the overall quantity of electricity. Electricity sales, at all hours, irrespective of other costs, drives the RPS requirement. There is no regulatory requirement that RPS resources need be procured any particular hour. It would be legal for a utility to procure the bulk of its RPS resources in the first half of the year. In the absence of a regulatory mechanism that connects the procurement of RPS resources in an hour to costs in that hour, the CRS correctly uses annual sales to allocate cost responsibility.

In contrast, DG-related costs are incurred in specific hours. As Cal Advocates acknowledges in its proposal for a successor net metering tariff, the impacts of DG resource values can be assigned on an hourly basis. For example, DG resource contribution to system capacity can be measured using the avoided cost calculator's hourly system generation capacity value.[32]

Cal Advocates' proposal would create a revenue requirement to collect DG-related costs generated late at night when the wind is calm as well as during sunny afternoons.[33] Unlike the regulatory mechanism that assigns RPS costs to all kilowatt-hours of generation, there is no similar regulatory mechanism for DG resources. It is more reasonable to assign DG-related costs to the hours in which they are incurred, and then to assign those costs among classes just as other hour-specific costs are assigned.

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[32] Cal Advocates, Direct Testimony, R.20-08-020 (June 18, 2021), p. 3-13, lines 6-13

[33] Cal Advocates does not state this explicitly, but a logical extension of its argument is to add DG costs into the CRS mechanism.

B. Marginal Energy Costs (MECs)

Q: How does SCE calculate MECs?

A: SCE develops a "fundamental price forecast from SCE's internal PLEXOS production simulation model."[34] The production costs were developed using an hourly net load shape, considering DER generation, based on normal weather conditions.[35]

Q: What is your opinion of SCE's method for calculating MECs?

A: We are concerned that SCE's method may not represent expected MECs, since it uses a year with average conditions. A year with average conditions is unlikely to produce MECs equal to the average MECs under uncertainty for the period that these rates will be in effect, any more than the MEC at the average load is the same as the average MEC over the course of the year. For example, the lower marginal cost of energy during a low-load year may not balance out the higher marginal cost of energy during a high-load year.

To illustrate this point, we analyzed MECs from PG&E's 2020 GRC data for forecast year 2021.[36] This is the same data set we discussed above with respect to MGCCs. The forecast year includes ten weather-year scenarios of energy prices, net loads, and adjusted net loads.

- First, we totaled up the net load and adjusted net load (ANL) for each weather-year scenario and for the average weather-year. For net load, WY 2013 was closes to the average. For ANL, WY 2007 was closest to the average.

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[34] SCE-02, p. 23, lines 2-11.

[35] IRP, pp. 46, D.2-2, D.2-9.

[36] PG&E, 2020 Phase 2 General Rate Case (A.19-11-019), workpaper GRC-2020-PhII_20200720_Ex02Ch02_ERRATA_MEC_Price_Model_Forecast_10Yrs_run1_PROP.xlsx, tab HourlyPrice.

- Second, we calculated the hourly MECs for WY 2007, WY 2013, and the Average by multiplying the energy price times the net load.
- Third, we totaled the MECs for each of the three years, as shown in Table 2.

Table 2: Illustration Comparing PG&E's MECs by Weather-Year Scenario to Average

	Total MECs ($ millions)
Average ANL Conditions (WY 2007)	$ 6,663
Average Net Load Conditions (WY 2013)	$ 6,812
Average MECs Across All Scenarios	$ 6,540

Since SCE's method uses normal (average) weather conditions for its forecast, a weather-year scenario with average net load conditions (i.e., WY 2013) provides a good representation of PG&E's MECs for a normal weather year. Compared to PG&E's method of averaging across the ten weather-year scenarios, SCE's method would overstate PG&E's MECs by about 4%.

This illustration shows that MECs during a normal weather year are not the same as the average MECs over many possible weather-years. SCE makes the mistake of assuming that the relationship of MECs to weather conditions is symmetrical, but energy prices are not correlated to temperature in a manner that balances out on average.

This illustration using PG&E's analysis does not demonstrate the size or direction of the error that may exist in SCE's calculation of MECs. SCE's workpapers do not include the type of data provided by PG&E, so we are unable to propose an improved calculation of MECs.

Q: How do you recommend SCE modify its MECs?

A: We recommend that SCE recalculate its MECs using PG&E's method. Since PG&E's method is publicly available and, for the most part, uses CAISO system data, SCE would need to make only modest modifications to the method to reflect any IOU-specific data such as the marginal costs at SCE's DLAP.

C. Marginal Distribution Costs (MDCs)

Q: How does SCE determine and allocate MDCs?

A: SCE analyzes marginal distribution cost for four sub-functions, which it calls "asset types": subtransmission substations (which step voltage down from transmission at 115 kV or higher to 66 kV), subtransmission lines (at 66 kV), distribution substations (which step voltage down from transmission, subtransmission, or higher distribution voltages to primary voltages between 2 kV and 33 kV), and distribution feeders.[37] For each asset type, SCE conducts a regression analysis of cumulative load-related investment as a function of the planned capacity added for that asset type.[38] SCE then classifies the costs of each asset type between Peak and Grid investments, allocates the Peak investments in proportion to class contributions to high-load hours on the equipment, and allocates the Grid investments using a complicated analysis of customer non-coincident and co-incident peaks.[39]

1. SCE's use of project capacities in determination of MDCs

Q: Do you support SCE's method for determining Marginal Distribution Costs and allocating them by hour?

A: No. We identified at least five categories of problems with SCE's methods.

First, the capacity added in a distribution project (or as SCE puts it, the capacity that SCE plans to add by constructing a project) is not a reasonable or useful driver of distribution costs in the MDC computations.

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[37] SCE-02, p. 27, note 46.

[38] SCE-02, p. 29, line 4, to p. 32, line 2.

[39] SCE-02, pp. 32, line 3 to p. 52 line 19.

Second, SCE classifies a large amount of the load-related costs identified by the regressions as being non-load-related, based on spurious arguments and an unnecessarily complex computation.

Third, SCE treats subtransmission costs as not being time-dependent, notwithstanding all evidence to the contrary.

Fourth, the thresholds that SCE uses to allocate time-dependent costs are not well justified.

Fifth, SCE's allocation of costs by hour assumes implausible relationships between load over the threshold and the contribution to distribution costs.

We also have a few comments, to further improve on Cal Advocates' revisions to SCE's approach.

Q: Why is planned capacity not a reasonable or useful driver of marginal distribution costs?

A: Marginal cost analyses generally establish a relationship between a cost numerator and a driver denominator. Those drivers are generally various measures of load or (for metering, billing and the like) customer count. SCE proposes to use its estimates of the capacity that SCE plans to add by constructing a project, which would be a highly irregular input to a marginal-cost computation. Cal Advocates recommends the use of a much more conventional driver (historical maximum demand) as the independent variable in the MDC regression.[40]

There are at least five reasons for using load, rather than any measure of capacity, as the metric for load-related additions.

First, utilities invest in load-related distribution to meet expected load, not because of some abstract need for capacity. Load is the driver of costs, with the added capacity being only an intermediate project. As a simple example, if a facility is

[40] Cal Advocates, p. 2-8, line 17 to p. 2-9, line 10.

planned with an expected maximum load of 2 MVA, and SCE decides engineering constraints require that it install a feeder with a 10 MVA capacity, the MDC computation should be based on the 2 MVA of load, not the 10 MVA of capacity.

The distinction between load and capacity is also evident in the process of assigning MDCs to hours and customer classes. MDCs are allocated as a price or cost per kilowatt of load (spread out over months or hours, depending on the rate design). SCE can and does estimate the hourly loads of each class but does not have any way to associate kVA of capacity with classes.

Second, the capacity SCE chooses to add to its system may not be closely related to customer load growth, as shown by the previous example. A megawatt or less of additional load can result in additions of many megawatts of capacity, especially where additions are constrained by the size of existing equipment that operates in parallel with the new equipment. If a feeder is nearing overload, SCE cannot select from a wide range of wire sizes to add a second feeder, on the same structure or nearby; balancing of loads generally requires similarity of equipment.

Another way to say this is that distribution capacity is lumpy. A small increase in load can trigger the need to duplicate existing capacity (such as by running a second feeder to serve a load area). While generation capacity can generally serve load anywhere in the SCE service territory, and transmission capacity will typically serve a large area, distribution projects are much more localized and excess distribution capacity is often of no real use until load grows in a very specific area.

Third, an increase in load does not necessarily result in an increase in capacity for just one element of the distribution system. SCE has recognized that at least four levels of distribution are necessary to get power from the substation to the final line transformer: subtransmission lines, sub-transmission A-Bank substations, distribution B-bank substations and distribution feeders. As SCE explains:

> electricity typically goes through three stages of power transformation: from 220 kV to 66 kV (or other subtransmission voltages), from 66 kV to 12 kV (or other primary distribution voltages), and from primary distribution voltages to…secondary voltage. The need for additional capacity is often studied independently at each of these stages in order to accommodate incremental load.[41]

Depending on the geographical location, there may be even more stages. For example, SCE has distribution substations that transform power from subtransmission voltages, such as 66 kV, to a primary distribution voltage, such as 12 kV, and additional substations that transform the power down to a lower primary voltage, such as 4 kV. An increase in load served at 4 kV may thus result in increases in capacity on 4 kV and 12 kV feeders, and two levels of distribution substations (e.g., 66 kV to 12 kV and 12 kV to 4 kV), in addition to any increase in subtransmission capacity.

Adding one MVA of capacity at the higher-voltage substation does not increase the amount of load that can be delivered through the lower-voltage distribution systems. If SCE adds up the capacity added on 4 kV, 12 kV and 33 kV to meet a load addition, it will be counting the effect of the load addition three times.[42] The same is true where two levels of substations are upgraded. A load addition at another point may require only one feeder upgrade and one substation upgrade to increase capacity all the way back to the subtransmission system. So, distribution project capacity has little relation to the load driving the costs.

Fourth, subtransmission and distribution systems are usually either networked, so several elements can serve as back-up for one another, or at least looped. In a looped system, if a feeder is interrupted or a substation transformer fails, a switch closes and power flows to the affected area from the other end of the feeder, from a different transformer. An increase in load may require not only a capacity increase on

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[41] SCE, Exhibit SCE-02, p. 9, lines 14–20.

[42] And if the capacity on a feeder is added in multiple projects, the same load growth may be counted even more times.

the normal feeder to the area, and the normal distribution substations, but also on the contingency feeder and the substation that feeds it. This is one more reason that the combined capacity additions on all the equipment at multiple stages, measured in kVA, may substantially exceed the load growth that triggers the upgrade.

Fifth, feeders are often upgraded in segments and SCE should not measure the capacity as the sum of the segments' capacity. A new load near the end of a feeder may require several projects to upgrade various portions of the feeder; summing up the capacity added in the first mile, the second mile, and so on will produce a value of added capacity greatly exceeding the load that can be carried by the upgrades. In addition, feeders branch. Serving new load may require upgrading a single-phase primary branch to three-phase, reconductoring a three-phase spur from the main feeder to the branch and reinforcing the main feeder. The costs of these projects are additive, but the capacity that they add is not.

Q: Is Cal Advocates correct that "Planned capacity will always incorporate reserve margins"[43]?

A: Not exactly. In a general sense, utilities always need more kVA of distribution capacity than the kW load they serve, for some of the reasons we discussed above. In many cases, utilities will install somewhat larger equipment to ensure compatibility with connected equipment, take advantage of economies of scale, accommodate underestimates of load, and avoid another reinforcement in the near term. While the sum of capacity on all the segments of equipment in an asset type is much greater than the load it serves, most of that difference results from factors quite different from those that drive the generation reserve requirement.

[43] Cal Advocates, Ch. 2, p. 8, line 11.

Q: What is your response to the MDC regression approaches proposed by SCE and Cal Advocates?

A: The combination of historical and forecast data appears to be appropriate. We have not reached an opinion regarding whether the results of the so-called NERA regression are preferable to the ratio of investment to growth (the Discounted Total Investment Method or DTIM).

As we discussed above, the independent variable used by SCE (cumulative capacity additions) is not useful. Cal Advocates' use of load as a cost driver is a great improvement over the SCE approach.

2. Use of historical maximum demand in MDC allocation

Q: Do you have any concerns about the details of Cal Advocates' regression approach?

A: Yes. Cal Advocates proposes to use historical maximum demand as the independent variable in the cost regression, rather than annual load. That proposal properly recognizes an important consideration, that investments are added to accommodate load growth and usually cannot be uninstalled if load flows. However, distribution capacity is added for expected future loads, not immediately to match actual load as it occurs. Actual load does not drive investment (other than for replacement after load-related damage), since the investment needs to be committed and made in advance.

The unprecedented summer peaks in 2020 were not accompanied by a surge in distribution capacity additions, since SCE did not know in 2017, 2018, 2019 or even early 2020 that it would be facing those loads. Similarly, expected load growth will often drive distribution projects, but the growth does not always materialize. The actual load on a feeder or substation may not live up to the forecast, for any of several reasons: new anticipated loads (such as new construction) may be delayed or canceled, efficiency and DERs may offset the growth, mild weather may result in lower-than-anticipated load for a year (the inverse of the summer 2020 situation), economic conditions may reduce power usage, and existing customers may scale back or eliminate their load as operations are shifted to other facilities.

Q: What is the alternative to using historical maximum loads, as suggested by Cal Advocates?

A: In preparing its distribution investment plans, SCE must use short- to mid-term forecasts of load by feeder (or segment), substation, subtransmission line, and so on. The additions in 2018, for example, would have been based on forecasts developed in the previous few years (roughly 2014 to 2017), with the earlier forecasts triggering design, permitting and procurement and some later forecast (probably the 2016 forecast, for many projects) triggering actual construction to meet a 2018 in-service date.

Rather than using the historical actual peak for each asset type, the regression should thus use the historical maximum investment-driving forecast.[44]

Q: Which forecast should be treated as driving distribution investment in a given year?

A: SCE should review its planning and construction schedules and propose the forecast lag for each asset type. For example, SCE may find that substantial spending and commitment for subtransmission substations is driven by the forecast three years prior to the in-service date, but decisions on most feeders are based on the forecast just one year before the service date. While the timing of commitments will vary among

[44] The loads for the forecast years would be the current forecast, which is the basis for estimating additions in those years.

projects, the loads used in the regression should be as close as possible to the loads on which the investment decisions were made.[45]

Until SCE completes and vets that study, we suggest using the Cal Advocates approach—rolling maximum load—but rather than using the load in each year forecast two years earlier, rather than the actual load in the year. This approach would eliminate the effect of weather variability on the regression.

Those forecast loads should be applied as the rolling maximum of past forecasts for each feeder, substation, etc., similar to Cal Advocates' treatment of actual peaks.

3. Distinction between peak and grid feeder costs

Q: How does SCE allocate the MDCs to time periods and customers?

A: SCE divides costs between Peak Costs (associated with substations and primary "Mainline or Backbone" circuit miles) and Grid Costs (for all subtransmission lines, radial primary and all secondary circuit-miles). The Peak Costs are allocated among hours in proportion to the excess of load over a threshold, producing a Peak Load Risk Factor (PLRF) for each hour. Grid Costs are allocated to rate classes using a complicated process that purports to estimate the ratio (Effective Demand Factor, or EDF) of customer load at the time of the feeder peak load to the customer's non-coincident peaks.

Q: Is it clear that the division of costs between Peak and Grid feeder costs is necessary?

A: No. Both approaches purport to estimate the contribution of classes to feeder peak exposure. The PLRF uses class contribution to high-load hours on the feeders, while

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[45] Given the variability in when investment decisions are made, we recommend using the historical maximum of the investment-driving forecasts for each modeled area and asset type.

the EDF uses a series of approximations to estimate contribution to load at a single hour. In general, all high-load hours contribute to distribution costs, so the PLRF is a more logical approach than the EDF. The PLRF also requires fewer approximations.

While SCE justifies the classification as being driven by the bidirectional flow on some parts of the system, as follows:

> … "peak" refers the distribution system's peak capacity function in meeting time-variant peak customer demand, whereas "grid" refers to the distribution system's function that enables the bi-directional flow of energy to and from customers.[46]

This justification is not consistent with the methods. The EDFs that SCE uses for the items it declares to be "grid" costs do not appear to reflect bi-directional flow. PLRFs that SCE uses for the items it declares to be "peak" costs can also reflect bi-directional flow.

Furthermore, bidirectional flow can occur on the main lines and even on subtransmission, so the distinction between unidirectional backbone lines and bidirectional radial lines does not make sense. So, SCE's justification for using two separate allocation methods falls apart.

SCE then jumps through a series of rhetorical hoops trying to explain why the "grid" costs it allocates with the time-sensitive peak-driven EDF cost allocation method should be recovered through *non-time-differentiated* facilities-related demand (FRD) charges:

[46] SCE-02, p. 32, lines 6-8.

> While SCE does not dispute some relevance of time sensitivity for grid-related assets, the general criteria with which the grid portion of the system has been designed and configured over time has caused those assets to primarily meet the needs of connectivity and the potential to share load-carrying capability. To capture the relatively minor time-dependent nature of such costs, SCE continues to use the EDF methodology when determining rate group contributions to such costs but proposes to recover these costs through non-time-differentiated FRD [facilities-related demand] charges.[47]

So, SCE thinks that the radial equipment has only some limited time sensitivity, even though the system must be sized to allow for connectivity of all load at peak times and to provide shared "load-carrying capability." SCE uses a complex peak-load computation to allocate those costs, only to propose recovering them through non-time-differentiated demand charges.

Q: Are the costs of the equipment that SCE would classify as "grid" facilities driven by load?

A: Yes. The sizing of radial subtransmission and distribution lines is driven by load, as are the number of lines. As load grows in an area, utilities add feeders to supplement supply to those areas. An area served with single-phase service at low loads may be upgraded to two-phase or three-phase service to meet rising load.

Utilities also upgrade the voltage along feeders (requiring new higher poles, new insulators, and new line transformers) to increase capacity.

Q: What are the approximations required in the EDF?

A: As SCE explains, the computation of the EDFs require a number of steps:

> Effective demand is expressed as a factor (effective demand factor, or EDF), which is the ratio of a customer's contribution to the peak load on a transmission or distribution circuit to the customer's annual non-coincident peak demand. EDFs vary by type of customer and by the voltage level of the circuit….

[47] SCE-02, p. 26, FN 43.

> Distribution circuit EDFs are calculated as follows. First, the number of customers by rate group is determined for each circuit and is used to develop a profile of the number of customers by rate group on a typical distribution circuit. These profiles are calculated for each type of customer, using an average of the circuits weighted by the number of customers of the particular type. …Next, a Monte Carlo simulation method is used to randomly populate each typical circuit type with customers from SCE's load research samples. This step is performed for each circuit type. Next, individual customers on each simulated circuit are selected, and the contribution of the customer to the circuit peak is determined. For example, if the Monte Carlo simulation is for a typical TOU-8 customer distribution circuit, the effect of one of the TOU-8 customer's load on the circuit is calculated. Finally, the second and third steps are repeated a sufficient number of times to produce statistically valid results. A similar approach is used to determine EDFs for subtransmission (e.g., 66 kV) circuits. Due to the greater geographic area typically served by these higher voltage circuits, a single typical customer profile is used for all customer types….
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> Because EDFs associate an individual customer's peak demand to that customer's contribution to delivery system demand, the marginal cost revenues associated with a rate group's design demand are defined as the product of that rate group's annual non-coincident peak demand, the EDF for that rate group, and the marginal cost per unit of design demand.[48]

Rather than actual contributions of customers to high-cost periods on each line, the EDF computation includes the development of average profiles weighted across circuits, development of "typical" circuits, using a Monte Carlo simulation to randomly populate each typical circuit type with customers from SCE's load research samples, selection of some number of simulated individual customers on each simulated circuit, determination of that that simulated customer's contribution to the peak load of the simulated circuit, and repetition for the previous steps.

The results of this process do not seem likely to reasonably reflect the contribution of each class to the need for capacity upgrades. Nor will it provide meaningful guidance as to the portion of the cost allocable to high-demand periods, for TOU rate design.

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[48] SCE-02, p. 50, line 6 to p. 52, line 11.

Q: What is SCE's justification for classifying subtransmission lines as "grid" rather than "peak" costs?

A: SCE says it does not have hourly data on subtransmission line loads.[49] That is an odd omission, since SCE has hourly data for customers, feeders, distribution substations and sub-transmission substations. It is not clear how SCE operates its complex system in real time without that information. SCE should add that metering data as soon as possible.

SCE also makes a functional argument that the subtransmission lines are not sized for peak loads.[50] That argument is hard to follow, as it includes statements that the lines are sized for the peak loads of the substations they serve;[51] acknowledgement that additional subtransmission lines are required for substations over 28 MVA;[52] and contradictory claims that "SCE's subtransmission system is uniquely configured as a radial grid" and that the system operates as a network or sub-network.

SCE admits that its planning of subtransmission lines "to accommodate…(i) directional power flows in normal and contingency scenarios; and (ii) congestion management on the subtransmission network…is typically done for peak load

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[49] SCE-02, p. 40, lines 3–5.

[50] SCE-02, p. 34, line 22 to p. 35 line 18).

[51] SCE states that its "subtransmission lines are designed for the non-coincident peak load of the B-banks they connect." (SCE-02, p. 35, lines 1–2) If those non-coincident peak loads are highly correlated, that may be a useful simplifying assumption. But if the non-coincident peak loads of the distribution substations occur in different seasons, or different times of the day, this practice may be a hold-over from an era in which SCE did not have hourly data for any of its equipment. If so, the method for allocating *marginal* distribution costs related to present-day investments in subtransmission lines should not be determined by outdated practices.

[52] Since the size of the substation is driven by load, the number of substations and of over-28MVA substations are functions of load.

conditions."[53] SCE then attempts to obscure this reality with a flurry of verbiage that simply points out that the subtransmission system serves other hours as well. The same can be said for all utility generation, transmission and distribution facilities, yet their costs are still time-dependent.

Q: How should the Commission deal with SCE's proposed classification of distribution costs?

A: The Commission should reject SCE's bifurcation of distribution and require that SCE treat all distribution as load related, using the PLRF method.

For the sub-transmission lines, until SCE has better data, it could average the PLRFs for the sub-transmission substations and the distribution substations.

4. PLRF thresholds

Q: What thresholds does SCE use for the PLRF computations?

A: SCE proposes to use load thresholds of:

- 90% of annual peak load for subtransmission substations,
- 73% of the average Planning Load level (PLL) for the feeder circuits on a substation, for feeders,
- 73% of PLL for distribution substations (using 2024 forecast load, as opposed to historical load).

We agree with Cal Advocates that SCE's proposal to change distribution substations from a threshold of 90% of PLL to 73% requires more justification.[54] In addition, SCE does not provide clear justification for either the 90% of peak load for subtransmission substations nor the 73% of the average PLL for feeders.

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[53] SCE-02, p. 35, lines 8–10.

[54] Cal Advocates, Ch. 2, p. 19 line 10 to p. 22, line 2.

Q: How should SCE design its PLRFs?

A: SCE should be capturing the hours with loads that drive investments, which would include three factors:

- the highest-load hours,
- the hours that could be highest-load with small shifts of usage patterns and weather, and
- the hours that contribute to heating of distribution equipment, resulting in reduced capacity at a later peak and to faster aging of the equipment.

The first two factors reflect the importance to maximum load in determining the sizing of distribution equipment. The third factor reflects the important role of heating on equipment life and capacity. While a generation system may fail almost immediately when supply cannot match demand (resulting in excursions of voltage or frequency), distribution systems rarely fail due to instantaneous load. Equipment that can tolerate 100 units of load for an hour, after a long period of low load, may fail if required to carry 80 units for 24 hours.

While there is little doubt that all of the highest-load hours drive costs due to reliability risk and effects on equipment life, not all hours with 73% or 80% of PLL or annual plant contribute equally to those costs. Those moderately high-load hours are important when they are followed by even higher loads later in the day. A similar moderately high-load hour may have no meaningful reliability risk or effect on equipment life if it is the highest load of the day.

For example, in Figure I-4 of SCE-02, the important hours may be those on days with the red and pink loads, include the yellow hours prior to the peaks.[55] But the

[55] That figure aggregates load in a different manner than SCE actually uses in its computations, but it is illustrative.

yellow hours in June and September may contribute almost nothing to the load-related costs.

SCE will need to conduct further analysis to develop the PLRF for each distribution subfunction (subtransmission substations, subtransmission lines, distribution substations, primary feeders and secondary lines). SCE should examine the engineering effects of non-peak loads and the associated heat buildup on equipment affects maximum useable capacity and useful life. Based on that analysis, it should propose for each asset type a technically-sound approximation, which may include all hours over a near-peak threshold, plus heating-relevant hours on the days of the peaks and near-peaks.

Q: Do you have recommendations regarding the thresholds for the PLRF for each subfunction?

A: Not at this time. We expect to have more information and be able to make interim recommendations in our rebuttal testimony.

Q: Aside from the issues of setting the threshold, do you have any concerns about SCE's computation of the PLRFs?

A: Yes. SCE computes the hourly PLRF contribution as zero in hours below the threshold and full load for hours at or above the threshold.[56] This approach is illustrated in SCE Figure I-5.[57] If the threshold is 73% of PLL, the PLRF contribution would be 0 at 72.9% of PLL, 0.73 at 73%, and 1.0 at 100%.

This approach makes no sense. If load imposes no cost at 72.9%, the cost at 73% must be small, but SCE assumes that the cost at 73% of PLL is nearly as high as the

[56] SCE-02, p. 40, line 9 to Equation 1.

[57] SCE-02, p. 42, Figure I-5.

cost at 90% of PLL. Neither the risk that the 73% hour will become the peak hour, nor the effect of the 73% hour on heating, could possibly justify that discontinuity.

The SCE approach is almost equivalent to a simple count of the hours over the 73% threshold. It is not an effective measure of load-related stress or risk.

Q: What would be a more reasonable computation of PLRF?

A: The PLRF contribution should start at zero at the threshold and rise smoothly, as a function of load–threshold, for load above threshold.[58] This is the approach taken by PG&E in its comparable computations.[59] Implementing this approach would not require any significant additional effort.

D. Marginal Customer Access Costs (MCACs) and Customer Charges

Q: Please describe SCE and Cal Advocates' positions on MCACs.

A: SCE proposes to use the real economic carrying charge (RECC) methodology for capital-related marginal customer costs, while Cal Advocates recommends the Commission continue to rely on the new customer only (NCO) method for SCE, as it has since 1995.

Cal Advocates proposes several adjustments to the NCO method as presented by SCE in Exhibit SCE-02, Appendix E. Several of these simply conform the NCO method results to Commission policy, such as excluding uncollectibles as affirmed in D.17-09-035,[60] in which the Commission decided which costs should be eligible for recovery through a residential fixed charge. We agree with Cal Advocates regarding the reasoning expressed in their testimony for continuing to use the NCO method to

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[58] For simplicity, the function may be assumed to be linear, although both the risk of peak and the heat-related effects are likely to increase faster than load.

[59] PG&E, 2020 General Rate Case Phase II, Exhibit PG&E-2 (A.19-11-019), Ch. 8, pp. 5-11.

[60] D.17-09-035, p. 19.

determine *marginal* customer access costs. We recommend that the Commission explicitly endorse Cal Advocates' method for this proceeding.

Q: Please describe SCE and Cal Advocates' positions on the customer charge.

A: SCE proposes to scale up the per-customer MCAC on an equal percent marginal cost (EPMC) basis.[61] Cal Advocates objects to applying the EPMC scalar to the customer charge.

We agree with Cal Advocates that the EPMC scalar should not be applied to the customer charge, and that instead those costs should be recovered through volumetric distribution rates. Cal Advocates recommends that the Commission extend to small business customers the treatment used for residential customers in D.17-09-035.[62] In that decision, the Commission determined that the customer charge should be limited to recovery of "customer-specific" costs including billing, customer inquiry, and establishing meters, service drops, and final line transformers. The Commission stated that the "EPMC recovers embedded distribution costs which are a mix of demand-related and customer-related costs. Inclusion in fixed charges would be inappropriate and could unfairly penalize small customers."[63]

Cal Advocates suggests that the arguments in the residential fixed charge decision apply equally to the circumstances of small business customers. For the most part, we agree.

In one respect, however, the Commission should treat commercial customers differently than residential customers. The Commission found that, "The need to differentiate between customer sizes is moot because the fixed charge calculation adopted in this decision includes only those customer costs that are the same for each

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[61] SCE-04, p. 5, lines 6-7.

[62] Cal Advocates, Ch. 8, p. 6, line 20 – p. 7, line 9.

[63] D.17-09-035, p. 28.

residential customer."[64] In the case of commercial customers, customer costs vary widely, as indicated by one phase or three phase service, shared or dedicated final line transformers, and other customer-selected service levels.[65] This difference can easily be accommodated within the framework adopted in D.17-09-035 by allowing for customer charges to vary based on customer-dependent service levels.

Q: How would SCE's proposed MCACs affect small businesses?

A: Small businesses would be disproportionately impacted by SCE's proposal. SCE proposes to increase the monthly customer charge for TOU-GS-1 from $11.10 (as of June 2020) to $19.50, which is a 76 percent increase.

In contrast, only one other rate (TOU-PA-2) would experience an increase in the customer charge. All other customers would experience a decrease or, in the case of residential customers, no change.[66]

Cal Advocates' proposal would result in monthly customer charge of $4.75.[67] Other customer classes would also receive lower customer charges since Cal Advocates' proposed MCACs are lower for every customer class.[68] This change requires compensating adjustments to distribution rates for each customer class to recover the same revenue in the form of higher marginal costs and EMPC scalars for volumetric and demand rates.

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[64] D.17-09-035, COL 15, p. 59.

[65] As discussed below, final line transformer costs vary widely among small-commercial customers, and we recommend improvements to the customer charge structure. In this docket, simply adopting Cal Advocates' recommendation would constitute adequate movement toward more realistic customer charges.

[66] SCE-04, p. 6, Table II-1.

[67] Cal Advocates, Ch. 8, p. 8, Table 8-3.

[68] Cal Advocates, Ch. 1, p. 3, Table 1-2.

Q: What customer charges do you recommend?

A: We recommend that the Commission adopt Cal Advocates' proposals for MCACs and for applying EPMC scaled costs to the volumetric distribution rates, but not to the TOU-GS-1 customer charge, resulting in a monthly customer charge of $4.75.[69]

Q: Do either SCE or Cal Advocates argue in favor of strictly applying marginal-cost principals to customer access costs?

A: No. Cal Advocates provides a straightforward explanation as to why customers are not charged the full marginal cost of connecting to the grid at the time of connection.

> Economic theory indicates that the most economically efficient price signal is sent when the decision to connect to the grid is marginal. For customers and developers considering whether to hook up to the grid, it is optimal that they be charged the full cost of connecting to the grid up front at the time when that decision is being made. They would be provided the price information needed to make an economically rational decision about whether the value they derive from connecting to the grid exceeds the cost of doing so. Charging customers the full cost to connect to the grid up front would mean excluding the capital costs associated with connecting customers to the grid from the revenue requirement.
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> In fact, most of these capital costs are recovered from all ratepayers through service and distribution line extension allowances. These allowances socialize these costs so that new customers are not responsible for paying the full cost up front to connect to the grid. In other words, each customer pays a small share of the costs for connecting new customers to the grid each year. While this method does not send the most economically efficient price signal to customers deciding whether to connect to the grid, it allows new customers to receive electric service without having to shoulder the full cost of connecting to the grid at the time of connection. Socializing new customer connection costs in this manner makes connecting to the grid more financially feasible and allows more customers to take electric service than could otherwise afford to.[70]

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[69] As discussed below, we are recommending consolidation of TOU-GS-1 and TOU-GS-2, with a service level differentiation of customer charges applied to the consolidated TOU-GS-1 tariff, so the $4.75 calculation would need to be updated with consolidated costs.

[70] Cal Advocates, Ch. 1, p. 3, line 13 through p. 4, line 14. Footnotes in original are omitted from the quotation.

Q: Does either the NCO method or the RECC method provide a sound connection between the choices that customers make and the costs that are caused by those choices?

A: No. In both the NCO and RECC methods, "each customer pays a small share of the costs for connecting new customers to the grid each year."[71] Customers are paying for the choices of other customers, and not even at the same time that those choices are made.

More specifically, Cal Advocates states that the NCO method "simulates the socialization of customer connection equipment costs" and that the RECC method relies on unrealistic assumptions "about how existing customers could reduce their usage of connection equipment to allow an additional customer to connect to the grid."[72] While we are persuaded that the NCO method is more reasonable than the RECC method, neither method is consistent with marginal cost theory because neither method sends clear and actionable price signals.

Q: What do you mean by clear and actionable price signals?

A: The portions of rates related to generation and the grid (transmission and distribution) send clear and actionable price signals because they align short- and long-term marginal costs with the decisions customers make regarding how much electricity they use and when they use it. As the Commission guides TOU rates, including CPP rates, towards more fully reflecting marginal costs, customer decisions will be better informed by the price signals, and customers can take action to reduce energy use or shift use to other time periods.

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[71] Cal Advocates, Ch. 1, p. 4, lines 8-9.

[72] Cal Advocates, Ch. 1, p. 6, lines 5-6, 8-13.

Q: What is the sticking point in resolving the NCO and RECC method debate?

A: Direct Access Consumer Coalition (DACC) Witness Mark Fulmer briefly explained this continuing argument in PG&E's ongoing 2020 Phase 2 GRC, as follows:

> The NCO versus RECC method debate has being going on for over 30 years. Both sides claim to be right, generally using the same arguments year after year. I find both sides' arguments to contain fatal flaws. With respect to the RECC method, I concur with PAO when it points out that the NCO method better simulates how connection costs are incurred and in isolation, and, depending upon how they are implemented, can be more consistent with marginal cost theory. With respect to the NCO method, I concur with PG&E when it points out that the NCO method, for revenue allocation purposes, completely fails when there is little or no or negative load growth in a particular customer class.[73]

The Commission has chosen to leave this question unresolved. In D.17-09-035, the Commission stated,

> We find that parties have made significant progress in articulating and presenting pros and cons of various methods for calculating capital-related customer costs in this proceeding. We recognize the merits of each method and some of the ways in which these methods can be further improved, as illustrated by the Energy Division's proposal to adjust the rental method and the Joint Parties suggestion to modify the NCO method. We see value in using a uniform method across utilities to maintain consistency; however, given the lack of consensus on this issue, the significant variation of customer costs that may result from each method, and the possible broader implications in General Rate Cases from pre-selecting a method, we will not adopt a single method to calculate capital-related customer costs at this time. We would like parties to continue exploring capital-cost calculation methods towards the goal of developing a more universally applied method. We also direct the utilities to show their range of results applying the methods discussed in this proceeding, namely the rental method, the NCO, the adjusted rental methods, and other alternatives to be developed going forward, if any, when they propose a fixed charge in the future.[74]

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[73] DACC, Direct Testimony of Mark Fulmer (A.19-11-019), p. 12, lines 3-11. Footnotes in original are omitted from the quotation.

[74] D.17-09-035, pp. 38-39.

Q: How should customer access costs be allocated?

A: DACC Witness Fulmer recommended that the Commission should allocate customer access costs based on embedded costs, with the total customer access costs for each customer class being assigned to each class. We agree with him that this "would provide the fairest alternative as it would assign costs to the classes which incurred those costs, in accordance with traditional cost causation principles."[75]

Q: Has the Commission considered embedded cost allocation for customer access costs?

A: Not recently. However, while embedded-cost allocation was not explicitly discussed in D.17-09-035, the Commission's decision took a step in that direction. As discussed above, the Commission has explicitly rejected the recovery of distribution costs above the MCAC in residential customer charges via the EPMC scalar.[76] That decision leaves the above-MCAC customer-related costs that are allocated to the residential class to be collected from the volumetric distribution rates.[77]

The Commission can now take an additional step and require that SCE develop an embedded-cost allocation of customer access costs by class, with no more than the marginal cost to be recovered through the customer charge for any class. This step

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[75] DACC, Direct Testimony of Mark Fulmer (A.19-11-019), p. 12, lines 16-18.

[76] D.17-09-035, p. 28.

[77] The basic formula in California rate practice is: Utility Revenue Requirement = Embedded Costs = Marginal Costs x EPMC Scalar. The Commission explained this as follows:

> Marginal cost revenue is revenue that would be collected if all the customers were charged at marginal cost. In contrast, utility revenue requirement is typically based on embedded (historical) costs as included in rate base. Because of the gap between authorized revenues and the marginal cost-based revenues, utilities typically multiply marginal cost revenue with a scalar, called equal percentage of marginal cost or EPMC scalar, to cover this shortfall. The EPMC scalar denotes the percentage by which the authorized distribution revenue requirement, which includes marginal and non-marginal customer costs, is below or above the marginal cost revenue. (D.17-09-035, p. 25)

would eliminate the cross-subsidization of distribution and customer-access costs, as well as ending the NCO vs RECC debate. As DACC Witness Fulmer testified, adopting an embedded cost method for customer access costs "would end the absurd perpetual motion machine of the NCO versus RECC debate."[78]

Q: Do you recommend that embedded cost allocation be adopted in this proceeding?

A: While we would support such a decision, we are realistic that implementing such a decision in this proceeding would be difficult. In D.17-09-035, the Commission suggested that in future proposals for fixed charges, the "range of results applying the methods" should be shown by the utilities in GRCs. We recommend that the Commission direct SCE to perform an embedded cost study of its customer access costs for its next GRC, and present rates including uniform customer charges (with appropriate service level differentiation such as three-phase service) based on those embedded costs. For all customer classes, the scope of customer costs should follow the D.17-09-035 guidelines for customer charges.

IV. Rate Design

A. New Real-Time Pricing Tariffs

Q: Is SCE proposing a real-time pricing (RTP) tariff using wholesale market prices from CAISO?

A: No. SCE states that it will "continue to explore the opportunity" to design such a rate upon completion of SCE's Customer Service Re-Platform (CSRP) implementation.[79]

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[78] DACC, Direct Testimony of Mark Fulmer (A.19-11-019), p. 12, lines 18-19.

[79] SCE-04, p. 58, lines 6-8.

Q: Are SCE's current RTP schedules "real-time pricing" rates, as that term is generally understood?

A: No. An RTP rate is generally understood to provide a direct link between customer prices and contemporaneous marginal supply costs. SCE's RTP schedules are based on pre-set hourly prices. There are three summer weekday hourly pricing profiles and two profiles each for weekends and winter weekdays, The profiles are based on the prior day's maximum temperature.

We will not list all the reasons this rate design is not an RTP rate, but the lack of any meaningful link to wholesale prices is disqualifying, as is the failure to reflect system conditions. Nonetheless, we are aware that this rate design has certain benefits, such as for agricultural users who must plan pumping schedules in advance to position equipment and schedule water delivery. We encourage SCE to collaborate on improvements to this rate with the limited set of customers who need the level of predictability it provides. For example, the tariff could use a link to day-ahead forecast rather than prior day maximum temperatures.

Fundamentally, this rate is more like a more complicated CPP rate than an RTP rate.

Q: Should a real-time pricing tariff be proposed in this proceeding?

A: Yes. We will cite three recent indications that California's energy policy is encouraging rapid development of RTP tariffs.

First, the California Energy Commission is undertaking the 2020 Load Management Rulemaking (Docket #19-OIR-01) to expand on efforts to increase efficiency and demand flexibility in California's electricity grid. One of the four proposed amendments. In April, CEC staff presented four proposed amendments to the Load Management Standards, including "Develop and submit locational rates that change at least hourly to reflect marginal wholesale costs."[80]

Second. CPUC Energy Division staff have released a draft *DER Action Plan 2.0 Update for 2021-2026*. Of the four tracks discussed in the action plan, the "Load Flexibility and Rates" track is heavily focused on RTP rates, mentioning them in thirteen of the twenty action elements. For example, one draft action element states, "By 2024, all utility customer classes have access to multiple rate options, including dynamic and RTP rate pilots that are informed by focus group research and supported by ME&O programs to match various customer preferences and engagement levels."[81]

Third, in the PG&E 2020 Phase 2 GRC proceeding, ALJ Doherty ruled that,

> In its 2019 decision denying a petition for rulemaking (D.19-03-002), the Commission reiterated that new dynamic rate designs can, and should, be addressed in individual utility general rate cases (GRCs). The Commission found in that the "analysis of a particular utility's costs and billing determinants in GRC Phase 2 proceedings is essential to the task of rate design, including… RTP tariffs." (D.19-03-002, Finding of Fact 12). In other words, a specific RTP rate proposal should be made and evaluated in the individual utility's GRC Phase 2 proceeding.[82]

While this ruling does not apply to SCE's application, there is no meaningful difference between the circumstances of PG&E and SCE.

SCE's stated reason for not developing new RTP rate designs—its ongoing CSRP implementation—is unpersuasive. We agree that SCE will need to complete its CSRP implementation before programming an RTP rate pilot into its system, but

[80] Karen Herter, *Proposed Amendments to the Load Management Standards*, Draft Staff Analysis (April 12, 2021), Efficiency Division, California Energy Commission, p. 11.

[81] CPUC Energy Division, *Draft Distributed Energy Resources Action Plan: Aligning Vision and Action* (July 23, 2021), p. 8.

[82] Ruling of ALJ Doherty, PG&E Phase 2 General Rate Case (A.19-11-019), August 27, 2020.

the timing of launching an RTP rate pilot and CSRP implementation are not in conflict. Even without the CSRP implementation, it is unlikely that a new RTP rate could be launched by SCE earlier than 2024.

For example, in the PG&E proceeding, the proposed schedule for the PG&E Commercial Electric Vehicle Day-Ahead Hourly RTP Pilot (A.20-10-011)[83] requires 18 months after a final Commission decision, as follows.

- Pilot planning – 3 months
- Recruitment and rate technology development – 8 months
- Pilot billing system programming – 7 months

While PG&E's timeline is somewhat elongated due to its own billing system overhaul, an RTP pilot launch requires significant work in parallel with the overhaul.

Delaying the RTP until the next GRC is unnecessary, fails to address the Commission's intent in D.19-03-002, and will result in SCE missing the draft Energy Division goal for RTP pilots by 2024.

Q: What do you recommend regarding RTP?

A: We recommend that the ALJ bifurcate this hearing and direct SCE to file an RTP pilot proposal in a separate track of this proceeding. We would recommend that SCE carefully review the testimony and settlements in the PG&E CEV DAHRTP Pilot and Phase 2 GRC cases. SBUA would be willing to engage with SCE, and we expect that several other parties active on the RTP issue in that proceeding would also be eager to assist.

The work in the PG&E proceeding has made significant progress in addressing a number of technical issues that SCE would need to resolve. Since the intent of an RTP rate is to provide customers with an opportunity to shift load and dispatch customer-owned generation in response to CAISO market pricing, the solutions

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[83] Attachment 6.

identified through the extensive work in the PG&E proceeding should be very relevant to SCE.

B. Consolidating GS-1 and GS-2 Classes

Q: Please summarize the issue of combining the GS-1 and GS-2 classes.

A: In Exhibit SCE-04 Appendix J, SCE provides a study of the appropriate demand threshold for a customer to qualify as a small business resulting from a settlement agreement approved by the Commission in the 2018 GRC Phase 2 Decision (D.18-11-027). SCE's current cutoff level of 20 kW between TOU-GS-1 and TOU-GS-2 is lower than similar tariffs used by PG&E, the Los Angeles Department of Water and Power, and Sacramento Municipal Utility District. SBUA's position is that including more customers in the small commercial class would facilitate delivery of programs and assistance to small businesses.

SCE states that it has not developed a position on this study, but "will consider and evaluate parties' positions on the study, and whether and how the findings should be implemented."[84] SCE did not discuss these findings with SBUA prior to filing this study in this application.

Q: What is your opinion of the study?

A: SCE's study provides strong support for consolidating the GS-1 and GS-2 customer classes. The study found that, "The average rates and ensuing bills of both options D follow the same pattern, albeit separated by a difference resulting from the revenue allocations. Thus, it is not a stretch to presume that a common rate structure may work for both populations should they be grouped together in the same class."

However, the analysis raises several issues, including:

- Customer charge,

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[84] Attachment 4 (SCE response to SBUA-SCE-002-JW, Question 05(c)).

- Accounts serving primarily lighting load, and
- Customers with demand at the high end of the GS-2 class.

In addition, the default rate would need to be reconciled, and an issue with SCE's Level Pay Plan should also be resolved.

As discussed below, we believe each of these issues can be addressed, and the Commission should consolidate GS-1 and GS-2 customer classes in this proceeding.

Q: What is the issue with the customer charge?

A: As shown in Table 3, the marginal cost of access, including transformer, service drop, and meter is substantially lower for GS-1 customers than for GS-2 customers. This is due to the different levels of service provided by the transformer and service drop.

Table 3: Total Marginal Customer Costs for GS-1 and GS-2 Classes

Table J-3
Marginal Customer Costs

Group	Customer Size	Phase	Designed kW per Customer	Transformer Description	Number of Customers Connected to Transformer	Transformer Cost	Marginal Cost of Access (TSM)
GS-1	N/A	Single	5-7 KW	75KVA 12KV 120/240 1P+	10	$5,044.91	$2,427.08
GS-1	N/A	Three	5-7 kW	75KVA 12KV 120/208Y 3P+	6	$10,354.52	$4,194.69
GS-2	Small	Single	25-80kW	75KVA 12KV 120/240 1P	1	$6,170.03	$9,487.02
GS-2	Small	Three	25-80kW	75KVA 12KV 120/208Y 3P+	1	$10,354.52	$14,907.91
GS-2	Medium	Three	130-165kW	150KVA 12KV 120/208Y 3P+	1	$11,948.61	$17,428.65

Currently, the monthly charges are $13.90 for TOU-GS-1 and $158.71 for TOU-GS-2. SCE is proposing monthly charges of $19.50 for TOU-GS-1, with an additional charge of $0.82 for three phase service, and $110.65 for TOU-GS-2, with an additional charge of $6.58 for three phase service.

The cost basis for these charges is shown in Table 4. Even though SCE is proposing three-phase service charges, the majority of the cost differentiation between single-phase, three-phase, and primary-voltage customers is not carried through to the proposed rates.

Table 4: Proposed Annual Customer Marginal Costs

Table I-18
Customer Marginal Costs
(2021$)

Rate Group		Capital ($/Customer/Yr.)	O&M ($/Customer/Yr.)	Total ($/Customer/Yr.)
Domestic		123.60	20.65	144.25
	Single Family	126.56	18.74	145.30
	Multiple	82.33	18.74	101.07
	TOUs	127.56	19.02	146.58
	Dom-Master Meter	1,051.77	156.55	1,208.32
GS-1		176.25	22.45	198.70
	Single Phase	97.83	21.88	119.71
	Three Phase	282.85	23.24	306.09
	Primary	955.49	21.32	976.81
TC-1		78.23	21.78	100.01
TOU GS-2		1,617.08	161.24	1,778.32
	Single Phase	1,051.77	156.55	1,208.32
	Three Phase	1,695.32	161.91	1,857.23
	Primary	955.49	149.69	1,105.17
TOU GS-3		2,798.19	641.01	3,439.20
	Secondary	2,844.92	643.14	3,488.06
	Primary	1,344.96	626.13	1,971.09
TOU-8		2,249.70	633.34	2,883.04
	TOU-8-Sec	1,406.20	636.10	2,042.29
	TOU-8-Pri	1,456.68	626.13	2,082.81
	TOU-8-Sub	13,873.18	626.13	14,499.31
AG <= 200		1,035.86	164.56	1,200.42
	Single Phase	505.74	159.30	665.05
	Three Phase	1,099.25	165.19	1,264.43
AG > 200		2,372.98	567.52	2,940.50
	3 Phase	2,443.22	567.52	3,010.74
	Primary	388.48	567.52	956.00
Street Lights (per customer)		97.83	21.76	119.59
Unmetered *(per lamp)				
	LS-1	2.33	0.00	2.33
	LS-2	0.93	0.02	0.95
	OL	2.33	0.22	2.55
	DWL	1.09	0.01	1.10

*Unmetered includes both a customer and per lamp customer marginal cost.

Q: How do you recommend customer charges be set for a consolidated GS-1 customer class?

A: To provide fair monthly customer charges, we recommend that customer charges be differentiated as shown in Table 5. This will capture the key elements that distinguish customer access costs among commercial customers, while remaining relatively simple.

Table 5: Recommended Customer Charges Structure for a Consolidated GS-1 Class[85]

	Single Phase	Three Phase	Primary Service
Shared Transformer			
Dedicated Transformer			

Q: What is the issue with accounts primarily serving lighting loads?

A: SCE identified that the average daily profile of accounts serving less than 4 kW in peak demand have an inverted load profile with higher usage during the nighttime. Many of these accounts are likely to be used mainly for lighting, whether for traditional commercial purposes, such as exterior lighting, but also for interior multi-family residential purposes such as hallways. As many as two-fifths of the GS-1 and GS-2 accounts may fit into this category, although they represent less than 4 percent of total annual sales.[86]

SCE comments that "it would seem consistent with the principle used in the division of classes to migrate them out of General Service and into a lighting rate."[87] However, SCE has not determined what appropriate schedule (AL, OL, DWL) these customers might be migrated to.[88]

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[85] There is insufficient information in the workpapers to calculate the proposed customer charges.

[86] Calculated from data provided in SCE-04, Appendix J, Tables J-1 and J-2, and Figure J-3.

[87] SCE-04, Appendix J, p. J-7.

[88] Attachment 4 (SCE response to SBUA-SCE-002-JW, Question 05(e)).

Q: Do you support migrating accounts primarily serving lighting loads to a lighting schedule?

A: Yes. SCE has provided solid evidence that this would be appropriate and generally in the customer's interest. Customers who prefer to stay on TOU rates should be allowed to do so.

Q: What is the issue for customers with demand at the high end of the GS-2 class?

A: Although SCE did not raise this issue in its study or data response, we noticed that there is a group of over 11,500 customers with peak demand of 150 kW to 200 kW, including 4,616 whose peak demand is rated at exactly 200 kW.[89] While there is no identified cost allocation issue with including these customers in a consolidated GS-1 class, there may be good reasons to migrate these customers to GS-3 customer class. For example, if most of these customers have higher customer access costs than other GS-2 customers, the resulting customer access costs may be more consistent within the consolidated GS-1 customer class. We also note that PG&E's small light and power rates eligibility boundary is 75 kW.

Q: What do you recommend with respect to customers with demand in the higher end of the range?

A: We recommend that the Commission include these customers in the consolidated GS-1 class but require SCE to study this issue further. If justified by further study, SCE could be permitted to shift higher demand customers into the GS-3 class when finalizing the consolidated rates and tariffs.

An alternative would be to simply shift the smallest GS-2 customers into GS-1 and retain a GS-2 class for larger customers, such as using the 150 kW threshold we observed. This could result in a fairly small customer class. Potential disadvantages

[89] SCE-04, Appendix J, Figure J-3, p. J-5.

of a small customer class include rate design complications due to a heterogeneous customer mix, excessive cost in maintaining a full range of rate options/riders, and unnecessary cost for customizing customer outreach.

Q: Why does the default rate need to be reconciled as part of consolidation?

A: The default rate for TOU-GS-1 is Option E, while TOU-GS-2 customers are defaulted to Option D. SCE does not discuss this difference in Appendix J. We recommend that the default rate for the consolidated TOU-GS-1 should remain Option E, but that all existing accounts would remain on their existing rate option, to minimize disruption. For example, a customer on TOU-GS-2-D would be migrated to TOU-GS-1-D.

Q: What is the issue with SCE's Level Pay Plan?

A: SCE's level pay plan (LPP) gives customers (including those in GS-1, but not G-2) the option to pay a flat bill for 11 months with an annual true-up to account for accumulated differences between actual and levelized bill amounts. Commission decision D.00-06-034 prohibits the expansion of LPP to other rate groups, so consolidation of GS-1 with GS-2 could result in effectively expanding LPP to include GS-2 customers.

Q: What terms do you recommend for the LPP in a consolidated GS-1 tariff?

A: To maintain compliance with D.00-06-034, LPP eligibility should be restricted to customers with continuing maximum demand of no more than 20 kW, consistent with the current limit for GS-1. SCE should review LPP accounts at the annual true-up and disqualify any non-compliant accounts from continued enrollment.

Implementing a 20-kW requirement could disqualify a small number of existing GS-1 and qualify a similarly small number of GS-2 customers, for reasons that are unclear. Even though the current monthly maximum demand for GS-1 is 20 kW, the study's Figure J-3 indicates that there are some GS-1 accounts with greater demand,

and some GS-2 accounts with lesser demand.[90] These irregular accounts represent less than 2 percent of either tariff's accounts.

Q: Do you recommend any transition period?

A: Yes. SCE should implement rates for the GS-1 and GS-2 classes using the existing tariff rules until the CRSP is available to program the new consolidated GS-1 rates. Once it is technically feasible to consolidate the rates, SCE should complete the transition as expeditiously as possible.

During the transition period, SCE should develop customer education materials to explain the rate changes. GS-1 customers should be informed that they will no longer be subject to a 20 kW maximum demand to remain on the rate. TOU-GS-2 Option E customers should be notified that the consolidated TOU-GS-1 Option E rate does not include demand charges and of the availability of the optional energy storage rate, unless the customer cap for TOU-GS-1 (ES) has been reached. SCE should review existing programs (e.g., energy efficiency, transportation electrification) and inform GS-2 customers of any opportunities previously restricted to the GS-1 class. Of course, all customers should be informed of the changes in rates.

C. Discounted Customer Charge for EV Meters

Q: Does SCE propose a rider to discount the customer charge for electric vehicle (EV) meters?

A: Yes, SCE proposes a monthly credit for customers on TOU-D-PRIME who are also paying a monthly charge for a separately metered Schedule TOU-EV-1 account. SCE explains that separate home and EV meters are potentially the only viable option for multi-unit dwellings (MUDs).

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[90] SCE-04, Appendix J, Figure J-3, p. J-5.

SCE's proposed monthly credit would not fully offset the EV meter charge since the $2.14 per month cost for the additional meter would need to be recovered.[91] SCE recognizes that "the service point and other associated facility costs are recovered through the customer charge of the primary meter."[92]

Q: Should a similar rider discount be made available for small businesses?

A: Yes. Similar to multi-family properties, small businesses in multi-tenant properties may not be able to install EV chargers without a separate meter. Whether owning or renting its business space, a small business may require separately metered EV chargers for its employees, customers, or business vehicles. These customers face the same barriers to EV adoption as do residents of MUDs. Depending on the property configuration, a small business could require more than one additional utility meter.

A small business that installs separately metered EV chargers must utilize the TOU-EV-7 rate. The meter charge and other components of the monthly charge for TOU-EV-7 are based on the GS-1 rate class. Currently, a TOU-EV-7 customer co-located with an existing customer is "viewed as a separate entity."[93]

Q: Please estimate the resulting monthly charge after the discount is applied.

A: Since the cost components for the GS-1 rate class are higher than for the residential rate class, the resulting meter charge (after the discount is applied) would be significantly higher than the monthly residential EV meter charge of $2.14.

In Table 6, we have attempted to estimate the small commercial meter charge. Because we were unable to locate the calculation of the residential meter charge, we were unable to determine what costs were included in the charge. According to SCE's testimony, the only cost included in the meter charge is the meter cost, to which SCE

[91] Attachment 5 (SCE response to SBUA-SCE-002-JW, Question 06.a).

[92] SCE-04, p. 37, lines 5-18.

[93] Attachment 4 (SCE response to SBUA-SCE-002-JW, Question 06.d).

(improperly) applies an EPMC scalar. This accounts for all but $0.17 of the total monthly residential EV meter charge.

Because we do not know what that $0.17 cost represents, we were unable to build a complete monthly small business EV meter charge. However, the charge would be at least $0.98 more than the residential charge. We do not fully understand why there would be a higher cost, since the equipment would be functionally identical whether it is supplied at a residence or to a commercial location. However, since the cost of the commercial meter is derived from overall average cost of small commercial meters, it may be reasonable.

Table 6: Components of Residential and Small Business Meter Costs and Charges, Applying SCE's Method

Customer Class	Monthly Meter Cost[94]	EPMC Cost[95]	Other Cost[96]	Total Monthly Cost
Residential	$ 1.67	$ 0.30	$ 0.17	$ 2.14
Small Commercial	$ 2.64	$ 0.48	Not determined	$ 3.12

Q: Are there any complications that SCE has pointed out?

A: Yes. In response to a data request, SCE pointed out two issues.

First, SCE stated that "there may be situations where either the existing service point or customer-side infrastructure would need to be upgraded to serve up to an

[94] Obtained from SCE-02 Distribution Streetlight Workpapers, tab Customer MC, cells S6 and S15 after setting non-meter costs to zero, with cell D10 updated to 10.3% as directed in SCE's response to SBUA-SCE-002-JW, Question 06.b Follow-up.

[95] The residential EPMC scalar cost was obtained from the RevAllo and RateDesign_M workpaper, tab Residential, comparing cell I14 to I8 and then applying the result to the monthly meter cost. For small commercial, the same workpaper and method was used, but the EPMC scalar was obtained from tab TOU-GS-1, comparing cell I19 to I8.

[96] For residential, this is the difference between the total monthly cost stated by SCE and the monthly meter cost and the EPMC cost. This may represent a portion of customer services, but we were unable to locate the calculation of this meter discount in workpapers.

additional load."[97] This could also be the case in a multi-unit dwelling and is not a reasonable basis to reject this proposal for small businesses. It would be reasonable to restrict eligibility for the credit to customers who would not require infrastructure upgrades or will be paying directly for those upgrades.

Second, SCE stated that "TOU-EV-7 load can be co-located with any commercial industrial rate."[98] As we understand SCE's proposed residential credit, the rider is a part of the customer's main TOU-D-PRIME rate, not a part of the TOU-EV-1 rate.[99] So the customer pays the full monthly charge on the bill for the TOU-EV-1 rate, and a discounted monthly charge on the TOU-D-PRIME rate. If the customer ceases taking service on TOU-EV-1, presumably SCE would remove the discount from the main account bill.

Similarly, we are proposing that the discounted monthly charge would be a rider on the TOU-GS-1 rate. SCE's concern about large customers (i.e., TOU-GS-3) is fully resolved by not revising those tariffs to include the monthly credit rider.

In summary, other than possibly restricting eligibility for the credit based on the need for service upgrades, we do not believe SCE's potential objections raise substantive issues with our proposals.

Q: What is your recommendation to the Commission?

A: We recommend that. if the Commission approves SCE's proposed monthly credit for customers on TOU-D-PRIME who are also paying a monthly charge for a separately metered Schedule TOU-EV-1 account, then it should offer a similar monthly credit to customers on the TOU-GS-1 rate who are also paying a monthly charge for a separately metered Schedule TOU-EV-7 account. The credits should be calculated

[97] Attachment 5 (SCE response to SBUA-SCE-002-JW, Question 06.c).

[98] *Id*.

[99] SCE-04, p. 37, lines 5-6, 14-16.

similarly, after applying any changes to the underlying costs and charges approved by the Commission such as removing the EPMC scalar cost.

V. Time of Use Periods

Q: Please summarize SCE's testimony on time of use periods.

A: SCE recommends continuing its current time of use periods. SCE's TOU Period Study includes a regression analysis on summer marginal costs. The regression analysis shows that costs are highest from 5 PM – 10 PM.[100] In the winter, when SCE uses a mid-peak rate, SCE's marginal costs show a smaller, earlier peak. SCE's TOU Period Study did not evaluate a 5 PM – 10 PM TOU peak period; the only alternatives SCE considered were 4 PM – 9 PM and 5 PM – 8 PM.

Q: What should the Commission do with respect to TOU periods?

A: The Commission and the parties have expended substantial effort over the years to setting CPP event and TOU periods. Unfortunately, the TOU periods that are being put into effect as part of the transition to mandatory TOU rates is based on now-outdated load data. In the Extreme Weather Event Reliability rulemaking (A.20-11-003), SBUA submitted evidence from all three IOUs demonstrating that the optimal CPP and TOU peak period has shifted from 4 PM to 9 PM (the period used by the IOUs for most purposes) to 5 PM to 10 PM. SBUA's testimony demonstrated that the peak period is shifting more rapidly than previously anticipated. The sooner the Commission shifts the TOU periods to better match costs, the better, for reducing NEM rate effects, improving the TRC benefits of rate designs, improving reliability and reducing carbon emissions. The Commission declined to adjust the peak periods in D.21-03-056. We suspect that the Commission will not be inclined to correct the

[100] SCE-02, p. D-7.

time periods in this proceeding, either. But the time periods should be reconciled with reality as soon as possible, considering other constraints.

In a brief comment, SCE suggests that it intends "to maintain TOU periods for at least six years."[101] In D.17-01-006, the Commission adopted a "goal of reviewing and re-setting Base TOU periods and rates every other GRC cycle." The Commission also stated that, "If adopted forecasts were to deviate significantly from updated actual data, and adjustment in TOU time periods more frequent than once every five years may be warranted."[102] The Commission should ensure that in the next GRC cycle, the IOUs update and synchronize TOU periods, so as to improve reliability and relieve small businesses and other customers from unnecessary costs that could be mitigated by sending customers more optimally timed price signals.

In this proceeding, we recommend that the Commission reject SCE's six-year policy and restate its expectation that SCE will propose updated TOU periods in its next Phase 2 GRC.

Q: Does this conclude your testimony?

A: Yes.

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[101] SCE-01, p. 17, line 11.

[102] D.17-01-006, p. 47.

Attachment 1

Paul L. Chernick

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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

"Price Effects as a Benefit of Energy-Efficiency Programs" (with John Plunkett), *2014 ACEEE Summer Study on Energy Efficiency in Buildings* (5) 57–5-69. 2014.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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PRESENTATIONS

"Rethinking Utility Rate Design—Retail Demand and Energy Charges," Solar Power PV Conference, Boston MA, February 24, 2016.

"Residential Demand Charges - Load Effects, Fairness & Rate Design Implications." Web seminar sponsored by the NixTheFix Forum. September 2015.

"The Value of Demand Reduction Induced Price Effects." With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 2015.

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

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

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

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

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

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

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

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

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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.

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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;

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"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.

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"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.

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ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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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, co-generation, 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; Carolina P&L certification of 500 MW combustion turbine; Southern Environmental Law Center. December 1995.

Need for new capacity. Purchased-power options. 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; surrebuttal, January 2010.

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

245. **Penn. PUC** 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.

364. **Penn. PUC** P-2014-2459362; Philadelphia Gas Works DSM Plan; Philadelphia Gas Works. October 2020.

Avoided costs of commodity and delivery. Water heater load shape. DRIPE.

365. **Cal. PUC** A.19-11-019; Pacific G&E Marginal Costs, Revenue Allocation, and Rate Design; Small Business Utility Advocates. November 2020. Joint testimony with John D. Wilson. Direct November 2020.

Marginal capacity costs for distribution, generation, transmission and customer access. Customer charges, demand charges, TOU differentials and periods, and real-time pricing.

366.

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

JOHN D. WILSON

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

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.

REPORTS

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

Houston Environmental Foresight Science Panel, *Houston Environment 1995*, Houston Advanced Research Center, 1996.

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

Florida Coastal Management Program, *Florida Assessment of Coastal Trends*, June 1997.

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

Office of Program Policy Analysis and Government Accountability, *Review of the Community Development Corporation Support and Assistance Program*, Report No. 97-45, February 1998.

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.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," with Mike O'Boyle, Ron Lehr, and Mark Detsky, Energy Innovation Policy & Technology LLC and Southern Alliance for Clean Energy, April 2020.

"Monopsony Behavior in the Power Generation Market," *The Electricity Journal* 33, with Mike O'Boyle and Ron Lehr (2020).

"Review of Nova Scotia Power's 2020 Integrated Resource Plan," prepared for the Nova Scotia Consumer Advocate, NSUARB Matter No. M08059, with Paul Chernick (January 2021).

"Implementing All-Source Procurement in the Carolinas," prepared for Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League and Upstate Forever, for submission in NCUC Docket E-100, Sub 165, and SCPSC Dockets 2019-224-E and 2019-225-E (February 2021).

"Intelligent Feeder Project: Comments on Nova Scotia Power's Final Report," prepared for the Nova Scotia Consumer Advocate, NSUARB Matter No. M09984 (June 2021).

PRESENTATIONS

"Clean Energy Solutions for Western North Carolina," presentation to Progress Energy Carolinas WNC Community Energy Advisory Council, February 7, 2008.

"Energy Efficiency: Regulating Cost-Effectiveness," Florida Public Service Commission undocketed workshop, April 25, 2008.

"Utility-Scale Renewable Energy," presentation on behalf of Southern Alliance for Clean Energy to the Board of the Tennessee Valley Authority, March 5, 2008.

"An Advocates Perspective on the Duke Save-a-Watt Approach," ACEEE 5th National Conference on Energy Efficiency as a Resource, September 2009.

"Building the Energy Efficiency Resource for the TVA Region," presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group, December 10, 2009.

"Florida Energy Policy Discussion," testimony before Energy & Utilities Policy Committee, Florida House of Representatives, January 2010.

"The Changing Face of Energy Supply in Florida (and the Southeast)," 37th Annual PURC Conference, February 2010.

"Bringing Energy Efficiency to Southerners," Environmental and Energy Study Institute panel on "Energy Efficiency in the South," April 10, 2010.

"Energy Efficiency: The Southeast Considers its Options," NAESCO Southeast Regional Workshop, September 2010.

"Energy Efficiency Delivers Growth and Savings for Florida," testimony before Energy & Utilities Subcommittee, Florida House of Representatives, February 2011.

"Rates vs. Energy Efficiency," 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 2013.

"TVA IRP Update," TenneSEIA Annual Meeting, November 19, 2014.

"Views on TVA EE Modeling Approach," presentation with Natalie Mims to Tennessee Valley Authority's Evaluating Energy Efficiency in Utility Resource Planning Meeting, February 10, 2015.

"The Clean Power Plan Can Be Implemented While Maintaining Reliable Electric Service in the Southeast," FERC Eastern Region Technical Conference on EPA's Clean Power Plan Proposed Rule, March 11, 2015.

"Renewable Energy & Reliability," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Challenges to a Southeast Carbon Market," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Solar Capacity Value: Preview of Analysis to Date," Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) meeting, Orlando, FL, November 2017.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Southeast Energy and Environmental Leadership Forum, Nicholas Institute for Environmental Policy Solutions, August 2020.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Indiana State Bar Association, Utility Law Section, Virtual Fall Seminar, September 2020.

EXPERT TESTIMONY

2008 **South Carolina PSC** Docket No. 2007-358-E, surrebuttal testimony on behalf of Environmental Defense, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2009 **North Carolina NCUC** Docket No. E-7, Sub 831, direct testimony on behalf of Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

Florida PSC Docket Nos. 080407-EG through 080413-EG, direct testimony on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council. Energy efficiency potential and utility program goals.

South Carolina PSC Docket No. 2009-226-E, direct testimony in general rate case on behalf of Environmental Defense, the Natural Resources Defense Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2010 **North Carolina NCUC** Docket No. E-100, Sub 124, direct testimony on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Adequacy of consideration of energy efficiency in Duke Energy Carolinas and Progress Energy Carolinas' 2009 integrated resource plans.

Georgia PSC Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in

Georgia Power's 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

Georgia PSC Docket No. 31082, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 demand side management plan, including program revisions, planning process, stakeholder engagement, and shareholder incentive mechanism.

2011 **South Carolina PSC** Docket No. 2011-09-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of South Carolina Electric & Gas's 2011 integrated resource plan, including resource mix, sensitivity analysis, alternative supply and demand side options, and load growth scenarios.

South Carolina PSC Docket Nos. 2011-08-E and 2011-10-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of Progress Energy Carolinas and Duke Energy Carolinas' 2011 integrated resource plans, including resource mix, sensitivity analysis, alternative supply and demand side options, cost escalation, uncertainty of nuclear and economic impact modeling.

2013 **Georgia PSC** Docket No. 36498, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2013 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues, economics of fuel switching and renewable resources.

South Carolina PSC Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

2014 **South Carolina PSC** Docket No. 2014-246-E, direct testimony generic proceeding on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Methods for calculating dependable capacity credit for renewable resources and application to determination of avoided cost.

2015 **Florida PSC** Docket No. 150196-EI, direct testimony in Florida Power & Light need certification case on behalf of Southern Alliance for Clean Energy. Appropriate reserve margin and system reliability need.

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.

2019 **Georgia PSC** Docket Nos. 42310 and 42311, direct testimony with Bryan A. Jacob in Georgia Power's 2019 integrated resource plan and demand side management plan on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in IRP, retirement of uneconomic plants, and use of all-source procurement process. Shareholder incentive mechanism for both renewable energy and DSM plan.

2020 **Nova Scotia UARB** Matter No. M09519, direct testimony with Paul Chernick in Nova Scotia Power's application for approval of the Smart Grid Nova Scotia Project on behalf of the Nova Scotia Consumer Advocate. Cost classification, decommissioning costs, justification for software vendor selection, and suggested changes to project scope.

Nova Scotia UARB Matter No. M09499, direct testimony with Paul Chernick in Nova Scotia Power's 2020 annual capital expenditure plan on behalf of the Nova Scotia Consumer Advocate. Potential to decommission hydroelectric systems, review of annually recurring capital projects, use of project contingencies, and cost minimization practices.

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.

Nova Scotia UARB Matter No. M09707, direct testimony with Paul Chernick on Nova Scotia Power's 2020 Load Forecast on behalf of the Nova Scotia Consumer Advocate. Impacts of recession, application of end-use studies, improvements to forecast components, and impact of time-varying pricing.

California PUC Docket A.19-10-012, direct and rebuttal testimony with Paul Chernick in San Diego Gas & Electric's application for the Power Your Drive Electric Vehicle Charging Program on behalf of the Small Business Utility Advocates. 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.

California PUC Docket A.19-08-013, 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.

Georgia PSC Docket Nos. 4822, 16573 and 19279, direct, rebuttal and surrebuttal testimony in Georgia Power Company's PURPA avoided cost review on behalf of the Georgia Large Scale Solar Association. Reviewing compliance with prior Commission orders. Application of capacity need forecast in projection of avoided capacity cost. Calculation of cost of new capacity. Proposal of standard offer contract.

California PUC Docket A.19-11-019, direct, reply and responsive testimony with Paul Chernick in Pacific Gas & Electric's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate design, including customer charges, demand charges, real time pricing tariffs, TOU differentials and periods.

Nova Scotia UARB Matter No. M09548, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of fuel contract costs. Scope of study on dispatch practices. Impact of greenhouse gas shadow pricing. Compliance issues related to resource planning.

2021 **California PUC** Docket R.20-11-003, direct and reply testimony on rulemaking to ensure reliable electric service in the event of an extreme weather event on behalf of the Small Business Utility Advocates. Modifications to Critical Peak Pricing programs and Time of Use periods. Modifications to load management programs.

Nova Scotia UARB Matter No. M09898, direct testimony on Nova Scotia Power's Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Effect of delays in power contract. Unit modeling assumptions. Variable capital costs. Application of Time-Varying Pricing.

Nova Scotia UARB Matter No. M09920, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2021 on behalf of the Nova Scotia Consumer Advocate. Cost minimization. Project contingency. Economic analysis model. Analysis of specific projects.

Nova Scotia UARB Matter No. M09777, direct testimony on Nova Scotia Power's Time-Varying Pricing Tariff Application on behalf of the Nova Scotia Consumer Advocate. Effect of proposed TVP tariffs on load, capacity savings, and energy costs. Recommended CPP tariffs. Treatment of demand charges in TVP tariffs. Implementation and evaluation of TVP tariffs. Lost revenue adjustment mechanism.

South Carolina PSC Docket Nos. 2019-224-E and 2019-225-E, surrebuttal testimony on 2020 Integrated Resource Plans filed by Duke Energy Carolinas and Duke Energy Progress. All-source procurement process. Process for resolution of disputed issues in IRP proceedings.

California PUC Docket A.20-10-011, direct and reply testimony with Paul Chernick in Pacific Gas & Electric's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot on behalf of the Small Business Utility

Advocates. Rate design for real time pricing tariff. Marketing to small businesses. Evaluation plan.

California PUC Docket R.20-08-020, direct and reply testimony with Paul Chernick in rulemaking to revisit net energy metering (NEM) tariffs on behalf of the Small Business Utility Advocates. Rate design for NEM tariff. Method for analyzing NEM tariff program.

Southern California Edison
A.20-10-012 – 2021 GRC Phase 2

DATA REQUEST SET CalAdv-SCE-011-NC

To: Cal Advocates
Prepared by: Elliot James Dean
Job Title: Associate Specialist, Analytics
Received Date: 3/30/2021

Response Date: 4/13/2021

Question 01:
Please provide the relative peak and flex probability models SCE used to develop the results reported in "SCE-02 - Table I-5 & I-6 - Capacity Allocation Tool (Results Summary)" workpapers for SCE Exhibit 2. Please provide detailed instructions on how to run the respective relative peak and flexibility probability models.

Response to Question 01:
SCE objects to the instruction stating that the data request is "continuing in nature" on the grounds it is unduly burdensome. Subject to and without waiving this objection, SCE responds as follows:

The models used to develop the results reported in "SCE-02 – Table I-5 & I-6 – Capacity Allocation Tool (Results Summary)" workpapers for SCE Exhibit 2 can be found in the attached zip folder. In this folder, you will find three macro-enabled excel workbooks that comprise the model. For instructions on how to navigate these workbooks and produce a model run, please refer to the Capacity Allocation Tool User Guide, which is also attached.

Two-page excerpt from Capacity Allocation Tool User Guide follows.

Capacity Allocation Study Documentation

Authors: Justin Kubassek, Carl Silsbee, Steven van Deventer, Benjamin Baker, Eliot Dean & Sean Hernandez

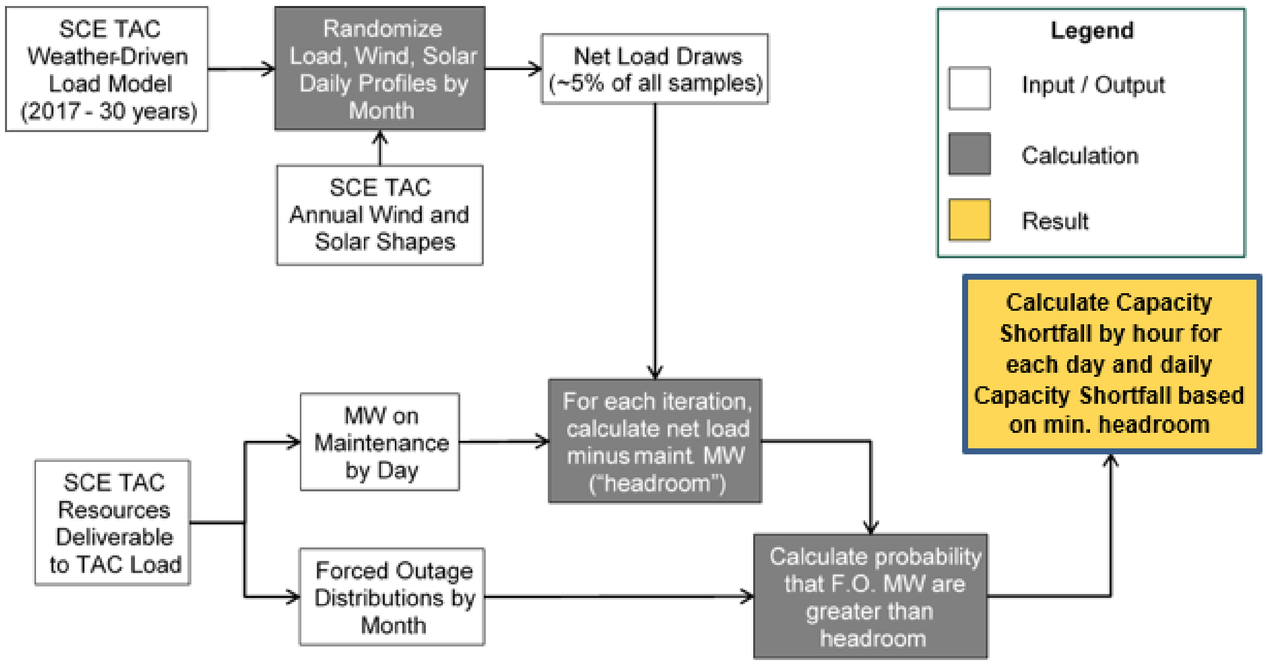
Resource & Environmental Planning & Strategy

1. Overview

SCE utilizes the Capacity Allocation Tool to spread the Generation Capacity Marginal Cost (GCMC) across TOU periods. The Capacity Allocation Tool works by identifying which month-hours of the year are the most vulnerable to capacity shortfalls. The Capacity Allocation Tool involves comparing forecasted SCE load to forecasted renewable generation and available capacity. If the load, net of renewable generation (i.e., net load), is greater than the available capacity, this indicates a capacity shortfall risk. On the other hand, if net load is less than available capacity, then there is residual capacity in case load were higher than forecasted, renewables were lower than forecasted, or outages were more severe than forecasted. The Capacity Allocation Tool utilizes this information to rank month-hours according to capacity shortfall risk and residual capacity. For each month-hour combination, the less the residual capacity, the greater the capacity shortfall risk – and the greater the GCMC allocation. This approach also determines an appropriate capacity value split between ramp and peak constraints. The study methodology is summarized in Figure 1 below.

Please note that the purpose of SCE's Capacity Allocation Tool is not to forecast the precise timing of future low-reserve margin events, nor is it to forecast the absolute magnitude of any single capacity shortfall. Rather, it is intended to be a relative distribution of risk used to allocate capacity value across hours based on a 1-in-10 planning scenario.

Figure 1 - Overview of Study Methodology



2. Inputs

A. Notes on setting up the Net Load input file

The Net Load input file ("CAT STEP 1 – 2024 Master File.xlsm") contains the hourly load, wind, and solar shapes. The hourly load is 30 unique system level load shapes based on 30 years of historical weather data that are scaled such that the average annual energy represents the internal energy forecasted by SCE minus distributed generation photo voltaic (DG PV) plus a shape for transportation electrification (TE).[1] DG PV is treated as supply side resources and in the total solar profile input as an annual shape. Wind and solar shapes are the total expected contracted RPS plus forecasted DG PV.

Inputs:

- 30 unique load shapes
    - internally developed
    - Load shapes in STEP ONE file should first be scaled to the study year based on annual energy forecasts

[1] TE is a deterministic input to the 30 years of weather shapes and does not vary by year.

Southern California Edison
A.20-10-012 – 2021 General Rate Case Phase 2

DATA REQUEST SET S B U A - S C E - 0 0 2 - J W

To:
Prepared by: Reuben Behlihomji
Job Title: Prin Mgr
Received Date: 6/14/2021

Response Date: 6/28/2021

Question 05.c,e:
For SCE-04, Appendix J.

c. Please explain SCE's position on whether and how the findings of Appendix J should be implemented.
e. Please provide a bill impact estimate of migrating accounts serving lighting loads to a lighting rate class. (p. J-8)

Response to Question 05.c,e:

c. Pursuant to Section B.6 of the Residential and Small commercial Settlement agreement in the 2018 GRC, Settling Parties agreed that SCE will conduct a study on whether its current TOU-GS-1 rate class should be expanded to include customers with monthly demand over 20 kW. SCE agreed to include the results of this study as part of its 2021 GRC Phase 2 application - SCE-04, Appendix J presents and describes SCE's findings on the study. While SCE has not developed a position on the study, SCE will consider and evaluate parties' positions on the study, and whether and how the findings in Appendix J should be implemented.

e. SCE has not conducted a bill impact estimate of migrating the lighting account loads to a lighting rate class – More specifically, SCE would need to consider the aggregate mix of this subgroup's consumption profile to determine the appropriate schedule (AL, OL, DWL) that these customers would be migrated to.

Southern California Edison
A.20-10-012 – 2021 General Rate Case Phase 2

DATA REQUEST SET S B U A - S C E - 0 0 2 - J W

To: SBUA
Prepared by: Alexander Echele
Job Title: Sr Spec.
Received Date: 6/14/2021

Response Date: 6/24/2021

Question 06.a-d:
Referencing SCE-04, p. 37: SCE is proposing a rider option under TOU-D-PRIME for separately metered residential loads.

a. Please confirm that the proposed rider option is to charge the customer the TOU-EV-1 meter charge ($2.14/month) as opposed to the TOU-D-PRIME customer charge (average of $14.24/month). If not confirmed, please clarify.
b. Please explain why the TOU-EV-7 meter charge is $0.365/day, an average of approximately $11.10/month. Specifically, why is the TOU-EV-7 meter charge substantially higher than the TOU-EV-1 meter charge?
c. Please explain whether SCE believes that some small businesses may require separately metered EV chargers provided through the same service point as the customer's primary meter. For example, a small business may contract with an EVSE provider in order to allow both customers and employees to access the EV chargers without having to become directly involved in billing for charging services.
d. Please explain whether SCE agrees that if the service point and other associated facility costs are recovered through the customer charge of the primary meter for a customer on a GS-1 rate, that it may be reasonable for SCE to also offer a rider option of a monthly credit to make the separately metered TOU-EV-7 monthly meter charge consistent with the TOU-EV-1 meter charge? If not, please explain why not.

Response to Question 06.a-d:

a) Yes, proposed rider option is to charge the customer the TOU-EV-1 meter charge of $2.14/month.
b) Fixed monthly customer charges include the following 4 components: 1) Final Line Transformation 2) Service Drop 3) Meter Charge and 4) Customer Billing. The TOU-EV-7 rate class is commensurate with the GS-1 rate class and the TOU-D-PRIME is commensurate with the residential rate class. The cost components that make up the fixed charge for the GS-1 rate class differ from the residential rate class, which is why the TOU-EV-7 fixed charge is greater than the TOU-EV-1 fixed charge.
c) Yes, it is possible that some small businesses may require separately metered EV chargers provided through the same service point, defined as the customer's breaker panel and/or meter panel. However, there may be situations where either the existing service point or

customer-side infrastructure would need to be upgraded to serve up to an additional load. Additionally, a TOU-EV-7 load can be co-located with any commercial industrial rate (i.e, TOU-GS-2, TOU-GS-3, or TOU-8), further complicating the differential in the customer charge that would be offered if a TOU-D-PRIME structure were adopted. Currently in these situations, the TOU-EV-7 load is treated as a separate entity from the existing GS load.

d) No, a TOU-EV-7 customer is viewed as a separate entity if it is co-located with an existing customer.

Southern California Edison
A.20-10-012 – 2021 GRC Phase 2

DATA REQUEST SET S B U A - S C E - 0 0 2 - J W

To: SBUA
Prepared by: Alexander Echele
Job Title: Rate Design, Sr. Specialist
Received Date: 6/14/2021

Response Date: 7/12/2021

Question 06.b Follow-up:
Please provide the differences in the cost components that make up the fixed charge for the GS-1 rate class and the TOU-D-Prime rate class as described in the response. Please explain the basis for each component where the cost differs between the rate classes.

Response to Question 06.b Follow-up:
Please see the attachment for further details that illustrate the differences in the 1) Final Line Transformation 2) Service Drop 3) Meter Charge and 4) Customer Billing customer charge components for the GS-1 and Residential rate classes. Cust Marginal Cost Summary and the Res & GS1 Typical Customer Cost tabs illustrate the difference in the cost components between the GS-1 & Residential rate rate groups. The Customer MC tab shows the Marginal Cost and Retail customer charges in columns Y to AB. Columns Y and Z represent the Marginal Cost estimates and columns AA and AB represent the retail rate proposal. SCE found a reference error for the residential class in cell D10 (shown in red). The correct value of cell D10 should be 10.3%. As a result, SCE shows the corrected marginal cost and retail rate values for the residential class in columns AD to AN. The EPMC (Equal Percent Marginal Change) scaler to convert the Marginal Cost component to the retail fixed charge proposals is approximately 18%.

Attachment 6

Application No.: A.20-10-011
Exhibit No.: PG&E-22
Date: June 3, 2021

Schedule Developed in Response to ALJ Doherty's Request during June 2, 2021 Hearings in A.20-10-011

In response to ALJ Doherty's request for a schedule that incorporates the Procedural Proposal in Exhibit PG&E-20, section V, and keeps the start of Pilot Phase 2 the same as in Exhibit PG&E-3, Table 3-1, PG&E has developed the schedule in the right hand column of the Table 1 below.

Table 1

Schedule Developed in Response to ALJ Doherty's Request during June 2, 2021 Hearings in A.20-10-011

Line No.	CEV RTP Activity	Current Schedule from Scoping Memo and Proposed Pilot Timeline in Supplemental Testimony	Proposed Schedule for MGCC Study and Limited Hearings and Revised Pilot Timeline Maintaining Pilot Launch in May 2023
1	Track 1 Evidentiary Hearings	June 1-4, 2021	
2	Track 1 Opening Briefs / Reply Briefs	July 2021 & August 2021	
3	MGCC Study Data Received from ED	N/A	August 2021
4	Track 1 Proposed Decision	Q3 2021	
5	Track 1 Final Decision	Q4 2021	
6	Conduct MGCC Study	N/A	August 2021 - December 2021 (5 months)
7	Track 2 Proposals / Testimony (PG&E plus all interested parties)	N/A	January 2022
8	Track 2 Rebuttal	N/A	February 2022
9	Track 2 Limited Evidentiary Hearings	N/A	March 2022
10	Track 2 Opening Briefs / Reply Briefs	N/A	April 2022
11	Track 2 Expedited Proposed Decision	N/A	April 2022 - May 2022
12	Track 2 Expedited Final Decision	N/A	May 2022
Pilot Timeline			
13	Pilot Phase 0 – Pilot Planning - Identify potential participants and technology partners, perform simulation/modeling of theoretical bill and load response impacts, finalize pilot project plan, including measurement and evaluation plan.	December 2021 – February 2022 (3 months)	June 2022 - August 2022 (3 months)
14	Pilot Phase 1 – Recruitment and Rate Technology Development – Complete Request for Proposal for technology partners, and enroll up to 50 customers, build and test customer technical integration with price discovery tools.	March 2022 – April 2023 (14 months)	September 2022- April 2023 (8 months)
15	Pilot Billing System Programming – expected to begin after Complex Billing System replacement is completed and stable. *Critical Path*	October 2022 – April 2023 (Current estimate) (7 months)	October 2022 – April 2023 (Current estimate) (7 months)
16	Pilot Phase 2 – Collect Pilot data and complete ongoing and interim analysis and gather lessons learned. Interim analysis and results shared January 2024.	**May 2023** – October 2024 (Dependent on line 4) (18 Months)	**May 2023** – October 2024 (Dependent on 15) (18 months)
17	Pilot Phase 3 – Analyze Pilot data and synthesize lessons learned.	November 2024 – January 2025 (3 months)	November 2024 - January 2025 (3 months)

Request:

PG&E and Parties will need the MGCC study data from the Energy Division by August 2021 to maintain a Pilot Phase 2 start date in **<u>May 2023</u>**. This assumes a five-month period to conduct the Track 2 MGCC study analysis, and a Track 2 Final Decision in May 2022. In the revised Pilot timeline, the timing for Pilot Phase 1 activities on line 14 is delayed and reduced from the schedule in PG&E Supplemental Testimony to enable the inclusion of MGCC study results in the determination of the MGCC calculation methodology plus the required additional Track 2 procedural steps. Slack had been built into Pilot Phase 1 timing due to critical path billing system work not being able to start before October 2022 and Track 1 Final Decision expected in Q4 of 2021. PG&E notes that Track 1 Proposed and Final Decision timing could have several months of flexibility, given critical path billing system work cannot start prior to October of 2022.