BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Liberty Utilities (CalPeco Electric) LLC (U933E) for Authority to Among Other Things, Increase Its Authorized Revenues for Electric Service, Update Its Energy Cost Adjustment Clause Billing Factors, Establish Marginal Costs, Allocate Revenues, And Design Rates, as of January 1, 2022.	Application 21-05-017 (filed May 28, 2021)

TESTIMONY OF
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ON BEHALF OF SMALL BUSINESS UTILITY ADVOCATES

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SBUA
Small Business Utility Advocates

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[1] Formulas and assumptions that differ from those in Liberty's MCOS-RD Workpaper are highlighted in pale yellow. Derivative calculations are generally not highlighted.

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 RII-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 fourteen 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 Exhibit RII-2.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than thirty times before utility regulators in California, five other U.S. states and Nova Scotia, and appeared numerous additional times before various regulatory and legislative bodies. I have testified before the California Public Utilities Commission in eight proceedings.

II. Introduction

Q: On whose behalf are you testifying?

A: We are testifying on behalf of Small Business Utility Advocates. SBUA's mission is to represent the utility concerns of the small business community. Promoting an electricity rate structure that facilitates the success of small commercial customers with cost effective utilities supplying clean and renewable energy is central to this mission.[2]

There are approximately 3,941,201 small businesses in the state that comprise of 99.8% of all employer firms, provide 48.8% of private sector employment, account for over 280,000 net new jobs, and comprise approximately 43.2% of California's $152.1 billion in exports.[3] Small businesses are not only vital to California's economic health and welfare but also constitute an important class of ratepayers for utility companies.

Small commercial ratepayers have historically consumed about 100 gigawatt-hours of electricity annually, representing 17% of Liberty's load and $22 million in revenues.[4] The ratepayer interests of this class often diverge from residential ratepayers and larger

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[2] *See*, SBUA website at www.utilityadvocates.org.

[3] California Small Business Profile, U.S. Small Business Administration Office of Advocacy. See www.sba.gov/sites/default/files/advocacy/2018-Small-Business-Profiles-CA.pdf.

[4] Liberty workpaper: CalPeco MCOS and Rate Design_vSupplemental (henceforth "Liberty MCOS-RD Workpaper"), tabs "Class Usage" and "2021 Auth. Rev."

commercial customers on a variety of utility matters. It is vital to small businesses that rate allocation and rate treatment are fair to all energy consumers.

Q: What is the scope of your testimony?

A: We address two issues from the Scoping Memo, including (2) whether Liberty's proposals to allocate revenues and design rates, including the resulting rates, are reasonable; and (3) whether the methodology employed for Liberty's marginal cost study and the results of its marginal cost study are reasonable.[5]

Q: Please summarize your recommendations.

A: With respect to Liberty's marginal cost study, we recommend:

1. Correction of Liberty's marginal generation capacity cost (MGCC) to represent a battery storage unit, rather than a combustion turbine. (Page 9)
2. Correction of Liberty's MGCC to $70.81 / kW-year based on the MGCC approved by the Commission for PG&E in D.21-11-016, as adjusted by Liberty's property tax multiplier, as shown in Attachment RII-5. (Page 10)
3. Approval of Liberty's proposed marginal energy costs (MECs). (Page 15)
4. Approval of Liberty's proposed marginal distribution demand cost (MDDC). (Page 16)
5. Correction of Liberty's proposed class-specific marginal distribution customer costs (MDDCs), as presented in Exhibit RII-5. Our corrections are based on revisions to the average cost per customer of new hookups, class-specific customer growth, and customer plant-related O&M cost. (Page 40)
6. Upgrading of Liberty's other outdated or unsupported data for its next rate case.

With respect to Liberty's revenue allocation, we recommend:

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[5] We did not investigate class-specific issues for the OLS or Street Lighting classes.

7. Correction of Liberty's proposed MGCC allocation to classes based on class contribution to coincident peak, as shown in Attachment RII-4. (Page 15)
8. Approval of Liberty's proposed allocation of MECs to classes. (Page 15)
9. Approval of Liberty's proposal to allocate its generation revenue requirement based on class-specific class-specific marginal generation costs, including MGCCs and MECs, as shown in Attachment RII-6. (Page 16)
10. Correction of Liberty's proposed MDDCs allocation to classes using a two-step process. First, the MDDCs should be allocated to TOU periods based on the share of the top load hours. (Page 27) Second, each TOU-period MDDC should be allocated to classes based on their shares of average load during top load hours. (Page 28) Our recommended MDDC allocation is presented in Attachment RII-4. The Commission should reject any use of Liberty's transformer load study as unsupported by credible data and methods and as an unreasonable method to measure non-coincident distribution peaks. (Page 22)
11. Approval of Liberty's proposal to allocate distribution demand costs to classes based on MDDCs, as shown in Attachment RII-6. (Page 30)
12. Correction of Liberty's proposed allocation of distribution customer costs to customers based on corrected MDCCs, as shown in Attachment RII-6. (Page 44)
13. Approval of Liberty's proposal to allocate wildfire mitigation costs using the same method used for MDDCs. (Page 46)

With respect to Liberty's rate design, we recommend:

14. Rejection of Liberty's proposal to use a uniform increase in rate elements to implement its rate increase because freezing in place the prior relative allocation of revenue recovery among rate elements misallocates revenue recovery. (Page 49)

15. Setting customer charges at the class distribution revenue requirement, but capped at no more than double the current charge, as shown in Attachment RII-3. (Page 44)
16. Collection of wildfire remediation costs, not through a monthly customer charge, but through distribution rates, as shown in Attachment RII-6. (Pages 48, 63)
17. Setting generation rates at the class average cost of service, with several schedule-specific features. (Page 50)
18. Setting distribution rates at the class average cost of service, with several schedule-specific features. (Page 50)
19. Application of Liberty's proposed adjustments to total class revenue requirements uniformly across each cost categories, except that Liberty's capping and revenue decrease adjustments should use an aggregated MCOS allocator rather than an MGCC allocator. (Page 51)
20. Directing Liberty to file an update of its TOU periods within one year of the order in this proceeding. (Page 58)

In addition, we have one recommendation resulting from our inspection of customer demand data, as follows:

21. Directing Liberty to audit the accounts of customers on Schedule A-2 to determine if they are eligible for Schedule A-1. For any Schedule A-1 customers who became eligible prior to Liberty's last annual review by the billing department, then Liberty should refund the amount of savings that the customer would have benefitted from if it had migrated the customer in a timely manner. (Page 63)

III. Generation Cost Allocation

A. Marginal Generation Capacity Cost (MGCC)

Q: Why is Liberty proposing a new method for determining its MGCC?

A: In D.16-12-024 and D.20-08-030, the Commission directed Liberty to develop a cost of service methodology that reflects its system's need, rather than "relying on NV Energy's generation-related demand costs, which could arguably be different from a California customer's peak summer and winter consumption pattern."[6]

Q: What is Liberty's proposed MGCC?

A: Liberty proposes to set its MGCC at $218.83 / kW-year based on a 2011 California Energy Commission cost estimate for a gas peaker unit adjusted for inflation to 2022 costs, with further AFUDC and carrying-cost adjustments.[7]

Q: Is the proposed MGCC reasonable?

A: No. All three major IOUs are using the current cost of battery storage as the basis for MGCC value. Liberty does not explain why it expects that its marginal capacity resource will be a gas peaker rather than battery storage.

The Commission should direct Liberty to use a battery storage unit to represent its marginal capacity resource, and adopt an MGCC that is consistent with those used by other IOUs. For example, in D.21-11-016, the Commission adopted PG&E's system

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[6] D.20-08-030, p. 77.

[7] Liberty testimony, Ch. 12, p. 14, lines 11-15; Liberty MCOS-RD Workpaper, tab "MGC-Derivation."

MGCC of $68.56 / kW-year, subject to the inclusion of a property tax adder or multiplier which has not yet been approved.[8]

In the interests of simplicity, we recommend that the Commission direct Liberty to use PG&E's MGCC, which is a recent and fully litigated value. However, it should be augmented by Liberty's property tax multiplier (rather than the forthcoming value for PG&E) which is 3.28% of annualized capacity deferral value.[9] If Liberty or another party makes a different proposal, we would accept any reasonably derived value based on the use of a battery storage unit to represent the marginal capacity resource. As shown in Attachment RII-5, our recommendation results in an MGCC value of $70.81 / kW-year.

B. Allocation of MGCCs to Customer Classes

Q: How does Liberty propose to allocate generation costs?

A: Liberty explains that it assigned MGCCs "to each TOU period based on a POP factor that determines each hour's likelihood of being the peak hour during each month. The costs were then assigned to each class based on class projected usage during the TOU periods."

This method results in allocating just 42% of MGCC to the four winter months, and identifies the peak hour as 9-10 pm in June, as shown in Liberty's heat map of probability of peak (POP) hours in Figure 1.

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[8] D.21-11-016, p. 65. Note that the system MGCC is relevant to the peak demand of the system, other categories of MGCC relate to local resource adequacy and flex or ramp MGCC. *Id.,* pp. 43-45. Liberty does not claim that local or flex MGCCs are incurred on its system.

[9] Liberty MCOS-RD Workpaper, tab "MGC-Derivation."

Figure 1: Probability of Peak Heat Map[10]

Probability of Peak %	Hour Ending 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Monthly Allocation
1	0.10%	0.04%	0.02%	0.02%	0.01%	0.01%	0.02%	0.13%	0.48%	0.98%	0.82%	0.47%	0.25%	0.18%	0.13%	0.15%	0.37%	1.37%	1.89%	1.61%	1.25%	0.69%	0.37%	0.12%	**11.48%**
2	0.06%	0.04%	0.03%	0.03%	0.03%	0.04%	0.09%	0.28%	0.56%	0.72%	0.63%	0.46%	0.33%	0.28%	0.27%	0.29%	0.32%	0.74%	1.41%	1.29%	0.94%	0.46%	0.24%	0.11%	**9.63%**
3	0.03%	0.02%	0.02%	0.02%	0.02%	0.03%	0.11%	0.35%	0.66%	0.88%	0.79%	0.59%	0.41%	0.34%	0.30%	0.29%	0.25%	0.43%	0.81%	0.96%	0.80%	0.40%	0.17%	0.07%	**8.74%**
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.29%	0.82%	1.18%	1.04%	0.64%	0.35%	0.25%	0.19%	0.16%	0.10%	0.16%	0.32%	0.61%	0.81%	0.34%	0.10%	0.01%	**7.42%**
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%	0.21%	0.47%	0.65%	0.59%	0.41%	0.27%	0.19%	0.14%	0.13%	0.15%	0.23%	0.40%	0.59%	1.05%	0.73%	0.18%	0.02%	**6.45%**
6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.04%	0.13%	0.17%	0.08%	0.04%	0.03%	0.03%	0.04%	0.07%	0.11%	0.19%	0.45%	1.77%	3.41%	0.28%	0.00%	**6.85%**
7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20%	0.37%	0.14%	0.02%	0.01%	0.01%	0.02%	0.08%	0.28%	0.62%	0.89%	1.76%	2.95%	0.51%	0.00%	**7.86%**
8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.08%	0.11%	0.05%	0.02%	0.01%	0.02%	0.03%	0.10%	0.25%	0.53%	0.88%	2.79%	2.02%	0.12%	0.00%	**7.01%**
9	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.19%	0.48%	0.39%	0.22%	0.08%	0.04%	0.02%	0.03%	0.10%	0.34%	0.71%	1.39%	1.57%	0.98%	0.26%	0.01%	**6.82%**
10	0.07%	0.04%	0.04%	0.05%	0.07%	0.11%	0.26%	0.64%	0.89%	0.66%	0.37%	0.18%	0.07%	0.04%	0.03%	0.03%	0.05%	0.17%	0.57%	1.00%	0.71%	0.33%	0.18%	0.10%	**6.66%**
11	0.18%	0.14%	0.12%	0.11%	0.12%	0.15%	0.28%	0.47%	0.52%	0.48%	0.42%	0.35%	0.31%	0.30%	0.31%	0.34%	0.46%	0.82%	0.89%	0.85%	0.75%	0.57%	0.43%	0.28%	**9.62%**
12	0.03%	0.01%	0.01%	0.01%	0.01%	0.02%	0.04%	0.09%	0.24%	0.54%	0.47%	0.26%	0.13%	0.09%	0.09%	0.12%	0.38%	1.87%	2.25%	1.95%	1.52%	0.85%	0.40%	0.10%	**11.47%**

Q: Why did Liberty develop the POP method?

A: Liberty explains:

> In the prior GRC, the Commission expressed concern with application of NV Energy's marginal costs to Liberty's seasons and TOU periods. Liberty addressed this concern in the current MCS study by developing a Probability of Peak ("POP") factor based on Liberty's hourly system demands.[11]

Liberty explains further:

> The Probability of Peak (POP) method determines each hour's likelihood of being the peak hour during each month. The method was developed consistent with how the Company incurs generation costs, i.e., based on monthly peak demands. Specifically, the Company has a service agreement with NV Energy for purchase of generation capacity and energy. Per the agreement, the Company is billed demand charges based on the greater of Company's monthly net coincident peak demands or monthly net contract demands.[12]

Q: Is the use of Liberty's POP method to allocate MGCC costs to classes consistent with the Commission's direction in D.20-08-030?

A: No. The Commission specifically rejected Liberty's prior reliance on the service agreement with NV Energy as a basis for its marginal costs, pointing out that "generation services are market-based."[13]

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[10] Liberty MCOS-RD Workpaper, tab "POP 12CP HM."

[11] Liberty testimony, Ch. 12, p. 10, lines 19-22.

[12] Attachment RII-8, SBUA DR 4-7(a).

[13] D.20-08-030, p. 77.

Since system MGCC is determined based on the system peak, the first relevant fact is that Liberty is a winter-peaking system. Over the 2015-2020 time period, the monthly peaks for non-winter months are far below the system peak, as shown in Table 1.

Table 1: Monthly Peak Demand, 2015-2020 (Winter and Summer Months Highlighted)[14]

Month	Peak Demand (kW)	Percent of 6-Year Peak
January	129,473	95%
February	116,346	85%
March	108,203	79%
April	88,028	64%
May	78,687	57%
June	76,778	56%
July	88,425	65%
August	79,180	58%
September	85,280	62%
October	90,511	66%
November	120,812	88%
December	136,953	100%

In contrast, Liberty's proposed MGCC cost allocation method allocates 21% of MGCCs to the summer months and another 20% of MGCCs to the non-summer (including winter and shoulder months) off-peak period. This is wholly incompatible with the Commission's usual understanding of what MGCCs represent.

The misallocation of MGCC is partially explained by Liberty's ungainly hybridization of the MGCC method directed by the Commission with the NV Power service agreement. Liberty attempts to allocate MGCCs to classes by identifying the probability that hours within each TOU period could contribute to monthly peaks. Fundamentally, the Commission should reject any method that includes consideration of 12 monthly peaks because, while relevant to NV Power's service contract, MGCCs are not driven by monthly peaks.

[14] Liberty MCOS-RD Workpaper, tab "POP 12CP." Note that load data for 2020 are incomplete and do not include November or December. This omission is not explained.

Q: Are there other problems with Liberty's POP method?

A: Yes. Liberty's POP method is so irregular that it is probably best understood by reviewing the workpaper directly, as any verbal description is likely to be inadequate. It is not even effective at allocating costs from the level monthly demand rate in the NV Power service agreement. Monthly cost allocations vary from 6.5% to 11.5%.[15] We will give several examples of the irregularities in Liberty's POP method.

The "Probability of Peak" calculation begins with the estimation of the average and standard deviation of the load for each of 8,760 hours, over six years (or just five years for November and December, for which Liberty did not have data in its analysis). Especially with so few years of data, calculating the standard deviation for each hour produces spurious variability. For most situations, it is better to characterize each month as having 20-30 observations[16] for each of the seven days of the week, rather than 28 to 31 distinct dates. The load characteristics of a day are more likely to vary with its place in the week than whether it happens to be the 12th, 13th, or 14th day of the month. This is particularly true for a vacation-oriented service territory, such as Liberty's. Each date in Liberty's analysis may include 0, 1 or 2 weekend days.

Even more important for Liberty, load increases significantly in holiday periods. The Thanksgiving weekend started on November 22 in 2016, November 23 in 2017, November 24 in 2018, November 26 in 2015, and November 28 in 2019. Falling in that weekend seems to have a larger effect on load than whether the date is the 22nd or the 30th. We would expect similar effects for weekends with Monday holidays, the days between a fixed holiday (Christmas, Veterans Day, July 4th) and the adjacent weekend, and the

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[15] Liberty MCOS-RD Workpaper, tab "POP 12CP."

[16] Since Liberty has 5-6 years of data and there are 4-5 of each days in each month, the number of observations for each day-month combination may vary from 20 (5 x 4) to 30 (6 x 5).

especially the Christmas–New Year week, during which 58 of the top 60 load hours occurred from 2015-2019.[17]

As an example of the variability of Liberty's data among dates that are unlikely to have fundamentally different load distributions, the standard deviation in the 6–7 AM hour is only 3,583 kW on January 5 but is 18,131 kW on January 11. It is not reasonable to use a method that assigns more than five times the load variability to January 11 than is assigned to January 5, illustrating the limited value of these statistics for measuring the risk that specific hours might drive the peak.

The use of the monthly maximum of the hourly average values has similar problems. Liberty computes the average load over the five or six years of data for each date, and then computes the maximum of those hours. The maximum load for each month would be better represented by the maximum over the roughly 150–180 observations for the month, or the average of the maximum load in the month for each of the six years. In Table 2, we provide an example for January comparing these methods.

Table 2: January Peak Demand, Calculated Using Three Methods[18]

Method	January Peak Demand (MW)
Maximum Hourly Load, 2015-2020	129.5
Average of Annual Maximums, 2015-2020	122.5
Liberty's POP Method: Maximum of Hourly Averages, 2015-2020	118.7

Liberty's idiosyncratic methods result in excessive POP in the summer months, and the particularly unreasonable result of the peak POP hours occurring in June, July and August on a winter-peaking system.

[17] Liberty MCOS-RD Workpaper, tab "Top_100."

[18] Liberty MCOS-RD Workpaper, tab "POP 12CP." Note that load data for 2020 are incomplete and do not include November or December. This omission is not explained.

Q: How should the Commission direct Liberty to allocate MGCC to classes?

A: The Commission should direct Liberty to allocate MGCC to classes based on class contribution to coincident peak, as shown in Attachment RII-5. Assuming the $70.81 / kW-year value recommended in Section III.A of our testimony, Table 3 provides our recommended allocation, using system coincident peak data and a loss factor adjustment provided by Liberty.

Table 3: Allocation of Marginal Generation Capacity Cost to Class[19]

	Class Contribution to System Peak (kW-yr)[20]	Loss Factor Adjustment[21]	MGCC Allocation
Residential Permanent	26,265	1.06	$ 1,968,603
Residential Non-Permanent	41,815	1.06	$ 2,782,301
S-M Master Residential	5,335	1.06	$ 73,559
Small Commercial	16,794	1.06	$ 1,749,199
Medium Commercial	12,230	1.06	$ 1,194,232
Large Commercial	26,117	1.02	$ 1,980,462
Irrigation	8	1.06	$ 10,253
OLS	124	1.06	$ 8,452
Street Lighting	73	1.06	$ 4,945
Total Company	**131,362**		**$ 9,772,007**

Note: MGCC Allocation ($) = MGCC ($/kW-yr) * Class Contribution to System Peak (kW-yr) * Loss Factor Adjustment

C. Marginal Energy Cost

Q: What is Liberty's proposal for marginal energy costs (MECs)?

A: Liberty used a forecast of 2021 hourly market purchase costs from its integrated resource plan (IRP) to calculate effective variable energy costs. These costs were then assembled

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[19] Attachment RII-4; RII MCOS-RD Workpaper, tab "Allocation-Summary."

[20] Attachment RII-8, SBUA DR 4-9, "SBUA-Liberty 4.9 Attachment."

[21] Liberty MCOS-RD Workpaper, tab "Allocation-Summary."

into average rates for each TOU period. This appears to be a reasonable basis for determining MECs for the Liberty system.

Liberty allocated those costs to classes based on hourly energy costs and total usage during each TOU period. This is a reasonable basis for allocating MEC to classes.

D. Generation Revenue Requirement

Q: What is Liberty's generation revenue requirement?

A: Liberty's proposed generation revenue requirement is $12.1 million.[22] This is primarily cost associated with its solar plant.[23] We support Liberty's proposal to allocate this revenue requirement to classes based on the class-specific marginal generation costs, including MGCCs and MECs, as shown in Attachment RII-6.

IV. Marginal Distribution Demand Costs

Q: What is Liberty's proposed marginal distribution demand cost?

A: Liberty proposes a total marginal distribution demand cost (MDDC) of $616.86 / kW. Liberty breaks this cost down into substation and "non-revenue" components, which we do not find useful.

Q: How does Liberty allocate MDDCs?

A: Liberty uses three methods: a combination of system peak and class energy use, a "transformer load study," and a non-coincident peak method.

Liberty's rationale is that some MDDCs vary by TOU period and some do not. Liberty assumed that 50% of incremental distribution facility investments do not vary with TOU periods, and the remainder, including all substation investments, do vary with

[22] Liberty MCOS-RD Workpaper, tab "Target Revenues."

[23] Liberty RevReq Workpaper, tab "Plant in Service."

TOU periods. Liberty does not identify which costs it assumes vary with TOU and which do not, nor how it estimated the 50/50 split.

A. Allocation of MDDCs Assumed to Vary with TOU Periods

Q: How does Liberty allocate the portion of MDDCs that it assumes vary with TOU periods?

A: Liberty asserts that it allocates this portion of the MDDCs to TOU periods based on the share of the top 100 load hours that fell in each period in 2015–2020, and that it allocates the TOU-period costs to customer classes in proportion to class energy use during all hours in each TOU such period, not just those that fall within the "top 100" hours.[24]

Liberty's workpapers do not align precisely with its testimony. Rather than "top 100 load hours" in each year, Liberty used the top 500 load hours for the years 2015-2019.[25] All 500 hours occur in the winter period (November – February), so no costs are allocated to summer TOU rate periods.

Q: Do you agree with Liberty's method of allocating MDDCs that are assumed to vary with TOU periods?

A: No. Liberty's allocation of peak demand costs to the top energy-use hours is a reasonable first step, but the allocation of MDDCs to time periods should focus on class contribution to peak demands, not energy use, during each TOU period.

Liberty's method goes awry when that allocation is then spread across all energy use, irrespective of whether that energy use occurs on a day that has high or low loads. Liberty's top 500 load hours occur on just 81 days in November - February, an average

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[24] Liberty testimony, Ch. 12, p. 13, lines 18-22.

[25] Liberty MCOS-RD Workpaper, tab "Top_100." Note that Liberty does not explain why 2020 load data that are used elsewhere in the workbook are excluded from this calculation.

of 16 days per year. Yet the MDDCs are allocated based on energy use that occurs during all eight non-summer months.

Class energy use is likely to differ from the average on high-load days. For example, 58 of the top 60 load hours occur between December 24 and January 1, when seasonal residential and resort activities peak. For this reason, focusing on energy use during a seasonal TOU period may misrepresent the class contribution to either energy or peak demand during the top load hours.

The problems with Liberty's allocation of costs to TOU periods are compounded by the failure to match the TOU periods to high-cost periods, as discussed in Section VII.B.

Q: What is the effect of Liberty's redistributing the allocation from the top 100 hours to the TOU periods that include those hours?

A: Liberty's approach overstates the contribution of permanent residential and small commercial customers to loads during the top 100 hours, while understating the loads for non-permanent residential, and large commercial customers, as shown in Table 4. For example, small commercial customers use 15.1% of system energy use in the winter on-peak period, but only 12.8% of system energy use in winter on-peak hours that are included in the top 100 hours, so the period energy overstates the contribution to the top 100 hours by 2.3 percentage points or 18%. In contrast, non-permanent residential customers use 29.2% in all hours and 31.5% in the top 100 hours, for an understatement of 2.3 percentage points or about 7%.

Q: How do you recommend Liberty allocate MDDCs that it assumes vary with TOU periods?

A: Liberty should utilize class-specific energy use data for the top 100 load hours and allocate MDDCs based on those data. We will discuss this further in Section IV.C.

Table 4: Comparison of Winter Energy Use Allocation: All Hours to Top 100 Hours[26]

Winter TOU Period	Residential Non-Permanent	Residential Permanent	Small Commercial	Medium Commercial	Large Commercial	Irrigation	OLS	Streetlight
On-Peak	-2%	4%	2%	1%	-5%	0%	0%	0%
Mid-Peak	-6%	6%	3%	2%	-5%	0%	0%	0%
Off-Peak	-7%	7%	3%	0%	-3%	0%	0%	0%

Calculation: Class Energy Use for All Hours / System Energy Use for All Hours – Class Energy Use for Top 100 Hours / System Energy Use for Top 100 Hours

B. Allocation of MDDCs Assumed to Not Vary with TOU Periods

Q: How does Liberty allocate MDDCs that it assumes do not vary with TOU periods?

A: In testimony, Liberty simply states that it assigns these MDDC costs "to each rate class based on NCP demands."[27] However, Liberty's workpapers demonstrate that it uses two components, arbitrarily weighted at 50% each, to calculate what it calls NCP demands. Those components are the class annual NCP demand, and the product of the average peak transformer loading per customer times the number of customers.[28]

Q: Please describe the first component of the MDDC computation, the annual NCP demand.

A: The class annual NCP demand for each class is the maximum of the twelve monthly loads for that class, apparently from a load research sample.[29] That is not an ideal measure of the loads driving the sizing of the distribution system, since feeders and substations serve more than one class and the peak loads on different pieces of equipment happen at

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[26] Attachment RII-8, SBUA DR 4-9, "SBUA-Liberty 4.9 Attachment." RII MCOS-RD Workpaper, tab "4.9 2022 Class 8760."

[27] Liberty testimony, Ch. 12, p. 14, lines 1-2.

[28] For three small classes—outdoor lighting, streetlighting, and irrigation—Liberty uses what it calls "class maximum kW," without any documentation. Attachment RII-10.

[29] Attachment RII-9, SBUA DR 3-17, "SBUA-Liberty 3.17 Attachment 2." Confusingly, Liberty uses the same NCP designation both for this method and for the average of the two methods.

different times, but it is a common method for estimating class contributions to distribution loads. Once Liberty's AMI system is fully implemented, this approximation can be replaced by actual measurements of the loads contributing to stress on each feeder and substation.

Liberty uses system-level class NCP because it designs distribution demand facilities "based on customer demands at the service level"; also, Liberty does not have class NCP data at the substation or feeder level.[30] For three small rate classes, Liberty unnecessarily relies on what it characterizes as transformer load study data; Liberty has the same system-level class NCP data available for those classes.[31]

Q: Please describe the second component of the MDDC computation, the transformer method.

A: The second method that Liberty uses in developing the MDDC allocator uses Liberty's estimate of the average loading of the final line transformers serving each class, as derived in a "transformer load study."[32] The "transformer load study" is a single-worksheet study appears to be based on data from 2013, and Liberty provided it without any formulas, derivation or explanation.[33]

This is a very unusual method for allocating distribution lines and substations.

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[30] Attachment RII-9, SBUA DR 3-6.

[31] Attachment RII-8, SBUA DR 4-9, "SBUA-Liberty 4.9 Attachment." This worksheet has the same 2022 load forecast used to generate the Attachment RII-9, SBUA DR 3-17, "SBUA-Liberty 3.17 Attachment 2," except that loads appear to be grossed up to account for line losses, generally about 11%.

[32] The average peak transformer loading per customer for residential non-permanent is adjusted from the main residential measure using a ratio from the second method.

[33] Attachment RII-10.

Q: Why does Liberty include the loads on the final line transformers in allocating the costs of the distribution system?

A: Liberty's explanation is as follows:

> The Transformer Load Study NCP and NCP Demands measure rate class demands utilizing different approaches. Transformer Load Study NCP measures rate class demands at transformers while NCP Demands measure rate class demands at meters.[34]

This response does not explain anything. The load on a feeder in each hour is the sum of the load on all the transformers served by that feeder; since the transformers may all peak at different times, the maximum load on the feeder does not have any obvious correlation with the maximum loads on the transformers it serves.

Q: In addition to the lack of any logical connection to the distribution maximum loads, are there any other problems with Liberty's estimates of the transformer loadings by class?

A: Yes. Among the many problems with the transformer loading study, we found:

- The data sources (e.g., actual hourly load measurements, assumptions derived from literature, etc.) are not identified.
- The customers per transformer in the transformer loading study are inconsistent with the customers per customer assumed for the MDCC computation.
- Liberty assumes that all residential customers share transformers in groups of four or five, even though some residential customers must be served by dedicated transformers.

[34] Attachment RII-11, SBUA DR 6-3a(i). To be clear, the NCP Demands measure diversified rate class demands, not maximum demand at the meters.

- For customer class A-1, the average peak is reported as 14.68 kW / customer, which is calculated based on an assumption of 4 customers per transformer. The transformer load is calculated from "100 groups of 4 random customers averaged." The worksheet also includes, but does not use, computations for 2 and 3 A-1 customers per transformer. Liberty's assumption of 4 customers per transformer for the MDDC calculation is entirely inconsistent with its assumption for the MDCC calculation that 83% of A-1 customers have dedicated transformers and that other 17% share in groups of ten.[35]
- For customer class A-3, the average peak is reported as 912.71 kW / customer. In one location, the worksheet states that there is 1 customer per transformer, and that the "final line transformer coincident loading" for A-3 is 776.8 kW / customer. The worksheet also states that there are 55 customers in class A-3 with "Non-Coincident Loading at Final Line Transformer" of 69,041 kW, which calculates to 1,247.7 kW / customer. We have not identified any basis for the 912.71 kW / customer value.
- For customer classes OLS, STRT, and PA, Liberty does not compute a transformer loading per customer and simply reports that the computations "use class maximum kW," and provides a class total in the transformer load line, without any further explained. The worksheet includes "weighting" values for these classes whose relevance is not evident.[36]

There are similarly unexplained calculations and data for the A-1 and A-2 customer classes. The transformer load study should be disregarded by the Commission as unsupported by credible data and methods.

[35] Liberty MCOS-RD Workpaper, tab "MDC Unit_Investments."

[36] Attachment RII-9, SBUA DR 3-16; Attachment RII-10.

Q: Is it reasonable for Liberty to use its transformer load study as a measure of non-coincident peak to allocate MDDCs?

A: No. A class non-coincident peak (NCP) is the maximum hourly demand, summed across all class members during the same hour. Not only are the transformer load data suspect due to the sources and methods used to estimate transformer loads, the calculation of class NCPs uses a flawed statistical method. As an intermediate measurements of load, with results that are so clearly at odds with direct measurements of class NCP, the study should be entirely disregarded.

The "transformer load study" conducted by Liberty appears to be based on some computation of the peak load on a typical transformer for the class. For the residential class, the analysis apparently grouped four or five customers and computes their diversified load for 2013. For the A-1 class, Liberty did the same, but just in groups of four customers. Liberty says that it used one hundred groupings of those four or five customers and then extrapolated the average demand of those one hundred samples to the entire class.[37]

Even if transformer loads were developed in a statistically valid manner and estimated using credible data and methods, the primary relevance of transformer loads is determining the size and number of transformers needed to serve customers. Transformers are included in the marginal customer cost, not in the distribution demand costs, so they have no direct relevance to estimating class non-coincident peaks or the allocation of the MDDC.

For example, imagine two restaurants, one that serves breakfast and the other that serves dinner. If those two restaurants are a class, then the class non-coincident peak is equal to whichever restaurant has the highest peak, since their demand peaks at different

[37] Attachment RII-10.

hours. It would be fundamentally incorrect to add peak demands from some customers in the morning and other customers in the afternoon, and then describe the sum as the "class non-coincident peak."

This simple example illustrates the flaw that results from what Liberty appears to have attempted in its transformer load study. Small businesses, in particular, are likely to have varied peak hours depending on whether they are offices, retail, restaurants, etc., and the transformer load study method will tend to overestimate the non-coincident peak of such customers. Indeed, the NCP calculated using the transformer load study method is higher than the other method for every class, with the small customer class having more than four times the NCP and most other classes having roughly double the NCP as calculated directly from customer metered data.

The only class with similar NCPs using both methods is the large commercial class, whose NCP is only 40% higher when using the transformer load study. These results are not surprising because the large customer class has some of the lowest load diversity. Liberty's large customer class has 53 members with an assumed average peak transformer loading of 913 kW. As shown in , a load factor calculated from the winter NCPs and usage for Liberty's large commercial customers is double that of Liberty's small commercial customers. This means that load varies less for the average large commercial customer.

Table 5: Class Transformer Load Factors, Comparing Using Liberty's Assumed Transformer Usage with Forecast Data for 2022[38]

	Residential Permanent	Residential Non-Permanent	Residential CARE	Small Commercial	Medium Commercial	Large Commercial
Calculation Using Liberty's Assumed Transformer Usage (Winter Data)						
(A) Number of Customers	17,656	25,660	571	5,323	254	53
(B) Avg. Peak Transformer Loading / Customer (kW)	4.07	3.50	4.07	14.68	104.40	912.71
(C) Annual Usage (kWh)	138,136,346	156,982,485	3,887,077	99,099,282	67,984,366	114,881,147
(D) Customer Use / Hour (kW) (C / (A x 8760))	0.89	0.70	0.78	2.13	30.55	247.44
(E) Load Factor (D / B)	22%	20%	19%	14%	29%	27%
Calculation Using Liberty's Forecast Data for 2022						
(F) NCP (kW)	27,874	42,410	6,824	18,672	13,286	35,128
(G) Annual Usage (MWh)	138,136	156,982	3,887	99,099	67,984	114,881
(H) Load Factor (G / (F * 8.76))	57%	42%	7%	61%	58%	37%

[38] Liberty MCOS-RD Workpaper, tabs "TOU Hours," "Class_NCPs," and "Class_Usage;" Attachment RII-9, SBUA DR 3-17, "SBUA-Liberty 3.17 Attachment 2," and Attachment RII-8, SBUA DR 4-9, "SBUA-Liberty 4.9 Attachment".

Compared to our example of the breakfast and dinner restaurants above, the large commercial customer is more like a full-day operation at a resort. Many of the 53 large customers on Liberty's system are likely to be at or near their peak transformer loading on peak hours. This may be why the transformer load study provides a similar value for this class to Liberty's forecast NCP data.

Q: Is it reasonable for Liberty to use NCP to allocate MDDCs?

A: In general, we do not favor the use of a non-coincident peak to allocate MDDCs. In general, MDDCs are driven by three factors, the geographical span of the system, the costs of insuring against certain risks (e.g., wildfire prevention), and the risk of overloading specific circuits.

Few Commissions allocate distribution costs based on the customer's contribution to system geographic size. MDDCs are generally allocated to otherwise-similar customers without respect to whether they are located in a densely-served region or at the end of a long feeder with few customers, in a rocky mountainous area or along a river valley.[39]

Similarly, Commissions infrequently distinguish between class contributions to factors that increase or decrease the costs to build and maintain distribution systems. An occasional exception is the allocation of more expensive underground distribution service costs to classes that use more of the underground system. Otherwise, Commissions generally do not assign costs that vary by geography (length of lines between customers, wildfire mitigation, for example) based on the location of customers in the various classes.

[39] California's large IOUs allocate marginal distribution costs by considering the relative contribution of each customer class to feeder demand, using a circuit-by-circuit analysis. Based on the physics of such circuits, this would ideally be calculated based on a multi-hour peak load, although it is usually simplified to a single-hour coincident peak load. But the end result is a uniform MDDC applied to all customer classes.

Class NCPs do not drive the loading on individual substations or feeders, unless each feeder serves only one class and experiences its maximum loads around the time of that class's peak. Most feeders and substations serve multiple classes, and their maximum loads occur at different time than the class loads. For example, Liberty provided a sample of 38 feeders over three years; those feeders exhibit annual peaks in every month (mostly in the winter) and in every hour of the day except hour-ending 9 AM (mostly from 4 PM to midnight).[40]

C. Recommendation for Allocation of MDDCs

Q: Do you recommend different methods for MDDCs that vary by TOU period?

A: No. We do not see any justification to distinguish between MDDCs that vary by TOU period and those that may not. On the margin, distribution costs are driven by load. For example, if an existing distribution line needs to be rebuilt, the cost will vary depending on what amount of load it is determined to carry, and that determination will be related to circuit-specific peak load conditions.

Q: What do you recommend for allocation of Liberty's MDDC?

A: We recommend a two-step process. First, Liberty's proposed MDDC of $616.86 / kW should be allocated to TOU periods based on the share of the top 500 load hours that fell in each period in 2015–2020, just as in the first step used by Liberty (see Section IV.A).

[40] Attachment RII-13.

Table 6: Allocation of Marginal Distribution Demand Cost to TOU Period[41]

Distribution Marginal Costs	Top 100 Hours %	TOU Allocation
Winter TOU – Peak	57.6 %	$ 355.31
Winter TOU - Mid-Peak	37.8 %	$ 233.17
Winter TOU - Off-Peak	4.6 %	$ 28.38
Summer TOU - Peak	0.0 %	$ -
Summer TOU - Off-Peak	0.0 %	$ -
Total		**$ 616.86**

Second, each TOU-period MDDC should be allocated to classes based on the share of average load during the top 100 load hours from Liberty's forecast for 2022.[42] As shown in Table 7, the top 100 load hours are entirely in the winter season and classes vary in terms of whether their average energy use are highest in the peak, mid-peak, or off-peak periods.[43]

[41] RII MCOS-RD Workpaper, tab "Allocation-Summary." Source data for "Top 100 Hours %" are from Attachment RII-8, SBUA DR 4-9, "SBUA-Liberty 4.9 Attachment."

[42] We would prefer using the same data as in the first step (top 500 load hours from historical data), but Liberty did not provide these by customer class. We consider these forecast data to be reasonable for this purpose.

[43] Note that the pattern of average energy use among periods is not necessarily the same as the class NCP or contributions to high-load hours among periods.

Table 7: Allocation of Marginal Distribution Demand Cost to Class

	Average Load During Top 100 Hours (kWh)			MDDCs			
	Winter Peak	**Winter Mid-Peak**	**Winter Off-Peak**	**Winter Peak**	**Winter Mid-Peak**	**Winter Off-Peak**	**Total**
Residential Permanent	27,295	21,048	21,192	$ 9,698,412	$ 4,907,782	$ 601,330	**$ 15,207,524**
Residential Non-Permanent	33,471	30,394	28,797	11,892,846	7,087,130	817,133	**19,797,109**
S-M Master Residential	402	348	335	142,749	81,118	9,499	**233,367**
Small Commercial	13,670	14,729	12,900	4,857,079	3,434,492	366,037	**8,657,607**
Medium Commercial	9,859	9,946	11,142	3,502,924	2,319,073	316,155	**6,138,152**
Large Commercial	22,034	25,690	27,448	7,828,965	5,990,347	778,854	**14,598,166**
Irrigation	4	2	6	1,265	388	163	**1,816**
OLS	115	1	109	40,695	269	3,093	**44,057**
Street Lighting	67	1	64	23,888	159	1,815	**25,862**
Total Company	**106,916**	**102,159**	**101,991**	**$ 37,988,822**	**$ 23,820,760**	**$ 2,894,079**	**$ 64,703,661**
RII MCOS-RD Workpaper, tab "4.9 2022 Class 8760." Source data from Attachment RII-8, SBUA DR 4-9, "SBUA-Liberty 4.9 Attachment," adjusted by winter line losses obtained by comparing those data with monthly load forecast data from Attachment RII-9, SBUA DR 3-17, "SBUA-Liberty 3.17 Attachment 2."				Calculated as TOU Allocation (Table 6) * Average Load During Top 100 Hours			

Q: What is the distribution demand revenue requirement?

A: Liberty's distribution demand requirement includes rate base; return on rate base; distribution O&M; A&G; depreciation of distribution plant; and related taxes. We support Liberty's proposal to allocate this revenue requirement to classes based on the class-specific MDDCs, as shown in Attachment RII-6.

V. Marginal Distribution Customer Costs and Customer Charges

Q: What are Liberty's proposed marginal distribution customer costs?

A: Liberty proposes the class-specific marginal distribution customer costs (MDCCs) shown in Table 8. Liberty's proposed MDCCs exceed its revenue requirement for customer costs, which seems unreasonable because a significant portion of distribution customer costs do not change significantly when new customers are added to the system, such as billing system costs.

Table 8: Liberty's Per Customer Proposed Marginal Distribution Customer Costs and Customer Charges[44]

	MDCC	Revenue Requirement	Customer Charge	Wildfire Charge
Residential Permanent	$ 10.01	$ 9.11	$ 10.00	$ 28.00
Residential Non-Permanent	20.16	18.36	10.00	28.00
S-M Master Residential	57.47	Included above		
Small Commercial	67.23	59.23	27.43	82.57
Medium Commercial	189.72	167.14	54.57	1,006.22
Large Commercial	1,058.49	932.56	720.06	9,261.43
Irrigation	13.65	12.02	26.21	164.25
OLS	None proposed			
Street Lighting	None proposed			

[44] Liberty MCOS-RD Workpaper, "RD" tabs and tabs "MDC-Derivation," "Target Revenues."

Q: What are Liberty's proposed monthly customer charges?

A: Liberty proposes both a conventional customer charge and a wildfire customer charge, as shown in Table 8. We will discuss the wildfire customer charge in Section VI below.

Q: How does Liberty calculate MDCCs?

A: Liberty's MDCCs include what it terms common and specific components. Common costs comprise customer accounts and customer service. Specific costs include the capital costs of new hookups and replacements and O&M.

Liberty calculates the cost of new hookups as the product of estimates of (1) the average cost of the meter, service drop, and transformer required to serve customers in each class and (2) the number of new hookups, which is in turn based on an analysis of historical and forecast customer growth in each class. Liberty adds in the cost of replacement equipment for 1.5% of the existing customers, at the cost of new hookups; Liberty provides no basis for the 1.5% replacement rate.

Liberty calculates customer O&M costs based on a share of total distribution O&M costs. The share of total distribution O&M costs is assumed to be the same as the share of annual distribution investments that are attributable to new hookups.

Liberty calculates customer account and service costs based on the average inflation-adjusted costs for 2011-2024. Allocation of these costs to customer classes is weighted based on the cost of new customer hookups.

Q: What is your overall opinion of Liberty's calculation of MDCCs?

A: We found numerous errors, unreasonable assumptions, and flawed methods. After discussing those problems, we will discuss how we have attempted to calculate reasonable MDCCs for each class.

A. Problems with Liberty's Cost of New Hookups

Q: What is your opinion of Liberty's calculation of the average cost per customer for new hookups?

A: Liberty includes the cost of the meter, service drop, and transformer in the cost of a new hookup. We have not reviewed the underlying unit costs, but they appear reasonable. However, there are three major problems with the average cost per customer for new hookups.

First, Liberty has used inconsistent and implausible assumptions about the number of customers served per transformer for the A-1 and A-2 customer classes, and possibly other classes. Second, we determined that Liberty's weighting of the customers using overhead and underground service is implausible. Third, Liberty's calculation of the annual number of new customers in each class is perplexing and relies on a calculation that is highly sensitive to the start and end dates.

Q: Please explain the contradictions in Liberty's data regarding the number of customers per transformer.

A: In the "MDC-Unit_Investments" tab of its marginal cost of service study, Liberty relied on undocumented estimates of the "number of customers that the respective transformer *can* serve."[45] (emphasis added) The average number of customers actually served by a transformer will be lower than some theoretical maximum.[46] Regardless of what those estimates were supposed to represent, Liberty's assumptions in this study included the following:

[45] Attachment RII-12, SBUA DR 7-1(b).

[46] The number of customers that a transformer can serve depends on the distance between customers, the size of the customers' maximum loads and their diversity. For the winter-peaking Liberty system, with many of the residential properties occupied primarily during weekends and holidays, diversity among residential customers sharing a transformer is likely to be low.

- While Liberty's cost of service study assumes that every residential customer shares its transformer with at least three other residential customers, Liberty assumed that only 17.4% of A-1 customers share a transformer.[47]
- No A-1 customers on overhead service share transformers with other customers.
- Each of the 83% of A-1 customers with a dedicated transformer has a 50 kVA (33% of customers) or 75 kVA 3-phase (50% of customers) transformer.

Liberty's only explanation for the origin of these cost inputs is that "The assumption was taken from the Company's marginal cost study filed in the Company's prior rate case, which reflected a general assessment of the Company's system design for each rate class."[48] In other words, Liberty has no data or analysis supporting its assumptions.

Liberty's assumptions that all residential customers share transformers but no small commercial customers on overhead service share transformers are inconsistent with each other given the way that distribution systems are normally built.

Liberty's estimated number of customers per transformer are implausible for residential and particularly for small and medium commercial customers. It is very unlikely that every residential customer shares its transformer with at least three and on average eight other residential customers; in a mountainous area, many homes are likely to be too remote to share transformers.[49]

Similarly, the idea that every A-1 customer would need its own 50 kVA transformer is implausible. Table 9 shows that 24% of A-1 customers had peak demands under 5 kW in 2020; even allowing for inter-annual load variation and the fact that kVA loads are

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[47] Liberty assumes that 58% of the A-1 customers are underground customers and that 30% of the underground customers (or 17.4% of all A-1 customers) share transformers.

[48] Attachment RII-11, SBUA DR 6(a) - (b); Attachment RII-12, SBUA DR 7-1(b) - (d).

[49] Voltage drop establishes the maximum length of the secondary and service lines from the transformer to the customers.

higher than kW loads, several of those very small A-1 customers could be served on a 50 kVA transformers. This is even more true because line transformers can be significantly overloaded during infrequent peak loads without reducing the expected life of the transformer, especially in the cold weather that dominates the Liberty peak loads. Since Liberty assumed that the shared A-1 transformers average $430 and the dedicated transformers average $9,865, Liberty has massively increased the transformer cost allocated to the small commercial class.

Table 9: Distribution of Annual Maximum Demand for A-1 Customers[50]

kW	Number ≤ kW	Percent ≤ kW
1	80	6%
5	317	24%
10	568	43%
15	737	56%
20	847	64%
25	959	72%
30	1,050	79%
35	1,125	85%
40	1,182	89%
45	1,220	92%
50	1,249	94%

Alternatively, many an A-1 customer, if it were the only load on a transformer, could be served by a 25 kVA or even 10 kVA transformer.

In three discovery responses, Liberty provided data that further undermine the assumptions in its cost of service study. In one response, Liberty reports that each residential customer shares its transformers with three or four other customers, for an average of 4.5, rather than the 4–30 customers, for an average of 7.2, assumed in the

[50] Attachment RII-8, SBUA DR 4-1(d), “a1 2020 kw.” Liberty provided the billing demands for only about 25% of its A-1 customers.

MDCC.[51] The same document reports that each A-1 customer shares a transformer with a second customer, rather than having a dedicated transformer. Those sharing assumptions would shift transformer costs off the A-1 class and onto the residential class.

In a second response, Liberty states that that 85.9% of commercial customers share transformers and 97.3% of residential customers share transformers.[52] This suggests that the cost of service study vastly overstates the number of commercial customers with a dedicated transformer while overlooking the existence of residential customers with shared transformers.

In a third discovery response, Liberty states that it has 8,453 transformers in service.[53] However, the assumptions in the MDC-Unit Investments tab of the cost of service study imply that there are 11,332 transformers in service. This overstates the average transformer cost per customer, and helps explain why Liberty's proposed MCAC exceeds its revenue requirement for customer access costs.

Q: Please explain the reason you determined that Liberty's weighting of the customers using overhead and underground service is implausible.

A: As noted above, when calculating transformer costs, Liberty assumed class-specific splits of customers between overhead and underground service. As with much of the other underlying data, Liberty relied on a study performed in a prior rate case and did not provide any basis for the assumed weightings.[54]

As discussed above, Liberty's cost of service study implies 11,332 transformers in service. It also implies that 44% of transformer installations support underground service,

[51] Attachment RII-10; Liberty MCOS-RD Workpaper, tab "MDC-Unit_Investments."

[52] Attachment RII-9, SBUA DR 3-5.

[53] Attachment RII-12, SBUA DR 7-1(a).

[54] Attachment RII-11, SBUA 6-6(a)(i).

which is substantially more than the 34% reported by Liberty on discovery.[55] This suggests that the class-specific weighting factors are erroneous.

Q: Please explain the errors in Liberty's estimates of the number of new customers.

A: The marginal customer cost in Liberty's computation depends, among other things, on the number of new customer installations and the rate of replacement for existing customer equipment. Liberty calculated the growth in customers in each class from 2011 to 2024 as the difference between the customer counts in those two years.[56] This number is used to calculate total customer-related investment over this time frame, which is used in Liberty's O&M calculation (discussed in Section V.B below). Liberty then multiplies this total 13-year customer growth by 20% to obtain the number of "new hook-ups." The resulting number is referred to as "Estimated Average Annual New Hookups" in subsequent steps of the analysis. This computation is riddled with errors.

First, the meaning and basis of the 20% "New Hook-Ups %" factor is perplexing.[57] One possibility is that Liberty attempted to estimate of the percentage of new customers who require the addition of a meter to an existing building, without a new service drop or increase in transformer service. Examples of the latter would be adding an accessory units in an existing home, or reconfiguring a large office building to hold several smaller firms. If Liberty was attempting to identify a subset of customers who only required a meter, its method entirely fails to do so.

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[55] Attachment RII-12, SBUA DR 7-1(a).

[56] Liberty MCOS-RD Workpaper, tab "MDC-Inputs." Oddly, Liberty identifies the 2011–2024 customer growth as "Customer Growth (2011-2019)."

[57] Asked for "the derivation of the Specific Marginal Customer Costs per Customer" including "all assumptions about the sharing of transformers and service drops," Liberty provided no derivation of the sharing assumptions. (Attachment RII-9, SBUA DR 3-8.) The same discovery response requested the derivation of the size and cost of transformers and the capacity and cost of service drops. Liberty simply pointed to its assumptions.

The other possibility is that Liberty arbitrarily or mistakenly chose 20% as a reasonable fraction of the 13-year customer growth to establish an annual rate. We cannot determine why Liberty would choose 20% in this instance, as Liberty has not supplied any supporting material in response to our discovery requests. It is possible that the 20% factor was left over from some earlier version of the marginal cost study, when Liberty was using only five years of data.

Second, Liberty's choice of the 13-year growth period produces atypical results.[58] Of the growth in A-1 customer number from 2011 to 2024, 79% occurred in 2012. It appears that 2011 is an anomalous year, as A-1 customer counts dropped from 2009 and 2010, as shown in Table 10. Furthermore, A-1 customer counts have been dropping since 2015 – the A-1 customer class might not be responsible for any growth-related portion of MCAC.

[58] Compared to other IOUs, Liberty uses a very long period for estimating the number of new customers. For example, SCE used 2017–2020 in A.20-10-012.

Table 10: Count and Change in A-1 Customers, 2009-2024[59]

Year	Count Number	Annual Increase	Increase to 2024	Annual Increase to 2024
2009	5,120		199	13
2010	5,100	(20)	219	16
2011	4,778	(322)	541	42
2012	5,204	426	115	10
2013	5,226	23	92	8
2014	5,304	78	15	1
2015	5,406	101	(87)	(10)
2016	5,401	(5)	(82)	(10)
2017	5,361	(40)	(42)	(6)
2018	5,329	(32)	(10)	(2)
2019	5,348	19	(29)	(6)
2020	5,314	(33)	4	1
2021	5,326	12	(7)	(2)
2022	5,323	(3)	(4)	(2)
2023	5,321	(2)	(2)	(2)
2024	5,319	(2)		

Rather than selecting arbitrary starting and ending points in a non-monotonic data series, it is often more reasonable to calculate an annual customer growth rate as the slope of a linear regression on the dataset. Since 2011 is such an outlier on the low side for a starting point, we recommend that the annual customer growth be computed from 2012 to 2024. Calculating the slope for the 2012 to 2024 period results in a growth rate of 4 customers per year for the A-1 class, compared to Liberty's estimate of 108 customers per year.

Q: What is your opinion of Liberty's 1.5% replacement rate for customer service equipment?

A: This assumption is unsupported, but we do not have a basis for suggesting an alternative.

In response to a request for support of Liberty's 1.5% replacement rate for transformers, services and meters, Liberty explained that "any analysis supporting the

[59] Liberty MCOS-RD Workpaper, tab "MDC-Inputs;" and, for 2009-2010 data: Sierra Pacific, FERC Form 1 p. 304.1 for the California territory.

replacement rate is no longer available."[60] In addition to being unreviewable, Liberty appears to be relying on data from before 2013 (and perhaps before 2007) for these calculations, when more recent (and verifiable) data should be readily available. The Commission should instruct Liberty to update the replacement rate for its next rate case.

B. Problems with Liberty's Cost of Customer O&M

Q: What is your opinion of Liberty's calculation of customer O&M costs?

A: First of all, this calculation is also riddled with errors. But more important, Liberty's complex method is entirely unnecessary as more relevant data are available from its FERC Form 1 filings.

Liberty's method begins by using the cost of new hookups discussed above and applying the *13-year* customer growth values for each class to estimate a total customer-related investment value. Both of those values are problematic, as discussed in Section V.A above. The results are then summed up for the system and compared to a calculation of total distribution plant additions. However, that value for distribution plant additions is the total for the years 2000–2024, representing *24, not 13, years* of growth. So the resulting ratio of customer-to-distribution plant investments is entirely incorrect.

This ratio is then applied to the total primary distribution O&M cost, along with the application of an inflation adjustment and weighting factors discussed above to obtain an inflation adjusted cost per "unweighted" customer.[61]

The use of the customer-to-distribution plant ratio and the total primary distribution O&M cost is entirely unnecessary. FERC Form 1 contains the O&M costs for all customer costs but service lines, and the service line O&M costs can be extracted from total primary

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[60] Attachment RII-9, SBUA DR 3-11.

[61] By "unweighted," Liberty means the cost per residential customer, which is then increased for other classes by a class-specific weighting factor.

line O&M costs by creating a ratio of service to total distribution line investment (also from FERC Form 1). The resulting inflation-adjusted cost per unweighted customer (calculated with the unsupported weighting factors) can then be included with new hookup and replacement costs to calculate total common costs using the same method as Liberty from this point forward.

C. Customer Account and Customer Service Costs

Q: What is your opinion of Liberty's calculation of customer account and customer service costs?

A: We do not contest these costs. We are surprised to find that Liberty is using weighting factors from 2007 to allocate the costs to classes.[62] As with other source data, Liberty did not provide any support or basis for its customer accounts or customer service weighting factors. The Commission should instruct Liberty to update these weighting factors for its next rate case.

D. Corrections to Liberty's MDCCs

Q: What corrections did you make to the Liberty's class-specific MDCCs?

A: To address the numerous and inter-related problems described above, we made the following changes.

1. To address problems with Liberty's average cost per customer of new hookups, we:
    - Increased the number of A-1 and A-2 customers per transformer as shown in Table 11, and
    - Reduced the percentage of customers with underground service as shown in Table 12.

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[62] Attachment RII-14, SBUA DR 2-2.

The resulting transformer count is approximately the same as that reported by Liberty.[63] For this reason, we believe the cumulative effect of our two adjustments is reasonable and supported by fact.

2. Corrected Liberty's errors in calculating class-specific customer growth by using the slope of a linear regression for the customer count data from 2012-2024, as shown in Table 13.
3. Replaced Liberty's erroneous calculation of customer plant-related O&M cost with an estimate derived from data filed by Liberty on FERC Form 1 for 2016-2020, which is allocated to classes using a weighting factor that is also corrected as a result of changes 1 and 2, as shown in Table 14.

Table 11: Changes to the Number of A-1 and A-2 Customers per Transformer

	Liberty Unsupported Estimate	Estimated to Reconcile Cost of Service Study with Liberty Transformer Data
Class A-1, Underground		
Single Phase (50 kVA)	1	4
Three Phase (75 kVA)	1	4
Three Phase (300 kVA)	10	10
Class A-1, Overhead		
Single Phase (50 kVA)	1	3.5
Three Phase (3 x 25 kVA)	1	11
Class A-2, Underground	1	1.25
Class A-2, Overhead	1	2

Sources: Liberty MCOS-RD Workpaper, tab MDC-Unit_Investments; RII MCOS-RD Workpaper, tab "MDC-Unit_Investments."

[63] Liberty provided data on the number of transformers. Attachment RII-12, SBUA DR 7-1(a). We used three data elements from those data to make the adjustments: total underground transformers, total overhead transformers, and total 3 transformer banks. Liberty also provided the number of 2 transformer banks, but no 2 transformer banks were used in the marginal cost of service study.

Table 12: Changes to the Percentage of Customers with Underground Service

Class	Liberty Unsupported Estimate	Estimated to Reconcile Cost of Service Study with Liberty Transformer Data
Residential Permanent	61.0 %	35.0 %
Residential Non-Permanent	61.0 %	35.0 %
S-M Master Residential	54.3 %	35.0 %
Small Commercial	58.0 %	55.0 %
Medium Commercial	76.0 %	60.0 %
Large Commercial	83.0 %	75.0 %
Irrigation	53.0 %	0.0 %

Sources: Liberty MCOS-RD Workpaper, tab MDC-Unit_Investments; RII MCOS-RD Workpaper, tab "MDC-Unit_Investments."

Table 13: Corrections to Class-Specific Annual Growth Rates

Class	Liberty Calculation Using 2011-2024 Data	Estimated from Slope of 2012-2024 Data
Residential Permanent	0	0
Residential Non-Permanent	928	291
S-M Master Residential	10	3
Small Commercial	108	4
Medium Commercial	8	4
Large Commercial	0	0
Irrigation	0	0

Sources: Liberty MCOS-RD Workpaper, tab MDC-Inputs; RII MCOS-RD Workpaper, tab "MDC-Inputs."

Table 14: Customer-Related O&M Costs Estimated from FERC Form 1 Data

Year	Liberty Weighting of Customer-Related Distribution O&M by Ratio of Estimated Additions		Estimate from FERC Form 1 Data	
	($ 2022)	($ / customer)	($ 2022)	($ / customer)
2015	197,033	4.09		
2016	193,513	4.00	$ 266,260	$5.51
2017	189,075	3.90	437,297	9.02
2018	274,511	5.63	226,385	4.65
2019	203,095	4.15	346,287	7.08
2020	234,585	4.78	408,850	8.33
2021	244,767	4.96		
2022	1,147,441	23.17		
2023	1,249,473	25.13		
2024	1,282,410	25.69		
Average Expense per Customer		$ 10.55		$ 6.92
Inflation Adjusted, Unweighted Expense per Customer		**$ 6.35**		**$ 5.64**

Sources: Liberty MCOS-RD Workpaper, tab MDC-Inputs; RII MCOS-RD Workpaper, tab "MDC-Inputs."

Q: What are the results of your changes to the MDCC and its allocation to classes?

A: We found that Liberty's proposed MDCCs are overstated for at least six customer classes, as shown in Table 15. (We did not investigate the OLS or Streetlighting MDCCs.) In some cases, such as residential permanent, the difference is immaterial. In other cases, such as for small commercial, Liberty's proposed MDCCs are nearly four times more than we found to be reasonable.

Table 15: Comparison of Proposed MDCCs

Class	Liberty Calculation		SBUA Calculation	
	Total	Per Customer	Total	Per Customer
Residential Permanent	$ 2,120,384	$ 120.09	$ 2,132,303	$ 120.77
Residential Non-Permanent	6,208,052	241.94	4,106,543	160.04
S-M Master Residential	393,468	689.66	289,891	508.11
Small Commercial	4,294,431	806.78	1,116,271	209.71
Medium Commercial	578,257	2,276.60	346,441	1,363.94
Large Commercial	673,200	12,701.89	645,840	12,185.67
Irrigation	1,624	163.78	1,510	152.24
OLS	147,142	Not calculated	147,142	Not calculated
Street Lighting	92,189	Not calculated	92,189	Not calculated
Total	**$ 14,508,748**	**N/A**	**$ 8,878,130**	**N/A**

Sources: Liberty MCOS-RD Workpaper, tab MDC-Derivation; RII MCOS-RD Workpaper, tab "MDC-Derivation."

E. Proposed Customer Charge

Q: What is the distribution customer revenue requirement?

A: Liberty's distribution revenue requirement includes rate base; return on rate base; meter expenses; customer service and accounts; transformers, services, and meters, and related taxes. We support Liberty's proposal to allocate this revenue requirement to classes based on the class-specific MDCCs, as shown in Attachment RII-6.

Q: What customer charges do you propose?

A: We proposed that the Commission set Liberty's customer charge based on the class distribution customer revenue requirement, but capped at no more than double the current charge, as shown in Table 16. We recommend a cap on increases to the customer charge to no more than double the current rate, and collecting the remainder in distribution rates. Our proposed cap on customer charges impacts two rate classes, as follows.

- Medium Commercial (A-2): The allocated distribution customer cost is $166.54. Because the current charge is $43.78, we cap our proposed charge at $87.56. The remaining costs should be collected in a distribution charge of $0.00353 per kWh.
- Large Commercial (A-3): The allocated MDCC is $1,492.48. Because the current charge is $517.94, we cap our proposed charge at $1,035.88. The remaining costs should be collected in a distribution charge of $0.00252 per kWh.

As discussed in Section VI, we recommend that wildfire costs be allocated and recovered with distribution rates.

Table 16: Comparison of Proposed Customer Charges

	Liberty Proposed			**SBUA Proposed**
	Customer Charge	**Wildfire Charge**	**Total**	
Residential Permanent	$ 10.00	$ 28.00	$ 38.00	$ 13.84
Residential Care	7.50	21.00	28.50	10.38
Residential Non-Permanent	10.00	28.00	38.00	19.77
Small Commercial	27.43	82.57	110.00	25.46
Medium Commercial	54.57	1,006.22	1,060.79	87.56
Large Commercial	720.06	9,261.43	9,981.49	1,035.88
Irrigation	26.21	164.25	190.46	48.20
OLS	None proposed			
Street Lighting	None proposed			

Sources: Liberty MCOS-RD Workpaper, rate design tabs "RD;" RII MCOS-RD Workpaper, rate design tabs "RD."

VI. Wildfire Cost Allocation and Rate Design

Q: Do you agree with Liberty's proposed method for allocating wildfire mitigation costs to classes?

A: Yes. Liberty proposes to allocate wildfire mitigation costs using the same method as it uses for MDDCs. We support this method, but using the corrected MDDC allocation method recommended in Section IV.C of our testimony.

Q: Do you agree with Liberty's proposed rate design for wildfire remediation costs?

A: No. Wildfire remediation costs are distribution system investments. They may result from a recognition that Liberty (and other utilities) failed to adequately consider wildfire risks when designing and maintaining their distribution systems, but the costs to remediate their systems to avoid causing wildfires and provide some level of reliability during wildfire events is a function of the distribution system.

It is entirely improper to recover these costs on a per customer basis. A customer should be able to connect to the grid for no more than the cost to connect to the grid. Liberty has confirmed that the wildfire mitigation costs "largely reflect non-customer distribution costs, such as covered conductors, pole replacement, and vegetation management and inspections."[64]

Liberty proposes that in addition to the costs of customer connection, customers who wish to connect to the grid should pay a monthly fee that recovers the cost of upgrades to its distribution system related to wildfire remediation. Liberty gives four reasons for its proposal.

First, Liberty points out that its "service territory is almost entirely located in high fire threat districts," and this makes its territory unique.[65] We do not contest these

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[64] Attachment RII-9, SBUA DR 3-20.

[65] Liberty testimony, Ch. 12 Supplemental, p. 2, lines 19-20.

assertions, but see no relevance to the cost of connecting a customer to the grid. For instance, Liberty does not suggest that its wildfire remediation costs may vary over the next several years depending on whether its customer load count falls or rises.

Second, Liberty states that its "work to mitigate the risk of wildfires benefits all customers," and that those costs are fixed.[66] We agree with the first statement, but the fact that costs benefit all customers does not mean that the cost should be collected through a customer charge. Generation costs, substations and feeders benefit all customers, but are not recovered through a customer charge. In addition, most of Liberty's distribution costs are fixed in the near term, but are collected through energy or demand charges, rather than customer charges.

In hindsight, Liberty should have built and maintained its system to the standards it now aspires. The costs to remediate its system to that standard are not any more fixed than the costs to build out the system in the first place.

Third, Liberty suggests that a monthly fee for wildfire costs achieves equity between higher-usage and lower-usage customers.[67] We do not see how it is equitable to charge every customer in a class the same amount for distribution costs that are otherwise allocated and recovered. In addition, Liberty's proposal would charge small commercial customers $82.57 per month for wildfire-related costs and medium commercial customers $1,006.22 per month. The difference between these customer classes is, of course, the level of usage – but using a step function rather than logical smoothly-varying usage-based charges. A large A-1 customer that grows enough to be moved to the A-2 class

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[66] *Id.,* p. 2, line 22 to p. 3, line 2.

[67] *Id.*, p. 2, lines 7-9; p. 3, lines 10-11. While Liberty's proposed third usage tier may or may not mitigate the burden of the wildfire fixed charge on low-usage and low-income residential customers, this remedy is not proposed for small business customers. Nor is it likely that tiers for small business customers would be practical.

would see an annual increase in unavoidable charges of $11,084 just for the added wildfire charges.

It is not reasonable or just to increase a business customer's total monthly charge (including the customer and wildfire-related costs) from $110 to $1,061 if its maximum demand exceeds 50 kW in any three months during the preceding 12 months. We discuss this issue further below in Section VIII. If Liberty's goal is to achieve equity among higher-usage and lower-usage customers, this is a strange way to go about it.

Fourth, Liberty states that "a separately stated wildfire mitigation customer surcharge on customer bills provides more cost transparency as to the primary cost driver …"[68] We can hardly argue with this assertion, but Liberty has now switched to the topic of bill presentation rather than rate design. There is no reason that Liberty cannot propose to separately state the wildfire mitigation costs on customer bills while collecting the revenue requirement in energy and demand charges, as it does other distribution costs.[69]

Q: How should wildfire remediation costs be recovered?

A: Wildfire remediation costs should be included in distribution rates and allocated in proportion to class MDDCs, as shown in Attachment RII-6. Liberty's justifications for its proposed monthly fee fail on grounds of being either unreasonable, unjust, or irrelevant.

[68] *Id.,* p. 3, lines 6-9.

[69] Interestingly, Liberty does not argue that the wildfire costs are actually driven by customer count. Which is wise, since very little of the mitigation costs are driven by customer-related equipment such as transformers or service drops.

VII. Rate Design

Q: How does Liberty propose to implement its rate increase?

A: Liberty proposes a uniform increase in rate elements, with adjustments to include fixed surcharges to recover wildfire mitigation costs, Tier 3 energy charges for the residential class, and an increase in the CARE discount rate. Liberty provides no specific rationale for its uniform increase in rate element method.[70]

Q: What is your opinion of Liberty's proposal?

A: As discussed in Section VI, we oppose the use of fixed surcharges to recover wildfire mitigation costs. We recommend rejecting Liberty's proposed use of a uniform increase in rate elements because freezing in place the prior relative allocation of revenue recovery among rate elements misallocates revenue recovery. Distribution costs (including wildfire mitigation costs) have increased far more than generation costs. A uniform increase in rate elements will effectively recover distribution costs through generation rates.

A uniform increase in rate elements is also unreasonable because Liberty's existing rate designs generally over-recover during the summer and under-recover during the winter. Better aligning cost recovery with seasonal differences in marginal and average costs will implement the Commission's intent for Liberty to adopt marginal cost based rates.

We have no objection to Liberty's proposals to add Tier 3 energy charges for residential customers or increases in the CARE discount rate.

A. Rate Design Proposal

Q: What rate design do you recommend?

A: We recommend the following practices:

[70] Attachment RII-8, SBUA DR4-11(a).

1. As discussed in Section V.E, the customer charge should be set based on the class marginal customer access cost, but capped at no more than double the current charge. Any remaining estimated customer costs should be recovered through an energy rate.
2. Generation rates should be set at the class average cost of service, with the following schedule-specific features.
   a. For residential tiered rates, Tier 3 should be set at the marginal generation cost, Tier 2 midway between Tiers 1 and 3, and Tier 1 at a level that results in collecting the class average cost of service.
   b. For Schedule A-2, the demand rate should be set to recover the proportion of generation costs attributable to the MGCC. We propose to implement the demand rate in the winter because Liberty is a winter-peaking system.
   c. For Schedule A-3, energy and demand rates should be scaled proportionate to the decrease in the revenue requirement.
3. Distribution rates should be set at the class average cost of service, with the following schedule-specific features.[71]
   a. For Schedule A-2, we propose to shift from a winter-only rate to a year-round rate design to ensure that all customers contribute to distribution costs. We set the winter-only demand rate to recover half

[71] All distribution EPMC costs are included in distribution rates. None are allocated to customer costs for consistency with D.17-09-035 as discussed later in this section. If EPMC costs are allocated to customer charges for A-2 and A-3 customer classes, it would cause those charges to even further exceed our proposed cap of double the existing monthly customer charge. Under our rate proposal, distribution customer costs in excess of the cap are recovered through an energy charge, so allocating EPMC costs to customer charges for these classes would produce very similar rates.

of the on-peak MDDC to move towards marginal cost principles.[72] The remainder of the revenue requirement is collected through a year-round energy rate. Schedule A-2 TOU rates are designed to be consistent with the base A-2 rates.

b. For Schedule A-3, energy and demand rates should be scaled proportionate to the increase in the revenue requirement.

Our recommended practices are intended to reflect the Commission's prior direction to Liberty in D.16-12-024 and D.20-08-030. As discussed in Section III.A, the Commission directed Liberty to develop a cost of service methodology that reflects its system's need, rather than "relying on NV Energy's generation-related demand costs, which could arguably be different from a California customer's peak summer and winter consumption pattern."[73] To the extent practicable, Liberty's cost of service should be reflected in rates.

Q: Please describe any technical changes you made.

A: Liberty made uniform adjustments to class revenue requirements, including capping class revenue requirements, ensuring no class had a revenue requirement decrease, and application of discounts and credits. Since we are not using a uniform increase in rate elements method, we applied these much smaller adjustments on a class-specific basis, uniformly across all four cost categories (generation, distribution, customer, and other costs).

Also, Liberty's capping and revenue decrease adjustments allocated the adjustments based on a MGCC allocator. Since all cost categories, and not just generation, were being adjusted, we changed the allocation from MGCC to an aggregated MCOS allocator.

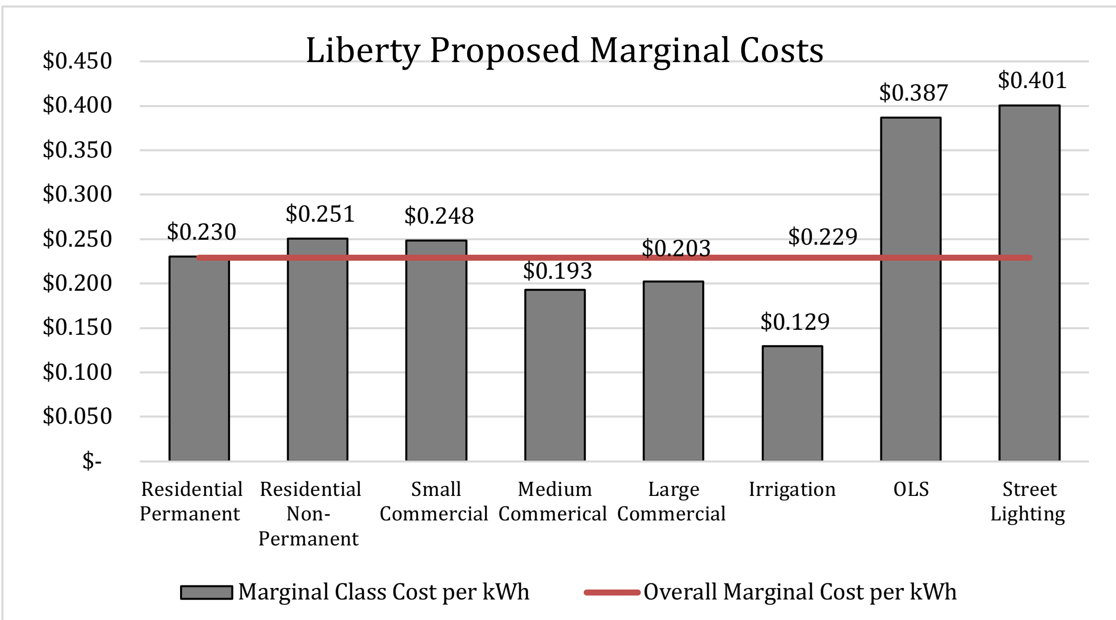
[72] We recommend that Liberty propose shifting all A-2 customers to TOU rates with no demand charge in its next rate case. The demand charge is an unnecessary complication and is not an effective tool for reducing peak demand on individual feeders.

[73] D.20-08-030, p. 77.

Q. What is the aggregate impact of your changes?

A: The impact of our changes to marginal costs is shown in Figure 2. There are substantial differences in both the level and allocation of marginal costs between our proposal and that of Liberty. We did not investigate class-specific issues for the OLS or Street Lighting classes, which may account for the relative similarity of the results in those two cases.

Figure 2: Liberty and SBUA Marginal Cost Proposals



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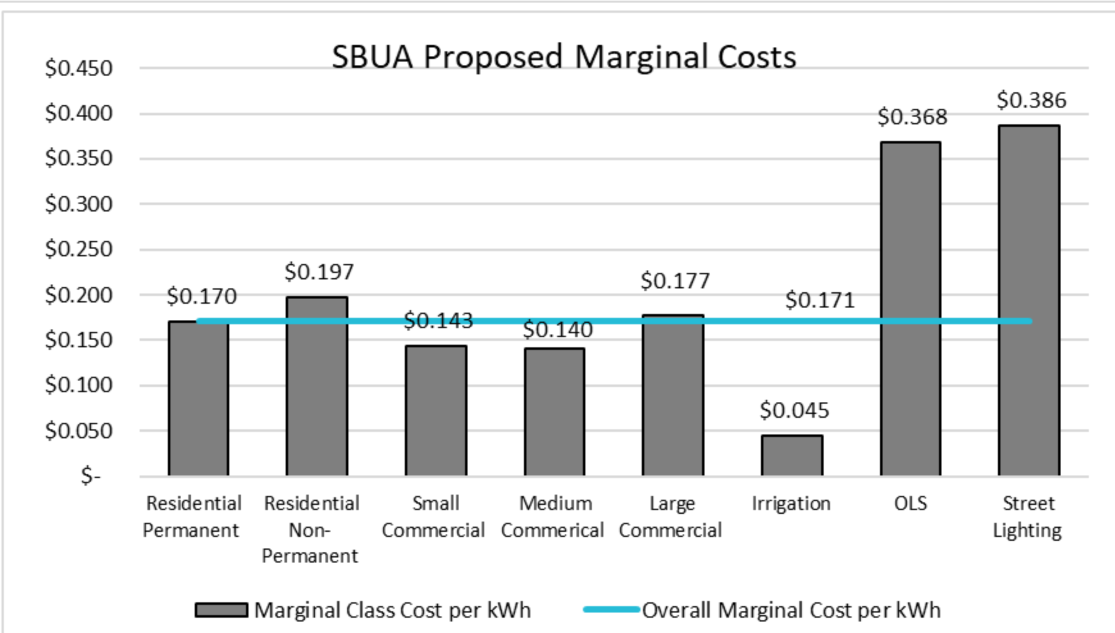

Rates incorporating all our recommendations are presented in Attachment RII-3.

Q: Why should the customer charge be set based on the marginal distribution customer cost (MDCC)?

A: In decision D.17-09-035, the Commission determined that the residential 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."[74] A residential customer charge should not exceed the MDCC.

As Cal Advocates noted in SCE's Phase 2 GRC, the Commission's conclusion with regard to residential fixed charges apply equally to the circumstances of small business customers.[75] We concur with this perspective, and recommend that the Commission direct Liberty to set monthly customer charges at the MDCC for residential customers and at least those commercial customers on Schedules A-1 and A-2.[76] We compute MDCC-

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

[75] Cal Advocates, Direct Testimony, A.20-10-012 (June 24, 2021), Ch. 8, p. 6, line 20 – p. 7, line 9.

[76] It would be reasonable for Liberty's customer charge to introduce service-level differentiation among commercial customers on the same rate schedule. In D.17-09-035, the Commission found for residential customers 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 residential customer." In the case of commercial customers, customer costs may vary, as indicated by one phase or three phase service, shared or dedicated final line transformers, and other customer-selected service levels. 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.

based customer charges (subject to capping, as necessary) for other rate schedules, for consistency.

Liberty has not proposed varying rates for its customers based on service levels, so the requisite marginal costs and billing determinants are not readily available.

Q: Why should generation and distribution energy rates be set at the class average cost of service?

A: Most of Liberty's existing energy rates are uniform, year-round rates. While it could be efficient to expand the use of seasonal rates, we are not proposing any major re-design of the existing rate schedules.[77]

For schedules with seasonal or TOU rates, the average cost of service should be specific to the season or TOU period. While we do not recommend the continued use of demand charges, we are not contesting their continued use by Liberty in this proceeding. For Schedule A-2, our proposed demand charges are intended to collect half the MGCC costs during the peak winter season. We tried to minimize rate design changes while emphasizing cost recovery during the appropriate peak periods.

For Schedule A-3, which includes both energy and demand rates, all rates should be increased uniformly based on the distribution or generation revenue requirement – we are not proposing any shift in the relative share of revenues among rates.[78]

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[77] Marginal costs should not be used in distribution rate design because the average cost of service is higher than the marginal cost of service. For example, if Tier 3 residential rates were set at the marginal cost of service, this would result in much higher rates for Tier 1 and Tier 2, which would result in low-demand residential customers paying a higher effective rate than customers with the highest levels of energy use.

[78] Schedule A-3 currently has (and is proposed to retain) a summer on-peak distribution demand charge that is much higher than the winter on-peak distribution demand charge. As discussed in Section IV.C of our testimony, Liberty's MDDCs occur in the winter period. We would favor re-design of Schedule A-3 rates to be better aligned with winter-peaking distribution costs, and

Since residential rates are currently tiered, it is practical to ensure that customers' highest levels of electric demand (Tier 3) are priced at the marginal generation cost. To determine reasonable Tier 1 and 2 rates, we set Tier 2 midway between Tiers 1 and 3. Then, Tier 1 is optimized at a level that results in collecting the class average cost of service.

B. TOU Periods

Q: What TOU periods does Liberty use?

A: Liberty proposes the TOU periods in Table 17. We did not find any testimony supporting this proposal.

Table 17: Liberty's Proposed TOU Periods

Winter Period (October to May)
On-Peak 5:01 p.m. to 10:00 p.m. daily Mid-Peak 7:01 a.m. to 5:00 p.m. daily Off-Peak All Other Hours
Summer Period (June to September)
On-Peak 5:01 p.m. to 10:00 p.m. daily Off-Peak All Other Hours

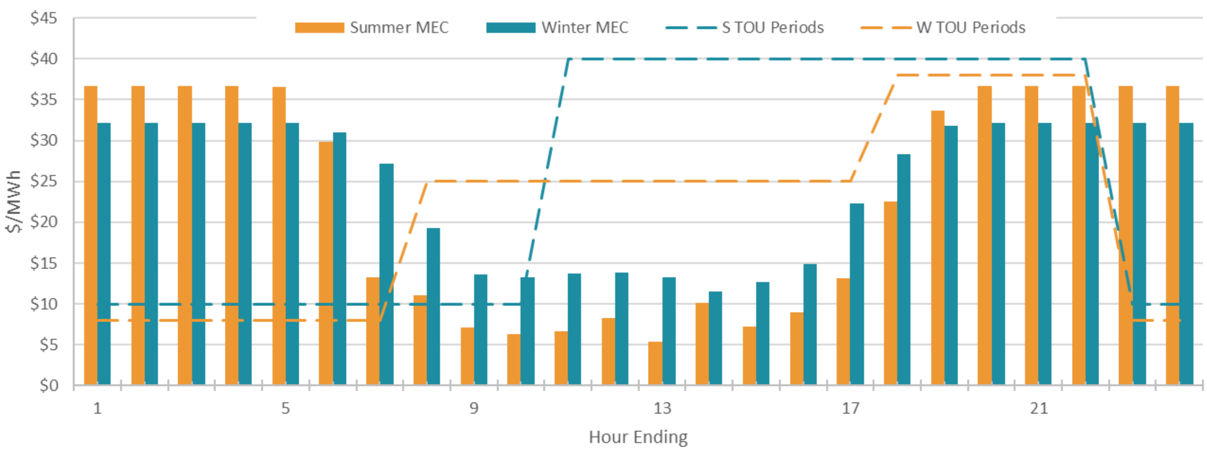
Source: Liberty MCOS-RD Workpaper, tab "TOU Factors."

encourage Liberty or parties representing Schedule A-3 customers to propose such a rate design. We also recommend maximizing cost recovery via energy rates rather than non-coincident demand charges. Non-coincident demand charges may not be well aligned with peak circuit distribution or peak system generation loads. If a customer's peak demand occurs outside of the peak period (circuit for distribution, system for generation), then the customer may face a perverse incentive to shift demand into the peak period. A more efficient design of Schedule A-3 rates could incentivize load reductions during winter peak periods. Such load reductions could, in turn, benefit all customers by avoiding distribution investments and potentially reducing generation prices.

Q. Are the TOU periods that Liberty proposes appropriate?

A: No. Liberty's TOU periods do not correspond to its marginal energy costs. As shown in Figure 3, the highest-priced energy periods are from 5 or 6 PM through the night to 6 or 7 AM. Since energy prices will tend to be high at times of high net load on the generation and transmission systems, the marginal generation and transmission capacity costs are probably also concentrated in those hours. Yet Liberty treats 10 PM to 7 or 10 AM as off-peak hours, and treats most of the lowest-cost hours as mid-peak in the winter and peak in the summer.

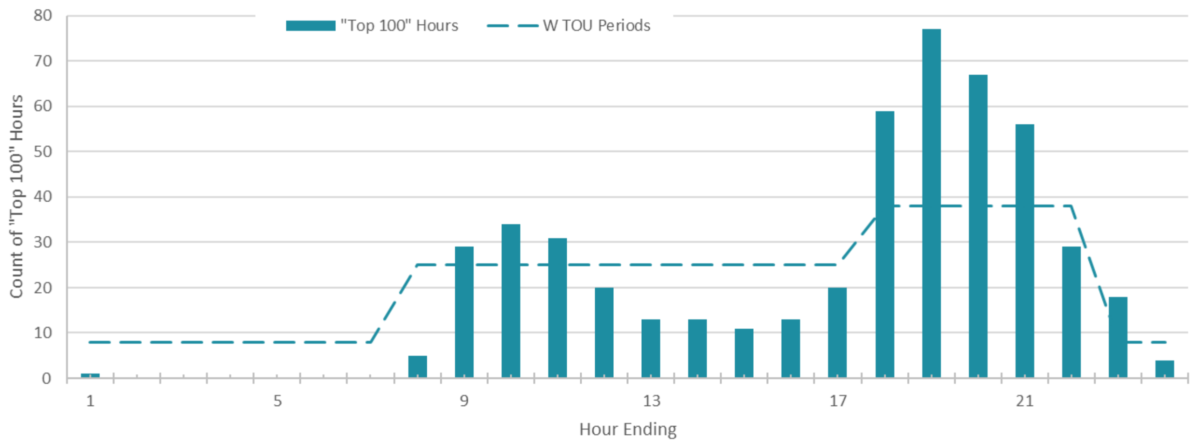
Figure 3: Marginal Energy Costs and Proposed TOU Periods[79]



Liberty's peak load data do provide somewhat better support for the winter TOU periods for purposes of allocating distribution costs. As shown in Figure 4, the occurrence of "top 100" hours (actually the top 500 hours over five years) corresponds reasonably well to the winter TOU period definition.

[79] Liberty MCOS-RD Workpaper, tab "IRP 2021-25 Energy."

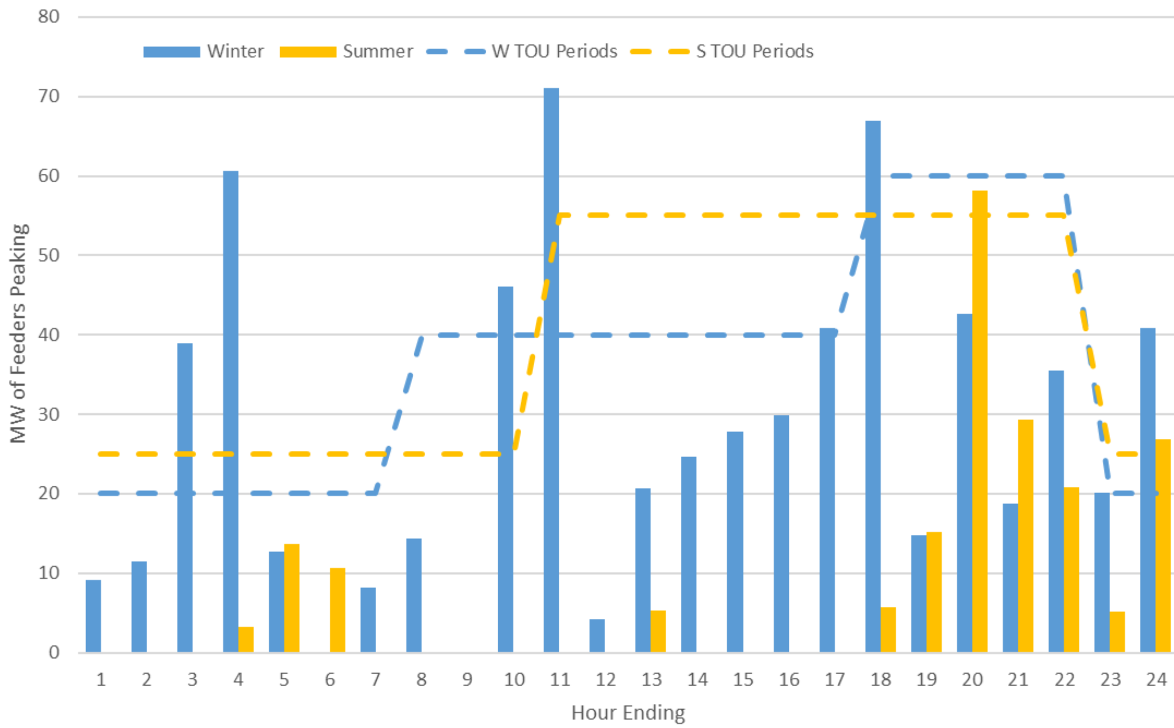
Figure 4: "Top 100" Hours and Proposed Winter TOU Periods[80]



However, the top hours for gross load do not necessarily describe well the drivers of distribution costs. Liberty should also reflect the timing of high loads on the feeders and substations. As shown in Figure 5, the limited sample data that Liberty has provided shows feeders peaking at a variety of hours in a variety of months.

80 RII MCOS-RD Workpaper, tab "Top_100."

Figure 5: Annual Peak Loads on Sampled Feeders, by Month 2019-2021[81]



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Q. What action should the Commission take regarding Liberty's TOU periods?

A: The Commission should direct Liberty to file an update of its TOU periods within one year of the order in this proceeding, with documentation of the time variation in marginal energy, generation capacity, transmission and distribution costs. Liberty's proposal should include a schedule for implementing any revisions and applying those revisions to rate calculations.

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[81] Attachment RII-13.

VIII. Impact of Schedule A-1 and A-2 Classification on Small Businesses

Q: How does Liberty classify and migrate customers between the A-1 and A-2 schedules?

A: Customers on Schedule A-1 are those customers whose monthly demand does not exceed 50 kW more than three months out of the year. If a customer exceeds this standard, Liberty migrates that customer to Schedule A-2. Liberty states that its "Billing Department annually reviews demand usage for all commercial customers and migrates rates, if needed. If customers go over or under the determined use for the Commercial rates based on Demand, Liberty migrates them accordingly and send them a letter."[82]

Q: Does it appear that Liberty is effectively implementing this policy?

A: It appears that Liberty may be more effective at migrating customers from A-1 to A-2 than vice versa. This may result in some Liberty customers paying excessive bills.

Based on monthly demand data for the subset of the customers for whom Liberty provided data, about 12% (29 of 240) of customers on Schedule A-2 could be migrated to Schedule A-1. In contrast, only 1% (17 of 1,324) of customers on Schedule A-1 could be migrated to Schedule A-2.[83] This asymmetric result suggests that Liberty is most diligent about migrating customers when it results in higher revenues.

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[82] Attachment RII-8, SBUA DRs 4-5 and 4-6.

[83] Calculations assume customers with 3rd largest monthly demand above/below 50 kW could be migrated up/down. RII Workpapers "RII A-1 Bill Impact" and "RII A-2 Bill Impact," which are supported by: Attachment RII-8, SBUA DR 4-1, "SBUA-Liberty 4(a) Attachment 1_vRevised" and Attachment RII-15, SBUA DR 4-1 Supplemental, "SBUA-Liberty 4(a) Attachment 1_vRevised 2."

Energy and demand data for Schedule A-1 and A-2 customers with a 3rd-largest billing demand at or near the 50 kW threshold are shown in Table 18.[84] It appears that Schedule A-1 customers at or near the 50 kW threshold typically have a significantly lower load factor than Schedule A-2 customers in that demand range, even though the load factors for customers on those schedules is similar.

Table 18: Energy and Demand Data for Schedule A-1 and A-2 Customers at or Near the 50 kW Threshold[85]

	Monthly Energy Use (kWh)	3rd Largest Demand (kW)	Load Factor
Schedule A-1			
Near (47 – 50 kW)	10,020	48.1	29%
Above 50 kW	12,232	134.9	12%
All Customers	3,526	15.6	31%
Schedule A-2			
Below 50 kW	11,913	43.4	38%
Near (50-53 kW)	14,555	51.1	39%
All Customers	21,179	89.7	32%

Load factor = Monthly Energy Use / (Demand * 8760 / 12)

Q: Does it matter whether a customer is promptly shifted to Schedule A-1 if the customer is eligible?

A: Low-usage customers on A-2 pay a monthly customer charge higher than A-1 customers, pay a demand charge, but pay lower energy rates. As shown in Table 19, a typical Schedule A-1 customer near the 50 kW threshold with monthly energy use of 10,020 kWh and demand of 48.1 kW would see a bill reduction of $116 (-6%) if migrated to Schedule

[84] We excluded a few customers whose billing data suggested that they may not have taken service for a significant portion of the year to avoid skew. For Schedule A-1 customers, "near" is defined as 47 – 50 kW. For Schedule A-2 customers, "near" is defined as 50-53 kW.

[85] RII Workpapers "RII A-1 Bill Impact" and "RII A-2 Bill Impact."

A-2. Under Liberty's proposed rates, a schedule migration would instead cause a bill increase of $1,058 (31%).

Table 19: Current and Proposed Bills for an A-1 Customer Near the 50 kW Threshold[86]

	Current	Proposed by Liberty	Proposed by SBUA
Schedule A-1	$ 2,134 / month	$ 2,324 / month	$ 2,327 / month
Schedule A-2	$ 2,018 / month	$ 3,382 / month	$ 2,613 / month
Migration Impact	- 6 %	31 %	11 %

While the current 6% bill reduction may not be available to every small business, if Liberty's proposed rates are approved, customers misclassified to Schedule A-2 will pay approximately 31% more than if classified on Schedule A-1. An additional $12,700 per year is enough to hire a part-time employee and is not a trivial expense.

An additional issue is that this $12,700 per year cost may significantly inhibit small business growth. A small business that is thinking of expanding production, adding walk-in refrigeration, or installing some other energy-intensive equipment may be discouraged by this sudden increase in costs or face a cashflow crunch when the electric bill increases sharply after migration to Schedule A-2.

Our proposed rate design mitigates this issue, but does not completely resolve it. While an 11% rate impact due to migration from Schedule A-1 to A-2 is undesirable, it is considerably more reasonable than a 31% rate impact.

Q: What is the reason for the bill impact?

A: The primary reason for bill impacts due to customer migration between rate schedules is the wildfire customer charge. As show in Table 16, both Liberty's and our proposed

[86] Assumes level monthly energy use and an average monthly demand of 24 kW (winter) and 26 kW (summer), which is substantially less than the 50 kW eligibility threshold. Calculations performed in bill impact models provided by Liberty. RII MCOS-RD Workpaper, tabs "A-1 RD" and "A-2 RD;" RII Workpapers "RII A-1 Bill Impact" and "RII A-2 Bill Impact."

monthly customer charges for Schedule A-3 increase – but Liberty's proposed increase is much steeper. As discussed in Section VI, Liberty's proposed wildfire customer charge would result in a bill impact of $11,084 for customers on Schedule A-2. This represents 87% of the rate migration impact.

Q: How did you calculate the bill impacts?

A: We requested bill impact analyses from Liberty. After inquiry by SBUA, Liberty updated its billing determinants for Schedule A-2 and indicated its intent to incorporate the revised billing demands into the Company's rebuttal testimony.[87]

The revised bill impact analysis provided by Liberty also replaced the class-average load factor that Liberty had used to calculate demand for various levels of customer energy use with a value determined from 2020 billing data supplied by Liberty.[88]

Our review of this revised bill impact analysis identified several additional errors.

- The function used to match monthly energy use to monthly demand for each customer failed to consider the location ID. Some customers have as many as 11 locations listed, and demand from one location was improperly matched with the energy usage data at all 11 locations.
- The bins for each usage level were improperly constructed to only include customers with usage below the reported level. For example, the 9,000 kWh usage customer data were an average for customers with usage between 5,000 and 9,000 kWh. We corrected this bin to include usage between 7,000 and 11,500 kWh by using the midpoint between each level to define the boundaries of the bin. This correction significantly affected the average kW for some bins.

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[87] Attachment RII-15.

[88] These data were provided in response to Attachment RII-8, SBUA DR 4-1(d). A supplemental response integrated them into Attachment RII-15, "SBUA-Liberty 4(a) Attachment 2_vRevised 2."

- The revised rate design for A-2 was not updated with the usage-specific average demand values developed in the workbook.[89]

Liberty's revised rate design, incorporating these corrections but no other changes, is shown in Attachment RII-7.

Q: What do you recommend to avoid excessive bills due to migration across schedules?

A: First, as discussed in Section VI, we recommend that the Commission reject Liberty's proposal to collect wildfire mitigation costs in a fixed monthly fee. Together with the customer charge, Liberty proposes monthly fees for Schedule A-1 of $110 and for Schedule A-2 of $1,061. This $951 per month fee increase is responsible for more than half of the billing differential illustrated in Table 19.

Second, we recommend that the Commission direct Liberty to audit the accounts of customers on Schedule A-2 to determine if they are eligible for Schedule A-1. Any customers who are eligible should be notified that they will be migrated to Schedule A-1 on the next billing cycle unless they opt to remain on Schedule A-2.

Furthermore, the audit should also determine when each customer became eligible for Schedule A-1. If a customer became eligible prior to Liberty's last annual review by the billing department, then Liberty should refund the amount of savings that the customer would have benefitted from if it had migrated the customer in a timely manner.[90]

Q: Does this conclude your testimony?

A: Yes.

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[89] Attachment RII-15, SBUA DR 4-1 Supplemental, tab "A-2 RD (Revised Rate Design)."

[90] If Liberty's billing department has not completed a review in the past 13 months, then Liberty should provide refunds from the first month that the customer would have been eligible up to the date of the migration. Attachment RII-8, SBUA DRs 4-5 and 4-6.

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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.

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

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

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

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

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

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

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

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

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

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

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

"Least Cost Planning and Gas Utilities." Demand-Side Management and the Global Environment Conference; Washington, D.C. April 22 1991.

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

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

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

New England Gas Association Gas Utility Managers' Conference. Woodstock, Vermont, September 10 1990.

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

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

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

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

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

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

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

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

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

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

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

17. **Mass. EFSC** 80-17, Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 1981.

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

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

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

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

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

20. **DC PSC** FC785, Potomac Electric Power rate case; DC Peoples Counsel. July 1982.

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

21. **N.H. PSC** DE 81-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 1982.

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

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

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

23. **Ill. CC** 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 1982.

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Profit-margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

    Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

54. **N.M. PSC** 2009, El Paso Electric rate moderation program; New Mexico Attorney General. August 1986.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

77. **Mass. DPU** 89-100, Boston Edison rates; Massachusetts Energy Office. June 1989.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

85. Ind. URC, integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1990.

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

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

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

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

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

88. Maine PUC 90-286, adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 1991.

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

89. Va. SCC PUE900070, commission investigation; Southern Environmental Law Center. March 1991.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Obligation to pursue integrated resource planning, failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Penn. PUC** I-900005, R-901880; investigation into demand-side management by electric utilities; Pennsylvania Energy Office. January 1992.

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

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

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

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

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

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

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

103. **N.C. UC** E-100 Sub 64, integrated-resource-planning docket; Southern Environmental Law Center. September 1992.

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

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

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

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

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

106. **Maine BEP,** in the matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 1992.

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

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

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

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

Demand-side management cost recovery and incentive mechanisms.

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

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

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

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

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

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

112. **Md. PSC** 8179, Approval of amendment to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

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

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

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

Demand-side-management planning, program designs, potential savings, and avoided costs.

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

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

116. **Ill. CC** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, February 1 1994; rebuttal, September 1994.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

130. **D.C. PSC** FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

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

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

Demand-side-management cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

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

Allocation of costs and benefits to rate classes.

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

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

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

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

135. **N.C. UC** E-2 Sub 669; 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. Joint testimony with John D. Wilson. Direct November 2020. Rebuttal February 2021. Supplemental direct on real-time pricing May 2021.

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

366. **N.S. UARB** M09777; NS Power Time Varying Pricing; Nova Scotia Consumer Advocate. February 2021. Joint testimony with John D. Wilson.

Net load as measure of capacity need. Effect of proposed TVP tariffs on load, capacity savings, and energy costs. Limits of TOU rates for long winter peaks. Improved critical-peak pricing (CPP) tariffs. Treatment of demand charges. Implementation and evaluation of program. Lost revenue adjustment mechanism.

367. **Cal. PUC** A.20-10-011; Pacific G&E Day-Ahead Real-time Commercial Electric Vehicle Tariff; Small Business Utility Advocates. Direct April 20, Rebuttal May 2021.

Rate design for real-time pricing tariff. Allocation of marginal generation capacity cost to hours. Maintaining revenue neutrality. Marketing the tariff to small businesses. Evaluation plan.

368. **Cal. PUC** R.20-08-020; Net Energy Metering Successor Tariff; Small Business Utility Advocates. Direct, June 2021, Rebuttal July 2021.

Rate design. Evaluation of alternatives. Required payback to continue behind-the-meter resource development. Encouraging storage and integrating with the grid.

369. **Cal. PUC** A.20-10-012; Southern California Edison Marginal Costs, Revenue Allocation, and Rate Design; Small Business Utility Advocates. Joint testimony with John D. Wilson. Direct July 2021.

Allocation of marginal generation capacity costs among subfunctions, hours, and classes. Expected marginal generation energy costs. Estimation and allocation of marginal distribution capacity costs. Allocation of customer access costs. Real-time pricing. Updating peak cost periods.

370. **Colorado PUC** 21AL-0236G; Black Hills Gas Rate Increase; Energy Outreach Colorado. Answer Testimony September 2021.

Minimizing investment in obsolescent distribution system. Class cost-of-service study (functionalization, classification and allocation of mains; allocation of services, meters and regulators). Residential customer charge. Consolidation of rate areas. Mitigation of rate increases.

371. **N.S. UARB** M10182/10183; NS Power Authorization to Overspend for Distribution and Transmission Routines; Nova Scotia Consumer Advocate. September 2021

Derivation and documentation of budgets. Interaction of inspection and failure rates. Upstream investments for new customers and new loads, line extensions for new customers, replacement of failed equipment,

372. **N.S. UARB** M10178; NS Power 2021 10-Year System Outlook; Nova Scotia Consumer Advocate. Comments September 2021.

Implications of more rapid decarbonization. Inconsistencies with IRP. Need for updated and coordinated planning.

373. **N.J. BPU** QO2106094; Medium- and Heavy-Duty Electric Vehicle Charging Ecosystem; NJR Clean Energy Ventures. Comments September 2021.

Problems with demand charges, particularly for EV charging. Superiority of time-varying energy charges.

374. **Colorado PUC** 21AL-0317E; Public Service of Colorado Rate Increase; Energy Outreach Colorado. Answer Testimony November 2021.

Return on regulatory asset. Jurisdictional and functional allocations. Allocation and recovery of rate increase prior to proceeding on cost allocation and rate design.

375. **N.S. UARB** M10279; NS Power Performance Standards; Nova Scotia Consumer Advocate. November 2021

System reliability standards, circuit reliability standards, standards and definitions for new service connection times, including for distributed generation. Avoiding self-referential standards.

376. **N.S. UARB** M10377; Power Purchase Agreement for the Purchase of Low-Impact Renewable Electricity; Nova Scotia Consumer Advocate. January 2022

Fixed versus escalating rates. Compensation for replacement renewable energy. Contract term.

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

JOHN D. WILSON

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Arlington MA 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, responsive, and reply to 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.

California PUC Docket A.20-10-012, direct testimony with Paul Chernick in Southern California Edison's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate allocation and design, including customer charges and real time pricing tariffs.

Nova Scotia UARB Matter No. M10176, direct testimony on Nova Scotia Power's Smart Grid Nova Scotia Solar Garden Pilot Rate Rider on behalf of the Nova Scotia Consumer Advocate. Addressing risks associated with future cost changes.

Nova Scotia UARB Matter No. M10110, direct testimony on Nova Scotia Power's Wreck Cove hydroelectric project on behalf of the Nova Scotia Consumer Advocate. Reasonableness of project and unresolved issues.

California PUC Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 3) on behalf of the Small Business Utility Advocates. Reasonableness and prudence of remedial and replacement software costs to be included in authorized revenue requirement.

Nova Scotia UARB Matter No. M10197, direct testimony on Nova Scotia Power's Tusket Main Dam Refurbishment Authorization to Overspend application on behalf of the Nova Scotia Consumer Advocate. Whether the project should proceed and whether full cost recovery is justified.

Colorado PUC Proceeding No. 21AL-0317E, answer testimony in Public Service Company of Colorado's 2021 general rate case (phase 1) on behalf of Energy Outreach Colorado. Reasonableness of capital project costs, choice of test year, adjustment to load to reflect effects of pandemic.

Liberty Utilities (CalPeco Electric)
Residential Permanent Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	24,559,163	$ 7,991,519	$ 32,550,682
Current Base Rates	15,564,453	$ 8,970,952	$ 24,535,405
$ Difference	8,994,710	(979,433)	8,015,277
% Difference	57.8%		32.7%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ -	214,666	$ -

Residential Permanent Tier III Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Revised Rates								
Customer Charge	$ 13.84			214,666	2,970,768			$ 2,970,768
Wildfire Charge	$ -			214,666	-			-
Tier 1 Energy		$ 0.13258	$ 0.00999	92,999,141		12,330,136	928,721	13,258,856
Tier 2 Energy		$ 0.13258	$ 0.02709	12,912,392		1,711,968	349,838	2,061,806
Tier 3 Energy		$ 0.13258	$ 0.04420	34,402,551		4,561,205	1,520,597	6,081,801
Revenue at Revised Rates				**140,314,083**	**$ 2,970,768**	**$ 18,603,308**	**$ 2,666,804**	**$ 24,373,232**
Current Rates								
Customer Charge	$ 9.67			219,296	$ 2,120,594			$ 2,120,594
Tier 1 Energy		$ 0.08197	$ 0.00911	96,281,508		7,892,195	877,125	8,769,320
Tier 2 Energy		$ 0.08197	$ 0.01681	47,322,728		3,879,044	795,495	4,674,539
Tier 3 Energy		$ 0.08197	$ 0.01681			-	-	-
Revenue at Current Rates				**143,604,236**	**$ 2,120,594**	**$ 11,771,239**	**$ 1,672,620**	**$ 15,564,453**

Liberty Utilities (CalPeco Electric)
Residential Permanent Rate Design

Residential Permanent Bill Impact Analysis: Current Rates vs. Proposed Rates

Monthly Usage (kWh)	Cumulative Bills %	Cumulative Usage %	Revised Bill $	Current Bill $	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
200.00	10.1%	1.7%	$ 52.74	$ 39.40	$ 13.34	33.9%
325.00	22.3%	5.9%	$ 77.05	$ 57.97	$ 19.07	32.9%
425.00	33.5%	11.4%	$ 96.50	$ 72.84	$ 23.66	32.5%
525.00	44.4%	18.2%	$ 115.95	$ 87.70	$ 28.25	32.2%
615.00	52.9%	24.6%	$ 134.64	$ 101.92	$ 32.72	32.1%
875.00	71.9%	43.0%	$ 195.65	$ 146.44	$ 49.21	33.6%
1100.00	82.0%	56.1%	$ 250.47	$ 184.98	$ 65.49	35.4%
1500.00	91.4%	71.8%	$ 347.92	$ 253.48	$ 94.44	37.3%
2000.00	96.0%	82.3%	$ 469.74	$ 339.11	$ 130.63	38.5%
4000.00	99.2%	93.2%	$ 957.01	$ 681.63	$ 275.37	40.4%
Summer Season						
100.00	4.4%	0.5%	$ 33.29	$ 24.53	$ 8.75	35.7%
200.00	15.1%	3.5%	$ 52.74	$ 39.40	$ 13.34	33.9%
275.00	26.3%	8.3%	$ 67.32	$ 50.54	$ 16.78	33.2%
350.00	37.8%	14.8%	$ 81.91	$ 61.69	$ 20.22	32.8%
450.00	52.4%	25.3%	$ 101.65	$ 76.76	$ 24.89	32.4%
600.00	69.3%	41.3%	$ 136.08	$ 102.45	$ 33.64	32.8%
750.00	80.7%	55.1%	$ 172.63	$ 128.13	$ 44.49	34.7%
1000.00	90.8%	70.7%	$ 233.53	$ 170.95	$ 62.59	36.6%
1500.00	97.0%	84.1%	$ 355.35	$ 256.58	$ 98.77	38.5%
3000.00	99.2%	91.9%	$ 720.80	$ 513.47	$ 207.33	40.4%

Liberty Utilities (CalPeco Electric)
Residential Permanent Rate Design

Residential Permanent Bill Impact Analysis: Proposed Rates vs. May Proposed Rates (Revenue Neutral Basis)

Monthly Usage (kWh)	Cumulative Bills %	Cumulative Usage %	Revised Bill $	May Proposed Bill $	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
200.00	10.1%	1.7%	$ 52.74	$ 54.39	$ (1.66)	-3.0%
325.00	22.3%	5.9%	$ 77.05	$ 78.85	$ (1.80)	-2.3%
425.00	33.5%	11.4%	$ 96.50	$ 98.42	$ (1.92)	-2.0%
525.00	44.4%	18.2%	$ 115.95	$ 117.98	$ (2.04)	-1.7%
615.00	52.9%	24.6%	$ 134.64	$ 136.60	$ (1.96)	-1.4%
875.00	71.9%	43.0%	$ 195.65	$ 194.51	$ 1.14	0.6%
1100.00	82.0%	56.1%	$ 250.47	$ 244.63	$ 5.84	2.4%
1500.00	91.4%	71.8%	$ 347.92	$ 333.73	$ 14.19	4.3%
2000.00	96.0%	82.3%	$ 469.74	$ 445.10	$ 24.64	5.5%
4000.00	99.2%	93.2%	$ 957.01	$ 890.59	$ 66.41	7.5%
Summer Season						
100.00	4.4%	0.5%	$ 33.29	$ 34.83	$ (1.54)	-4.4%
200.00	15.1%	3.5%	$ 52.74	$ 54.39	$ (1.66)	-3.0%
275.00	26.3%	8.3%	$ 67.32	$ 69.07	$ (1.74)	-2.5%
350.00	37.8%	14.8%	$ 81.91	$ 83.74	$ (1.83)	-2.2%
450.00	52.4%	25.3%	$ 101.65	$ 103.55	$ (1.91)	-1.8%
600.00	69.3%	41.3%	$ 136.08	$ 136.96	$ (0.88)	-0.6%
750.00	80.7%	55.1%	$ 172.63	$ 170.38	$ 2.25	1.3%
1000.00	90.8%	70.7%	$ 233.53	$ 226.06	$ 7.47	3.3%
1500.00	97.0%	84.1%	$ 355.35	$ 337.44	$ 17.92	5.3%
3000.00	99.2%	91.9%	$ 720.80	$ 671.55	$ 49.25	7.3%

Liberty Utilities (CalPeco Electric)
Residential Permanent Rate Design

Residential CARE Bill Impact Analysis: Current Rates (20% Discount) vs. Proposed Rates (25% Discount)

Monthly Usage (kWh)	Cumulative Bills %	Cumulative Usage %	Revised Bill $	Current Bill $	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
200.00	13.1%	2.6%	$ 39.32	$ 31.34	$ 7.98	25.5%
325.00	28.2%	8.6%	$ 57.41	$ 46.09	$ 11.32	24.6%
425.00	40.4%	15.6%	$ 71.89	$ 57.89	$ 14.00	24.2%
525.00	51.6%	23.6%	$ 86.36	$ 69.69	$ 16.67	23.9%
615.00	60.0%	30.9%	$ 100.27	$ 80.98	$ 19.29	23.8%
875.00	76.9%	49.6%	$ 145.73	$ 116.37	$ 29.37	25.2%
1100.00	85.8%	62.8%	$ 186.59	$ 146.99	$ 39.60	26.9%
1500.00	93.3%	77.3%	$ 259.22	$ 201.43	$ 57.79	28.7%
2000.00	97.2%	87.5%	$ 350.01	$ 269.48	$ 80.53	29.9%
4000.00	99.8%	97.5%	$ 713.16	$ 541.68	$ 171.48	31.7%
Summer Season						
100.00	4.8%	0.7%	$ 24.85	$ 19.54	$ 5.31	27.2%
200.00	19.3%	5.4%	$ 39.32	$ 31.34	$ 7.98	25.5%
275.00	32.6%	12.3%	$ 50.18	$ 40.19	$ 9.99	24.8%
350.00	45.7%	21.1%	$ 61.03	$ 49.04	$ 11.99	24.5%
450.00	60.8%	34.0%	$ 75.72	$ 61.00	$ 14.72	24.1%
600.00	76.4%	51.5%	$ 101.37	$ 81.42	$ 19.96	24.5%
750.00	86.1%	65.5%	$ 128.61	$ 101.83	$ 26.78	26.3%
1000.00	93.9%	79.8%	$ 174.00	$ 135.86	$ 38.15	28.1%
1500.00	98.3%	91.1%	$ 264.79	$ 203.91	$ 60.89	29.9%
3000.00	99.7%	97.1%	$ 537.16	$ 408.06	$ 129.10	31.6%

Liberty Utilities (CalPeco Electric)
Residential Permanent Rate Design

Residential CARE Bill Impact Analysis: Current Rates (20% Discount) vs. Proposed Rates (20% Discount)

Monthly Usage (kWh)	Cumulative Bills %	Cumulative Usage %	Revised Bill $	Current Bill $	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
200.00	13.1%	2.6%	$ 41.94	$ 31.34	$ 10.60	33.8%
325.00	28.2%	8.6%	$ 61.24	$ 46.09	$ 15.15	32.9%
425.00	40.4%	15.6%	$ 76.68	$ 57.89	$ 18.79	32.5%
525.00	51.6%	23.6%	$ 92.11	$ 69.69	$ 22.42	32.2%
615.00	60.0%	30.9%	$ 106.96	$ 80.98	$ 25.98	32.1%
875.00	76.9%	49.6%	$ 155.45	$ 116.37	$ 39.08	33.6%
1100.00	85.8%	62.8%	$ 199.03	$ 146.99	$ 52.04	35.4%
1500.00	93.3%	77.3%	$ 276.50	$ 201.43	$ 75.07	37.3%
2000.00	97.2%	87.5%	$ 373.34	$ 269.48	$ 103.86	38.5%
4000.00	99.8%	97.5%	$ 760.71	$ 541.68	$ 219.03	40.4%
Summer Season						
100.00	4.8%	0.7%	$ 26.51	$ 19.54	$ 6.97	35.7%
200.00	19.3%	5.4%	$ 41.94	$ 31.34	$ 10.60	33.8%
275.00	32.6%	12.3%	$ 53.52	$ 40.19	$ 13.33	33.2%
350.00	45.7%	21.1%	$ 65.10	$ 49.04	$ 16.06	32.7%
450.00	60.8%	34.0%	$ 80.77	$ 61.00	$ 19.76	32.4%
600.00	76.4%	51.5%	$ 108.13	$ 81.42	$ 26.71	32.8%
750.00	86.1%	65.5%	$ 137.18	$ 101.83	$ 35.35	34.7%
1000.00	93.9%	79.8%	$ 185.60	$ 135.86	$ 49.75	36.6%
1500.00	98.3%	91.1%	$ 282.45	$ 203.91	$ 78.54	38.5%
3000.00	99.7%	97.1%	$ 572.97	$ 408.06	$ 164.91	40.4%

Liberty Utilities (CalPeco Electric)
Residential Non-Permanent Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	34,064,281	$ 10,616,327	$ 44,680,608
Current Base Rates	17,925,019	$ 10,992,483	$ 28,917,502
$ Difference	16,139,262	(376,157)	15,763,106
% Difference	90.0%		54.5%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ -	311,972	$ -

Residential Non-Perma Tier III Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Revised Rates								
Customer Charge	$ 19.77			311,972	$ 6,169,160			$ 6,169,160
Wildfire Charge	$ -			311,972	$ -			$ -
Tier 1 Energy						-	-	-
Tier 2 Energy		$ 0.16443	$ 0.01026	111,580,081		18,347,510	1,144,845	19,492,355
Tier 3 Energy		$ 0.16443	$ 0.04523	47,228,098		7,765,884	2,136,265	9,902,149
Revenue at Revised Rates				**158,808,179**	**$ 6,169,160**	**$ 26,113,394**	**$ 3,330,611**	**$ 35,563,664**
Current Rates								
Customer Charge	$ 9.67			304,428	$ 2,943,817			$ 2,943,817
Tier 1 Energy						-	-	-
Tier 2 Energy		$ 0.08197	$ 0.01681	151,662,300		12,431,759	2,549,443	14,981,202
Tier 3 Energy		$ 0.08197	$ 0.01681			-	-	-
Revenue at Current Rates				**151,662,300**	**$ 2,943,817**	**$ 12,431,759**	**$ 2,549,443**	**$ 17,925,019**

Liberty Utilities (CalPeco Electric)
Residential Non-Permanent Rate Design

Residential Non-Permanent Bill Impact Analysis: Current Rates vs. Proposed Rates

Monthly Usage (kWh)	Cumulative Bills %	Cumulative Usage %	Revised Bill $	Current Bill $	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
200.00	30.8%	5.4%	$ 68.08	$ 43.92	$ 24.16	55.0%
325.00	46.7%	12.1%	$ 98.28	$ 65.33	$ 32.95	50.4%
425.00	55.9%	17.7%	$ 122.43	$ 82.46	$ 39.98	48.5%
525.00	63.2%	23.4%	$ 146.59	$ 99.58	$ 47.00	47.2%
615.00	68.6%	28.4%	$ 168.32	$ 114.99	$ 53.33	46.4%
875.00	79.3%	41.3%	$ 235.45	$ 159.52	$ 75.93	47.6%
1100.00	85.3%	50.8%	$ 297.67	$ 198.06	$ 99.61	50.3%
1500.00	91.5%	63.9%	$ 408.27	$ 266.56	$ 141.71	53.2%
2000.00	95.3%	74.6%	$ 546.53	$ 352.19	$ 194.34	55.2%
4000.00	99.1%	91.3%	$ 1,099.57	$ 694.71	$ 404.86	58.3%
Summer Season						
100.00	14.1%	1.8%	$ 43.93	$ 26.80	$ 17.13	63.9%
200.00	34.5%	8.5%	$ 68.08	$ 43.92	$ 24.16	55.0%
275.00	46.9%	15.0%	$ 86.20	$ 56.77	$ 29.43	51.8%
350.00	56.8%	21.9%	$ 104.32	$ 69.61	$ 34.70	49.9%
450.00	67.2%	31.1%	$ 128.47	$ 86.74	$ 41.73	48.1%
600.00	77.8%	43.4%	$ 165.63	$ 112.43	$ 53.21	47.3%
750.00	84.7%	53.8%	$ 207.11	$ 138.12	$ 69.00	50.0%
1000.00	91.4%	66.5%	$ 276.24	$ 180.93	$ 95.31	52.7%
1500.00	96.5%	80.1%	$ 414.50	$ 266.56	$ 147.94	55.5%
3000.00	99.3%	92.6%	$ 829.27	$ 523.45	$ 305.82	58.4%

Liberty Utilities (CalPeco Electric)
Residential Non-Permanent Rate Design

Residential Non-Permanent Bill Impact Analysis: Proposed Rates vs. May Proposed Rates (Revenue Neutral Basis)

Monthly Usage (kWh)	Cumulative Bills %	Cumulative Usage %	Revised Bill $	May Proposed Bill $	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
200.00	30.8%	5.4%	$ 68.08	$ 69.29	$ (1.21)	-1.7%
325.00	46.7%	12.1%	$ 98.28	$ 101.11	$ (2.84)	-2.8%
425.00	55.9%	17.7%	$ 122.43	$ 126.57	$ (4.14)	-3.3%
525.00	63.2%	23.4%	$ 146.59	$ 152.03	$ (5.44)	-3.6%
615.00	68.6%	28.4%	$ 168.32	$ 174.94	$ (6.61)	-3.8%
875.00	79.3%	41.3%	$ 235.45	$ 241.12	$ (5.67)	-2.4%
1100.00	85.3%	50.8%	$ 297.67	$ 298.40	$ (0.73)	-0.2%
1500.00	91.5%	63.9%	$ 408.27	$ 400.23	$ 8.04	2.0%
2000.00	95.3%	74.6%	$ 546.53	$ 527.51	$ 19.02	3.6%
4000.00	99.1%	91.3%	$ 1,099.57	$ 1,036.65	$ 62.91	6.1%
Summer Season						
100.00	14.1%	1.8%	$ 43.93	$ 43.83	$ 0.10	0.2%
200.00	34.5%	8.5%	$ 68.08	$ 69.29	$ (1.21)	-1.7%
275.00	46.9%	15.0%	$ 86.20	$ 88.38	$ (2.18)	-2.5%
350.00	56.8%	21.9%	$ 104.32	$ 107.48	$ (3.16)	-2.9%
450.00	67.2%	31.1%	$ 128.47	$ 132.93	$ (4.46)	-3.4%
600.00	77.8%	43.4%	$ 165.63	$ 171.12	$ (5.49)	-3.2%
750.00	84.7%	53.8%	$ 207.11	$ 209.30	$ (2.19)	-1.0%
1000.00	91.4%	66.5%	$ 276.24	$ 272.95	$ 3.29	1.2%
1500.00	96.5%	80.1%	$ 414.50	$ 400.23	$ 14.27	3.6%
3000.00	99.3%	92.6%	$ 829.27	$ 782.08	$ 47.19	6.0%

Liberty Utilities (CalPeco Electric)
A-1 Class Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	15,429,159	$ 9,241,469	$ 24,670,628
Current Base Rates	12,515,344	$ 10,095,502	$ 22,610,846
$ Difference	2,913,815	(854,033)	2,059,782
% Difference	23.3%		9.1%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ -	63,875	$ -

A-1 Class Rate Design	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (A-1 <= 20kW)								
Customer Charge	$ 25.46			59,375	$ 1,511,634			$ 1,511,634
Wildfire Charge	$ -			59,375	-			-
Energy		$ 0.11581	$ 0.02095	61,420,183		7,113,276	1,286,855	8,400,131
Proposed Rates (A-1A > 20 kW)								
Customer Charge	$ 25.46	-		4,500	114,579			114,579
Wildfire Charge	$ -			4,500	-			-
Energy		$ 0.11581	$ 0.02095	37,982,522	$ -	4,398,883	795,797	5,194,679
Revenue at Proposed Rates				99,402,704	$ 1,626,214	**$ 11,512,159**	**$ 2,082,651**	$ 15,221,024
Proposed Rates (A-1 <= 20kW)								
Customer Charge	$ 17.38			60,378	$ 1,049,371			$ 1,049,371
Energy		$ 0.09335	$ 0.01867	63,685,729		5,945,063	1,189,013	7,134,075
Proposed Rates (A-1A > 20 kW)								
Customer Charge	$ 17.38			4,446	77,270			77,270
Energy		$ 0.09335	$ 0.01867	37,980,960		3,545,523	709,105	4,254,627
Revenue at Current Rates				101,666,688	$ 1,126,641	$ 9,490,585	$ 1,898,117	$ 12,515,344

Liberty Utilities (CalPeco Electric)
A-1 Class Rate Design

A-1 Class Rate Design

Bill Impact Analysis Total Charges	Month Usage	Proposed Bill	Current Bill	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season					
50% Below Avg. Usage	785.1	$ 205.83	$ 183.29	$ 22.54	12.3%
25% Below Avg. Usage	1,177.7	$ 296.02	$ 266.25	$ 29.77	11.2%
Average Usage	1,570.3	$ 386.20	$ 349.21	$ 37.00	10.6%
25% Above Avg. Usage	1,962.8	$ 476.39	$ 432.16	$ 44.22	10.2%
50% Above Avg. Usage	2,355.4	$ 566.57	$ 515.12	$ 51.45	10.0%
Summer Season					
50% Below Avg. Usage	756.9	$ 199.35	$ 177.33	$ 22.02	12.4%
25% Below Avg. Usage	1,135.4	$ 286.30	$ 257.31	$ 28.99	11.3%
Average Usage	1,513.9	$ 373.24	$ 337.29	$ 35.96	10.7%
25% Above Avg. Usage	1,892.3	$ 460.19	$ 417.26	$ 42.93	10.3%
50% Above Avg. Usage	2,270.8	$ 547.14	$ 497.24	$ 49.90	10.0%

Liberty Utilities (CalPeco Electric)
A-2 Class Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	10,293,080	$ 6,118,365	$ 16,411,446
Current Base Rates	8,849,575	$ 6,480,720	$ 15,330,296
$ Difference	1,443,505	(362,355)	1,081,150
% Difference	16.3%		7.1%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ -	3,048	$ -

A-2 Class Rate Design Proposed Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (A-2)								
Customer Charge	$ 87.56	$ 0.00353		3,048	$ 266,883			$ 266,883
Wildfire Charge	$ -			3,048	-			-
Winter Energy		$ 0.09463	$ 0.01680	45,574,506	160,779	4,312,798	765,652	5,239,228
Summer Energy		$ 0.09463	$ 0.01084	21,720,176	76,625	2,055,419	235,537	2,367,581
Winter Demand		$ 12.40	$ 2.97	139,842		1,733,594	414,760	2,148,354
Summer Demand		$ -	$ -	61,966		-	-	-
Power Factor				0.00561%	$ 28	$ 455	$ 79	562
V/T Discount				-0.00539%	$ (27)	$ (437)	$ (76)	(540)
Proposed Rates (A-2 TOU)								
Customer Charge	$ 87.56	$ 0.00353		-	$ -			$ -
Wildfire Charge	$ -			-	-			-
Winter Energy - On-Peak		$ 0.30477	$ 0.01491	131,045	462	39,938	1,954	42,355
Winter Energy - Mid-Peak		$ 0.15250	$ 0.01097	187,889	663	28,653	2,061	31,377
Winter Energy - Off-Peak		$ 0.02622	$ 0.01685	194,953	688	5,112	3,285	9,085
Summer Energy - OnPeak		$ 0.06706	$ 0.00642	236,540	834	15,862	1,518	18,214
Summer Energy - Off-Peak		$ -	$ 0.00916	196,029	692	-	1,795	2,486
Winter Demand		$ 12.40	$ 6.45	1,441		17,868	9,301	27,169
~~Winter Demand - Mid-Peak~~		$ -	$ -	1,522		-	-	-
Summer Demand		$ -	$ -	1,359		-	-	-
Non-TOU Maximum		$ -	$ -	2,165		-	-	-
Revenue at Proposed Rates				68,241,136	$ 507,626	**$ 8,209,262**	**$ 1,435,867**	$ 10,152,755

Liberty Utilities (CalPeco Electric)
A-2 Class Rate Design

A-2 Class Rate Design Proposed Rates (TOU A-2 EV)	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (TOU A-2 EV)								
Customer Charge	$ 87.56	$ 0.00353		3,048	$ 266,883			$ 266,883
Wildfire Charge	$ -			3,048	-			-
Winter Energy - On-Peak		$ 0.48674	$ 0.08431	9,625,053	33,955	4,684,855	811,532	5,530,343
Winter Energy - Mid-Peak		$ 0.15250	$ 0.00731	20,337,980	71,749	3,101,558	148,623	3,321,930
Winter Energy - Off-Peak		$ 0.02622	$ 0.01469	16,125,359	56,887	422,830	236,862	716,579
Summer Energy - OnPeak		$ -	$ 0.00932	11,742,244	41,424	-	109,453	150,878
Summer Energy - Off-Peak		$ -	$ 0.01243	10,410,500	36,726	-	129,397	166,124
Winter Demand - On-Peak		$ -	$ -	1,441		-	-	-
Winter Demand - Mid-Peak		$ -	$ -	1,522		-	-	-
Summer Demand - OnPeak		$ -	$ -	1,359		-	-	-
Non-TOU Maximum		$ -	$ -	2,165		-	-	-
Revenue at Proposed Rates					$ 507,625	$ 8,209,244	$ 1,435,867	$ 10,152,736

Liberty Utilities (CalPeco Electric)
A-2 Class Rate Design

A-2 Class Rate Design Current Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Current Rates								
Customer Charge	$ 43.78			3,041	$ 133,135			$ 133,135
Winter Energy		$ 0.05022	$ -	48,589,535		2,440,166	-	2,440,166
Summer Energy		$ -	$ 0.04261	20,801,324		-	886,344	886,344
Winter Demand		$ 12.97	$ -	319,673		4,146,156	-	4,146,156
Summer Demand		$ -	$ 8.43	147,539		-	1,243,754	1,243,754
Power Factor				0.00561%	$ 7	$ 369	$ 119	496
V/T Discount				-0.00539%	$ (7)	$ (355)	$ (115)	(477)
Current Rates (A-2 TOU)								
Customer Charge	$ 139.16				$ -			$ -
Winter Energy - On-Peak		$ 0.05022	$ -			-	-	-
Winter Energy - Mid-Peak		$ 0.05022	$ -			-	-	-
Winter Energy - Off-Peak		$ 0.05022	$ -			-	-	-
Summer Energy - OnPeak		$ -	$ 0.04261			-	-	-
Summer Energy - Off-Peak		$ -	$ 0.04261			-	-	-
Winter Demand - On-Peak		$ 12.97	$ -			-	-	-
Winter Demand - Mid-Peak		$ 12.97	$ -			-	-	-
Summer Demand - OnPeak		$ -	$ 8.43			-	-	-
Non-TOU Maximum		$ -	$ -			-	-	-
Revenue at Current Rates				69,390,859	$ 133,135	$ 6,586,337	$ 2,130,103	$ 8,849,575

Liberty Utilities (CalPeco Electric)
A-2 Class Rate Design

A-2 Class Rate Design

Bill Impact Analysis Total Charges	Month Usage	Average Demand	Proposed Bill	Current Bill	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
50% Below Avg. Usage	11,161	67	$ 3,294	$ 2,418	$ 876	36.2%
25% Below Avg. Usage	16,742	71	$ 4,455	$ 3,231	$ 1,223	37.9%
Average Usage	22,323	75	$ 5,597	$ 4,029	$ 1,568	38.9%
25% Above Avg. Usage	27,903	85	$ 6,838	$ 4,910	$ 1,928	39.3%
50% Above Avg. Usage	33,484	93	$ 8,057	$ 5,773	$ 2,284	39.6%
Summer Season						
50% Below Avg. Usage	11,134	67	$ 2,514	$ 2,343	$ 171	7.3%
25% Below Avg. Usage	16,701	73	$ 3,727	$ 3,265	$ 462	14.2%
Average Usage	22,268	74	$ 4,940	$ 4,138	$ 803	19.4%
25% Above Avg. Usage	27,835	84	$ 6,153	$ 5,098	$ 1,055	20.7%
50% Above Avg. Usage	33,402	93	$ 7,366	$ 6,038	$ 1,329	22.0%

Liberty Utilities (CalPeco Electric)
A-3 Class Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	23,191,559	$ 10,703,363	$ 33,894,921
Current Base Rates	14,550,924	$ 11,128,658	$ 25,679,582
$ Difference	8,640,635	(425,295)	8,215,340
% Difference	59.4%		32.0%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ -	636	$ -

A-3 Class Rate Design Proposed Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (A-3)								
Customer Charge	$ 1,035.88	$ 0.00252		636	$ 658,820			$ 658,820
Wildfire Charge	$ -			636	-			-
Winter Energy - On-Peak		$ 0.06255	$ -	17,245,812	43,473	1,078,697	-	1,122,170
Winter Energy - Mid-Peak		$ 0.05184	$ -	34,278,478	86,408	1,776,849	-	1,863,257
Winter Energy - Off-Peak		$ 0.02416	$ -	32,556,978	82,069	786,540	-	868,609
Summer Energy - OnPeak		$ -	$ -	16,441,052	41,444	1,381,009	-	1,422,453
Summer Energy - Off-Peak		$ 0.03811	$ -	14,679,055	37,003	559,466	-	596,468
Winter Demand - On-Peak		$ 13.44	$ 1.61	360,936		4,850,284	581,807	5,432,090
Winter Demand - Mid-Peak		$ 4.11	$ 1.15	424,779		1,746,219	487,518	2,233,737
Summer Demand - OnPeak		$ 6.30	$ 11.58	117,999		743,637	1,366,262	2,109,899
Non-TOU Maximum		$ 14.37	$ -	463,582		6,660,741	-	6,660,741
Power Factor				0.03612%	343	7,074	880	8,296
V/T Discount				-0.37120%	(3,523)	(72,694)	(9,041)	(85,258)
Revenue at Proposed Rates				115,201,374	$ 946,035	**$ 19,517,822**	**$ 2,427,425**	$ 22,891,282

Liberty Utilities (CalPeco Electric)
A-3 Class Rate Design

A-3 Class Rate Design Proposed Rates (TOU A-3 EV)	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (TOU A-3 EV)								
Customer Charge	$ 1,035.88	$ 0.00252		636	$ 658,820			$ 658,820
Wildfire Charge	$ -			636	-			-
Winter Energy - On-Peak		$ 0.54160	$ 0.03374	17,245,812	43,473	9,340,266	581,807	9,965,545
Winter Energy - Mid-Peak		$ 0.16191	$ 0.01422	34,278,478	86,408	5,550,092	487,518	6,124,018
Winter Energy - Off-Peak		$ 0.02416	$ -	32,556,978	82,069	786,540	-	868,609
Summer Energy - OnPeak		$ 0.20358	$ 0.08310	16,441,052	41,444	3,347,078	1,366,262	4,754,784
Summer Energy - Off-Peak		$ 0.03811	$ -	14,679,055	37,003	559,466	-	596,468
Winter Demand - On-Peak		$ -	$ -	360,936		-	-	-
Winter Demand - Mid-Peak		$ -	$ -	424,779		-	-	-
Summer Demand - OnPeak		$ -	$ -	117,999		-	-	-
Non-TOU Maximum		$ -	$ -	463,582		-	-	-
Power Factor				0.03612%	343	7,074	880	8,296
V/T Discount				-0.37120%	(3,523)	(72,694)	(9,041)	(85,258)
Revenue at Proposed Rates				115,201,374	$ 946,035	$ 19,517,822	$ 2,427,425	$ 22,891,282

Liberty Utilities (CalPeco Electric)
A-3 Class Rate Design

A-3 Class Rate Design Current Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Current Rates (A-3)								
Customer Charge	$ 517.94			667	$ 345,466			$ 345,466
Winter Energy - On-Peak		$ 0.03231	$ -	19,150,142		618,741	-	618,741
Winter Energy - Mid-Peak		$ 0.02760	$ -	36,927,575		1,019,201	-	1,019,201
Winter Energy - Off-Peak		$ 0.01456	$ -	30,986,254		451,160	-	451,160
Summer Energy - OnPeak		$ 0.04279	$ -	18,512,444		792,147	-	792,147
Summer Energy - Off-Peak		$ 0.02312	$ -	13,880,177		320,910	-	320,910
Winter Demand - On-Peak		$ 7.17	$ 1.86	388,023		2,782,125	721,723	3,503,847
Winter Demand - Mid-Peak		$ 2.12	$ 1.28	472,468		1,001,632	604,759	1,606,391
Summer Demand - OnPeak		$ 3.00	$ 11.92	142,184		426,551	1,694,828	2,121,379
Non-TOU Maximum		$ 5.82	$ -	656,461		3,820,604	-	3,820,604
Power Factor				0.03612%	125	4,057	1,091	5,273
V/T Discount				-0.37120%	(1,282)	(41,697)	(11,215)	(54,195)
Revenue at Current Rates				119,456,592	$ 344,308	$ 11,195,430	$ 3,011,186	$ 14,550,924

Liberty Utilities (CalPeco Electric)
A-3 Class Rate Design

A-3 Class Rate Design

Bill Impact Analysis Total Charges	Month Usage	Average Demand	Proposed Bill	Current Bill	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
50% Below Avg. Usage	97,898	1,506	$ 14,543	$ 12,034	$ 2,510	20.9%
25% Below Avg. Usage	146,847	2,258	$ 21,297	$ 17,791	$ 3,506	19.7%
Average Usage	195,796	3,011	$ 28,051	$ 23,549	$ 4,502	19.1%
25% Above Avg. Usage	244,745	3,764	$ 34,805	$ 29,307	$ 5,498	18.8%
50% Above Avg. Usage	293,694	4,517	$ 41,559	$ 35,065	$ 6,494	18.5%
Summer Season						
50% Below Avg. Usage	72,847	720	$ 8,919	$ 9,715	$ (795)	-8.2%
25% Below Avg. Usage	109,270	1,080	$ 12,861	$ 14,313	$ (1,452)	-10.1%
Average Usage	145,694	1,440	$ 16,803	$ 18,912	$ (2,109)	-11.2%
25% Above Avg. Usage	182,117	1,800	$ 20,745	$ 23,510	$ (2,766)	-11.8%
50% Above Avg. Usage	218,541	2,160	$ 24,686	$ 28,109	$ (3,422)	-12.2%

Liberty Utilities (CalPeco Electric)
PA Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	48,186	$ 68,964	$ 117,150
Current Base Rates	48,137	$ 82,775	$ 130,912
$ Difference	49	(13,811)	(13,762)
% Difference	0.1%		-10.5%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ -	119	$ -

PA Rate Design	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates								
Customer Charge	$ 48.20			119	$ 5,735			$ 5,735
Widlfire Charge	$ -			119	-			-
Energy		$ 0.00849	$ 0.04710	741,788		6,297	34,939	41,235
Revenue at Proposed Rates				741,788	$ 5,735	$ 6,297	$ 34,939	$ 46,971
		-						
Current Rates								
Customer Charge	$ 17.38			229				$ -
Energy		$ 0.02753	$ 0.02637	819,233		22,553	21,603	44,157
Revenue at Current Rates				819,233	$ -	$ 22,553	$ 21,603	$ 44,157
								(3,980)

Bill Impact Analysis Total Charges	Month Usage	Proposed Bill	Current Bill	Increase / (Decrease) $	Increase / (Decrease) %
50% Below Avg. Usage	2,979	$ 491	$ 479	$ 12	2.5%
25% Below Avg. Usage	4,469	$ 712	$ 710	$ 2	0.3%
Average Bill	5,959	$ 933	$ 941	$ (7)	-0.8%
25% Above Avg. Usage	7,448	$ 1,155	$ 1,171	$ (17)	-1.4%
50% Above Avg. Usage	8,938	$ 1,376	$ 1,402	$ (26)	-1.9%

Liberty Utilities (CalPeco Electric)
HPS Outdoor Lights Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	274,333	$ 35,279	$ 309,612
Current Base Rates	173,851	$ 40,970	$ 214,821
$ Difference	100,482	(5,691)	94,791
% Difference	57.8%		44.1%

HPS Outdoor Lights Rate Design	Distribution Rate	Generation Rate	Billing Determinants	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (OLS)						
Existing, Overhead Pole Rates by Lumen						
5,800 Lumen Light @ 29 kWh/mo.	$ 17.02	$ 0.53	6,266	106,640	3,323	109,963
9,500 Lumen Light @ 41 kWh/mo.	17.20	0.91	6,220	106,973	5,681	112,654
16,000 Lumen Light @ 67 kWh/mo.	17.81	1.36	2,255	40,158	3,070	43,228
22,000 Lumen Light @ 85 kWh/mo.	18.39	1.51	91	1,668	137	1,806
These Poles/Service add to the Existing Pole Rate (above)						
New Wood Pole	$ 12.31	$ 1.00	74	912	74	986
New Metal Pole (< 22,000 lumens)	16.26	-	111	1,807	-	1,807
New Metal Pole (=> 22,000 lumens)	17.26	-	-	-	-	-
Underground Service	8.32	-	111	924	-	924
Revenue at Proposed Rates			14,832	$ 259,082	$ 12,211	$ 271,367
Current Rates (OLS)						
Existing, Overhead Pole Rates by Lumen						
5,800 Lumen Light @ 29 kWh/mo.	$ 10.41	$ 0.10	6,781	70,567	656	71,222
9,500 Lumen Light @ 41 kWh/mo.	10.68	0.17	6,625	70,787	1,121	71,908
16,000 Lumen Light @ 67 kWh/mo.	11.13	0.25	2,387	26,573	606	27,179
22,000 Lumen Light @ 85 kWh/mo.	11.83	0.29	93	1,104	27	1,131
These Poles/Service add to the Existing Pole Rate (above)						
New Wood Pole	$ 8.16		74	604	-	604
New Metal Pole (< 22,000 lumens)	10.77		111	1,196	-	1,196
New Metal Pole (=> 22,000 lumens)	11.44		-	-	-	-
Underground Service	5.51		111	611	-	611
Revenue at Current Rates			15,887	$ 171,441	$ 2,410	$ 173,851

Liberty Utilities (CalPeco Electric)
HPS Street Lights Rate Design

Base Revenues	Base Rates		Other Charges		Total Rates
Target Base Rates	177,107	$	20,709	$	197,816
Current Base Rates	90,506	$	24,660	$	115,166
$ Difference	86,601		(3,951)		82,650
% Difference	95.7%				71.8%

HPS Street Lights Rate Design		Distribution Rate		Generation Rate	Billing Determinants		Distribution Revenues		Generation Revenues		Total Revenues
Proposed Rates (SL)											
Existing, Overhead Pole Rates by Lumen											
5,800 Lumen Light @ 29 kWh/mo.	$	27.35	$	0.49	747		20,438		367		20,806
9,500 Lumen Light @ 41 kWh/mo.	$	27.21	$	0.81	1,009		27,456		820		28,276
22,000 Lumen Light @ 79 kWh/mo.	$	33.20	$	1.74	3,608		119,784		6,289		126,072
These Poles/Service add to the Existing Pole Rate (above)											
New Wood Pole	$	15.86									
New Metal Pole (< 22,000 lumens)	$	21.85									
New Metal Pole (=> 22,000 lumens)	$	22.21									
Underground Service total	$	10.74									
Total, poles					5,729						
Underground Service					2,830						
Revenue at Proposed Rates					5,364	$	167,678	$	7,476	$	175,154
Current Rates (SL)											
Existing, Overhead Pole Rates by Lumen											
5,800 Lumen Light @ 29 kWh/mo.	$	15.73	$	0.07	693		10,909		50		10,958
9,500 Lumen Light @ 41 kWh/mo.		15.78		0.12	929		14,654		111		14,765
22,000 Lumen Light @ 79 kWh/mo.		17.06		0.23	3,748		63,933		850		64,783
These Poles/Service add to the Existing Pole Rate (above)											
New Wood Pole	$	8.47									
New Metal Pole (< 22,000 lumens)		11.66									
New Metal Pole (=> 22,000 lumens)		11.85									
Underground Service total		5.73									
Total, poles					5,729						
Underground Service					2,830						
Revenue at Current Rates					5,370	$	89,495	$	1,011	$	90,506

Liberty Utilities (CalPeco Electric)
Marginal Cost of Service Allocation

Marginal Cost of Service Class Allocation	Total Company	Residential Permanent	Residential Non-Permanent	S-M Master Residential	Small Commercial	Medium Commercial	Large Commercial	Irrigation	OLS	Street Lighting
Marginal Generation (Capacity)	$ 12,048,781	$ 2,798,585	$ 3,298,699	$ 81,571	$ 2,075,830	$ 1,417,089	$ 2,348,938	$ 12,184	$ 10,022	$ 5,863
Marginal Generation (Energy)	13,999,503	3,322,112	3,790,607	93,683	2,350,432	1,616,992	2,781,947	16,291	17,319	10,122
Marginal Distribution (TOU)	64,703,661	15,207,524	19,797,109	233,367	8,657,607	6,138,152	14,598,166	1,816	44,057	25,862
Marginal Distribution (Non-TOU)										
Marginal Customer (Common)	3,865,422	1,061,615	1,542,838	57,306	534,659	129,844	535,689	996	-	2,475
Marginal Customer (Specific)	5,012,708	1,070,687	2,563,705	232,585	581,612	216,596	110,151	514	147,142	89,715
Total Marginal Costs	**99,630,075**	**23,460,523**	**30,992,957**	**698,513**	**14,200,141**	**9,518,674**	**20,374,891**	**31,800**	**218,540**	**134,036**
Total Marginal Costs %	**100.00%**	**23.55%**	**31.11%**	**0.70%**	**14.25%**	**9.55%**	**20.45%**	**0.03%**	**0.22%**	**0.13%**
MCOS (Generation)	$ 26,048,284	$ 6,120,696	$ 7,089,305	$ 175,254	$ 4,426,262	$ 3,034,082	$ 5,130,885	$ 28,475	$ 27,340	$ 15,985
Generation Allocator	100.00%	23.50%	27.22%	0.67%	16.99%	11.65%	19.70%	0.11%	0.10%	0.06%
MCOS (Distribution-Demand)	$ 64,703,661	$ 15,207,524	$ 19,797,109	$ 233,367	$ 8,657,607	$ 6,138,152	$ 14,598,166	$ 1,816	$ 44,057	$ 25,862
Distribution-Demand Allocator	100.00%	23.50%	30.60%	0.36%	13.38%	9.49%	22.56%	0.00%	0.07%	0.04%
MCOS (Distribution-Customer)	$ 8,878,130	$ 2,132,303	$ 4,106,543	$ 289,891	$ 1,116,271	$ 346,441	$ 645,840	$ 1,510	$ 147,142	$ 92,189
Distribution-Customer Allocator	100.00%	24.02%	46.25%	3.27%	12.57%	3.90%	7.27%	0.02%	1.66%	1.04%

Liberty Utilities (CalPeco Electric)
Marginal Cost of Service Allocation

Marginal Generation (Capacity)

Generation Marginal Costs ($/kW) $ 84.16
At Generation Level

	Total Company	Residential Permanent	Residential Non-Permanent	S-M Master Residential	Small Commercial	Medium Commercial	Large Commercial	Irrigation	OLS	Street Lighting
Class Contribution to System Peak	**128,760**	31,415	41,515	484	16,794	12,230	26,117	8	124	73
Loss Factor Adjustment		1.06	1.06	1.06	1.06	1.06	1.02	1.06	1.06	1.06
Total Generation Costs ($)	**$ 12,048,781**	**$ 2,798,585**	**$ 3,298,699**	**$ 81,571**	**$ 2,075,830**	**$ 1,417,089**	**$ 2,348,938**	**$ 12,184**	**$ 10,022**	**$ 5,863**

Marginal Generation (Energy)

Generation Marginal Energy Costs	**2021-2025 (IRP)**
Winter TOU - Peak	$ 31.51
Winter TOU - Mid-Peak	$ 15.66
Winter TOU - Off-Peak	$ 31.57
Summer TOU - Peak	$ 19.30
Summer TOU - Off-Peak	$ 25.70

Generation Cost Allocation	Total Company	Residential Permanent	Residential Non-Permanent	S-M Master Residential	Small Commercial	Medium Commercial	Large Commercial	Irrigation	OLS	Street Lighting
Total Usage (MWh)										
Winter TOU - Peak	93,116	27,203	26,719	710	14,029	9,449	14,800	20	118	68
Winter TOU - Mid-Peak	177,283	42,889	46,722	1,180	30,006	20,055	36,391	37	1	1
Winter TOU - Off-Peak	144,441	30,817	39,303	924	22,831	15,855	34,234	38	277	161
Summer TOU - Peak	90,900	21,264	25,065	610	17,268	11,985	14,354	297	36	21
Summer TOU - Off-Peak	76,880	15,963	19,173	463	14,964	10,640	15,102	316	162	96
Total Usage (MWh)	**582,620**	**138,136**	**156,982**	**3,887**	**99,099**	**67,984**	**114,881**	**709**	**593**	**347**
Generation Cost Allocation ($)										
Winter TOU - Peak	$ 2,933,949	$ 857,124	$ 841,860	$ 22,378	$ 442,043	$ 297,732	$ 466,311	$ 641	$ 3,707	$ 2,155
Winter TOU - Mid-Peak	2,776,124	671,617	731,640	18,483	469,873	314,050	569,859	577	16	10
Winter TOU - Off-Peak	4,559,568	972,805	1,240,685	29,154	720,717	500,505	1,080,676	1,204	8,739	5,084
Summer TOU - Peak	1,754,185	410,355	483,701	11,776	333,239	231,282	276,997	5,739	689	409
Summer TOU - Off-Peak	1,975,677	410,211	492,721	11,893	384,560	273,425	388,104	8,131	4,168	2,464
Total Generation Energy ($)	**$ 13,999,503**	**$ 3,322,112**	**$ 3,790,607**	**$ 93,683**	**$ 2,350,432**	**$ 1,616,992**	**$ 2,781,947**	**$ 16,291**	**$ 17,319**	**$ 10,122**

Liberty Utilities (CalPeco Electric)
Marginal Cost of Service Allocation

Marginal Distribution (TOU)

	Substation	Non-Revenue	Weighted Cost	Total (No Weighting)
Distribution Marginal Costs ($/kW)	$ 104.61	$ 512.25	$ 360.74	$ 616.86
TOU Demand Percentage	100%	50%		

Distribution Marginal Costs (TOU)	**Top 100 Hours %**	TOU Allocation	**TOU Allocation**
Winter TOU - Peak	57.6%	$ 207.79	$ 355.31
Winter TOU - Mid-Peak	37.8%	$ 136.36	$ 233.17
Winter TOU - Off-Peak	4.6%	$ 16.59	$ 28.38
Summer TOU - Peak	0.0%	$ -	$ -
Summer TOU - Off-Peak	0.0%	$ -	$ -

Average Class Contribution to Top 100 Load Hours, by TOU Period (kW)										
Winter TOU - Peak	106,916	27,295	33,471	402	13,670	9,859	22,034	4	115	67
Winter TOU - Mid-Peak	102,159	21,048	30,394	348	14,729	9,946	25,690	2	1	1
Winter TOU - Off-Peak	101,991	21,192	28,797	335	12,900	11,142	27,448	6	109	64
Summer TOU - Peak	-	-	-	-	-	-	-	-	-	-
Summer TOU - Off-Peak	-	-	-	-	-	-	-	-	-	-
Total Usage (MWh)	**311,066**	**69,535**	**92,662**	**1,084**	**41,299**	**30,946**	**75,172**	**11**	**225**	**132**
Distribution Cost Allocation ($)										
Winter TOU - Peak	$ 37,988,822	$ 9,698,412	$ 11,892,846	$ 142,749	$ 4,857,079	$ 3,502,924	$ 7,828,965	$ 1,265	$ 40,695	$ 23,888
Winter TOU - Mid-Peak	23,820,760	$ 4,907,782	$ 7,087,130	$ 81,118	$ 3,434,492	$ 2,319,073	$ 5,990,347	$ 388	$ 269	$ 159
Winter TOU - Off-Peak	2,894,079	$ 601,330	$ 817,133	$ 9,499	$ 366,037	$ 316,155	$ 778,854	$ 163	$ 3,093	$ 1,815
Summer TOU - Peak	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Summer TOU - Off-Peak	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dist. Costs (TOU) ($)	**$ 64,703,661**	**$ 15,207,524**	**$ 19,797,109**	**$ 233,367**	**$ 8,657,607**	**$ 6,138,152**	**$ 14,598,166**	**$ 1,816**	**$ 44,057**	**$ 25,862**

Liberty Utilities (CalPeco Electric)
Determination of Revenue Targets (Excluding ECAC, VM, CEMA)

Revenue Targets	Total Company	
Revenue Requirements (Generation)	$ 12,112,859	
Revenue Requirements (Distribution - Demand)	$ 85,030,715	*Demand-related Distribution Revenue Requirement*
Revenue Requirements (Distribution - Customer)	$ 12,782,549	*Meters, Services & Transformers-related Revenue Requirement*
Revenue Requirements (Other)	$ 1,443,214	
Revenue Requirements (Wildfire Management)	$ 30,702,000	*These are also included in the DDC Revenue Requirements in cell B9*

Allocation of Wildfire Management Costs

Revenue Targets	Total Company	Residential Permanent	Residential Non-Permanent	Small Commercial	Medium Commercial	Large Commercial	Irrigation	OLS	Street Lighting
Distribution - Demand	$ 64,703,661	$ 15,308,908	$ 19,929,092	$ 8,657,607	$ 6,138,152	$ 14,598,166	$ 1,816	$ 44,057	$ 25,862
Allocation %	100.0%	23.7%	30.8%	13.4%	9.5%	22.6%	0.0%	0.1%	0.0%
Revenue Requirements (Wildfire Management)	$ 30,702,000	$ 7,264,104	$ 9,456,389	$ 4,108,050	$ 2,912,564	$ 6,926,855	$ 862	$ 20,905	$ 12,272

Step 1: Equal Percentage of the Marginal Cost (EPMC) Allocation

Revenue Targets	Total Company	Residential Permanent	Residential Non-Permanent	Small Commercial	Medium Commercial	Large Commercial	Irrigation	OLS	Street Lighting
Marginal Cost of Service (Generation)	$ 26,048,284	$ 6,201,898	$ 7,183,358	$ 4,426,262	$ 3,034,082	$ 5,130,885	$ 28,475	$ 27,340	$ 15,985
Allocation %	100.0%	23.8%	27.6%	17.0%	11.6%	19.7%	0.1%	0.1%	0.1%
Generation Revenues (Reconciled)	$ 12,112,859	$ 2,883,979	$ 3,340,373	$ 2,058,281	$ 1,410,895	$ 2,385,941	$ 13,241	$ 12,714	$ 7,433
Marginal Cost of Service (Distribution-Dem)	$ 64,703,661	$ 15,308,908	$ 19,929,092	$ 8,657,607	$ 6,138,152	$ 14,598,166	$ 1,816	$ 44,057	$ 25,862
Allocation %	100.0%	23.7%	30.8%	13.4%	9.5%	22.6%	0.0%	0.1%	0.0%
Dist. Demand Revenues (Reconciled)	$ 85,030,715	$ 20,118,296	$ 26,189,939	$ 11,377,448	$ 8,066,490	$ 19,184,270	$ 2,386	$ 57,898	$ 33,987
Marginal Cost of Service (Distribution-Cust)	$ 8,878,130	$ 2,231,382	$ 4,297,355	$ 1,116,271	$ 346,441	$ 645,840	$ 1,510	$ 147,142	$ 92,189
Allocation %	100.0%	25.1%	48.4%	12.6%	3.9%	7.3%	0.0%	1.7%	1.0%
Dist. Customer Revenues (Reconciled)	$ 12,782,549	$ 3,212,697	$ 6,187,243	$ 1,607,184	$ 498,798	$ 929,868	$ 2,174	$ 211,852	$ 132,733
Marginal Cost of Service	$ 99,630,075	$ 23,761,467	$ 31,390,526	$ 14,200,141	$ 9,518,674	$ 20,374,891	$ 31,800	$ 218,540	$ 134,036
Allocation %	100.0%	23.8%	31.5%	14.3%	9.6%	20.5%	0.0%	0.2%	0.1%
Other Revenues (Reconciled)	$ 1,443,214	$ 344,202	$ 454,714	$ 205,699	$ 137,885	$ 295,145	$ 461	$ 3,166	$ 1,942
Revenue Requirements (Reconciled)	**$ 111,369,336**	**$ 26,559,175**	**$ 36,172,270**	**$ 15,248,613**	**$ 10,114,068**	**$ 22,795,224**	**$ 18,262**	**$ 285,630**	**$ 176,094**
Other Operating Revenue Credit Allocation %	100.0%	43.1%	49.7%	6.6%	0.4%	0.0%	0.0%	0.1%	0.1%
Other Operating Revenue (OOR) Credit $	$ 1,443,214	$ 622,568	$ 716,989	$ 95,064	$ 5,684	$ 202	$ 26	$ 1,059	$ 1,621
Target Base Revenues (After OOR Credit)	**$ 109,926,122**	**$ 25,936,607**	**$ 35,455,281**	**$ 15,153,549**	**$ 10,108,384**	**$ 22,795,022**	**$ 18,236**	**$ 284,571**	**$ 174,473**
Current Authorized Revenues (2021)	**$ 69,717,808**	**$ 15,564,453**	**$ 17,925,019**	**$ 12,515,344**	**$ 8,849,575**	**$ 14,550,924**	**$ 48,137**	**$ 173,851**	**$ 90,506**
Class Revenue Increase (Step 1)	$ 40,208,313	$ 10,372,154	$ 17,530,262	$ 2,638,205	$ 1,258,808	$ 8,244,098	$ (29,901)	$ 110,720	$ 83,967
Class Revenue Increase (Step 1) %	57.7%	66.6%	97.8%	21.1%	14.2%	56.7%	-62.1%	63.7%	92.8%

Liberty Utilities (CalPeco Electric)
Determination of Revenue Targets (Excluding ECAC, VM, CEMA)

Revenue Targets	Total Company	Residential Permanent	Residential Non-Permanent	Small Commercial	Medium Commercial	Large Commercial	Irrigation	OLS	Street Lighting
Step 2: Cap Mechanism									
Class Revenues subjected to cap	$ 24,815,048	$ 24,540,932						$ 274,116	
Revenue to be re-allocated	$ 1,406,130	$ 1,395,675						$ 10,455	
MCOS Allocation % Remaining Classes	100.0%		41.5%	18.8%	12.6%	26.9%	0.0%		0.2%
Class share of re-allocated Revenue	$ 1,406,130		$ 583,465	$ 263,942	$ 176,926	$ 378,714	$ 591		$ 2,491
Class Revenue Target (Step 2)	$ 109,926,122	$ 24,540,932	$ 36,038,746	$ 15,417,491	$ 10,285,310	$ 23,173,736	$ 18,827	$ 274,116	$ 176,964
Class Revenue Increase (Step 2)	$ 40,208,313	$ 8,976,479	$ 18,113,727	$ 2,902,147	$ 1,435,735	$ 8,622,812	$ (29,310)	$ 100,265	$ 86,458
Class Revenue Increase (Step 2) %	57.7%	57.7%	101.1%	23.2%	16.2%	59.3%	-60.9%	57.7%	95.5%
Step 3: No Class gets revenue decrease									
Class Revenues subjected to condition	$ 18,827						$ 18,827		
Increase to Current Revenues	$ 48,137						$ 48,137		
Revenue Increase to be re-allocated	$ (29,310)						$ (29,310)		
MCOS Allocation % Remaining Classes	100.0%	23.9%	31.5%	14.3%	9.6%	20.5%		0.2%	0.1%
Class share of re-allocated Revenue Increase	$ (29,310)	$ (6,992)	$ (9,238)	$ (4,179)	$ (2,801)	$ (5,996)		$ (64)	$ (39)
Class Revenue Target (Step 3)	**$ 109,926,122**	**$ 24,533,939**	**$ 36,029,508**	**$ 15,413,312**	**$ 10,282,509**	**$ 23,167,740**	**$ 48,137**	**$ 274,052**	**$ 176,925**
Class Revenue Increase (Step 3)	$ 40,208,313	$ 8,969,486	$ 18,104,490	$ 2,897,969	$ 1,432,934	$ 8,616,816	$ -	$ 100,201	$ 86,419
Class Revenue Increase (Step 3) %	57.7%	57.6%	101.0%	23.2%	16.2%	59.2%	0.0%	57.6%	95.5%
Class Revenue Allocation %	100.0%	22.3%	32.8%	14.0%	9.4%	21.1%	0.0%	0.2%	0.2%
Wildfire Management Related	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

Liberty Utilities (CalPeco Electric)
Determination of Revenue Targets (Excluding ECAC, VM, CEMA)

Revenue Targets	Total Company	Residential Permanent	Residential Non-Permanent	Small Commercial	Medium Commercial	Large Commercial	Irrigation	OLS	Street Lighting
Allocation of Other Discounts/ Charges (Matrix_Solution)									
Class Revenue Targets (Proposed)	**$ 110,039,138**	**$ 24,559,163**	**$ 36,066,551**	**$ 15,429,159**	**$ 10,293,080**	**$ 23,191,559**	**$ 48,186**	**$ 274,333**	**$ 177,107**
Class Revenue Increase	$ 40,321,329	$ 8,994,710	$ 18,141,532	$ 2,913,815	$ 1,443,505	$ 8,640,635	$ 49	$ 100,482	$ 86,601
Class Revenue Increase %	57.8%	57.8%	101.2%	23.3%	16.3%	59.4%	0.1%	57.8%	95.7%
After Allocation of Other Discounts / Charges									
Other Discounts / Charges Allocation	$ 113,016	$ 25,224	$ 37,042	$ 15,847	$ 10,572	$ 23,819	$ 49	$ 282	$ 182
Other Discounts / Charges Allocation %	100.0%	22.3%	32.8%	14.0%	9.4%	21.1%	0.0%	0.2%	0.2%
Equal Allocation of Adjustments to Revenue Components									
Revenue Requirements (Reconciled)	**$ 111,369,336**	**$ 26,559,175**	**$ 36,172,270**	**$ 15,248,613**	**$ 10,114,068**	**$ 22,795,224**	**$ 18,262**	**$ 285,630**	**$ 176,094**
Class Revenue Targets (Proposed)	**$ 110,039,138**	**$ 24,559,163**	**$ 36,066,551**	**$ 15,429,159**	**$ 10,293,080**	**$ 23,191,559**	**$ 48,186**	**$ 274,333**	**$ 177,107**
Class Revenue Change (Cumulative)	$ (1,330,198)	$ (2,000,012)	$ (105,720)	$ 180,546	$ 179,012	$ 396,335	$ 29,924	$ (11,296)	$ 1,013
Class Revenue Change %	-1.2%	-7.5%	-0.3%	1.2%	1.8%	1.7%	163.9%	-4.0%	0.6%
Generation Revenues (Reconciled)	$ 12,112,859	$ 2,883,979	$ 3,340,373	$ 2,058,281	$ 1,410,895	$ 2,385,941	$ 13,241	$ 12,714	$ 7,433
Generation Revenues (Proposed)	$ 11,997,984	$ 2,666,804	$ 3,330,611	$ 2,082,651	$ 1,435,867	$ 2,427,425	$ 34,939	$ 12,211	$ 7,476
Dist. Demand Revenues (Reconciled)	$ 85,030,715	$ 20,118,296	$ 26,189,939	$ 11,377,448	$ 8,066,490	$ 19,184,270	$ 2,386	$ 57,898	$ 33,987
Dist. Demand Revenues (Proposed)	$ 84,052,032	$ 18,603,308	$ 26,113,394	$ 11,512,159	$ 8,209,262	$ 19,517,822	$ 6,297	$ 55,608	$ 34,182
Dist. Customer Revenues (Reconciled)	$ 12,782,549	$ 3,212,697	$ 6,187,243	$ 1,607,184	$ 498,798	$ 929,868	$ 2,174	$ 211,852	$ 132,733
Dist. Customer Revenues (Proposed)	$ 12,562,508	$ 2,970,768	$ 6,169,160	$ 1,626,214	$ 507,626	$ 946,035	$ 5,735	$ 203,474	$ 133,496
Other Revenues (Reconciled)	$ 1,443,214	$ 344,202	$ 454,714	$ 205,699	$ 137,885	$ 295,145	$ 461	$ 3,166	$ 1,942
Other Revenues (Proposed)	$ 1,426,613	$ 318,282	$ 453,385	$ 208,135	$ 140,325	$ 300,277	$ 1,215	$ 3,041	$ 1,953
Summary Metrics									
Class kWh Usage	$ 582,620,318	$ 139,955,771	$ 159,050,137	$ 99,099,282	$ 67,984,366	$ 114,881,147	$ 709,079	$ 593,401	$ 347,134
Marginal Cost of Service (Generation)	$ 26,048,284	$ 6,201,898	$ 7,183,358	$ 4,426,262	$ 3,034,082	$ 5,130,885	$ 28,475	$ 27,340	$ 15,985
$ per kWh	$ 0.0447	$ 0.0443	$ 0.0452	$ 0.0447	$ 0.0446	$ 0.0447	$ 0.0402	$ 0.0461	$ 0.0460
Marginal Cost of Service (Distribution)	$ 73,581,791	$ 17,540,290	$ 24,226,447	$ 9,773,879	$ 6,484,592	$ 15,244,007	$ 3,326	$ 191,199	$ 118,051
$ per kWh	$ 0.1263	$ 0.1253	$ 0.1523	$ 0.0986	$ 0.0954	$ 0.1327	$ 0.0047	$ 0.3222	$ 0.3401
Marginal Cost of Service (Generation + Dist.)	$ 99,630,075	$ 23,742,188	$ 31,409,805	$ 14,200,141	$ 9,518,674	$ 20,374,891	$ 31,800	$ 218,540	$ 134,036
$ per kWh	$ 0.1710	$ 0.1696	$ 0.1975	$ 0.1433	$ 0.1400	$ 0.1774	$ 0.0448	$ 0.3683	$ 0.3861
Current Revenues	$ 69,717,808	$ 15,564,453	$ 17,925,019	$ 12,515,344	$ 8,849,575	$ 14,550,924	$ 48,137	$ 173,851	$ 90,506
$ per kWh	$ 0.1197	$ 0.1112	$ 0.1127	$ 0.1263	$ 0.1302	$ 0.1267	$ 0.0679	$ 0.2930	$ 0.2607
Proposed Revenues	$ 110,039,138	$ 24,559,163	$ 36,066,551	$ 15,429,159	$ 10,293,080	$ 23,191,559	$ 48,186	$ 274,333	$ 177,107
$ per kWh	$ 0.1889	$ 0.1755	$ 0.2268	$ 0.1557	$ 0.1514	$ 0.2019	$ 0.0680	$ 0.4623	$ 0.5102

Liberty Utilities (CalPeco Electric)
Derivation of Marginal Cost of Generation Capacity (Peaker Deferral Method)

PG&E Adopted MGCC pre-tax	$	68.56
Post-Tax	$	76.35
Tax Adder	$	7.79
PG&E Property Tax Rate		1.25%
Liberty Property Tax		0.64%
Liberty Tax Adder	$	3.99
Total MGCC, without PRM	$	72.55
NV Power PRM		16%
Total MGCC, with PRM	$	84.16

PRM is from:
NV Power, Testimony of John McGinley, PUCN Docket # 21-060-01,
(June 1, 2021, Volume 2), p. 4.
This is based on the fact that Liberty's resource adequacy obligations are assigned
by the NV Energy North System BAA.
Source: Liberty 2020 IRP (September 1, 2020), R.20-05-003, p. 23.

Tax Adder & PG&E Property tax rates from:
Joint Stipulation of PG&E and CLECA, A.19-11-019 (January 21, 2022), pp. 2, 7.

Liberty Utilities (CalPeco Electric)
Derivation of Marginal Cost of Distribution (Customer)

Customer-Related Investment: Transformer, Service and Metering Costs
Marginal Customer Costs Using the NCO Method

Line No.	Description	Adjustment Factor	Residential Permanent	Residential Non-Permanent	S-M Master Residential	Small Commercial	Medium Commercial	Large Commercial	Irrigation
1	Long Run Unit Investment		$ 1,806.80	$ 1,806.80	$ 9,292.28	$ 3,103.27	$ 13,264.22	$ 50,739.50	$ 10,814.31
2	With General Plant Loading	6.14%	$ 1,917.79	$ 1,917.79	$ 9,863.09	$ 3,293.89	$ 14,079.02	$ 53,856.33	$ 11,478.61
3	PVRR Cost	177%	$ 3,392.61	$ 3,392.61	$ 17,448.03	$ 5,826.97	$ 24,906.10	$ 95,273.08	$ 20,305.93
4	Estimated Average Annual New Hookups		-	291	3	4	4	-	-
5	Total CA customers		17,656	25,660	571	5,323	254	53	10
6	Replacements at 1.5% of 2019 customers	1.50%	265	385	9	80	4	1	-
7	PVRR of new hookups plus replacements		$ 899.04	$ 2,293.54	$ 202.94	$ 492.18	$ 196.34	$ 95.27	$ -
8	PVRR per customer		$ 50.92	$ 89.38	$ 355.70	$ 92.46	$ 773.00	$ 1,797.61	$ -
9	Plant-Related A&G Loading	2.10%	$ 1.07	$ 1.88	$ 7.46	$ 1.94	$ 16.22	$ 37.72	$ -
10	With A&G Loading		$ 51.99	$ 91.26	$ 363.17	$ 94.40	$ 789.22	$ 1,835.33	$ -
11	Customer Plant-Related O&M		$ 5.64	$ 5.64	$ 28.99	$ 9.68	$ 41.38	$ 158.29	$ 33.74
12	Customer Accounts and Service								
13	Customer Accounts		$ 43.94	$ 43.94	$ 54.04	$ 54.04	$ 198.16	$ 2,302.80	$ 54.04
14	Customer Service		$ 9.68	$ 9.68	$ 35.53	$ 35.53	$ 257.71	$ 6,710.62	$ 35.53
15	Subtotal Customer-related O&M		$ 59.26	$ 59.26	$ 118.56	$ 99.25	$ 497.25	$ 9,171.71	$ 123.31
16	With O&M-related A&G Loading	11.87%	$ 66.29	$ 66.29	$ 132.64	$ 111.04	$ 556.30	$ 10,260.84	$ 137.95
17	Customer-related Costs Exc. Working Capital		$ 118.28	$ 157.55	$ 495.81	$ 205.44	$ 1,345.51	$ 12,096.16	$ 137.95
18	**Working Capital**								
19	M&S	1.05%	$ 20.12	$ 20.12	$ 103.48	$ 34.56	$ 147.71	$ 565.04	$ 120.43
20	CWC Plant-related	0.22%	$ 4.29	$ 4.29	$ 22.06	$ 7.37	$ 31.48	$ 120.43	$ 25.67
21	O&M-related	2.45%	$ 1.62	$ 1.62	$ 3.25	$ 2.72	$ 13.62	$ 251.24	$ 3.38
22	Total Working Capital		$ 26.03	$ 26.03	$ 128.78	$ 44.64	$ 192.82	$ 936.71	$ 149.47
23	Revenue Requirement	9.56%	$ 2.49	$ 2.49	$ 12.31	$ 4.27	$ 18.42	$ 89.51	$ 14.28
24	Customer Common		**$ 60.13**	**$ 60.13**	**$ 100.44**	**$ 100.44**	**$ 511.20**	**$ 10,107.34**	**$ 100.44**
25	Customer Specific		**$ 60.64**	**$ 99.91**	**$ 407.67**	**$ 109.27**	**$ 852.74**	**$ 2,078.33**	**$ 51.79**
26	Total Customer-related		$ 120.77	$ 160.04	$ 508.11	$ 209.71	$ 1,363.94	$ 12,185.67	$ 152.24
27	Monthly Cost		$ 10.06	$ 13.34	$ 42.34	$ 17.48	$ 113.66	$ 1,015.47	$ 12.69
28	Number of Customers		17,656	25,660	571	5,323	254	53	10
29	Total Customer Common		**$ 1,061,615**	**$ 1,542,838**	**$ 57,306**	**$ 534,659**	**$ 129,844**	**$ 535,689**	**$ 996**
30	Total Customer Specific		**$ 1,070,687**	**$ 2,563,705**	**$ 232,585**	**$ 581,612**	**$ 216,596**	**$ 110,151**	**$ 514**

Liberty Utilities (CalPeco Electric)
A-2 Class Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	11,030,639	$ 6,118,365	$ 17,149,005
Current Base Rates	8,849,575	$ 6,480,720	$ 15,330,296
$ Difference	2,181,064	(362,355)	1,818,709
% Difference	24.6%		11.9%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ 3,066,962	3,048	$ 1,006.22

A-2 Class Rate Design Proposed Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (A-2)								
Customer Charge	$ 54.57			3,048	$ 166,329			$ 166,329
Wildfire Charge	$ 1,006.22			3,048	3,066,962			3,066,962
Winter Energy		$ 0.06937	$ -	45,574,506		3,161,689	-	3,161,689
Summer Energy		$ -	$ 0.05886	21,720,176		-	1,278,484	1,278,484
Winter Demand		$ 17.92	$ -	139,842		2,505,526	-	2,505,526
Summer Demand		$ -	$ 11.65	61,966		-	721,612	721,612
Power Factor				0.00561%	$ 181	$ 318	$ 112	612
V/T Discount				-0.00539%	$ (174)	$ (305)	$ (108)	(588)
Proposed Rates (A-2 TOU)								
Customer Charge	$ 54.57			-	$ -			$ -
Wildfire Charge	$ 1,006.22			-	-			-
Winter Energy - On-Peak		$ 0.06937	$ -	131,045		9,091	-	9,091
Winter Energy - Mid-Peak		$ 0.06937	$ -	187,889		13,035	-	13,035
Winter Energy - Off-Peak		$ 0.06937	$ -	194,953		13,525	-	13,525
Summer Energy - OnPeak		$ -	$ 0.05886	236,540		-	13,923	13,923
Summer Energy - Off-Peak		$ -	$ 0.05886	196,029		-	11,539	11,539
Winter Demand - On-Peak		$ 17.92	$ -	1,441		25,825	-	25,825
Winter Demand - Mid-Peak		$ 17.92	$ -	1,522		27,278	-	27,278
Summer Demand - OnPeak		$ -	$ 11.65	1,359		-	15,823	15,823
Non-TOU Maximum		$ -	$ -	2,165		-	-	-
Revenue at Proposed Rates				68,241,136	$ 3,233,292	$ 5,755,967	$ 2,041,381	$ 11,030,639

Liberty Utilities (CalPeco Electric)
A-2 Class Rate Design

A-2 Class Rate Design Proposed Rates (TOU A-2 EV)	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (TOU A-2 EV)								
Customer Charge	$ 54.57			3,048	$ 166,329			$ 166,329
Wildfire Charge	$ 1,006.22			3,048	3,066,962			3,066,962
Winter Energy - On-Peak		$ 0.23665	$ -	9,625,053		2,277,733	-	2,277,733
Winter Energy - Mid-Peak		$ 0.15558	$ -	20,337,980		3,164,166	-	3,164,166
Winter Energy - Off-Peak		$ 0.01948	$ -	16,125,359		314,068	-	314,068
Summer Energy - OnPeak		$ -	$ 0.12913	11,742,244		-	1,516,273	1,516,273
Summer Energy - Off-Peak		$ -	$ 0.05044	10,410,500		-	525,107	525,107
Winter Demand - On-Peak		$ -	$ -	1,441		-	-	-
Winter Demand - Mid-Peak		$ -	$ -	1,522		-	-	-
Summer Demand - OnPeak		$ -	$ -	1,359		-	-	-
Non-TOU Maximum		$ -	$ -	2,165		-	-	-
Revenue at Proposed Rates					$ 3,233,292	$ 5,755,967	$ 2,041,381	$ 11,030,639

Liberty Utilities (CalPeco Electric)
A-2 Class Rate Design

A-2 Class Rate Design Current Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Current Rates								
Customer Charge	$ 43.78			3,041	$ 133,135			$ 133,135
Winter Energy		$ 0.05022	$ -	48,589,535		2,440,166	-	2,440,166
Summer Energy		$ -	$ 0.04261	20,801,324		-	886,344	886,344
Winter Demand		$ 12.97	$ -	319,673		4,146,156	-	4,146,156
Summer Demand		$ -	$ 8.43	147,539		-	1,243,754	1,243,754
Power Factor				0.00561%	$ 7	$ 369	$ 119	496
V/T Discount				-0.00539%	$ (7)	$ (355)	$ (115)	(477)
Current Rates (A-2 TOU)								
Customer Charge	$ 139.16				$ -			$ -
Winter Energy - On-Peak		$ 0.05022	$ -			-	-	-
Winter Energy - Mid-Peak		$ 0.05022	$ -			-	-	-
Winter Energy - Off-Peak		$ 0.05022	$ -			-	-	-
Summer Energy - OnPeak		$ -	$ 0.04261			-	-	-
Summer Energy - Off-Peak		$ -	$ 0.04261			-	-	-
Winter Demand - On-Peak		$ 12.97	$ -			-	-	-
Winter Demand - Mid-Peak		$ 12.97	$ -			-	-	-
Summer Demand - OnPeak		$ -	$ 8.43			-	-	-
Non-TOU Maximum		$ -	$ -			-	-	-
Revenue at Current Rates				69,390,859	$ 133,135	$ 6,586,337	$ 2,130,103	$ 8,849,575

Liberty Utilities (CalPeco Electric)
A-2 Class Rate Design

A-2 Class Rate Design

Bill Impact Analysis Total Charges	Month Usage	Average Demand	Proposed Bill	Current Bill	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season						
50% Below Avg. Usage	11,161	67	$ 3,929	$ 2,418	$ 1,511	62.5%
25% Below Avg. Usage	16,742	71	$ 4,847	$ 3,231	$ 1,616	50.0%
Average Usage	22,323	75	$ 5,743	$ 4,029	$ 1,714	42.6%
25% Above Avg. Usage	27,903	88	$ 6,818	$ 4,956	$ 1,862	37.6%
50% Above Avg. Usage	33,484	93	$ 7,742	$ 5,773	$ 1,969	34.1%
Summer Season						
50% Below Avg. Usage	11,134	67	$ 3,705	$ 2,343	$ 1,362	58.1%
25% Below Avg. Usage	16,701	73	$ 4,713	$ 3,265	$ 1,448	44.4%
Average Usage	22,268	74	$ 5,653	$ 4,138	$ 1,515	36.6%
25% Above Avg. Usage	27,835	88	$ 6,755	$ 5,128	$ 1,627	31.7%
50% Above Avg. Usage	33,402	93	$ 7,746	$ 6,038	$ 1,708	28.3%

February 3, 2022

DATA REQUEST RESPONSE

LIBERTY UTILITIES (LIBERTY)
A.21-05-017
Test Year 2022 General Rate Case

Data Request No.: SBUA Set 4

Requesting Party: Small Business Utility Advocates

Originator: James Birkelund james@utilityadvocates.org
Jennifer Weberski jennifer@utilityadvocates.org

Date Received: January 11, 2022

Due Date: January 25, 2022

Extension: January 28, 2022

REQUEST NO. 1:

Re: Response to SBUA-Liberty 4(a), Attachments 1 and 2

a. Please provide an explanation of the “Rate” code values (tabs A1 and A2, respectively), including the significance of the “M” designation.
b. Please explain whether there is any special billing when two customer IDs are identified for the same location (e.g., Attachment 2, location ID 88500122) or two rates identified for the same location and customer (e.g., Attachment 2, location ID 88143799).
c. Please explain why customers with maximum monthly usage below 500 kWh are in class A-2 (e.g., Attachment 2, location ID 88500335).
d. Please provide a worksheet similar in layout to tabs A1 and A2, respectively, with the monthly maximum demand values for each location and customer.

RESPONSE TO REQUEST NO. 1:

Liberty acknowledges the attachments 1 and 2 incorrectly showed residential customer information, not A-1 and A-2 customer information. Please see revised attachments "SBUA-Liberty 4(a) Attachment1_vRevised" and "SBUA-Liberty 4(a) Attachment2_vRevised" for the correct A-1 and A-2 customer information.

a. Rate codes are unique identifiers to indicate which rate (e.g. A1 or A2) each customer is assigned. The "M" designation indicates the customer is on the CARE rate and also a Green Cross/Medical customer.
b. The 88500122, Customer 88252534 is on the regular 88E42 CARE rate and Customer 88100124 is on both the Care and Green Cross/Medical Rate.
c. This is a residential customer. Please see the revised attachments for the A-1 and A-2 customer information.
d. Please see attachments "a1 2020 kw" and "a2 2020 kw"

Response prepared by Tim Lyons.

REQUEST NO. 2:

Re: Response to SBUA-Liberty 4(a), Attachment 1. It appears that there are approximately 1,600 Class A-1 customers whose monthly usage in 2020 never exceeded 400 kWh.

a. Has Liberty investigated to determine what types of customers these are? For example, hallway lighting load.
b. Please provide any available information regarding business characteristics of these customers. If necessary to protect customer confidentiality, aggregate responses appropriately. For example:
   i. Business NAICS code
   ii. Number of customers at same street address
   iii. Non-profit status
   iv. Temporary meter
c. Has Liberty investigated to determine if any of these low-usage meters could be consolidated with other meters on the same property?
   i. If the response is that the customer would have to initiate such a request, has Liberty ever conducted customer-specific outreach to inform customers of opportunities to consolidate meters and thus reduce bills?
   ii. Does Liberty plan to conduct any such outreach in the future?

RESPONSE TO REQUEST NO. 2:

As mentioned in response to question 1, the attachments referenced shows residential customers. This explains why there are 1,600 customers whose monthly usage never exceeded 400 kwh.

Response prepared by Tim Lyons.

REQUEST NO. 3:

Re: Response to SBUA-Liberty 4(a), Attachment 2.

a. Please confirm that Liberty used customer-specific monthly usage in the bill impact analysis. If not confirmed, please explain.
b. Please confirm that Liberty used an average demand based on class average demand and energy in the bill impact analysis.
    i. If not confirmed, please explain.
    ii. If confirmed, please explain why Liberty did not use customer-specific monthly demand in its bill impact analysis.

RESPONSE TO REQUEST NO. 3:

a. Confirm.
b. Confirm.
    i. Customer specific monthly demand data was not available at the time of when the analysis was conducted.

Response prepared by Tim Lyons.

REQUEST NO. 4:

Re: Response to SBUA-Liberty 4(a), Attachments 1 and 2.

Please explain why Liberty considers it reasonable and just to increase a business customer's monthly charge from $110 to $1,061 if its maximum demand exceeds 50 kW in any three months during the preceding 12 months. For example, for a customer whose demand is 40 kW in 9 months and 60 kW in 3 months, please explain how it is reasonable and just to charge that customer $951 per month more than a customer whose maximum demand is 40 kW for 12 months per year.

RESPONSE TO REQUEST NO. 4:

The proposed rate design is based on the aggregate demand and cost characteristics of all customers within the rate class. As a result, fixed charges will have a larger ($ per kWh) impact on lower use customers within the rate class and a smaller ($ per kWh) impact on higher use customers within the rate class.

Response prepared by Tim Lyons.

REQUEST NO. 5:

Does Liberty proactively transfer a Class A-1 customer to Class A-2 if its maximum demand exceeds 50 kW in any three months during the preceding 12 months, or does that customer have to request the change?

RESPONSE TO REQUEST NO. 5:

Liberty's Billing Department annually reviews demand usage for all commercial customers and migrates rates, if needed. If customers go over or under the determined use for the Commercial rates based on Demand, Liberty migrates them accordingly and send them a letter.

REQUEST NO. 6:

Does Liberty proactively transfer a Class A-2 customer to Class A-1 if its maximum demand does not exceed 50 kW in any three months during the preceding 12 months, or does that customer have to request the change?

RESPONSE TO REQUEST NO. 6:

Liberty's Billing Department annually reviews demand usage for all commercial customers and migrates rates, if needed. If customers go over or under the determined use for the Commercial rates based on Demand, Liberty migrates them accordingly and send them a letter.

REQUEST NO. 7:

Re: Ch 12, p. 10. Please explain why Liberty used the Probability of Peak factor method.

a. Identify any other utilities that Liberty is aware of that use this same exact method.
b. Identify any other utilities that Liberty is aware of that use a very similar method, and explain the reasons for each difference (e.g., why did Liberty select each variation?).

RESPONSE TO REQUEST NO. 7:

a. The Probability of Peak (POP) method determines each hour's likelihood of being the peak hour during each month. The method was developed consistent with how the Company incurs generation costs, i.e., based on monthly peak demands. Specifically, the Company has a service agreement with NV Energy for purchase of generation capacity and energy. Per the agreement, the Company is billed demand charges based on the greater of Company's monthly net coincident peak demands or monthly net contract demands. The Company is not aware of another utility that uses this same exact method.
b. The Probability of Peak method was used to allocate generation costs by Otter Tail Power Company in South Dakota (Docket EL-18-021, Exhibit____DGP-1 - Schedule 2 - 2018 Marginal Cost Study). Please refer to (a).

Response prepared by Tim Lyons.

REQUEST NO. 8:

Re: Ch 12, p. 10 and CalPECO MCOS and Rate Design_vSupplemental Workpaper, tab POP 12CP. Please explain why Liberty believes it is appropriate to use a 12CP method. In your response, please address the following points.

a. The monthly peaks during November – February are 85-100% of the 6-year peak, but the monthly peaks during March – October are less than 80% of the 6-year peak.
b. Please confirm that the only costs allocated using the 12CP allocator are generation capacity. If not confirmed, please clarify.
c. The basis for determining that marginal costs allocated using the 12CP method should be allocated to all months.

RESPONSE TO REQUEST NO. 8:

a. Please refer to Response 7. Liberty incurs generation costs based on monthly peak demands through the year.
b. Confirmed.
c. Please refer to Response 7. Liberty incurs generation costs based on monthly peak demands through the year.

Response prepared by Tim Lyons.

REQUEST NO. 9:

Re: CalPECO MCOS and Rate Design_vSupplemental Workpaper, tab Allocation-Summary.

a. Please confirm that the formula for generation costs is:
   Costs ($) = loss factor adjustment (unitless) * total usage (MWh) * TOU allocation ($/kW)
b. If (a) is not confirmed, please explain.
c. If (a) is confirmed, please explain why the units do not balance ($ <> $ thousandhours)
d. Please explain why Liberty uses total usage (MWh) rather than class specific peak demand (kW) in the allocation formula.
e. Please provide the class specific peak demand (kW) data by TOU period.

RESPONSE TO REQUEST NO. 9:

a. Confirmed.
b. Please refer to the response to (a).

c. The units do not balance as the Company used MWh usage as a proxy for peak demand to derive the Generation capacity costs. The Company followed the approach approved by the Commission in the Company's most recent rate proceeding (Application 18-12-001).
d. Please refer to (c).
e. Please refer to SBUA-Liberty 4.9 Attachment

Response prepared by Tim Lyons.

REQUEST NO. 10:

Re: CalPECO MCOS and Rate Design_vSupplemental Workpaper, tab POP 12CP.

a. Please explain why the monthly peaks are the maximum of the average (cells AF4:15) rather than the maximum of all values (cell AF1).
b. Please explain why the 12CP analysis does not consider weekday/weekend effects when calculating the weighted POP allocator.

RESPONSE TO REQUEST NO. 10:

a. The hourly peaks are considered as 5-year average to normalize for year-over-year volatility in hourly peak demands.
b. The Company's service agreement with NV Energy for purchase of generation capacity and energy does not differentiate between weekdays vs. weekends.

Response prepared by Tim Lyons.

REQUEST NO. 11:

Re: Ch. 12, p. 18. Please explain why the "proposed rates were developed for each class based on a uniform increase in rate elements." In your response, please explain:

a. Why Liberty did not increase distribution and generation rates based on differing increases in marginal costs.
b. Why Liberty did not increase demand and energy rate components (where applicable) based on differing increases in marginal costs.

RESPONSE TO REQUEST NO. 11:

a. Please refer to Chapter 12, p. 2. The proposed uniform increase in rate elements in the May 2021 filing seemed a reasonable approach since the Company was planning to submit a revised rate design following the May 2021 filing. The Company subsequently filed in September 2021 a revised rate design in the Chapter 12 Supplemental filing. The revised rate design included fixed surcharges to recover Wildfire mitigation costs, Tier III energy charges, and a proposed increase in the CARE discount rate.
b. Please refer to response 11, part a.

Response prepared by Tim Lyons.

Attachments

January 19, 2022

DATA REQUEST RESPONSE

LIBERTY UTILITIES (LIBERTY)
A.21-05-017
Test Year 2022 General Rate Case

Data Request No.: SBUA Set 3

Requesting Party: Small Business Utility Advocates

Originator: James Birkelund james@utilityadvocates.org
Jennifer Weberski jennifer@utilityadvocates.org

Date Received: December 27, 2021

Due Date: January 11, 2022

Extension: January 18, 2022

REQUEST NO. 1:

Please provide all workpapers that have been provided to any party in this proceeding. (Note that SBUA does not have access to all workpapers.)

RESPONSE TO REQUEST NO. 1:

Please see link to workpapers provided in data request submission e-mail.

REQUEST NO. 2:

Please provide “the depreciation study developed for this proceeding” (Liberty Testimony Chapter 8, p. 5, line 5. (SBUA does not have access to this unnamed workpaper.)

RESPONSE TO REQUEST NO. 2:

See response to question 1.

REQUEST NO. 3:

Please provide a list of Liberty substations, including for each:

a. Station name.
b. Number of transformers.
c. MVA of transformers.
d. High-side and low-side nominal voltages.
e. The 2019, 2020 and 2021 peak loads on the substation.
f. Time and date of the 2019, 2020 and 2021 peak loads on the substation.
g. Load, date and time of the monthly peak on the substation, for each month from January
1. 2018 to December 2021.
h. Any information on the mix of customer class loads served on the substation.

RESPONSE TO REQUEST NO. 3:

Liberty does not track peak loads at the substation or feeder level. Liberty would have to manually query thousands of records to provide this level of requested detailed information. As a sample output, Liberty has compiled substation peak loads at select substation locations. See file attachment "Substation Load Sample." Only total system peak loads are maintained for the requested time period.

Response prepared by Travis Johnson.

REQUEST NO. 4:

Please provide a list of Liberty feeders, including for each:

a. Feeder designation.
b. Voltage.
c. Length.
d. The 2019, 2020 and 2021 peak loads on the feeder.
e. Time and date of the 2019, 2020 and 2021 peak loads on the feeder.
f. Load, date and time of the monthly peak on the feeder, for each month from January
2. 2018 to December 2021.
g. Any information on the mix of customer class loads served on the feeder.

RESPONSE TO REQUEST NO. 4:

Liberty does not track peak loads at the substation or feeder level. Liberty would have to manually query thousands of records to provide this level of requested detailed information. Please see attachment "Feeder Data 2019 through 2021" for a data sample.

Response prepared by Travis Johnson.

REQUEST NO. 5:

Please provide any available data on the share of Liberty customers who share their transformer with one or more other customers, for each rate class, including at least permanent residential, seasonal residential, and small commercial.

RESPONSE TO REQUEST NO. 5:

Liberty estimates, using its GIS database, that approximately 85.9% of commercial customers share a transformer and 97.3% of residential customers share a transformer. This estimate is based on 32,873 accounts which have transformer data out of the total 50,570 total accounts. Transformer data for the remaining accounts is not readily available at the requested rate class level and would require a detailed study. See supporting data below for the transformer relationship analysis.

Account Type	Total with Transformer Relationship	Count Sharing Transformer	Percentage Sharing Transformer
COMMERCIAL	2,641	2,268	85.9%
RESIDENTIAL	30,232	29,411	97.3%

Response prepared by Travis Johnson.

REQUEST NO. 6:

Please explain why Liberty allocates distribution costs on class NCP, rather than class contributions to substation or feeder peaks.

RESPONSE TO REQUEST NO. 6:

The Company allocated distribution demand costs on class NCP because generally distribution demand facilities are designed based on customer demands at the service level. Further, class NCP data by substation or feeder was not available to allocate distribution costs by substation or feeder.

Response prepared by Tim Lyons.

REQUEST NO. 7:

For each rate class, please provide the following data for each year, 2019–2021:

a. Estimated annual NCP in MW
b. Time and date of annual NCP.
c. Class load at the time of the permanent residential and seasonal residential NCPs.

RESPONSE TO REQUEST NO. 7:

Liberty is only able to provide 2020 and forecasted 2021 data. Please see attachment "2020-21 NCP by rate class"

Response prepared by Tim Lyons.

REQUEST NO. 8:

Please provide the derivation of the Specific Marginal Customer Costs per Customer (Table 12-2), including:

a. all assumptions about the sharing of transformers and service drops,
b. the size and cost of transformers,
c. the capacity and cost of service drops, and

RESPONSE TO REQUEST NO. 8:

The referenced costs per customers in Table 12-2 are in the Company's marginal cost study, tab "MDC Derivation", line 24 for Customer Common Costs per Customer, line 25 for Customer Specific Costs per Customer, and line 26 for Total Costs per Customer. The costs in lines 24-26 are annual amounts that when divided by 12 will produce the numbers in Table 12-2 which are monthly amounts.

Assumptions regarding the transformers and service drops are in the Company's marginal cost study, tab "MDC-Unit_Investments".

Response prepared by Tim Lyons.

REQUEST NO. 9:

Please provide the derivation of Estimated Average Annual New Hookups for each class in Exhibit TSL/TAS-3, p. 3.

RESPONSE TO REQUEST NO. 9:

Please refer to the Company's marginal cost study, tab "MDC-Inputs", line 4 for the Estimated Average Annual New Hookups and rows 34-57 for its derivation.

Response prepared by Tim Lyons.

REQUEST NO. 10:

Please provide the actual Annual New Hookups for each year, 2010–2020.

RESPONSE TO REQUEST NO. 10:

Please refer to the Company's response to 9.

Response prepared by Tim Lyons.

REQUEST NO. 11:

Please provide the derivation of a 1.5% replacement rate for transformers, services and meters in Exhibit TSL/TAS-3, p. 3.

RESPONSE TO REQUEST NO. 11:

The 1.5% replacement rate was taken from the Company's marginal cost studies filed in the Company's prior rate case, which reflected a general assessment of the composite replacement rate for transformers, services, and meters. We understand any analysis supporting the replacement rate is no longer available.
Response prepared by Tim Lyons.

REQUEST NO. 12:

Does a 1.5% replacement rate for transformers, services and meters equate to a 67-year average life for that equipment?

a. If so, please explain why the Company believes that life to be reasonable.
b. If not, please explain how the 1.5% replacement rate is consistent with shorter equipment lives.

RESPONSE TO REQUEST NO. 12:

See response to question 11. The 1.5% replacement rate does not factor in the proposed average life or future net removal cost embedded in Liberty's depreciation rate study.
Response prepared by Tim Lyons.

REQUEST NO. 13:

Please explain how the 1.5% replacement rate reflects the cost of removal and salvage value.

RESPONSE TO REQUEST NO. 13:

See response to question 12. The 1.5% replacement rate does not include the cost of removal and net salvage that are reflected in Liberty's depreciation rate proposal.
Response prepared by Tim Lyons.

REQUEST NO. 14:

Please reconcile the 1.5% replacement rate with the proposed depreciation rates of 2.61%, 1.93%, and 4.60%, respectively for transformers, services and meters in Table 9-5.

RESPONSE TO REQUEST NO. 14:

See responses to questions 12 and 13.
Response prepared by Tim Lyons.

REQUEST NO. 15:

Please provide the workpaper CalPeco MCOS and Rate Design v Supplemental Workpaper.xlsx, referenced in responses to Cal Advocates Liberty-020-MPS requests 1 and 2. SBUA has not been provided this workpaper, or access to it.

RESPONSE TO REQUEST NO. 15:

Please see Liberty's response to question 2 of SBUA data request set two.

Response prepared by Tim Lyons.

REQUEST NO. 16:

Please provide the "Company Transformers Study" sited in *(sic)*

RESPONSE TO REQUEST NO. 16:

Please refer to SBUA-Liberty 3.16 Attachment.

Response prepared by Tim Lyons.

REQUEST NO. 17:

Please provide all workpapers supporting Exhibit TSL-S7 to Exhibit TSL-S10.

RESPONSE TO REQUEST NO. 17:

Please refer to SBUA-Liberty 3.17 Attachment 1 through SBUA-Liberty 3.17 Attachment 4

Response prepared by Tim Lyons.

REQUEST NO. 18:

Please provide the derivation of the Table 12-3 Marginal Energy Costs from the IRP results.

RESPONSE TO REQUEST NO. 18:

Table 12-3 is in the Company's marginal cost study, tab "IRP 2021-25 Energy", columns H-I, rows 20-26.

Response prepared by Tim Lyons.

REQUEST NO. 19:

Please explain why Table 12-3 Marginal Energy Costs shows off-peak costs higher than onpeak and mid-peak for both the summer and winter periods.

a. Please provide a set of TOU periods for which the peak price is the highest price in each season and the off-peak price is the lowest price in each season.

RESPONSE TO REQUEST NO. 19:

The marginal cost of energy is based on the Company's most recent Integrated Resource Plan (IRP). The differential between the off-peak and peak costs in both the summer and winter seasons appears to be explained in part by the cost of the Company's solar production.

Response prepared by Tim Lyons.

REQUEST NO. 20:

Chapter 12 Supplemental, Figure 4 shows all wildfire costs to be non-customer distribution costs. Does Liberty agree that all these costs are indeed non-customer distribution costs? If not, please explain what portions of each line are customer costs or any other category of costs.

RESPONSE TO REQUEST NO. 20:

Please refer to Chapter 12 Supplemental, Figure 3 that shows the Wildfire Mitigation O&M and Capital Expenditures. The Company believes that the Wildfire Mitigation costs shown in Figure 3 largely reflect non-customer distribution costs, such as covered conductors, pole replacement, and vegetation management and inspections.

Response prepared by Tim Lyons.

REQUEST NO. 21:

Please reconcile the $30,702,000 Wildfire Cost total in Chapter 12 Supplemental, Figure 4, with the values in Chapter 12 Supplemental, Figure 3.

RESPONSE TO REQUEST NO. 21:

Please refer to the table below for derivation of the Wildfire Mitigation costs of $30,702,000.

WF ins		10.438
WMP		2.468
VM		13.785
Total O&M		26.691
Capital RR		
2021		33.463
2022		15.895
		49.358
Return @ 7.42%	$	3.66
working cash		4.693
return @ 7.42%	$	0.35
Add'l return		4.011
WMP-related RR		30.702

Response prepared by Tim Lyons.

REQUEST NO. 22:

Chapter 12 Supplemental, Figure 3:

a. For each line of Table 4-1 and Table 4-2, please identify the portion of the cost that is specifically related to the customer-related costs of meters, services, and final line transformers, or to "customer account and customer service costs, such as those related to meter reading, billing, and customer records." (Chapter 12, page 11, lines 10–22).
b. Please provide a reconciliation of Table 6-1 with Table 4-2. Specifically, please:

i) Indicate which lines of Table 4-2 are reflected in each line of Table 6-1.
ii) Provide all A&G and other adders applied to the Table 4-2 data.

RESPONSE TO REQUEST NO. 22:

a. Please refer to the Company's response to 20.

Response prepared by Tim Lyons.

b. See table below for the reconciliation of expenses between Table 4-2 and Table 6-1. Since most of the expenses recorded to the wildfire mitigation plan memorandum account are O&M type work activities, A&G expenses were not included in the Table 4-2 forecast.

	WF Opex in Fixed Charge calc	Table 4-2	Table 6-1		
WF Insurance	10,438	-	10,438		
WMP (non-VM)	2,468	2,468	2,468		
WMP - VM	13,785	13,785	13,785		
	26,691	16,253	26,691		
Table 4-2 notes:					
Table 4-2 only shows WMP specific forecast costs and not WF insurance costs					
Table 6-1 notes:					
The sum of WF insurance $10.438M and WMP (non-VM) $2.468M totals $12.906M shown in Table 6-1					
as Wildfire Mitigation (WMP MA and WEMA)					

Response prepared by Manasa Rao.

REQUEST NO. 23:

Please provide the following for a volumetric wildfire rate design, recovering the wildfire costs through energy charges for residential, PA and A-1 rates, and an equal percentage increase of all non-customer distribution charges in the rates with demand charges:

a. Chapter 12 Supplemental, Figure 5

b. Exhibit TSL-S10

RESPONSE TO REQUEST NO. 23:

a. Please refer to Figure 1 below.
b. Please refer to Figure 2 (residential permanent), Figure 3 (residential non-permanent), Figure 4 (PA) and Figure 5 (A-1) below.

Figure 1 (Wildfire Costs per kWh)

Derivation of Wildfire Charges	Wildfire Costs	Sales kWh	Wildfire Costs per kWh
Residential Permanent	$ 7,734,788	140,314,083	$ 0.05512
Residential Non-Permanent	8,686,360	158,808,179	0.05470
Small Commercial	5,273,948	99,402,704	0.05306
Medium Commerical	3,066,962	68,241,136	0.04494
Large Commercial	5,890,273	115,201,374	0.05113
Irrigation	19,546	741,788	0.02635
OLS	19,309		
Street Lighting	10,814		
Total	$ 30,702,000		

Figure 2 (residential permanent)

Liberty Utilities (CalPeco Electric)
Residential Permanent Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	24,563,948	$ 7,991,519	$ 32,555,467
Current Base Rates	15,564,453	$ 8,970,952	$ 24,535,405
$ Difference	8,999,494	(979,433)	8,020,062
% Difference	57.8%		32.7%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ 7,734,788	214,666	$ 36.03

Residential Permanen Tier III Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Revised Rates								
Customer Charge	$ 10.00			214,666	$ 2,146,659			$ 2,146,659
Wildfire Charge	$ -			214,666	-			-
Tier 1 Energy		$ 0.13569	$ 0.01438	92,999,141		12,619,048	1,337,093	13,956,141
Tier 2 Energy		$ 0.14531	$ 0.02653	12,912,392		1,876,238	342,562	2,218,799
Tier 3 Energy		$ 0.15492	$ 0.02653	34,402,551		5,329,659	912,689	6,242,348
Revenue at Revised Rates				**140,314,083**	**$ 2,146,659**	**$ 19,824,945**	**$ 2,592,343**	**$ 24,563,948**
Current Rates								
Customer Charge	$ 9.67			219,296	$ 2,120,594			$ 2,120,594
Tier 1 Energy		$ 0.08197	$ 0.00911	96,281,508		7,892,195	877,125	8,769,320
Tier 2 Energy		$ 0.08197	$ 0.01681	47,322,728		3,879,044	795,495	4,674,539
Tier 3 Energy		$ 0.08197	$ 0.01681			-	-	-
Revenue at Current Rates				**143,604,236**	**$ 2,120,594**	**$ 11,771,239**	**$ 1,672,620**	**$ 15,564,453**

Bill Impact Analysis	Monthly Usage (kWh)	Tier 1 Usage (kWh)	Tier 2 Usage (kWh)	Tier 3 Usage (kWh)	Revised Bill $	Current Bill $	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season								
50% Below Avg. Usage	357.2	357.2	0.0	0.0	$ 82.15	$ 62.76	$ 19.39	30.9%
25% Below Avg. Usage	535.8	535.8	0.0	0.0	$ 118.23	$ 89.31	$ 28.92	32.4%
Average Usage	714.4	577.9	136.5	0.0	$ 159.31	$ 118.94	$ 40.37	33.9%
25% Above Avg. Usage	893.0	577.9	173.4	141.7	$ 203.30	$ 149.53	$ 53.77	36.0%
50% Above Avg. Usage	1071.6	577.9	173.4	320.3	$ 247.65	$ 180.11	$ 67.53	37.5%
Summer Season								
50% Below Avg. Usage	263.6	263.6	0.0	0.0	$ 63.23	$ 48.84	$ 14.39	29.5%
25% Below Avg. Usage	395.3	395.3	0.0	0.0	$ 89.85	$ 68.43	$ 21.42	31.3%
Average Usage	527.1	441.0	86.1	0.0	$ 119.63	$ 89.96	$ 29.67	33.0%
25% Above Avg. Usage	658.9	441.0	132.3	85.5	$ 151.90	$ 112.53	$ 39.37	35.0%
50% Above Avg. Usage	790.7	441.0	132.3	217.3	$ 184.62	$ 135.10	$ 49.52	36.7%

Figure 3 (residential non-permanent)

Liberty Utilities (CalPeco Electric)
Residential Non-Permanent Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	34,064,281	$ 10,616,327	$ 44,680,608
Current Base Rates	17,925,019	$ 10,992,483	$ 28,917,502
$ Difference	16,139,262	(376,157)	15,763,106
% Difference	90.0%		54.5%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ 8,686,360	311,972	$ 27.84

Residential Non-Perm Tier III Rates	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Revised Rates								
Customer Charge	$ 10.00			311,972	$ 3,119,720			$ 3,119,720
Wildfire Charge	$ -			311,972	$ -			$ -
Tier 1 Energy						-	-	-
Tier 2 Energy		$ 0.15640	$ 0.03195	111,580,081		17,451,086	3,564,462	21,015,548
Tier 3 Energy		$ 0.17829	$ 0.03195	47,228,098		8,420,296	1,508,717	9,929,013
Revenue at Revised Rates				**158,808,179**	**$ 3,119,720**	**$ 25,871,382**	**$ 5,073,179**	**$ 34,064,281**
Current Rates								
Customer Charge	$ 9.67			304,428	$ 2,943,817			$ 2,943,817
Tier 1 Energy						-	-	-
Tier 2 Energy		$ 0.08197	$ 0.01681	151,662,300		12,431,759	2,549,443	14,981,202
Tier 3 Energy		$ 0.08197	$ 0.01681			-	-	-
Revenue at Current Rates				**151,662,300**	**$ 2,943,817**	**$ 12,431,759**	**$ 2,549,443**	**$ 17,925,019**

Bill Impact Analysis	Monthly Usage (kWh)	Tier 1 Usage (kWh)	Tier 2 Usage (kWh)	Tier 3 Usage (kWh)	Revised Bill $	Current Bill $	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season								
50% Below Avg. Usage	274.6	0.0	274.6	0.0	$ 80.08	$ 56.70	$ 23.38	41.2%
25% Below Avg. Usage	411.9	0.0	411.9	0.0	$ 115.12	$ 80.22	$ 34.90	43.5%
Average Usage	549.2	0.0	549.2	0.0	$ 150.16	$ 103.73	$ 46.43	44.8%
25% Above Avg. Usage	686.5	0.0	686.5	0.0	$ 185.20	$ 127.25	$ 57.95	45.5%
50% Above Avg. Usage	823.8	0.0	751.3	72.6	$ 221.83	$ 150.76	$ 71.07	47.1%
Summer Season								
50% Below Avg. Usage	215.5	0.0	215.5	0.0	$ 65.00	$ 46.58	$ 18.42	39.5%
25% Below Avg. Usage	323.3	0.0	323.3	0.0	$ 92.49	$ 65.03	$ 27.46	42.2%
Average Usage	431.0	0.0	431.0	0.0	$ 119.99	$ 83.48	$ 36.51	43.7%
25% Above Avg. Usage	538.8	0.0	538.8	0.0	$ 147.49	$ 101.94	$ 45.55	44.7%
50% Above Avg. Usage	646.5	0.0	573.4	73.2	$ 176.59	$ 120.39	$ 56.20	46.7%

Figure 4 (PA)

Liberty Utilities (CalPeco Electric)
PA Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	72,592	$ 68,964	$ 141,556
Current Base Rates	48,137	$ 82,775	$ 130,912
$ Difference	24,455	(13,811)	10,644
% Difference	50.8%		8.1%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ 19,546	119	$ 164.25

PA Rate Design	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates								
Customer Charge	$ 26.21			119	$ 3,119			$ 3,119
Widlfire Charge	$ -			119	-			-
Energy		$ 0.04784	$ 0.04582	741,788		35,484	33,989	69,473
Revenue at Proposed Rates				741,788	$ 3,119	$ 35,484	$ 33,989	$ 72,592
Current Rates								
Customer Charge	$ 17.38			229	$ 3,980			$ 3,980
Energy		$ 0.02753	$ 0.02637	819,233		22,553	21,603	44,157
Revenue at Current Rates				819,233	$ 3,980	$ 22,553	$ 21,603	$ 48,137
								-

Bill Impact Analysis Total Charges	Month Usage	Proposed Bill	Current Bill	Increase / (Decrease) $	Increase / (Decrease) %
50% Below Avg. Usage	2,979	$ 582	$ 479	$ 103	21.6%
25% Below Avg. Usage	4,469	$ 860	$ 710	$ 150	21.2%
Average Bill	5,959	$ 1,138	$ 941	$ 198	21.0%
25% Above Avg. Usage	7,448	$ 1,416	$ 1,171	$ 245	20.9%
50% Above Avg. Usage	8,938	$ 1,694	$ 1,402	$ 292	20.8%

Figure 5 (A-1)

Liberty Utilities (CalPeco Electric)
A-1 Class Rate Design

Base Revenues	Base Rates	Other Charges	Total Rates
Target Base Rates	19,751,818	$ 9,241,469	$ 28,993,287
Current Base Rates	12,515,344	$ 10,095,502	$ 22,610,846
$ Difference	7,236,474	(854,033)	6,382,441
% Difference	57.8%		28.2%

Wildfire-Related	No. of Bills	WF Cost / Bill
$ 5,273,948	63,875	$ 82.57

A-1 Class Rate Design	Customer Charge	Distribution Rate	Generation Rate	Billing Determinants	Customer Revenues	Distribution Revenues	Generation Revenues	Total Revenues
Proposed Rates (A-1 > 20kW)								
Customer Charge	$ 27.43			59,375	$ 1,628,599			$ 1,628,599
Wildfire Charge	$ -			59,375	-			-
Energy		$ 0.15090	$ 0.03018	61,420,183		9,268,271	1,853,654	11,121,925
Proposed Rates (A-1A <= 20 kW)								
Customer Charge	$ 27.43			4,500	123,445			123,445
Wildfire Charge	$ -			4,500	-			-
Energy		$ 0.15090	$ 0.03018	37,982,522		5,731,541	1,146,308	6,877,849
Revenue at Proposed Rates				99,402,704	$ 1,752,044	$ 14,999,812	$ 2,999,962	$ 19,751,818
Current Rates (A-1 > 20kW)								
Customer Charge	$ 17.38			60,378	$ 1,049,371			$ 1,049,371
Energy		$ 0.09335	$ 0.01867	63,685,729		5,945,063	1,189,013	7,134,075
Current Rates (A-1A <= 20 kW)								
Customer Charge	$ 17.38			4,446	77,270			77,270
Energy		$ 0.09335	$ 0.01867	37,980,960		3,545,523	709,105	4,254,627
Revenue at Current Rates				101,666,688	$ 1,126,641	$ 9,490,585	$ 1,898,117	$ 12,515,344

A-1 Class Rate Design

Bill Impact Analysis Total Charges	Month Usage	Proposed Bill	Current Bill	Increase / (Decrease) $	Increase / (Decrease) %
Winter Season					
50% Below Avg. Usage	785.1	$ 242.59	$ 183.29	$ 59.30	32.4%
25% Below Avg. Usage	1,177.7	$ 350.17	$ 266.25	$ 83.93	31.5%
Average Usage	1,570.3	$ 457.76	$ 349.21	$ 108.55	31.1%
25% Above Avg. Usage	1,962.8	$ 565.34	$ 432.16	$ 133.18	30.8%
50% Above Avg. Usage	2,355.4	$ 672.92	$ 515.12	$ 157.80	30.6%
Summer Season					
50% Below Avg. Usage	756.9	$ 234.86	$ 177.33	$ 57.53	32.4%
25% Below Avg. Usage	1,135.4	$ 338.58	$ 257.31	$ 81.27	31.6%
Average Usage	1,513.9	$ 442.30	$ 337.29	$ 105.01	31.1%
25% Above Avg. Usage	1,892.3	$ 546.02	$ 417.26	$ 128.75	30.9%
50% Above Avg. Usage	2,270.8	$ 649.74	$ 497.24	$ 152.49	30.7%

Response prepared by Tim Lyons.

REQUEST NO. 24:

"Total monetized benefits for the C1 Program are estimated at $909M over the assumed 20-year useful asset life. Based on deployment schedule, annual benefits are estimated to begin in the first year of deployment, ramping up through the fourth year, then remaining steady throughout the life of the assets. Annual benefits achieve reference year levels starting in the fifth year, plus an adjustment for inflation and system growth." (A Review of Liberty's Customer First Program, p. 11)

a. Please provide the computation of the $909M benefits over 20 years.
b. Please provide the inflation and discount rates used in the analysis.
c. Please identify the "first year of deployment."
d. Please explain the difference between the anticipated fourth-year benefits, at the end of the ramp-up period, and the "reference year levels starting in the fifth year."
e. Please reconcile the four-year ramp-up with the statement that "Based on the deployment schedule, annual benefits are estimated to begin in the first year of deployment, ramping up through the first 18 months post-deployment, then remaining steady through the life of the assets." (A Review of Liberty's Customer First Program, p. 42)
f. Please provide the expected benefits each year from 2023 to 2026.
g. Please explain why the first year of savings (2024) is expected to produce only $0.574 million in benefits (Table 13-2), compared to reference-year savings of $39M (A Review of Liberty's Customer First Program, Figure 3)

RESPONSE TO REQUEST NO. 24:

a. Please see attachment "C1_20years"
b. For benefit savings, the inflation rate used is 2.5% beginning in 2021. The discount rate used is 7.25%
c. The "first year of deployment" differs by Liberty region. The different transformations are deployed at different times for different Liberty operating companies.
d. The difference between the fourth-year benefits and the reference year level is related to the impact of escalation and a benefit growth rate that is non-compounding. The benefit growth rate of 0.5% assumes a modest growth in the number of customers. As described in Section 8.4.1 of the CRA report, "Annual benefits achieve reference year levels starting in the fifth year, plus an adjustment for inflation and system growth."
e. The four-year period is a result of differing deployments by region. This is shown in Figure 2 of the CRA report. We assume that once an entity deploys Customer First there is an 18-month ramp up period to maturity for that region. There is not full maturity across Liberty until 2025.
f. As described in chapter 13 of Liberty's testimony, Customer First is a set of enterprise-wide investments, upgrades, improvements, and changes across the Liberty Utilities' Enterprise and its operating utilities, including Liberty CalPeco. The CRA report provides estimates of benefits at a total enterprise level for Liberty Utilities. These estimates were made in 2020. The expected benefits each year are shown below.

Annual Benefits

	2023	2024	2025	2026
OpEx	$14,223,777	$21,554,117	$22,864,823	$23,550,768
CapEx	$5,600,905	$8,583,568	$9,111,820	$9,385,174
Productivity	$8,041,662	$12,015,722	$12,735,272	$13,117,330
Total	$27,866,344	$42,153,407	$44,711,914	$46,053,272

g. Table 13-2 describes the CalPeco specific anticipated savings as a result of Customer First. The reference-year savings of $39M are based on an initial estimate of benefits for the entire Liberty Utilities enterprise as a result of Customer First. These initial estimates were made in 2020.

Response prepared by Karen Hall.

REQUEST NO. 25:

Please reconcile the savings in Table 13-2 with the Cumulative Benefits ($M) in A Review of Liberty's Customer First Program, Figure 4.

a. Please provide the workpapers supporting that Figure 4.

RESPONSE TO REQUEST NO. 25:

Please see response to question 24, part a.

Response prepared by Karen Hall.

REQUEST NO. 26:

For each of the following items (A Review of Liberty's Customer First Program, p. 46), please explain whether considers it to be benefit to customers, and provide the derivation of the savings:

a. "Direct cost savings of $0.9M based on an expected reduction in current annual write-offs." Please explain whether this item reflects earlier disconnection of customers who fall behind on bill payment, and if not, what it represents.
b. "Direct cost savings of $0.4M based on an increased ability to invest and earn a return through reduced lag from meter read to billing." Please explain whether this item reflects customers being billing and paying Liberty earlier. If so, please explain how the analysis reflected the cost to customers of paying earlier.

RESPONSE TO REQUEST NO. 26:

a. The increased access to data and ease of use will aid Customer Service Reps in customer communication and working with customers (Section 1.6 Customer Benefits). There will be an automated collection process which will reduce the timeline for collection. This will lead to better enforcement of billing and allow for easier communication with customers in establishing payment schedules.
b. Yes, this item does reflect customers paying Liberty in a more efficient manner. This analysis does not reflect cost to customers of paying earlier, as this is an analysis of benefits generated at the Liberty enterprise level that inure to ratepayers through cost reductions and efficiencies. Please note, this analysis was done prior to the adoption of the COVID-related disconnections moratorium.

Response prepared by Karen Hall.

Attachments

Forecasted 2022 Calendar Year Data: Full Year Residential Customers:

	sales	No. cust	Percent of Sales	Percent of Cust
total res	299,122,262	43,887		
d-1	268,290,473	40,043	89.69%	91.24%
care	26,778,204	3,748	8.95%	8.54%
ds-1	2,989,199	45	1.00%	0.10%
dm-1	1,064,386	51	0.36%	0.12%
check on total	299,122,262	43,887	100.00%	100.00%

2022 Load Research Analysis Non-coincident Class Peak - MW

peak	SYSTEM	CALRES	A1	A2	A3	CALSTRT	CALOLS	CALIS	CAL_SUM	Total
Winter On	131,362	80,326	18,019	13,882	33,172	121	205	112	131,362	145,838
Winter Mid	117,904	67,490	20,649	14,690	38,849	22	37	107	117,904	141,843
Winter Off	117,194	61,106	15,836	13,880	37,203	117	199	112	117,194	128,453
Summer On	88,534	53,737	17,484	14,643	15,028	126	216	695	88,534	101,928
Summer Off	80,355	44,873	15,793	11,830	14,767	121	208	746	80,355	88,340
Max	131,362	80,326	20,649	14,690	38,849	126	216	746	131,362	155,602

Annual Diversity 1.18

Transformer Loading Estimates

Customer Class	Average Hourly Peak1	Method Used
Residential	4.2	100 Groups of 4 Random Customers Averaged
Residential	3.9	100 Groups of 5 Random Customers Averaged
Residential	3.9	100 Groups of 6 Random Customers Averaged
Residential	3.7	100 Groups of 7 Random Customers Averaged
Residential	3.9	100 Groups of 8 Random Customers Averaged
Residential	3.8	100 Groups of 9 Random Customers Averaged
A1 - Commercial	22.1	100 Groups of 2 Random Customers Averaged
A1 - Commercial	18.7	100 Groups of 3 Random Customers Averaged
A1 - Commercial	14.7	100 Groups of 4 Random Customers Averaged
A2 - Commercial	86.2	Non-Coincident Annual Hourly Peak of All Customers Averaged
A3 - Commercial	1,247.7	Non-Coincident Annual Hourly Peak of All Customers Averaged

1Source: Output from program SASTEST.SPR.BZ\sas\CALIFORNIA\TEST\LOAD_RESEARCH\

CAL_EXTRACT[PROGRAMS\TRANSFORMER LOADING/XFMRLDCA.SAS

Updated # of Customers Below for 2013

Customer Class	Customers per transformer	Final Line Transformer Coincident Loading	Customers in Class	Non-Coincident Loading at Final Line Transformer	Weighting		Avg Peak/customer	eak/cus/kw			
Residential	4	16.8	41,614	87,389	0.5	Residential	4.07				4.2
Residential	5	19.7		81,979	0.5						3.94
Residential	6	23.5									3.92
Residential	7	25.9									3.70
Residential	8	30.9									3.86
Residential	9	34.3									3.81
A1 - Commercial	2	44.1	5,030			A1-Commercial	14.68				22.05
A1 - Commercial	3	56.1									18.7
A1 - Commercial	4	58.7		73,820	1						14.675
A2 - Commercial	1	109.0	229	19,725	1	A2-Commercial	104.40	#N/A	forecast	86.196	108.99
A3 - Commercial	1	776.8	55	69,041	1	A3-Commercial	912.71	#N/A	forecast		776.84
		OLS		197	0.00059	OLS	197.00				
		STRT		104	0.00031	STRT	104.00				
		PA		399	0.00120	PA	399.00				
		Total custs	46,928	332,654							

Note: OLS, STRT and PA use class maximum kW.

February 8, 2022

DATA REQUEST RESPONSE

LIBERTY UTILITIES (LIBERTY)
A.21-05-017
Test Year 2022 General Rate Case

Data Request No.: SBUA Set 6

Requesting Party: Small Business Utility Advocates

Originator: James Birkelund james@utilityadvocates.org
Jennifer Weberski jennifer@utilityadvocates.org

Date Received: January 26, 2022

Due Date: February 4, 2022

Extension:

REQUEST NO. 1:

A-1 RD tab of A3CC-Liberty 21 Attachment.xlsx: Please confirm that the headings "Proposed Rates (A-1 > 20kW) and "Proposed Rates (A-1A <= 20 kW)" are reversed.

RESPONSE TO REQUEST NO. 1:

Confirmed. The headings were inadvertently reversed.

Prepared by Tim Lyons.

REQUEST NO. 2:

Please provide the "Transformer Load Study" cited in Allocation-Summary tab of A3CC-Liberty 21 Attachment.xlsx.

RESPONSE TO REQUEST NO. 2:

Please refer to the SBUA-Liberty 3.16 Attachment provided in response to SBUA Set 3.

Response prepared by Tim Lyons.

REQUEST NO. 3:

Allocation-Summary tab of A3CC-Liberty 21 Attachment.xlsx:

a. Please explain why the Company uses multiple distribution load allocators (Transformer Load Study NCPs %, NCP Demands (MW) and the TOU Allocation).
   i. Please provide the rationale for using each of the three distribution load allocators.
   ii. Please explain which account numbers or types of distribution plant are represented by each of the allocators.
   iii. Please explain how the Company derived the relative weights for the three distribution load allocators.
   iv. Please confirm that 50% of the distribution demand costs are allocated on the TOU Allocation, with another 25% allocated on each of the Transformer Load Study NCPs % and the NCP Demands (MW) allocators.

b. Please explain why the Company uses a measure of transformer loading as an allocator for a portion of distribution demand costs, when line transformers are included distribution customer costs.

c. Please explain why Irrigation, OLS and Street Lighting are shown as having no NCP in row 156.

RESPONSE TO REQUEST NO. 3:

a. The Transformer Load Study NCPs and NCP Demands were used to allocate distribution demand costs to each rate class. The TOU Allocation was used to allocated distribution demand costs to each TOU period.
   i. The Transformer Load Study NCP and NCP Demands measure rate class demands utilizing different approaches. Transformer Load Study NCP measures rate class demands at transformers while NCP Demands measure rate class demands at meters. The marginal cost study utilized an average of both rate class demands.
   ii. There are two types of distribution plant represents by the allocators: (1) substation plant investments (362), and (2) non-revenue plant investments (360-361 and 364-373). We note the latter investments inadvertently included Accounts 368-373.
   100 percent of substation plant investment was allocated based on the TOU Allocation. 50 percent of the non-revenue plant investment was allocated based

on an average of the Transformer Load Study NCPs and NCP Demands and 50 percent was allocated based on the TOU Allocation

iii. The allocation of substation plant investment reflects its planning requirements as meeting system peak demands. The allocation of non-revenue plant investments reflects its requirements as meeting system demand as well as class demands.

iv. Please see response to ii.

b. The Transformer Load Study NCP is not used to allocate transformer costs. It is used to allocate distribution demand costs.
c. There are no metered NCP Demands for the Irrigation, OLS, and Street Lighting rate classes. Thus, the allocation of distribution demand costs utilizing NCP demands relies only on the Transformer Load Study NCPs.

Response prepared by Tim Lyons.

REQUEST NO. 4:

MDD-Plant_Investments tab:

a. Please reconcile the “Total Distribution Plant Additions” column and the “Substation Plant Additions” column with the “Additions” column of page 206 of the Company’s FERC Form 1, for each year for which CalPECo produced a stand-alone FERC Form 1.
b. Please explain which customer-allocated distribution accounts the Company excluded from the “Total Distribution Plant Additions.”
c. If any accounts are included in both MDD and MDC, please explain why and whether this arrangement results in double-counting some costs.
d. Please explain why the Company describes Total Distribution Plant Additions” minus “Substation Plant Additions” as “Customer/Nonrevenue Additions.”
    i. In what sense are these distribution costs customer-related and/or not related to revenue.

RESPONSE TO REQUEST NO. 4:

a. FERC Form 1 for 2020 only reflected classified distribution plant additions for the year. The plant forecast model included general ledger account 106 - unclassified plant additions at year-end in the amount of $35 million
b. Please refer to response to 3.(a).(ii).
c. Please refer to response to 3.(a).(ii).
d. Please refer to response to 3.(a).(ii). The “Customer/Nonrevenue Additions” column includes all distribution plant additions, other than substation plant additions.

Response prepared by Tim Lyons.

REQUEST NO. 5:

MDD-Inputs tab of A3CC-Liberty 21 Attachment.xlsx:

a. Please explain why the analysis sets the demand-related % of distribution O&M as the percentage of investment that is for substations.
b. Please explain why the Company forecast “Primary Distribution O&M” to quintuple from 2020 to 2021.
c. Please provide all available documentation of the “Company Forecasts” from which the “Primary Distribution O&M” for 2021–2024.
d. Please provide the actual “Primary Distribution O&M” for 2021.
e. Please list the accounts that the Company intended to be in “Primary Distribution O&M.”
f. Please explain why note (1) defines “Primary Distribution O&M” as “Accounts 585, 596, and 598, which are just the operating expenses for (585) Street Lighting and Signal System Expenses, (586) Meter Expenses and (587) Customer Installations Expenses,” but no maintenance expenses?
g. Please reconcile the “Primary Distribution O&M” column with the O&M data on p. 322 of the Company’s FERC Form 1.

RESPONSE TO REQUEST NO. 5:

a. The analysis is estimating that portion of distribution O&M that is related to peak demand. Substation investments reflect increases in peak demand.
b. The increase is primarily related to Wildfire Mitigation Plan expenses. Please see table 6-1 in Chapter 6 of Liberty’s Testimony which illustrates the O&M forecast.
c. The Primary Distribution O&M forecast is presented in the Company’s Revenue Requirement model, Tab ‘O&M’, Cols G through O, Row 61
d. The total distribution O&M for 2021 was $8,971,887.
e. The Primary Distribution O&M includes all distribution operations and maintenance expenses (Accounts 580 through 598). Note (1) has inadvertent error.
f. Please see response to part (e).
g. Liberty included the wrong distribution expense amount for 2020. The 2020 amount should be $7,091,888 and match Liberty’s FERC Form 1.

Response prepared by Tim Lyons.

REQUEST NO. 6:

MDC-Unit_Investments tab of A3CC-Liberty 21 Attachment.xlsx:

a. Please provide the data and derivation for the following:
    i. the Underground (U/G) Investment % for each class
    ii. the Percentage Installations columns for Overhead and Underground Installations
b. Please reconcile the assumption that 80% of A-1 customers are served by three-phase service with the data in the A-1 RD tab, which report only 7% of A-1 customers to have loads over 20 kW.
    i. Please explain why the Company would serve most A-1 customers with loads under 20 kW at three-phase service.
c. Please explain why the Company would serve 50% of customers with 75 kVA (or 3 × 25 kVA) dedicated transformers, rather than dedicated 50 kVA transformers, if only 7% of customers have loads over 20 kW.
d. Please explain why the Company assumes all A-1 customers with dedicated transformers require at least 50 kVA, if only 7% of customers have loads over 20 kW.
e. Please explain why 4 Permanent Residential customers, averaging 810 kWh/month apiece (tab Res_Perm RD), can share a 25 kVA transformer, but most A-1 customers under 20 kW, averaging 1,034 kWh/month (tab A-l RD), require dedicated 50 kVA or larger transformers.

RESPONSE TO REQUEST NO. 6:

a.
    i. The Underground (U/G) Investment percentage for each class was taken from the Company's marginal cost study filed in the Company's prior rate case, which reflected a general assessment of the percentage for each rate class.
    ii. The Percentage Installations columns for Overhead and Underground Installations was taken from the Company's marginal cost study filed in the Company's prior rate case, which reflected a general assessment of the percentage for each rate class.
b. The assumption was taken from the Company's marginal cost study filed in the Company's prior rate case, which reflected a general assessment of the Company's system design for each rate class.
    i. Please refer to (b).
c. Please refer to (b).

d. Please refer to (b).
e. Please refer to (b).

Response prepared by Tim Lyons.

REQUEST NO. 7:

Class_NCPs tab of A3CC-Liberty 21 Attachment.xlsx:

a. Please provide the derivation of the class NCPs in lines 27, 28, 37-40, 43-45, with all supporting data and reports.
b. Please explain why line 37 does not equal the sum of lines 24–26.
c. Please explain why line 37 does not equal the sum of lines 38-40.
d. Please explain why line 43 does not equal the sum of lines 44 and 45.
e. Please provide the derivation of the "Avg. Peak Transformer Loading / Customer" row, with all supporting data and reports.

RESPONSE TO REQUEST NO. 7:

a. The supporting workpapers were provided in the Company's response to SBUA-Liberty 3.17 Attachment 2.
b. Line 37 represents total Residential Class NCPs. Lines 24-26 represent individual residential sub-classes NCPs (permanent, non-permanent, sub-metered).
c. Line 37 represents total Residential Class NCPs. Lines 38-40 represent individual residential sub-classes NCPs (permanent, non-permanent, CARE).
d. Line 43 represents total A-3 class NCPs. Lines 44-45 represent individual A-3 sub-classes NCPs (Ski, Non-Ski).
e. Please refer to SBUA-Liberty 3.16 Attachment.

REQUEST NO. 8:

With regard to the file "2020-21 NCP by rate class.xls,"

a. Please provide the derivation of the 2020 estimates, with all supporting data and reports.
b. Please explain the meaning of the "Note: 2021 values not based on rate class load study but rather spreading the 2021 monthly sales forecast by month and ranked day of week hourly proportions by rate class."
c. Please provide the calculations that produced the 2021 row.

RESPONSE TO REQUEST NO. 8:

a. Liberty's "2020-21 NCP by rate class" file is based on a load research sample derived from sample of Liberty's customer data. The information would be voluminous to provide in totality. Liberty can provide a sample dataset in a supplemental response by the end of this week.
b. The load research sample 2020 rate class hourly load analysis results were used to spread the 2021 GRC monthly rate class sales forecast with line losses added into hourly values to support marginal cost analyses. The hourly values were derived by first converting the 2020 rate class loads into hourly proportions. Second, the monthly hourly proportions were ranked by day of the week (e.g., the first Friday of the month would be assigned the number 1, second Friday number 2, third Friday number 3, fourth Friday number 4, and the fifth Friday number 5. If there were 5 Fridays in a 2021 month but only 4 Fridays in 2020, then the 2020 4th Friday proportions were utilized for the 5th Friday). Third, day of week hourly proportions were converted into the 2021 monthly hourly proportions using the day of the week (e.g., if the 1st of the month was on Thursday then day 1 of the would have the 1st Thursday hourly proportions). Fourth, the 2021 GRC monthly rate class customer sales values were converted into hourly loads by employing the monthly hourly proportions described in the previous step. Fifth, rate class line losses (which vary by season and time of day) are added to the rate class hourly loads. Last, system hourly loads were computed by summing the hourly rate class loads. The end product is 8760 rows of hourly and system 2021 loads.
c. The development of the 2021 hourly rate class loads was explained above in response to part b. Using the 2021 rate class hourly loads, analysis was done by sorting rate class specific hourly loads in descending order to identify the annual peak value, the hour and date.

February 8, 2022

DATA REQUEST RESPONSE

LIBERTY UTILITIES (LIBERTY)
A.21-05-017
Test Year 2022 General Rate Case

Data Request No.: SBUA Set 7

Requesting Party: Small Business Utility Advocates

Originator: James Birkelund james@utilityadvocates.org
Jennifer Weberski jennifer@utilityadvocates.org

Date Received: January 26, 2022

Due Date: February 4, 2022

Extension:

REQUEST NO. 1:

Regarding the allocation of transformer costs in the MDC:

a. Please provide the total number of final line transformers in service by rating (e.g., single phase 50 kVA, three phase 300 kVA, etc.).
b. Please reconcile the customer per transformer data in CalPeco MCOS and Rate Design v Supplemental Workpaper, tab MDC-Unit_Investments with the percentage sharing transformer data in Liberty's response to SBUA DR 3-5. The response to SBUA DR 3-5 indicates that only 14.1% of customers are served on an unshared transformer.

MDC-Unit_Investments

Rate Class	Percent of Underground Installations with 1 Customer Served per Transformer	Percent of Overhead Installations with 1 Customer Served per Transformer
A-1	70%	100%
A-2	100%	100%
A-3	100%	100%
Irrigation	100%	100%

c. Please provide support for each estimate of the number of customers served per transformer in CalPeco MCOS and Rate Design v Supplemental Workpaper, tab MDC-Unit_Investments.
d. Regarding the unit investments cost calculations, please provide support for each cost per unit value in CalPeco MCOS and Rate Design v Supplemental Workpaper, tab MDC-Unit_Investments.

RESPONSE TO REQUEST NO. 1:

a. Liberty has approximately 8,453 active transformers in its current Geospatial Information System ("GIS"). Please note that Liberty is upgrading its GIS to accurately account of all system assets.

	Bank Count	Transformer Count
Padmount Transformers	n/a	2852
1 Transformer Overhead Banks	4936	4936
2 Transformer Overhead Banks	91	182
3 Transformer Overhead Banks	161	483
Total	5188	8453

b. The customer per transformer data in the MCOS file is number of customers that the respective transformer can serve. This is shown for rate design purposes to calculate an average cost per customer.
c. The assumption was taken from the Company's marginal cost study filed in the Company's prior rate case, which reflected a general assessment of the Company's system design for each rate class.
d. The assumption was taken from the Company's marginal cost study filed in the Company's prior rate case, which reflected a general assessment of the Company's system design for each rate class.

Response prepared by Tim Lyons.

Substaion	Feeder	Voltage (kV)	OH miles	UG Miles	Length (Miles)	2019 peak load (MW)	Date and Time	2020 peak load (MW)	Date and Time	2021 peak load (MW)	Date and Time
Portola	31	14.4	13.6	1.84	15.44	4.8	10/31 8AM	12.1	7/17 8PM	7.9	8/17 9PM
	32	14.4	20.97	1.66	22.63	9.9	10/31 3PM	4.2	11/17 12AM	3.2	8/18 4AM
Cemetery	41	14.4	6	1.36	7.36	0.3	N/A	0.3	N/A	0.3	N/A
	42	14.4	3.42	0.23	3.65	0.3	N/A	0.3	N/A	0.3	N/A
Sierra Brooks	51	14.4	0.18	0.22	0.4	0.65	12/18 11PM	0.74	11/17 12PM	0.73	7/10 10PM
Stampede	8700	24.9	0.32	0.5	0.82	N/A	N/A	N/A	N/A	N/A	N/A
Russell Valley	7900	14.4	3.29	2.39	5.68	N/A	N/A	N/A	N/A	N/A	N/A
Hobart	7700	12.5	8.95	0.09	9.04	0.18	5/24 10AM	0.14	7/13 1PM	0.14	11/4 12PM
Glenshire	7400	14.4	32.89	8.84	41.73	2.7	12/17 1PM	3.1	2/4 10AM	4.4	12/14 10PM
	7600	14.4	5.24	0.53	5.77	1.3	12/17 11AM	1.5	1/6 11AM	0.24	12/14 9PM
Truckee	7202	14.4	12.12	0.93	13.05	1.9	9/28 1PM	11	12/3 12PM	0.75	11/24 11AM
	7203	14.4	9.82	60.42	70.24	9.1	12/10 1AM	13.4	11/13 7PM	14.4	10/26 10AM
	7204	14.4	6.82	0.76	7.58	N/A	N/A	N/A	N/A	N/A	N/A
Northstar	8400	14.4	0	5.75	5.75	10.6	9/19 6AM	1.2	1/2 5AM	1.3	10/24 10PM
	8500	14.4	0	16.28	16.28	12.5	1/3 11PM	9.5	2/4 8AM	12.1	12/9 6PM
	8600	14.4	0.13	9.58	9.71	10.2	11/25 10PM	10.3	11/25 10PM	10.3	11/24 3AM
Kings Beach	4201	14.4	9.16	5.25	14.41	N/A	N/A	1.4	12/31 7PM	6.8	7/29 5AM
	4202	14.4	9.45	4.53	13.98	N/A	N/A	3.8	12/31 6PM	9.2	7/21 10PM
	5100	14.4	0.66	0.31	0.97	N/A	N/A	N/A	N/A	9.9	10/12 10AM
	5200	14.4	23.24	0.11	23.35	N/A	N/A	N/A	N/A	11.8	2/14 4AM
Tahoe City	5201	14.4	21.45	11.65	33.1	13.1	1/17 8PM	11.9	12/28 11AM	11.5	1/2 2AM
	7100	14.4	13.25	9.96	23.21	9.3	12/1 10PM	4.2	1/18 9PM	6.9	2/13 8PM
	7200	14.4	1	0.03	1.03	2.4	2/14 1PM	1.4	11/5 4AM	3.4	12/25 12PM
	7300	14.4	57.48	11.84	69.32	12.5	2/22 3PM	9.4	12/29 5PM	12.1	2/14 4AM
Squaw Valley	7201	14.4	11.98	6.27	18.25	7.3	12/15 5PM	9.4	8/5 12PM	12.8	12/14 3AM
	8100	14.4	0	2.92	2.92	1.5	12/28 2PM	1.5	1/2 12PM	3.6	12/20 5PM
	8200	14.4	4.91	6.05	10.96	2.9	12/28 2PM	3.2	6/12 1PM	3.2	12/20 5PM
	8300	14.4	1.38	12.79	14.17	10.9	12/29 6PM	33.5	12/26 11AM	35.3	12/15 4AM
Silver Lake	257	24.9	2.97	0.02	2.99	11.8	11/1 12PM	11.5	8/9 8PM	11.9	7/9 8PM
Washoe	201	24.9	7.26	0.003	7.263	N/A	N/A	N/A	N/A	N/A	N/A
California	204	24.9	4.37	0.61	4.98	17.4	7/12 12PM	9.8	2/4 11AM	19.5	9/8 8PM
Meyers	3100	14.4	17.6	5.68	23.28	7.3	3/4 1PM	8.2	3/7 5PM	7.1	12/2 10AM
	3200	14.4	21.76	20.63	42.39	9.4	2/9 6PM	8.7	1/17 6PM	12.3	12/4 12PM
	3300	14.4	51.67	5.28	56.95	11.4	2/5 10AM	10.9	7/20 10PM	15.9	12/14 3AM
	3400	14.4	55.1	11.5	66.6	5.4	10/3 3PM	9.2	12/13 6PM	11.5	1/19 5AM
	3500	14.4	27.11	9.09	36.2	13.3	10/1 8PM	7.45	11/6 9PM	9.2	12/14 5PM
Stateline	2200	14.4	0.31	1.48	1.79	9.8	5/11 2PM	5.1	9/5 11PM	5.7	7/10 6PM
	2300	14.4	2.96	3.54	6.5	8.2	5/26 7AM	15.7	9/27 9PM	6.95	10/11 11PM
	3101	14.4	15.62	6.9	22.52	8.3	3/4 1PM	6.8	1/18 9PM	6.9	7/27 5AM
	3501	14.4	13.97	5.57	19.54	29.9	4/18 4PM	9.35	11/26 8PM	12.9	12/15 6PM
Muller	1296	12.47	55.62	3.56	59.18	10.4	12/7 2PM	12.3	11/5 11AM	15.2	6/28 7PM
Topaz	1261	12.47	43.09	13.89	56.98	2.6	8/24 9PM	3.1	7/11 8PM	3.1	7/17 9PM

January 10, 2021

DATA REQUEST RESPONSE

LIBERTY UTILITIES (LIBERTY)
A.21-05-017
Test Year 2022 General Rate Case

Data Request No.:	SBUA Set 2
Requesting Party:	Small Business Utility Advocates
Originator:	James Birkelund james@utilityadvocates.org Jennifer Weberski jennifer@utilityadvocates.org
Date Received:	December 23, 2021
Due Date:	January 10, 2022

REQUEST NO. 1:

Liberty Testimony, Ch. 8, p. 10, lines 9-11. The testimony states that authorized expenses are $0.371 million and that Liberty requests “to keep annual spending at $0.420 million per year.” Please reconcile these figures.

RESPONSE TO REQUEST NO. 1:

Liberty’s expenses for the Solar Initiative Program Balancing Account is currently $0.371 million. As detailed in Chapter 5, Liberty is proposing a budget of $0.420 million a year for the years 2022-2024.

Response prepared by Dan Marsh.

REQUEST NO. 2:

Liberty Testimony, Ch. 12, p. 11, lines 13-18. Please provide the weightings study.

RESPONSE TO REQUEST NO. 2:

Please see attachment "CalPeco MCOS and Rate Design_vSupplemental Workpaper" for the Company's marginal cost study. The referenced weightings are in tab "MDC Inputs", lines 130-163. The Customer Accounts weightings were taken from the marginal cost study filed in the Company's prior rate case, which were based on the Company's analysis of FERC accounts 901-904 for the twelve-month period ending September 30, 2007. The Customer Service weightings were taken from the marginal cost study filed in the Company's prior rate case, which were based on the Company's analysis of FERC accounts 907-910 for the twelve-month period ending September 30, 2007.

Response prepared by Tim Lyons.

REQUEST NO. 3:

Liberty Testimony Ch. 12, p. 11, lines 20-21. Please provide the average facility investments study and the calculation of the annual cost per customer. Please provide original data to support all costs, loadings, requirements, and any other intermediate values.

RESPONSE TO REQUEST NO. 3:

Calculation of the average facility investments per customer for each rate class and supporting data are in the Company's marginal cost study, tab "MDC-Unit_Investments". Calculation of the annual cost per customer for each rate class and supporting data are in the Company's marginal cost study, tab "MDC-Derivation".

Response prepared by Tim Lyons.

REQUEST NO. 4:

Liberty Testimony, Supplemental Ch. 12, Exhibit TSL-S6.

a. Please provide a bill impact analysis for Class A-1 and Class A-2 similar to that produced for residential customers (e.g., p. 3), including the current bill, proposed bill, and May bill.
b. Please provide a working copy of Exhibit TSL and the response to (a) with all formulas and source data intact.

RESPONSE TO REQUEST NO. 4:

a. Please refer to SBUA-Liberty 4(a) Attachment 1 for Class A-1 and SBUA-Liberty 4(a) Attachment 2 for Class A-2.
b. Please refer to attachment "CalPeco MCOS and Rate Design_vSupplemental Workpaper"

Response prepared by Tim Lyons.

Attachments

February 18, 2022

DATA REQUEST RESPONSE

LIBERTY UTILITIES (LIBERTY)
A.21-05-017
Test Year 2022 General Rate Case

Data Request No.: SBUA Set 4 - Supplemental

Requesting Party: Small Business Utility Advocates

Originator: James Birkelund james@utilityadvocates.org
Jennifer Weberski jennifer@utilityadvocates.org

Date Received: January 11, 2022

Due Date: January 25, 2022

Extension: January 28, 2022

REQUEST NO. 1:

Re: Response to SBUA-Liberty 4(a), Attachments 1 and 2

a. Please provide an explanation of the "Rate" code values (tabs A1 and A2, respectively), including the significance of the "M" designation.
b. Please explain whether there is any special billing when two customer IDs are identified for the same location (e.g., Attachment 2, location ID 88500122) or two rates identified for the same location and customer (e.g., Attachment 2, location ID 88143799).
c. Please explain why customers with maximum monthly usage below 500 kWh are in class A-2 (e.g., Attachment 2, location ID 88500335).
d. Please provide a worksheet similar in layout to tabs A1 and A2, respectively, with the monthly maximum demand values for each location and customer.

SUPPLEMENTAL RESPONSE TO REQUEST NO. 1:

Please see revised attachment "SBUA-Liberty 4(a) Attachment2_vRevised 2." This supplemental response reflects rates that have been revised due to a change in A-2 billing demands. The revised A-2 billing demands do not change the results of the marginal cost study. The revised billing demands will be incorporated into the Company's rebuttal testimony.

Response prepared by Tim Lyons