BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates	Rulemaking 22-07-005 (Filed July 14, 2022)

Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association

April 7, 2023

EXECUTIVE SUMMARY OF RECOMMENDATIONS

This testimony presents the recommendations of the Solar Energy Industries Association (SEIA) on the issues concerning new residential fixed charges, in Track A of Phase 1 of this rulemaking on implementing rate designs that incentivize demand flexibility. SEIA recommends that the Commission adopt cost-based, income-graduated monthly fixed charges that satisfy the requirements of Assembly Bill 205 (AB 205), enacted in 2022. This will add new monthly fixed charges to certain residential rate schedules of the California investor-owned utilities (IOUs) that lack such charges today, including adding fixed charges to the default residential rates.

The Commission's Rate Design Principles state that rates should be based on marginal costs, should reflect cost causation, and should promote economic efficiency in the use of energy. In addition, P.U. Code Section 739.9(a) clearly defines a "fixed charge" as a charge "not based on the volume of electricity consumed." To be consistent with these principles and statutory guidance, new cost-based residential fixed charges should be designed to collect no more than the IOUs' marginal customer access costs, which is the only element of the IOUs' cost of service that does not vary with a customer's usage. This also would be in line with the Commission's longstanding rate design policies for non-residential customers, which, for decades, have limited the fixed charges in non-residential rates to only customer access costs. Utility rates also include certain types of costs not directly related to the IOUs' generation, transmission, and distribution services; the testimony discusses why there is no basis for including these costs in a residential fixed charge.

To establish income-graduated fixed charges in compliance with AB 205, the Commission should make use of the fact that the state's current low-income programs already establish three graduated rate tiers for residential customers based on the federal poverty limits (FPL), with the California Alternate Rates For Energy (CARE) and Family Energy Rate Assistance (FERA) programs providing graduated, need-based discounts for overall residential bills. Customers qualifying for CARE (incomes of 200% of the FPL or below) would receive a 30% to 35% discount in their residential fixed charge; customers qualifying for FERA (incomes between 200% and 250% of the FPL) would receive an 18% discount.

SEIA's proposal would result in the fixed charges shown in **Table ES-1** for the default residential rates of the three large IOUs. The same fixed charges also would apply to those residential rates of Pacific Gas & Electric (PG&E) and San Diego Gas & Electric (SDG&E) that do not include a monthly fixed charge today; the small residential fixed charge of less than $1 per month in Southern California Edison's current residential rates would be increased to the levels shown in Table ES-1. Finally, SEIA proposes no change to the residential electrification or EV charging rates of the IOUs that, as the result of past adopted settlements or Commission decisions, have higher fixed charges today than the cost-based levels in Table ES-1.

Table ES-1: *SEIA's Proposed Fixed Charges for Default Residential Rates ($ per month)*

Utility	Tier 1: CARE		Tier 2: FERA+		Tier 3: All others	
	Discount	Fixed Charge	*Discount*	Fixed Charge	*Discount*	Fixed Charge
PG&E	*35%*	4.93	*18%*	7.45	*0%*	9.09
SCE	*32.5%*	5.32	*18%*	7.71	*0%*	9.41
SDG&E	*34%*	7.43	*18%*	10.77	*0%*	13.14

SEIA has used the common E3 model developed for this case to calculate the bill impacts of our proposal. Generally, our proposal would reduce the volumetric portion of the IOUs' default rates by small amounts in the range of $0.01 to $0.06 per kWh, and would result in modest bill impacts. There would be small rate reductions (generally less than 2%) for many CARE and FERA customers on TOU rates and small rate increases (less than 1%) for low-usage customers in cool coastal climate zones. These impacts are manageable for all customers and would not impair customers' incentive to conserve energy and to use electricity at times that are beneficial to the electric system as a whole. This outcome is consistent with the Commission's rate design principles to encourage the efficient use of energy and to minimize bill impacts in any transition to new rates.

We recommend that the Commission use the established CARE and FERA programs to comply with the income-graduation requirements of AB 205. Another of the Commission's central rate design principles is that a change in rates should be understood and accepted by customers. The CARE and FERA programs are well-known to customers; CARE in particular has high penetration. There are established marketing programs for CARE and FERA, as well as procedures for income verification. Linking the new fixed charges to CARE and FERA eligibility will minimize the customer education required to gain customer acceptance and understanding of the new rates.

SEIA cautions the Commission that adopting new fixed charges for some residential rate schedules is only a small step in advancing the state's electrification efforts. In general, fixed charges should not be expected to play a major role in rate designs that promote electrification. SEIA's proposed fixed charges will result in a small decrease in volumetric rates across the board. Far more important to promoting electrification are cost-based, time-sensitive volumetric rates, with low off-peak rates to encourage incremental usage in low-demand hours and high on-peak rates to signal when customers should avoid using energy to maintain system reliability. Fixed charges by definition do nothing to encourage the stated goal of this rulemaking – encouraging customers to be flexible in when they impose demands on the electric system. The only way for customers to respond to high fixed charges is to leave the system entirely – a result that may become increasingly economic in the future and that the Commission should strive to avoid.

Finally, the Commission should decline to adopt fixed charge proposals that are specific to any particular type of distributed energy resource (DER). One of the Commission's rate design principles is that rate design should be technology-agnostic. For example, with respect to one type of DER – solar – the Commission has just finished crafting a new net billing tariff for solar customers that involved striking a delicate balance between the involved interests – a balance that would be upset by new solar-specific fixed charges. More broadly, a proliferation of DER-specific rates will not advance the rate design principle that customers should understand and accept the rates that they pay. What the Commission should do is to focus on implementing a few basic time-of-use rate designs based on marginal costs for broad customer classes. This will encourage customers to be more flexible and intelligent in when they place demand on the grid, and to invest in multiple types and combinations of DERs – outcomes which should be the Commission's goals in our rapidly electrifying world.

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I. INTRODUCTION

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae*, which is **Attachment RTB-1** to this testimony. As reflected in my CV, I have almost 40 years of experience on rate design and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the Commission, working on the implementation of PURPA. Since leaving the Commission in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony, studies, or reports on numerous occasions before this Commission as well as state regulatory commissions in many other states. My CV includes a list of the formal testimony that I have sponsored before this Commission and in other state regulatory proceedings concerning electric and gas utilities.

Q: Please describe more specifically your experience on rate design.

A: Over the last 15 years, I have sponsored testimony on rate design issues in numerous General Rate Case (GRC) Phase 2 proceedings at this Commission involving all three of the major California investor-owned utilities (IOUs). I also represented several solar industry groups in the CPUC's major investigation from 2012-2015 into residential rate design in California, and testified on behalf of the Solar Energy Industries Association (SEIA) and Vote Solar in R. 20-08-020, the Commission's rulemaking to revise California's policies for customer-sited renewable distributed generation (DG).

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of SEIA. SEIA is the national trade association of the United States solar industry. Through advocacy and education, SEIA and its 1,000 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. SEIA's members have a strong interest in the adoption and implementation of innovative, forward-looking policies and programs that will accelerate the development of solar photovoltaic (PV) generation. The views contained in this testimony represent the position of SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

Q: What is the purpose of your testimony?

A: My testimony presents SEIA's proposal for income-graduated fixed charges for the residential customers of the IOUs, pursuant to the requirements of Assembly Bill 205 (AB 205), enacted in 2022.

II. POLICY BACKGROUND

A. Purpose of this Rulemaking on Demand Flexibility

Q: What is the purpose of this rulemaking proceeding?

A: This OIR focuses on a broad review of innovative electric rate designs that can improve the ability of customers to shift or change their electric demand in ways that will help California achieve its climate, clean energy, and environmental justice goals. In the coming years, California's electricity use is expected to rise significantly, as the state pursues the widespread electrification of buildings and transportation to meet the state's climate goals. Given this growth in demand, ensuring reliable electric service during peak demand periods in the summer will continue to be a challenge. Finally, the state's electric rates are high, presenting a challenge to customers' ability to afford this essential commodity – especially given that customers also will be asked (or required) to make new long-term investments in electrification technologies such as electric vehicles (EVs) and heat pumps. In this environment, there needs to be an increasing emphasis on time-varying and dynamic rates that encourage customers to focus their increased electricity use at times when electricity supplies are cleaner, more abundant, and lower in cost.

As set forth in the OIR, the objectives of this proceedings are as follows:

1. enhance the reliability of California's electric system;
2. make electric bills more affordable and equitable;
3. reduce the curtailment of renewable energy and greenhouse gas emissions associated with meeting the state's future system load;
4. enable widespread electrification of buildings and transportation to meet the state's climate goals;
5. reduce long-term system costs through more efficient pricing of electricity; and
6. enable participation in demand flexibility by both bundled and unbundled customers.

Q: What is the specific purpose of your testimony in the context of this OIR?

A: The Scoping Memo for this OIR, issued on November 2, 2022, established two phases to this OIR, with Phase 1 divided into two concurrent tracks. This testimony responds to the issues in Track A of Phase 1 concerning the implementation of income-graduated fixed charges in the residential rates for all IOUs, to comply AB 205. It makes sense for this track of Phase 1 to proceed immediately, as AB 205 includes a deadline of July 1, 2024 to establish income-graduated fixed charges in the IOUs' default residential rates. That said, it is important to keep in mind the broad scope for this OIR and to recognize that new residential fixed charges are not the only needed rate design change. Moreover, in my opinion, as discussed in Section V of this testimony, new fixed charges will do little to advance the Commission's demand flexibility goals.

B. Assembly Bill 205

Q: What are the key provisions of Assembly Bill 205 concerning residential fixed charges?

A: AB 205 amends Section 739.9 of the Public Utilities Code, with the following essential provisions:

- The new law allows (but does not require) the Commission to authorize fixed charges for any rate schedule applicable to residential customers, without a cap on the amount of the fixed charge.
- AB 205 requires the PUC, no later than July 1, 2024, to approve a fixed charge for the "default" residential rate schedules that apply to residential customers who do not affirmatively choose another optional rate.
- The fixed charge must be established on an income-graduated basis, with no fewer than three income thresholds, "so that a low-income ratepayer in each baseline territory would realize a lower average monthly bill without making any changes in usage."
- The PUC must ensure that the approved fixed charges do not unreasonably impair incentives for beneficial electrification and greenhouse gas reduction.

It is also important to note the portions of P.U. Code Section 739.9 that AB 205 did not change. Section 739.9(a) defines "fixed charge" as "any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, or other charge not based on the volume of electricity consumed." Further, Section 739.9(e) specifies that "[t]he commission may adopt new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of the fixed costs of providing electric service to residential customers," while ensuring that the approved fixed charges (1) "Reasonably reflect an appropriate portion of the different cost of serving small and large customers," (2) "Not unreasonably impair incentives for conservation and energy efficiency," and (3) "Not overburden low-income customers."

C. Revised Rate Design Principles

Q: As part of Track B of Phase 1 of this OIR, the Commission has been considering changes to its Rate Design Principles. Please discuss the status of that review.

A: On March 16, 2023, the Commission issued a proposed decision (PD) in this docket presenting proposed revisions to the Rate Design Principles. The new principles set forth in this PD are listed below.

1. All residential customers (including low-income customers and those who receive a medical baseline or discount) should have access to enough electricity to ensure that their essential needs are met at an affordable cost.
2. Rates should be based on marginal cost.
3. Rates should be based on cost causation.
4. Rates should encourage economically efficient (i) use of energy, (ii) reduction of greenhouse gas emissions, and (iii) electrification.
5. Rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner.
6. Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs.
7. Customers should be able to understand their rates and rate incentives and should have options to manage their bills.

8. Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals.
9. Rate design should not be technology-specific and should avoid creating unintended cost-shifts.
10. Transitions to new rate structures should (i) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (ii) minimize or appropriately consider the bill impacts associated with such transitions.

SEIA's proposal in this testimony has been guided by these principles.

D. The Importance of Time-Dependent Rates

1. Default TOU rates for all customer classes

Q: Have Commission rate design policies strongly supported the use of time-dependent rates for all customer classes, including residential?

A: Yes. In 2012, the Commission launched a rulemaking proceeding on retail rate reform for residential customers (R. 12-06-013). D. 15-07-001 in this rulemaking announced a goal to implement default time-of-use (TOU) rates for residential customers. As part of this process, in 2015 the Commission instituted a rulemaking (R. 15-12-012) to develop "a framework for designing, implementing, and modifying time periods for use in future time-of-use (TOU) rates," including the "development of the principles, methodologies, and data sources needed to identify TOU periods."[1] Subsequent general rate case (GRC) Phase 2 cases adopted new TOU periods for all three IOUs following the guidelines developed in R. 15-12-012, with a new, consistent statewide peak period of 4 p.m. to 9 p.m. The Commission then developed and oversaw a multi-year transition to default TOU rates for all of the IOUs' residential customers. This transition is now substantially complete. At the same time, all non-residential customers have moved to TOU rates with the 4 p.m. to 9 p.m. peak period.

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[1] *See* R. 15-12-012, at p. 2.

2. Time-dependent delivery rates

Q: Are the IOUs' costs for the electric grid that delivers power also time dependent?

A: Yes. An important part of the move to TOU rates has been the Commission's recognition that a significant share of the electric utilities' transmission and distribution (T&D or "delivery") costs are time-dependent. This has resulted in a significant move away from the use of delivery rate components that do not vary with time. For example, recent Commission rate cases have moved away from the use in commercial and industrial (C&I) rates of non-coincident demand charges (NCDCs) that are not time-dependent. As one example, in D. 17-08-030, the Commission rejected San Diego Gas & Electric's (SDG&E) proposal to recover 100% of its distribution costs through NCDCs in its medium and large C&I rates. Instead, the Commission adopted SEIA's proposal that 100% of substation costs and 50% of distribution costs should be collected through time-dependent rates; this reduced the overall recovery of distribution costs through NCDCs to 39%. It is useful to quote D. 17-08-030 to provide the broader context:

> … the CPUC is moving to greater use of TOU and other time-varying rates. TOU is now mandatory for all C&I customers, we have established a transition plan for residential customers to move to default TOU rates, and TOU rates are now mandatory for net energy metering (NEM) 2.0 customers. This trend of increasing CPUC reliance on time dependent rates is important because it would be inconsistent to simultaneously increase our use of noncoincident demand charges which are non-time dependent.[2]

Other recent GRC Phase 2 and Rate Design Window decisions also have reduced the use of NCDCs and encouraged the greater use of time-dependent charges throughout the IOUs' electric rate designs.[3]

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[2] *See* Decision 17-08-030, p. 40.

[3] See D. 18-08-013, at pp. 47-51, criticizing PG&E's excessive reliance on NCDCs; also D. 22-11-022, at pp. 24-26, rejecting an SDG&E proposal for a fixed monthly customer charge that would be set annually at one of four tiers using the average of a customer's top three monthly non-coincident demand peaks over the last 12 months.

3. State policies support storage resources.

Q: Why has state policy supported the growth of storage resources?

A: The time-dependence of utility costs and the state's increasing reliance on renewable resources whose output varies over time have resulted in the increasing emphasis of state policy on the development and deployment of storage resources. Assembly Bill 2514 (PU Code Section 28836 *et seq.*), enacted in 2010, directed the Commission "to consider a variety of possible policies to encourage the cost-effective deployment of energy storage systems."[4] Responding quickly to this legislation, the Commission opened a rulemaking in December 2010, stating that it viewed "the enactment of AB 2514 as an important opportunity for this Commission to continue its rational implementation of advanced sustainable energy technologies and the integration of intermittent resources in our electricity grid," and as a means to provide economic and environmental benefits for the state.[5] In subsequent GRC Phase 2 cases for Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), the Commission has adopted new rates designed to encourage deployment of customer-sited storage. For residential customers, these new storage-friendly rates include EV2 for PG&E and TOU-D-PRIME for SCE. These rates feature volumetric TOU rates with large differentials between on- and off-peak rates that encourage the daily cycling of the storage capacity, with the storage discharged during the peak period when marginal costs and greenhouse gas emissions are the highest.

4. Electrification rates

Q: Why has the Commission prioritized the development of residential rates that support electrification of buildings and transportation?

A: Customer adoption of electrification measures is an essential element of the state's effort to reduce greenhouse gas (GHG) emissions and to fight climate change. The California Air Resources Board's most recent update to its AB 32 Scoping Plan seeks to achieve

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[4] P.U. Code Section 2836 (a).

[5] R.10-12-007, at pp. 2 and 4.

carbon neutrality by 2045. The Commission has recognized that this goal is only achievable in a "High DER" future in which all Californians make personal, long-term investments in the distributed energy resources (DERs) – rooftop solar, on-site storage, electric vehicles (EVs), and residential electric heat pumps – that will be needed to reduce carbon pollution in the energy, building, and transportation sectors.[6] Electrifying vehicles (to replace the use of gasoline and diesel) and buildings (to displace natural gas for water heating and space conditioning) is widely viewed as the least-cost means to reduce carbon emissions in the transportation and building sectors, emissions that accounted for 40% and 11% of the state's GHG emissions in 2019, respectively.[7]

For residential customers to have an economic incentive to adopt these DERs, the rate that they pay for the electricity to power the DER must be competitive with the fossil fuel that is displaced, such that the savings in operating costs contribute to offsetting what can be the higher capital cost of the DER, compared to the fossil-fueled alternative.[8] To accomplish this, economic electrification in California will require a dramatic expansion of off-peak electric use, given that average residential rates are high. Low-cost off-peak power is also needed to charge the storage that will serve on-peak loads, and to provide adequate savings to incent the beneficial daily cycling of storage. To encourage residential electrification, the Commission has approved optional electrification rates for

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[6] On June 14, 2021, the Commission issued a new rulemaking (OIR) "to modernize the electric grid for a high distributed energy resources future."

[7] California Air Resources Board, *California Greenhouse Gas Emissions for 2000 to 2019: Trends of Emissions and Other Indicators* (released July 28, 2021), at p. 8 (Figure 4). Available at https://ww2.arb.ca.gov/sites/default/files/classic/cc/ca_ghg_inventory_trends_2000-2019.pdf.

[8] For example, if gasoline costs in the range of $3 to $5 per gallon, EV charging costs for a typical EV must be below the range of $0.20 to $0.40 per kWh to provide the fuel cost savings that are an important driver of EV adoption. This assumes that a typical EV traveling 3 miles per kWh replaces a gasoline vehicle with mileage of 35 to 45 miles per gallon.

residential customers that adopt specific DERs (EVs, heat pumps, and storage).[9] These rates have much larger on-to-off-peak rate differences than current default residential time-of-use (TOU) rates, have no baseline credits or usage tiers, and also include fixed monthly charges in the range of $14 to $16 per month.[10] In the future, pursuant to D. 22-12-056, new solar customers will be required to use these electrification rates.

E. A Brief History of Residential Fixed Charges for the Electric IOUs

Q: Can you provide a brief history of the Commission's consideration and adoption of residential fixed charges for the electric IOUs?

A: The Commission has not approved and implemented new residential fixed charges – except for a small SCE fixed charge of less than $1 per month – in the last 35 years, finding repeatedly that residential fixed charges would impair incentives for customers to conserve energy, even if a small residential fixed charge was justified on the grounds of marginal costs, cost causation, and economic efficiency.[11] The Commission has also had reservations about bill impacts and residential customers' understanding and acceptance of fixed charges.[12] For example, in December 1987 the Commission replaced SDG&E's

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[9] The approved electrification rates are E-ELEC and EV2 for PG&E, TOU-D-PRIME for SCE, and TOU-ELEC for SDG&E. See D. 21-11-016 and D. 18-08-013 for PG&E; D. 18-11-027 for SCE, and D. 22-11-022 for SDG&E.

[10] For PG&E and SCE, the adopted monthly fixed charges in the electrification rates were the product of non-precedential settlements. For SDG&E, the $16 per month fixed charge for TOU-ELEC was determined in D. 22-11-022 after litigation, with the level of the charge chose to be "consistent with SCE's and PG&E's rate schedules established to promote residential electrification." The Commission also found that "[a] flat $16 per month customer charge will be easily understood by customers and will be still high enough to achieve a meaningful reduction in the remaining volumetric rates." See D. 22-11-022, at p. 27 and Findings of Fact 13 and 14.

[11] See D.88-07-023, rescinding a $4.50 per month fixed charge for SDG&E that had been approved a year earlier; D.11-05-047, rejecting PG&E's proposal for a $3 fixed charge; and D.14-06-007, rejecting SDG&E's proposed $5 fixed charge for its residential gas service.

[12] See D. 96-04-050, at pp. 161-162, citing D.86-12-091, D.87-12-066, D.87-12-069, D.88-07-023, D.89-12-057, and D.93-06-087.

residential minimum bill of $5 per month with a monthly fixed charge of $4.80 (equivalent to about $12 today). Less than seven months later, after what the Commission acknowledged as "vehement" protests from large numbers of SDG&E customers, the Commission accepted SDG&E's request to withdraw the residential fixed charge, citing customers' lack of understanding and acceptance of the new charge.[13] A few years later, in D. 93-06-087, considering a residential fixed charge for SCE, the Commission stated that a residential customer charge "is consistent with and supported by our well-established principle of marginal cost-based rate design," would "collect revenues more closely in proportion to cost causation thereby reducing subsidies," and "better inform customers of the system costs their consumption causes, and promote greater overall economic efficiency."[14] Nonetheless, in D. 96-04-050, the Commission adopted a fixed charge of less than $1 per month for SCE, out of a concern that a larger charge would adversely impact smaller customers such as apartment dwellers.[15]

Most recently, the Commission reviewed its policies concerning residential fixed charges in 2015-2017, following the passage of AB 327 which added Sections 739.9(e) and (f) authorizing the Commission to adopt new residential fixed charges of up to $10 per month (with adjustments for inflation). D. 15-07-001 found that certain requirements must be met before a residential fixed charge is adopted, including establishing which costs the charge should cover, setting a consistent methodology across utilities, and completing the transition to default TOU rates.[16] The Commission also expressed significant concern with customer understanding and acceptance of a residential fixed

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[13] See D. 87-12-069 and D. 88-07-023 (July 8, 1988), at p. 1.

[14] See D. 93-06-087, at p. 27, cited in D. 15-07-001, at p. 195.

[15] See D. 96-04-050, at pp. 169-173.

[16] See D. 15-07-001 at p. 190: "we find that a fixed charge linked to costs that do not change as a result of individual customer usage is not appropriate unless certain requirements are met. These requirements include ensuring that the charge reflects appropriate costs, establishing a consistent methodology across utilities, and waiting until each utility has shifted to default TOU rates."

charge, finding that "it is very clear that customers are unlikely to understand or accept the need for fixed charges without customer education."[17]

The Commission then undertook the review of the costs that should be included in a fixed charge, culminating in D. 17-09-035. That order conducted a thorough review of the potential costs that could be included in a residential fixed charge, based on the statutory language in Section 739.9 that remains operative today. The Commission rejected the utility position that all costs except marginal energy costs are "fixed costs" that could be included in a fixed charge,[18] concluding that the fixed costs eligible for a residential fixed charge must be (1) customer-specific; and (2) not vary with usage in kWh or kW.[19] The order determined that a residential fixed charge could include the costs of a minimum set of customer access facilities (meter, service drop, and transformer) plus revenue cycle services.[20] Just as important, the Commission found:

> …[f]or the purpose of this decision, fixed charges cannot cover any costs that vary with demand and must exclude generation charges, transmission charges and all non-bypassable charges such as public purpose program charges. We also determine that the equal percentage of marginal cost scalar will not be applied when calculating fixed costs for purposes of setting a fixed charge.[21]

After this order, in the consolidated rate design window proceeding that implemented default TOU rates for the residential customers of the three IOUs, the Commission considered proposals from PG&E and SDG&E to establish new residential fixed charges as part of their default residential rates and from SCE to increase its existing small residential fixed charge. In D. 20-03-003, the Commission rejected these proposals for the time being, finding that "the utilities have not sufficiently planned

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[17] *Id.*, at p. 216.

[18] See D. 17-09-035, at p. 11: "the Joint Utilities consider all costs of providing electric service that are allocated to residential customers, except marginal energy costs, to be fixed costs."

[19] *Id.*, at p. 15.

[20] *Id.*, at p. 2 and 32-33.

[21] *Id.*, at p. 2.

for the marketing, education, and outreach necessary to ensure a successful introduction of a new or expanded residential fixed charge."[22] In this order, the Commission also rejected an SDG&E proposal for an optional residential rate with a very high monthly fixed charge of approximately $72 per month, and directed SDG&E to propose an un-tiered residential TOU rate that would encourage residential electrification, similar to SCE's TOU-D-PRIME electrification rate.[23] This directive led to the subsequent adoption of SDG&E's TOU-ELEC residential electrification rate in D. 22-11-022.

III. SEIA'S PROPOSAL FOR INCOME-GRADUATED FIXED CHARGES

A. SEIA Proposal

Q: In this section of your testimony, how have you structured the presentation of SEIA's proposal for income-graduated fixed charges?

A: I respond to each of the questions that the Scoping Memo asked parties to address related to their proposals. Each of the questions from the Scoping Memo is italicized.

Q: 1. How should the Commission establish an income-graduated fixed charge for residential rates for all investor-owned electric utilities in accordance with AB 205 and Pub. Util. Code Section 739.9?

A. The Commission should make use of the fact that the state's current low-income (LI) programs already establish three graduated rate tiers for residential customers based on the federal poverty limits (FPL), with the CARE and Family Energy Rate Assistance

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22 D. 20-03-003, at p. 2, Finding of Fact 1 and Conclusion of Law 1.

23 *Id.*, at pp. 42-44.

(FERA) programs providing graduated, need-based discounts for overall residential bills, as shown in **Table 1**.

Table 1: *Current Residential Income-Graduated Rate Discounts*

LI Program / Customer Group	Eligibility	Rate Discount (%)
1. CARE	Up to 200% of the FPL	30% to 35% (differs by IOU)
2. FERA	200% to 250% of the FPL	18%
3. All other customers	Above 250% of the FPL	none

As a result, any residential fixed charge will have three income-graduated tiers when the existing CARE and FERA discounts are applied to these rate components. The CARE and FERA eligibility requirements are a function of both household income and size, using 13 different income thresholds and 7 household size ranges (see **Figure 1** and the accompanying discussion below).

Q: ***a. Should the Commission establish an income-graduated fixed charge for all residential rates or only certain residential rates?***

A: All residential rates that have fixed charges, including the fixed charges in the existing electrification rates, will be income-graduated with three tiers and 13 income thresholds, as a result of the application of the CARE and FERA discounts. As discussed below, in order to comply with AB 205, SEIA recommends establishing new cost-based fixed charges for the default residential rates which do not have cost-based fixed charges today. Fixed charges at the same level as those in the default rates also should be implemented for any optional residential rates that do not currently have cost-based fixed charges (such as the increasing block residential rates).

Q: ***b. What costs should be recovered through the fixed charge and what methodology should be used to calculate these costs?***

A: The Commission's Rate Design Principles 2, 3, and 4 state that rates should be based on marginal costs, should reflect cost causation, and should promote economic efficiency in the use of energy. In addition, P.U. Code Section 739.9(a) clearly defines a "fixed charge" as a charge "not based on the volume of electricity consumed" that collects "a reasonable portion of the fixed costs of providing electric service to residential customers." Consistent with these principles and the statutory definition of a fixed charge, a residential fixed charge should collect only marginal customer access costs.

Marginal costs. The only category of marginal costs that are not driven by customer usage ("the volume of electricity consumed") are marginal customer access costs. These are the costs of the transformer, service drop, and meter required to provide a customer with access to the grid, plus the associated operating costs for revenue cycle services such as billing and customer care. Marginal customer access costs are caused simply as a function of being a utility customer, without regard to how much power the customer uses. All of the other marginal costs of utility service depend on the volume of electricity that a customer consumes over a certain time period.

Cost causation. A fixed charge should only recover those costs that are not caused by the customer's use of energy or capacity from the electric system. Again, these costs are limited to the customer-related costs required to hook up to the system and to receive a bill each month. In contrast, energy costs are caused by the use of kWh of energy in specified time periods. Demand- or capacity-related costs for generation, transmission, or distribution are caused by the use of kW of capacity, which is measured generally by the customer's volume of energy use over short time periods of high demand either on the electric system as a whole or on the distribution system from which the customer receives service.[24]

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[24] For example, demand charges in non-residential rates typically are based on a customer's maximum use of energy over a 15-minute time period.

Economic efficiency. Electric rates will promote the economically efficient use of energy by customers if they are based on marginal costs and reflect accurately how each category of costs are caused. As a result, an efficient rate design will limit fixed monthly charges only to the marginal customer access costs that are caused simply by the customer's presence on the system and that do not depend on the amount of electricity that the customer consumes.

Q: Is your conclusion that fixed charges should be limited to marginal customer access costs consistent with longstanding Commission rate design practices and policies?

A: Yes, it is. For example, for many decades, the Commission has limited the fixed charges in non-residential rates to only customer access costs. All other utility costs are recovered through energy (per kWh) or demand (per kW) charges that depend on customer usage over certain time periods. As set forth above in my brief history of residential fixed charges for the California electric IOUs, this has also been the Commission's policy conclusion with respect to residential fixed charges. Nonetheless, the Commission's concerns over customer acceptance, equity between small and large customers, and conservation impacts have prevented the implementation of any residential fixed charges except for SCE's small charge that was implemented in 1996.

Q: Is limiting fixed charges for residential customers to customer access costs also broadly consistent with typical practices in the U.S. utility industry?

A: Yes. Customer-related costs that are driven by the number of customers, not by customer usage of kWh or kW, are the common component in the residential fixed charges of U.S. utilities.[25] Some utilities also include a portion of their distribution costs in the

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[25] See Ahmad Faruqui and Kirby Leyshon, *Fixed charges in electric rate design: A survey*, The Electricity Journal (November 2017), at p. 34 and Table 2: "The cost categories that are most commonly included in fixed costs collected by fixed charges for the utilities in the survey are customer-related costs. Several utilities defined customer-related costs as costs that vary with the number of customers on the system. These costs typically include meters and meter services, meter reading and billing, service drop, customer service, and customer records and collection."

residential fixed charge, although this practice is much more contested, with a range of outcomes.[26] This Commission has never included distribution costs in monthly fixed charges in electric rate design, to my knowledge.[27] I generally agree with the perspective of the Regulatory Assistance Project (RAP) in its paper *Smart Rate Design for a Smart Future* that including distribution and other costs in a high fixed monthly charge "is neither cost-based nor economically efficient:"[28]

> This approach [high fixed charges]… deviates from long-established rate design principles holding that only customer-specific costs — those that actually change with the number of customers served — properly belong in fixed monthly fees. It also deviates from accepted economic theory of pricing on the basis of long-run marginal costs.[29]

Q: What are the IOU's residential marginal customer access costs today?

A: **Table 2** shows the current residential marginal customer access costs for the three IOUs.[30]

Table 2: *IOU Residential Marginal Customer Access Costs*

Utility	Marginal Customer Access Costs *($/month)*	Source
PG&E	$7.59	D. 21-11-016 and Advice 6566-E
SCE	$7.88	Settlement approved in D. 22-08-001
SDG&E	$11.26	Settlement approved in D. 21-07-010

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26 *Id.*, at Table 2.

27 See D. 17-09-035, at p. 13: "Historically, the Commission has separated distribution costs into two categories: customer-related and demand-related. Specifically, the meter, service drop, and final line transformer were considered as customer-related grid access facilities; all other distribution facilities were considered demand-related [footnote citing D.86-08-083 and D.88-12-085]."

28 Lazar, J. and Gonzalez, W., *Smart Rate Design for a Smart Future* (Montpelier, VT: Regulatory Assistance Project, 2015), at p. 9. Available at: http://www.raponline.org/document/download/id/7680.

29 *Id.*, at p. 48.

30 To be consistent across the IOUs, the values shown in Table 2 are taken from the residential marginal customer access costs and customer counts used in the E3 model developed for this case.

Q: Rates set at marginal costs tend to under recover the revenue requirement, which is based on embedded (i.e. historical) costs. As a result, to set rates that cover the revenue requirement, rates based on marginal costs are scaled up by an equal percentage of marginal costs (EPMC) until they collect the full revenue requirement. Should a cost-based customer charge include only marginal customer access costs, or should it also include the scaled-up "EPMC scalar" costs?

A: A cost-based customer charge should include only marginal customer access costs, without an EPMC scalar. The delivery component of rates includes both customer access and distribution costs. Unlike other marginal costs, marginal customer access costs are based on the full embedded costs of customer access facilities and the associated customer care costs. As a result, any additional delivery costs that are added to marginal customer and distribution costs when these marginal costs are scaled up to the delivery revenue requirement are distribution costs, and are not customer-related. Thus, EPMC scalar costs should not be included in a fixed charge.

Q: Utility rates also include a variety of costs that are collected in certain "non-bypassable charges" (NBCs). To ensure that these costs are collected, why shouldn't NBCs be included in a fixed charge?

A: First, many NBCs cover generation-related costs that are caused by customers' use of energy (kWh) and capacity (kW). Thus, they are not fixed costs and cannot be recovered through a fixed charge. These include the costs in the Competition Transition Charge, Nuclear Decommissioning Charge, New System Generation Charge (PG&E and SCE), Local Generation Charge (SDG&E), Reliability Services Charge, and the Power Charge Indifference Adjustment Charge. In sum, recovering generation costs in a fixed charge would be contrary to Rate Design Principle No. 3 that rates should be based on cost causation. Further, if a fixed charge that included generation costs was assessed on both bundled and unbundled customers, this could upset the competitive balance between different types of load-serving entities (LSEs).

Second, there are directions in statute that bear on how a number of NBCs should be recovered from ratepayers:

- P.U. Code Section 327(a)(7) requires that CARE costs be allocated in electric rates on the basis of equal cents per kWh. Thus, it is most consistent with cost causation to also collect these costs in a volumetric, $ per kWh rate.
- The Wildfire Fund NBC charge was established by the Commission pursuant to P.U. Code Section 3289(a)(2). This section provides that "[t]he charge shall be collected in the same manner as that for the payments made to reimburse the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code." At the time of enactment of P.U. Code Section 3289(a)(2), the DWR bond charge was collected from residential customers as a volumetric, $ per kWh charge.
- P.U. Code Section 432 provides that the PUC Reimbursement Fee Charge is allocated among regulated utilities on the basis of kWh sales. Accordingly, these costs are collected from customers on a volumetric, $ per kWh basis.

Finally, programs such as energy efficiency, demand response, and the Self-Generation Incentive Program (SGIP) can be viewed as state policy-driven programs designed to provide alternatives to utility-scale generation. As a result, the costs for these programs should be recovered in usage-based rates for the same reason as generation costs.

Q: ***c. What income thresholds should the Commission establish for the income-graduated fixed charge?***

A: The Commission should use the existing income thresholds and eligibility requirements for CARE and FERA to establish income-graduated fixed charges. The CARE and FERA income thresholds are based on the federal poverty guidelines and use both household income and household size. **Figure 1** is a graphic showing the 13 different income thresholds that are used to determine CARE or FERA eligibility.

Figure 1

CARE/FERA Eligibility Requirements by Household Income and Size							
Household Income	**Household Size (number of persons)**						
	1-2	**3**	**4**	**5**	**6**	**7**	**8**
$ 36,620	CARE	CARE	CARE	CARE	CARE	CARE	CARE
$ 46,060	FERA+	CARE	CARE	CARE	CARE	CARE	CARE
$ 55,500	None	FERA	CARE	CARE	CARE	CARE	CARE
$ 57,575	None	FERA	FERA	CARE	CARE	CARE	CARE
$ 64,940	None	None	FERA	CARE	CARE	CARE	CARE
$ 69,375	None	None	FERA	FERA	CARE	CARE	CARE
$ 74,380	None	None	None	FERA	CARE	CARE	CARE
$ 81,175	None	None	None	FERA	FERA	CARE	CARE
$ 83,820	None	None	None	None	FERA	CARE	CARE
$ 92,975	None	None	None	None	FERA	FERA	CARE
$ 93,260	None	None	None	None	None	FERA	CARE
$ 104,775	None	None	None	None	None	FERA	FERA
$ 116,575	None	None	None	None	None	None	FERA
$ 150,000	None	None	None	None	None	None	None
$ 200,000	None	None	None	None	None	None	None
Above	None	None	None	None	None	None	None
	Legend:	CARE	FERA	Added for FERA+			

There are important reasons to use the existing income thresholds and eligibility requirements for CARE and FERA:

- **Let's not re-invent the wheel.** The CARE and FERA programs are well-established, have budgets and procedures for marketing, enrollment, and income verification, and are familiar to customers. Participation in CARE is very high (85% - 95%), and, in D. 21-06-015, the Commission has directed the IOUs to take steps to increase participation in FERA to comparable levels to CARE by 2026. It makes no sense to overlay on the existing CARE and FERA programs a new program of income-graduated fixed charges that has completely different eligibility requirements. That would only engender customer confusion and require the utilities to spend significant new resources on marketing, customer education, and administration for what would be a new low-income program.

- **Household size is a critical factor** in the need for energy assistance, as shown by the inclusion of household size in the federal poverty guidelines and in the longstanding CARE/FERA eligibility requirements. It is obvious that a single-person-household with an income of $100,000 is in a much different economic position than a family of six with the same $100,000 income. Income-graduated fixed charges that consider only household income will discriminate unduly against families and children.

- **Only a minor change to the existing FERA eligibility requirements** is needed to produce three tiers of income-graduated fixed charges for all residential customers. FERA currently has a minimum size of 3 persons per household. SEIA proposes that the second FERA tier of income-graduated fixed charges also should apply to 1-2 person households with incomes from $36,621 to $46,060. This small addition to the FERA eligibility requirements is shown in the blue-shaded cell in Figure 1. We call this slight expansion of the FERA eligibility standards "FERA+"; it would apply only to the income-graduated fixed charges. We are not proposing an expansion of FERA discounts for the remainder of the rate to 1-2 person households.

Q: d. How should the fixed charge vary by income threshold?

A: There should be three tiers of fixed charges, using the existing FERA and CARE discounts shown in Table 1:

- The highest Tier 3 fixed charge would apply to customers who do not qualify for CARE or FERA.
- The Tier 2 fixed charge would be set at an 18% discount to the Tier 3 charge, and would apply to customers whose income and household size qualify for FERA+.
- The Tier 1 fixed charge would apply to CARE customers. P.U. Code Section 739.1(c)(1) was modified by AB 205 and now requires that the effective CARE discount not include costs to recover fixed charge discounts. As a result, the Tier 1 fixed charge would be set at the prevailing CARE discount (30% to 35%, depending on the IOU) below what the Tier 3 charge would be before adding recovery of the fixed charge discounts to the Tier 3 charge.

Finally, the rates for all three tiers are calculated such that the entire three-tier structure recovers the utility's marginal customer access costs allocated to the residential class. SEIA used the E3 model developed for this case to perform this calculation.

The resulting fixed charges for default residential rates are shown in **Table 3**. All of the fixed charges in the table are in $ per month.

Table 3: *SEIA's Proposed Fixed Charges for Default Residential Rates ($ per month)*

Utility	Tier 1: CARE		Tier 2: FERA+		Tier 3: All others	
	Discount	Fixed Charge	*Discount*	Fixed Charge	*Discount*	Fixed Charge
PG&E	*35%*	4.93	*18%*	7.45	*0%*	9.09
SCE	*32.5%*	5.32	*18%*	7.71	*0%*	9.41
SDG&E	*34%*	7.43	*18%*	10.77	*0%*	13.14

Q: Table 3 shows SEIA's proposed fixed charges for the default residential rates. To which other residential rates would these new fixed charges apply?

A: The fixed charges in Table 3 also would apply to those residential rates of Pacific Gas & Electric (PG&E) and San Diego Gas & Electric (SDG&E) that do not include a monthly fixed charge today. In addition, the small residential fixed charge of less than $1 per month in Southern California Edison's current residential rates would be increased to the levels shown in Table 3. Thus, the fixed charges in Table 3 also would apply to the IOUs' increasing block rates (E-1 for PG&E, D for SCE, and DR for SDG&E) and to optional rates such as EV2 for PG&E. Finally, there would be no change to the existing residential fixed charges in the residential electrification or EV charging rates of the IOUs which, as the result of past approved settlements or decisions, have higher fixed charges than the cost-based levels in Table 3. These rates include E-ELEC for PG&E, TOU-D-Prime for SCE, and TOU-ELEC and EV-TOU-5 for SDG&E.

Q: e. How should the fixed charge be designed so that a typical low-income customer would realize a lower average monthly bill without making any changes to usage?

A: The first-tier (CARE) and second-tier (FERA+) discounts to the fixed charge will ensure that low-income customers in these tiers will realize a lower average monthly bill compared to a third-tier (non-low-income) residential customer with the same usage.

Q: ***f. How should the fixed charge vary between default residential rates and non-default residential rates?***

A: For the default residential rates, and for any other residential rate that does not currently have a monthly fixed charge in excess of 100% of marginal customer access costs, new residential fixed charges should be set at the levels shown in Table 3 above.

As a result, customers on both the default and these optional residential rates would receive the CARE and FERA+ discounts applied to the new fixed charge added to these rates. For the optional residential rates that have significant fixed charges today, such as the existing electrification rates, the current CARE and FERA discounts would continue to apply to these fixed charges, with the slight expansion of FERA+ to cover 1-2 person households. Thus, all residential fixed charges would be income-graduated, with three tiers and 13 income thresholds, in compliance with AB 205.

Q: Have you calculated the bill impacts of the SEIA proposal?

A: Yes. Using the common E3 model developed for this case, SEIA presents in **Attachment RTB-2** the bill impacts of our recommended income-graduated fixed charges for residential default rates and certain optional residential rates, in the format requested by the presiding ALJ. Based on the results from the E3 model, SEIA's fixed charges reduce the volumetric portion of the IOUs' default rates by about $0.02 per kWh, with a range of reductions from $0.01 to $0.06 per kWh.[31] The bill impact analysis for SEIA's proposal shows that the impacts on low-income customers are generally modest reductions (2% or less) in the rates for CARE and FERA customers on TOU rates, except for small increases (less than 1%) in cooler coastal climate zones where usage and bills are lower. Rates would increase by small amounts for higher-income customers, especially in coastal climate zones. Overall, the rate impacts are modest, in a range of +1% to -2%.

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[31] For SDG&E's winter default rates (TOU-DR1), the reduction approaches $0.06 per kWh.

Q: Have any of the California IOUs recently expressed support for the residential fixed charge structure that SEIA is proposing?

A; Yes. Pursuant to Senate Bill (SB) 695, the IOUs file annual reports with the Commission on their recommendations to limit cost and rate increases. PG&E's most recent SB 695 report includes the recommendation that "PG&E supports having a fixed monthly charge in residential rates, consistent with rate design policies adopted by public utility regulators around the country and similar to the fixed monthly charges that have been in all of PG&E's non-residential rates for years."[32] As noted above, the fixed charges in non-residential rates have been limited to no more than marginal customer access costs, so PG&E's statement of support is consistent with the limited new residential fixed charges that SEIA has proposed. PG&E's SB 695 report also notes that the existing CARE and FERA discounts will result in an income-graduated fixed charge structure:

> …any approved fixed charge would already have three levels built into it based on income: the approved fixed charge for non-CARE customers, along with two discounted levels for FERA and CARE customers who are eligible for line-item discounts on their bills (which would include the fixed cost component)."[33]

Again, this supports the income-graduated structure based on CARE and FERA that SEIA is proposing.

Q: g. How should income levels be verified, and how often should verification occur?

A: Income verification should use the same processes now employed for CARE and FERA.

Q: h. How should customers be informed about the fixed charge and impacts on their bills?

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32 PG&E, *2022 SB 695 Report: IOU recommendations to limit cost and rate increases (Electric and Gas IOUs)*, at Question 001, p. 3, available on the CPUC website at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/actions-to-limit-utility-cost-and-rates-annual-report-to-the-governor-and-legislature-may-2022.

33 *Id*, at Question 002, p. 3.

A: Existing channels to market and publicize CARE and FERA can be used for customer education on the new income-graduated fixed charges.

B. Adjustments to Residential Rate Components

Q: 2. How should residential rate components of investor-owned utilities' electric rates, including volumetric rates and the California Alternate Rates for Energy (CARE) discount methodology, be adjusted to reflect fixed charges in accordance with AB 205?

A: In all residential tariffs that today do not have a fixed charge that covers marginal customer access costs, the IOU should remove from volumetric rates the marginal customer access costs that in the future will be collected in the new fixed charges.

C. Adjusting the Average Effective CARE Discount

Q: 3. How should the Commission implement the requirements of AB 205 to adjust the average effective discount for CARE so that it does not reflect any charges for which CARE customers are exempted, discounts to fixed charges or other rates paid by non-CARE customers, or bill savings resulting from participation in other programs?

A: The E3 model uses a method that first calculates a "base rate" that does not include the costs from which CARE customers are exempted. CARE rates are then calculated by applying the relevant CARE discount to this base rate. The standard rates for non-CARE customers are then determined by adding back the costs that were excluded from the base rate as well as the costs of the CARE discounts.[34] This approach appears to SEIA to be reasonable and is consistent with SEIA's calculation of its proposed fixed charges.

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[34] See Slide 18 from the E3 presentation at the E3 fixed charge tool and income verification follow-up workshop, held on February 1, 2023.

IV. THE ISSUES WITH DER-SPECIFIC FIXED CHARGES

Q: In D. 22-12-056 in R. 20-08-020, the Commission adopted a new net billing tariff (NBT) for customers who install solar. The record in R. 20-08-020 included consideration of whether solar customers should pay solar-specific fixed charges to recover, for example, NBCs associated with their use of their own solar production behind the meter. D. 22-12-056 declined to adopt any such solar-specific fixed charge, observing that fixed charge reform for all ratepayers, more broadly, would be addressed in this demand flexibility rulemaking.[35] Why should the Commission decline to adopt solar-specific fixed charges in this case?

A: Solar-specific fixed charges are not necessary because, under SEIA's proposal, regardless of what rate schedule a residential customer is on, the solar customer will be paying marginal customer access costs (unless they are eligible for a low-income discount). A central provision of D. 22-12-056 is that new residential solar customers who take service under the new Net Billing Tariff (NBT) must take service under one of the IOU's existing residential electrification rates.[36] These rates already include monthly fixed charges of $14 to $16 per month that exceed the IOUs' marginal customer access costs. In addition, solar customers under the NEM 1.0 and 2.0 programs who are served under other residential rate schedules (such as the default residential TOU rates) will now bear new fixed charges that are based on 100% of marginal customer access costs (with appropriate low-income discounts). Layering any additional fixed charge on top of those already included in solar customers' rates is therefore unnecessary.

Furthermore, the process to craft the new NBT in R. 20-08-020 was lengthy, contentious, and resource-intensive. D. 22-12-056 struck a delicate balance between the involved interests. Significant further efforts will be needed to implement the NBT and

[35] See D. 22-12-056, at p. 115.

[36] *Id.*, at pp. 111-112 and 159-160.

to market it successfully to customers, to avoid a significant contraction in the market for solar and storage DERs. The adoption of an additional solar-specific fixed charge in 2023 or 2024, above those already included in the electrification rates, would change the analysis of the economics of solar and solar-plus-storage systems that was the basis for the NBT, would be detrimental to the implementation of the NBT, and could re-open the difficult issues resolved in D. 22-12-056.

Q: Does this concern also apply to any increase to the existing, substantial fixed charges in the IOU electrification rates that NBT customers must use?

A: Yes, it does.

Q: Are there legal issues with a fixed charge that would seek to recover costs allegedly associated with the behind-the-meter (BTM) use of a customer's own solar generation?

A: Yes. Solar customers can use a significant portion of their solar generation to serve their own loads, behind the meter, with the power so consumed never touching the utility grid. There are significant legal issues with solar-specific fixed charges, including jurisdictional issues with assessing costs, including NBCs, on the BTM consumption of solar that is produced on-site and that never touches the electric grid. Should such a proposal be made in this case, SEIA will address these legal issues in briefs.[37]

Q: More generally, are there important long-term reasons why the Commission should not pursue technology-specific rates, including fixed charges, for customers who install a particular type of distributed energy resource (DER)?

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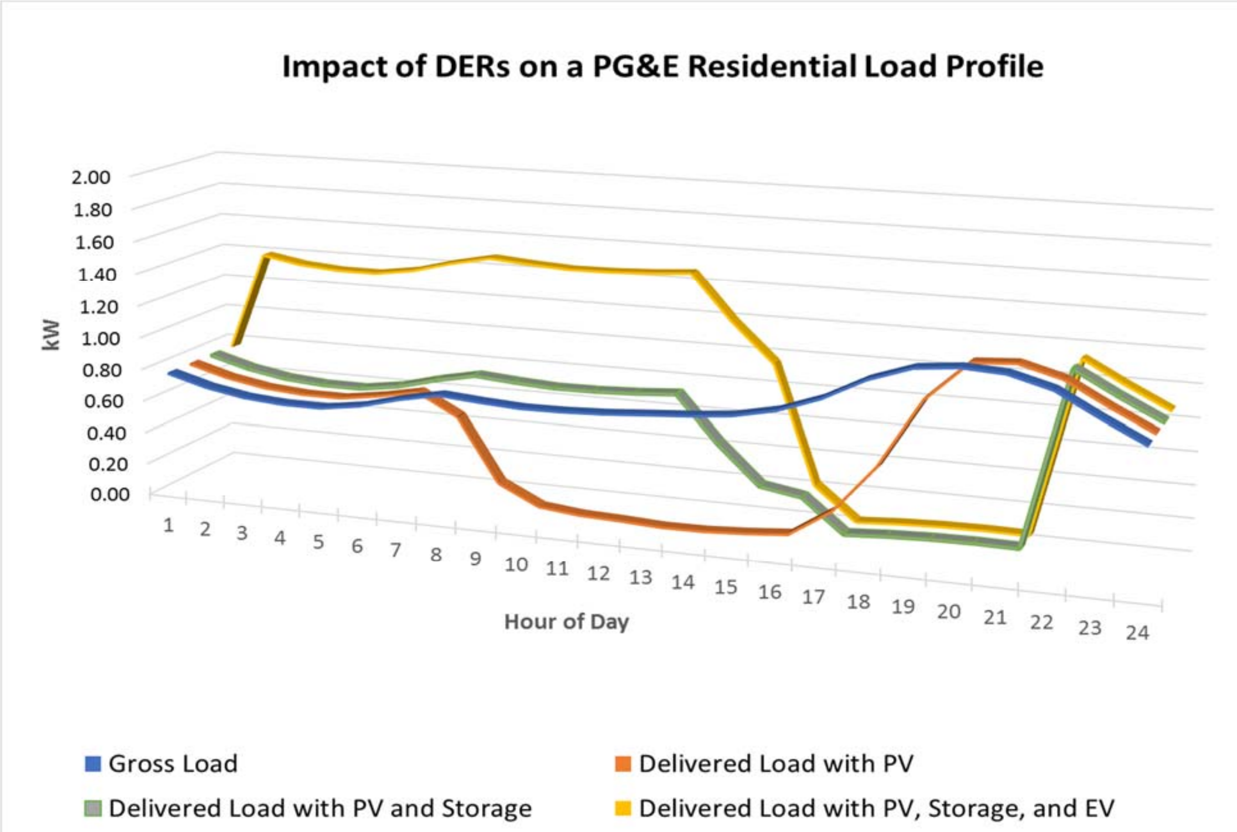
[37] SEIA and other solar parties briefed why many NBCs are not applicable to BTM solar consumption in their June 10, 2022 comments in R. 20-08-020. See R. 20-08-020, *Comments of the Solar Energy Industries Association and Vote Solar on Administrative Law Judge's Ruling Setting Aside Submission of the Record to Take Comment on a Limited Basis* (filed June 10, 2022), at pp. 14-23.

A: Yes. The adoption of multiple types of DERs – storage, electric vehicles (EVs), heat pumps for water and space heating, solar, and smart thermostats – will be critical to the electrified economy needed to meet California's long-term climate goals. I fully expect electric customers increasingly to adopt multiple types of DERs, as the adoption of one DER leads to another. We are already seeing this – for example, based on data generated from discovery in R. 20-08-020, 34% of EV customers also have solar. This is about three times the penetration of solar among all customers.[38] Thus, a solar-only customer today can be expected to add more DERs in the future. Each of these DER technologies can have as significant an impact on the profile of a customer's electric usage as adopting solar. **Figure 2** below shows four residential load profiles that illustrate how a single residential customer's load profile for delivered energy can change as the customer adopts three different DER technologies in succession. The four profiles are:

1. **Blue:** PG&E residential customer using 7,500 kWh per year with no DERs
2. **Orange:** the customer adds solar with output equal to 75% of the annual load.
3. **Green:** customer adds 11 kWh of battery storage; storage is charged during solar production hours, and discharged in the 4 p.m. to 9 p.m. peak period.
4. **Yellow:** customer buys an EV using 3,500 kWh per year. EV is charged between 2 a.m. and 3 p.m.

[38] See R. 20-08-020, *Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar* (served July 16, 2021), at p. 57 and footnote 89.

Figure 2



Notably, at the end of this process, the customer's usage of delivered energy from the PG&E system actually has increased to 8,450 kWh, compared to its pre-DER usage of 7,500 kWh per year. These four profiles of delivered loads are each distinct and different from each other.[39] One could design four different rates for each of these different combinations of DERs, perhaps with four different levels of fixed charges. But that could require a further proliferation of additional rates for other types of DERs (for example, for heat pump customers who use electricity for water or space heating), as well as yet more rates for different combinations of these DERs. The electric rates of PG&E and the other IOUs are already complex, and the number of specific rates and rate options

[39] I note that the second, third, and fourth types of DER customer have on-site solar production that exports "received" power to the grid in certain hours. The second solar-only profile exports in the midday hours; the third and fourth profiles use on-site storage to shift exports into the peak evening hours. Figure 4 does not show these exports.

has mushroomed in recent years, even without DER-specific rates. Going down the path of proliferating DER-specific rates will not advance the Commission's rate design Principle No. 7 that rates should be understandable, and is contrary to Principle No. 9 that rate design should not be technology-specific. This path of mushrooming rate options makes little sense in an electrifying world in which a key policy goal is to encourage customers to adopt multiple types and combinations of DERs. Instead, the Commission should focus on implementing a few basic time-of-use rate designs based on marginal costs for broad customer classes. In order to advance the Commission's rate design principles, these designs should be relatively simple, readily understood, and usable by the full range of DER customers.

V. THE LIMITATIONS OF FIXED CHARGES IN PROMOTING DEMAND FLEXIBILITY AND BENEFICIAL ELECTRIFICATION

Q: Please discuss the impact of your fixed charge proposal on the state's electrification efforts.

A: The greater use of fixed charges in residential rates, to recover marginal customer access costs as SEIA recommends, will reduce volumetric rates. This will provide a modest encouragement to electrification, through a small reduction in the cost of incremental electric use. However, the Commission should be realistic about the limitations of fixed charges to promote electrification. Fixed charges must be used judiciously, to avoid pushing customers off the grid. Moreover, fixed charges are not the most important rate design change necessary to encourage demand flexibility and beneficial incremental use in electrification technologies.

Q: What are the limitations of fixed charges at promoting electrification?

A: Rates that advance demand flexibility must allow customers to change their use of electricity at certain times of the day, in ways that allow the customer to minimize their electric bills. Fixed charges perform poorly in this regard. Fixed charges reduce the portion of the monthly bill that a customer can manage by reducing or shifting their loads, or by investing in various DERs. For this reason, fixed charges should be limited to those costs that do not vary with customer usage. Second, by definition, fixed charges do nothing to send signals to customers to increase the flexibility of their electric demand, which is the goal of this OIR. What is critical to encouraging more flexible customer demands are accurate, cost-based, time-dependent volumetric rates. As I discussed in Section II.D, Commission policy in recent years has focused – correctly, in my view – on increasing the time-dependence of usage-based rates and providing customers with more tools to respond to time-dependent price signals. Finally, customers are not going to make long-term investments in any type of DER unless rate design provides them with the flexibility to use the DER to manage their overall energy costs in a way that supports their investment in a DER over its economic life.

By definition, customers can only pay a fixed charge; the only way to "manage" or to reduce such a charge, if it is too high, is to leave the system entirely. This type of demand flexibility – grid defection – is not desirable because customers who move off the grid make little or no contribution to its costs. Grid defection may become increasingly economic in California due to the combination of the state's rising electric rates and the declining costs of solar and battery technologies. It is important to note that there can be different levels of grid defection – it does not have to be a customer moving 100% to off-the-grid service from a solar-plus-storage system or (worse) from an on-site fossil generator. The principal obstacle to grid defection using solar and storage is the extended periods of cloudy or rainy weather during the low-solar winter months. During this time of year, a customer could return briefly to the grid to charge their batteries during extended low-solar periods, could supplement the solar with backup fossil generation, or could refill their home batteries from an EV (using emerging vehicle-to-home technologies) that can be charged elsewhere at public or workplace charging facilities. To avoid the potential for significant and growing grid defection, the use of fixed charges must be limited. Hence the wisdom of a policy that limits residential fixed charges to those marginal customer access costs that do not vary with usage.

Q: What types of rate design are best for encouraging demand flexibility?

A: Dynamic, time-varying, volumetric rates with low off-peak rates – to encourage incremental electric use when clean energy is abundant and low-cost – and high on-peak rates – to discourage use when demand is high and capacity scarce – are far more important than fixed charges for maximizing demand flexibility and beneficial electric use by California consumers. Today, the California grid relies to an increasing extent on variable wind and solar resources, with growing amounts of short-duration battery storage that can store excess renewable energy to meet the evening "net load" peak after the sun sets. In this world, the most valuable customers (i.e. those that are the least expensive to serve) are the ones with the flexibility to place their load on the grid at times when renewable energy is most abundant, and to minimize their use from the grid during the 4 p.m. to 9 p.m. net load peak hours. These are also the customers who are best positioned to invest in those electrification DERs – such as EVs, home storage, and heat pump water heaters – that will be most economic if they are powered with off-peak electricity.

Q: The optional electrification rates that the Commission has approved have higher monthly fixed charges than those that SEIA has recommended for default residential rates. Does this indicate that, from the perspective of encouraging electrification, fixed charges should be higher than those that SEIA has proposed?

A: No. First, the current electrification rates are largely the product of non-precedential settlements. Further, in approving these optional electrification rates, the Commission has indicated clearly that it may be departing from the rate design policies appropriate for default residential rates, in consideration of the public policy benefits of promoting adoption of electrification technologies.[40] Finally, the higher fixed charges in the electrification rates play just a minor role in making those rates attractive to customers who adopt DERs such as EVs, storage, and heat pumps.

The fixed charges of $14 to $16 per month in the electrification rates reduce the overall level of these rates by just $0.01 to $.02 per kWh, compared to the cost-based fixed charges that SEIA has proposed for default residential rates. What is far more important is that the electrification rates have larger differentials between on-peak and off-peak rates than the default rates, resulting in lower off-peak rates that are much more attractive for incremental electric use such as EV charging. In addition, unlike the default residential rates, the electrification rates are not tiered by usage. For example, **Table 4** compares the volumetric components of the PG&E E-TOU-C default rate (with the fixed charges that SEIA has proposed) to the PG&E EV2 and E-ELEC electrification rates. We have also added SEIA's proposed fixed charge to the EV2 rate, which has no fixed charge today. The table shows the E-TOU-C rate for Tier 2 (above baseline) usage, which is likely to be the marginal rate for incremental usage to charge a new EV.

Table 4: *EV2 and E-ELEC Electrification Rates vs. the Default E-TOU-C ($/kWh)*

Rate	Fixed Charge *($/month)*	Summer			Winter		
		Peak	Part	Off-peak	Peak	Part	Off-peak
E-TOU-C (Tier 2)	9.09	0.467	0.404		0.371	0.354	
EV2	9.09	0.528	0.420	0.230	0.404	0.388	0.230
E-ELEC	15.00	0.546	0.373	0.314	0.302	0.280	0.266

The off-peak rates in EV2 and E-ELEC (green shaded cells) are much lower than the off-peak rates for E-TOU-C (red shaded cells), by $0.09 to $0.17 per kWh (i.e. 22% to 43%

[40] See D. 21-11-016 at pp. 113-114, in a PG&E general rate case Phase 2 order: "the design of the fixed charge for E-ELEC is intended to further state policy goals related to decarbonization and therefore has a particular policy purpose that may justify any dissonance with previous Commission decisions regarding the application of EPMC to residential fixed charges."

lower). The lower off-peak rates in EV2 and E-ELEC provide a far greater incentive for EV adoption than the marginal off-peak E-TOU-C rate. Even more important, the low off-peak rates in EV2 and E-ELEC signal to EV customers the critical information on <u>when</u> they should charge their vehicles to minimize adverse impacts on the grid – a price signal that fixed charges completely fail to convey. The key problems with the current residential default rates such as E-TOU-C are that they are both tiered and "TOU-lite," with on-to-off-peak TOU differentials that are far less than marginal costs. Making progress on these aspects of the default residential rate design will be a more effective way to promote electrification than adopting very large fixed charges. SEIA looks forward to the discussion of further ways to expand the use of dynamic and time-varying rates in Track B of this OIR.

In sum, residential fixed charges should be limited to utility costs that do not vary with usage – principally, marginal customer access costs for metering, service drop, billing, and customer service costs. Such a limit recognizes that, in the long run, few costs truly are fixed. Customers are not going to make long-term investments in the DERs that are central to the state's electrification goals unless rate design allows them to use DERs to manage and to reduce their energy costs in a meaningful way.

VI. CONCLUSION

Q: P.U. Code Section 739.9 requires that any new or expanded residential fixed charge must "(1) Reasonably reflect an appropriate portion of the different cost of serving small and large customers, (2) Not unreasonably impair incentives for conservation and energy efficiency, and (3) Not overburden low-income customers." In conclusion, please summarize how your proposal for an income-graduated fixed charge satisfies these statutory requirements.

A: I will discuss each of these requirements in turn.

Reasonably reflect an appropriate portion of the different cost of serving small and large customers. SEIA's proposed income-graduated fixed charges are limited strictly to customer access costs. All residential customers require similar facilities and services to access the electric system, and thus customer access costs do not vary substantially between small and large residential customers. Customer access costs are not based on usage, and thus there is not a usage-based difference in these costs between small and large customers.

Not unreasonably impair incentives for conservation and energy efficiency. SEIA's proposal would result in a modest reduction in the volumetric rates for default residential customers. As a result, customers would retain a strong incentive to conserve energy and to use it efficiently. In addition, the reduction in volumetric rates would not impact the TOU rate differentials in current rates, which are essential to signaling the times of day when it is most efficient to use energy, or to conserve it.

Not overburden low-income customers. The bill impact analysis for SEIA's proposal shows that the impacts on low-income customers are generally modest reductions (2% or less) in the rates for CARE and FERA customers on TOU rates, except for small increases (less than 1%) in cooler coastal climate zones where usage and bills are lower. Rates increase modestly for higher-income customers, especially in coastal climate zones.

Q: Does this conclude your testimony in this case?

A: Yes, it does.

Attachment RTB-1

CV of R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

- *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

- *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

- *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

- *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

- *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

- *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

- *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

- *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar Parties** (R. 14-07-002 — September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 16-09-003 — April 28, 2017)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 17-06-030 — March 23, 2018)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

88. Prepared Direct and Rebuttal Testimony on behalf of **Calpine Corporation** (A. 17-11-009 – July 20 and August 20, 2018)

    - *Gas transportation rates for electric generators, gas storage and balancing issues*

89. Prepared Direct Testimony on behalf of **Gas Transmission Northwest LLC** and the **City of Palo Alto** (A. 17-11-009 – July 20, 2018)

    - *Rate design for intrastate backbone gas transportation rates*

90. Prepared Direct Testimony on behalf of **EVgo** (A. 18-11-003 – April 5, 2019)

    - *Electric rate design for commercial electric vehicle charging*

91. Prepared Direct and Rebuttal Testimony on behalf of **Vote Solar** and the **Solar Energy Industries Association** (R. 14-10-003 — October 7 and 21, 2019)

    - *Avoided cost issues for distributed energy resources*

92. Prepared Direct and Rebuttal Testimony on behalf of **EVgo** (A. 19-07-006 – January 13 and February 20, 2020)

    - *Electric rate design for commercial electric vehicle charging*

93. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 19-03-002 — March 17, 2020)

    - *Electric rate design issues for solar and storage customers*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

   - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

   - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

   - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

   - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of **Vote Solar** (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

    - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

    - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

    - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
   http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

2. Direct Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018; Docket E-100 Sub 158; June 21, 2019)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910,01911, and 1912 — March 16, 2018).

   - *Resource value of solar resources in Oregon*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
   https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

    - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

    - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

    - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

Fixed Charge Tool Outputs for
SEIA's Income-Graduated Fixed Charges

Fixed Charge Tool Outputs - Cover Sheet

Purpose:
This section of the tool is formatted to be easily printed or saved as a PDF and filed as a part of testimony.

Instructions:
This worksheet automatically draws values from the rest of the tool.
This worksheet displays both rate design details and bill impacts for all three IOUs.
Please run the macro (button above) to re-generate model results using current inputs to ensure that the rate design details and bill impacts are aligned.
This macro can also be run from the Rate Design Dashboard worksheet. Please see the Rate Design Dashboard worksheet for further details.

How to Save as PDF:
Click "File", then "Print", then select "Microsoft Print to PDF". Click the large "Print" button to choose a file location and name.

How to Print:
Click "File", then "Print", then select your choice of printer.

Table of Contents

Energy+Environmental Economics

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44 Montgomery Street, Suite 1500
San Francisco, CA 94104
Phone: 415-391-5100

Model Release Date: March 23, 2023

Revenue Requirement Allocations

PG&E

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 183,408,243	FALSE	FALSE	0%	0%	100%
Generation	Marginal Energy Cost	$ 538,263,216	FALSE	TRUE	0%	0%	100%
Generation	Marginal Generation Capacity Cost	$ 218,481,550	FALSE	TRUE	0%	0%	100%
Generation	Non-Marginal Generation	$ 865,996,766	FALSE	TRUE	0%	0%	100%
Distribution	Marginal Customer Access	$ 454,792,861	FALSE	FALSE	100%	0%	0%
Distribution	Marginal Distribution Capacity Cost - Primary	$ 439,382,040	FALSE	FALSE	0%	0%	100%
Distribution	Marginal Distribution Capacity Cost - New Business	$ 476,043,853	FALSE	FALSE	0%	0%	100%
Distribution	Marginal Distribution Capacity Cost - Secondary	$ 29,945,145	FALSE	FALSE	0%	0%	100%
Distribution	Non-Marginal Distribution	$ 1,833,578,625	FALSE	FALSE	0%	0%	100%
Transmission	Transmission	$ 1,447,654,612	FALSE	FALSE	0%	0%	100%
Line Items	Public Purpose Programs - SGIP	$ 58,854,252	TRUE	FALSE	0%	0%	100%
Line Items	Wildfire Fund Charge	$ 63,120,120	TRUE	FALSE	0%	0%	100%
Line Items	Wildfire Hardening Charge	$ 68,921,008	TRUE	FALSE	0%	0%	100%
Line Items	Recovery Bond Charge	$ 215,256,658	TRUE	FALSE	0%	0%	100%
Line Items	Recovery Bond Credit	$ (215,256,658)	TRUE	FALSE	0%	0%	100%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 230,732,710	FALSE	FALSE	0%	0%	100%
Line Items	Nuclear Decommissioning	$ 37,938,712	FALSE	FALSE	0%	0%	100%
Line Items	New System Generation Charge	$ 96,956,158	FALSE	FALSE	0%	0%	100%
Line Items	Competition Transition Charge	$ 8,518,646	FALSE	FALSE	0%	0%	100%
Line Items	Energy Cost Recovery Account	$ (19,846,861)	FALSE	FALSE	0%	0%	100%
Line Items	Residential CARE Contribution		TRUE	FALSE	0%	0%	100%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (891,914,356)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 7,032,741,656**					

SCE

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 18,066,203	FALSE	FALSE	0%	0%	100%
Generation	Marginal Energy Cost	$ 606,708,166	FALSE	TRUE	0%	0%	100%
Generation	Marginal Generation Capacity Cost	$ 584,831,167	FALSE	TRUE	0%	0%	100%
Generation	Non-Marginal Generation	$ 1,378,829,544	FALSE	TRUE	0%	0%	100%
Distribution	Marginal - Customer	$ 427,567,610	FALSE	FALSE	100%	0%	0%
Distribution	Marginal - Grid	$ 888,543,196	FALSE	FALSE	0%	0%	100%
Distribution	Marginal - Peak	$ 503,372,326	FALSE	FALSE	0%	0%	100%
Distribution	Non-Marginal Distribution	$ 1,845,967,040	FALSE	FALSE	0%	0%	100%
Transmission	Base Transmission	$ 599,320,433	FALSE	FALSE	0%	0%	100%
Transmission	Transmission Balancing Accounts	$ (1,839,212)	FALSE	FALSE	0%	0%	100%
Line Items	Public Purpose Programs - SGIP	$ 23,619,309	TRUE	FALSE	0%	0%	100%
Line Items	Wildfire Fund Charge	$ 103,390,404	TRUE	FALSE	0%	0%	100%
Line Items	Wildfire Hardening Charge	$ 17,556,861	TRUE	FALSE	0%	0%	100%
Line Items	Recovery Bond Charge	$ -	TRUE	FALSE	0%	0%	100%
Line Items	Recovery Bond Credit	$ (40,575,857)	TRUE	FALSE	0%	0%	100%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 313,291,510	FALSE	FALSE	0%	0%	100%
Line Items	Nuclear Decommissioning	$ 2,364,701	FALSE	FALSE	0%	0%	100%
Line Items	New System Generation Charge	$ 148,976,188	FALSE	FALSE	0%	0%	100%
Line Items	Residential CARE Contribution		TRUE	FALSE	0%	0%	100%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (660,034,291)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 6,995,933,045**					

SDG&E

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 180,005,950	FALSE	FALSE	0%	0%	100%
Generation	Marginal Energy Cost	$ 100,915,850	FALSE	TRUE	0%	0%	100%
Generation	Marginal Generation Capacity Cost	$ 57,547,258	FALSE	TRUE	0%	0%	100%
Generation	Non-Marginal Generation	$ 163,094,812	FALSE	TRUE	0%	0%	100%
Distribution	Marginal - Customer	$ 183,005,936	FALSE	FALSE	100%	0%	0%
Distribution	Marginal Demand - Non-Coincident Peak	$ 198,205,378	FALSE	FALSE	0%	0%	100%
Distribution	Marginal Demand - Coincident Peak	$ 26,974,391	FALSE	FALSE	0%	0%	100%
Distribution	Non-Marginal Distribution	$ 490,650,411	FALSE	FALSE	0%	0%	100%
Transmission	Base Transmission	$ 537,401,722	FALSE	FALSE	0%	0%	100%
Transmission	Transmission Balancing Accounts	$ (111,012,377)	FALSE	FALSE	0%	0%	100%
Line Items	Public Purpose Programs - SGIP	$ 8,781,000	TRUE	FALSE	0%	0%	100%
Line Items	Wildfire Fund Charge	$ 29,143,070	TRUE	FALSE	0%	0%	100%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 61,433,000	FALSE	FALSE	0%	0%	100%
Line Items	Nuclear Decommissioning	$ 526,530	FALSE	FALSE	0%	0%	100%
Line Items	Local Generation Charge/New System Generation Cha	$ 81,949,029	FALSE	FALSE	0%	0%	100%
Line Items	Competition Transition Charge	$ 11,052,908	FALSE	FALSE	0%	0%	100%
Line Items	Total Rate Adjustment Component - Baseline adjustme	$ 1,000,000	FALSE	FALSE	0%	0%	100%
Line Items	Reliability Services	$ 177,809	FALSE	FALSE	0%	0%	100%
Line Items	Residential CARE Contribution		TRUE	FALSE	0%	0%	100%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (178,549,476)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 2,020,852,676**					

Rate Design Inputs

		PG&E	SCE	SDG&E
Customer charge option		User-Defined CARE Charges	User-Defined CARE Charges	User-Defined CARE Charges
Customer Charge Weighting is used when Customer Charge Option is set to "Uniform Weights"				
Customer Charge Weighting	[0,25]	1	1	1
	[25,50]	1	1	1
	[50,75]	2	2	2
	[75,100]	2	2	2
	[100,150]	3	3	3
	[150,200]	3	3	3
	200+	3	3	3
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	$ 4.93	$ 5.32	$ 7.43
	[25,50]	$ 4.93	$ 5.32	$ 7.43
	[50,75]	$ 4.93	$ 5.32	$ 7.43
	[75,100]	$ 4.93	$ 5.32	$ 7.43
	[100,150]	$ 4.93	$ 5.32	$ 7.43
	[150,200]	$ 4.93	$ 5.32	$ 7.43
	200+	$ 4.93	$ 5.32	$ 7.43
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	$ 1.00	$ 1.00	$ 1.00
	[25,50]	$ 1.00	$ 1.00	$ 1.00
	[50,75]	$ 1.00	$ 1.00	$ 1.00
	[75,100]	$ 1.22	$ 1.22	$ 1.22
	[100,150]	$ 1.22	$ 1.22	$ 1.22
	[150,200]	$ 1.22	$ 1.22	$ 1.22
	200+	$ 1.22	$ 1.22	$ 1.22
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ -	$ -	$ -
Demand Charge Options	Billing determinant to use	X Highest Demand Months	X Highest Demand Months	X Highest Demand Months
	No. of highest demand months to include	$ 3	$ 3	$ 3
Adjustments to distribution rate		Constant Ratio	Constant Ratio	Constant Ratio
Include baseline credit from existing rate	(if applicable)	TRUE	TRUE	TRUE

Revenue Requirement Components

PG&E

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 454,792,861	$ -	$ 4,764,311,884

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ -	$ -	$ 444,768,973

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 2,778,949,663
NBCs	$ 277,190,068
Non-Dist	$ 1,708,172,152

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 375,847,966
Non-Dist	$ 68,921,008

SDG&E

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 183,005,936	$ -	$ 1,478,364,750

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ -	$ -	$ 37,924,070

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 715,830,179
NBCs	$ 73,012,438
Non-Dist	$ 689,522,133

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 37,924,070
Non-Dist	$ -

SCE

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 427,567,610	$ -	$ 4,318,062,384

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ -	$ -	$ 103,990,718

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 3,237,882,561
NBCs	$ 315,656,211
Non-Dist	$ 764,523,612

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 127,009,713
Non-Dist	$ (23,018,996)

New Rates

	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E
	E-1	E-1	E-TOU-C	E-TOU-C	EV2-A	EV2-A
	Non-CARE	CARE	Non-CARE	CARE	Non-CARE	CARE
Income Bracket (1000$):						
[0,25]	$ 7.45	$ 4.93	$ 7.45	$ 4.93	$ 7.45	$ 4.93
[25,50]	$ 7.45	$ 4.93	$ 7.45	$ 4.93	$ 7.45	$ 4.93
[50,75]	$ 7.45	$ 4.93	$ 7.45	$ 4.93	$ 7.45	$ 4.93
[75,100]	$ 9.09	$ 4.93	$ 9.09	$ 4.93	$ 9.09	$ 4.93
[100,150]	$ 9.09	$ 4.93	$ 9.09	$ 4.93	$ 9.09	$ 4.93
[150,200]	$ 9.09	$ 4.93	$ 9.09	$ 4.93	$ 9.09	$ 4.93
200+	$ 9.09	$ 4.93	$ 9.09	$ 4.93	$ 9.09	$ 4.93
Tier Credits/Charges ($/kWh)						
Baseline Credit	$ 0.069	$ 0.045	$ 0.072	$ 0.047	$ -	$ -
High Usage Charge	$ -	$ -	$ -	$ -	$ -	$ -
Demand Charges ($/kW)						
Billing Determinant	X Highest Demand I	X Highest Demand I	X Highest Demand I	X Highest Demand I	X Highest Demand I	X Highest Demand I
No. of Highest Demand Months	3	3	3	3	3	3
Demand Charge ($/kW-mo)	$ -	$ -	$ -	$ -	$ -	$ -
Energy Charges ($/kWh)						
Summer - Peak	$ 0.373	$ 0.228	$ 0.467	$ 0.290	$ 0.526	$ 0.328
Summer - Part-Peak	$ 0.373	$ 0.228	$ -	$ -	$ 0.420	$ 0.259
Summer - Off-Peak	$ 0.373	$ 0.228	$ 0.404	$ 0.249	$ 0.230	$ 0.136
Winter - Peak	$ 0.373	$ 0.228	$ 0.371	$ 0.227	$ 0.404	$ 0.249
Winter - Part-Peak	$ 0.373	$ 0.228	$ -	$ -	$ 0.388	$ 0.238
Winter - Off-Peak	$ 0.373	$ 0.228	$ 0.354	$ 0.216	$ 0.230	$ 0.136
Total CARE Program Funding - Modeled						
Customer		$ -		$ -		$ -
Demand		$ -		$ -		$ -
Volumetric - Delivery		$ (512,834,336)		$ (512,834,336)		$ (512,834,336)
Volumetric - Generation		$ (431,894,113)		$ (423,536,307)		$ (418,748,960)
Total CARE Credits		$ (944,728,448)		$ (936,370,643)		$ (931,583,295)
Residential CARE Funding		$ 256,139,604		$ 253,873,593		$ 252,575,623
Non-Res CARE Funding		$ 688,588,844		$ 682,497,050		$ 679,007,672
Total IOU forecast CARE program size						
2023 Forecast (Existing Rates)		$ (891,914,356)		$ (891,914,356)		$ (891,914,356)
Modeled Credits as % of Forecast		6%		5%		4%

Not Included in SEIA Proposal | **Not Included in SEIA Proposal**

~~PG&E~~	~~PG&E~~	SCE	SCE	SCE	SCE	~~SCE~~	~~SCE~~
~~E-ELEC~~	~~E-ELEC~~	D	D	TOU-D-4-9	TOU-D-4-9	~~TOU-D-PRIME~~	~~TOU-D-PRIME~~
~~Non-CARE~~	~~CARE~~	Non-CARE	CARE	Non-CARE	CARE	~~Non-CARE~~	~~CARE~~
~~$ 7.45~~	~~$ 4.93~~	$ 7.71	$ 5.32	$ 7.71	$ 5.32	~~$ 7.71~~	~~$ 5.32~~
~~$ 7.45~~	~~$ 4.93~~	$ 7.71	$ 5.32	$ 7.71	$ 5.32	~~$ 7.71~~	~~$ 5.32~~
~~$ 7.45~~	~~$ 4.93~~	$ 7.71	$ 5.32	$ 7.71	$ 5.32	~~$ 7.71~~	~~$ 5.32~~
~~$ 9.09~~	~~$ 4.93~~	$ 9.41	$ 5.32	$ 9.41	$ 5.32	~~$ 9.41~~	~~$ 5.32~~
~~$ 9.09~~	~~$ 4.93~~	$ 9.41	$ 5.32	$ 9.41	$ 5.32	~~$ 9.41~~	~~$ 5.32~~
~~$ 9.09~~	~~$ 4.93~~	$ 9.41	$ 5.32	$ 9.41	$ 5.32	~~$ 9.41~~	~~$ 5.32~~
~~$ 9.09~~	~~$ 4.93~~	$ 9.41	$ 5.32	$ 9.41	$ 5.32	~~$ 9.41~~	~~$ 5.32~~
~~$ -~~	~~$ -~~	$ 0.057	$ 0.039	$ 0.085	$ 0.057	~~$ -~~	~~$ -~~
~~$ -~~	~~$ -~~	$ 0.064	$ 0.044	$ -	$ -	~~$ -~~	~~$ -~~
~~X Highest Demand I~~	~~X Highest Demand I~~	X Highest Demand I	X Highest Demand I	X Highest Demand I	X Highest Demand I	~~X Highest Demand I~~	~~X Highest Demand I~~
~~3~~	~~3~~	3	3	3	3	~~3~~	~~3~~
~~$ -~~	~~$ -~~	$ -	$ -	$ -	$ -	~~$ -~~	~~$ -~~
~~$ 0.546~~	~~$ 0.341~~	$ 0.367	$ 0.238	$ 0.543	$ 0.357	~~$ 0.636~~	~~$ 0.420~~
~~$ 0.373~~	~~$ 0.229~~	$ 0.244	$ 0.155	$ 0.435	$ 0.284	~~$ 0.379~~	~~$ 0.246~~
~~$ 0.314~~	~~$ 0.190~~	$ 0.244	$ 0.155	$ 0.334	$ 0.216	~~$ 0.251~~	~~$ 0.160~~
~~$ 0.302~~	~~$ 0.183~~	$ 0.367	$ 0.238	$ 0.475	$ 0.311	~~$ 0.579~~	~~$ 0.381~~
~~$ 0.280~~	~~$ 0.168~~	$ 0.244	$ 0.155	$ 0.359	$ 0.232	~~$ 0.230~~	~~$ 0.145~~
~~$ 0.266~~	~~$ 0.159~~	$ 0.244	$ 0.155	$ 0.326	$ 0.210	~~$ 0.230~~	~~$ 0.145~~
	~~$ -~~		$ -		$ -		~~$ -~~
	~~$ -~~		$ -		$ -		~~$ -~~
	~~$ (512,834,336)~~		$ (361,429,971)		$ (361,429,971)		~~$ (361,429,971)~~
	~~$ (405,034,979)~~		$ (339,559,859)		$ (347,681,851)		~~$ (354,957,511)~~
	~~$ (917,869,314)~~		$ (700,989,830)		$ (709,111,821)		~~$ (716,387,482)~~
	~~$ 248,857,419~~		$ 180,152,375		$ 182,239,704		~~$ 184,109,528~~
	~~$ 669,011,896~~		$ 520,837,455		$ 526,872,117		~~$ 532,277,954~~
	~~$ (891,914,356)~~		$ (660,034,291)		$ (660,034,291)		~~$ (660,034,291)~~
	~~3%~~		6%		7%		~~9%~~

Not Included in SEIA Proposal

SDG&E	SDG&E	SDG&E	SDG&E	SDG&E	SDG&E	SDG&E	SDG&E
DR	DR	TOU-DR1	TOU-DR1	~~EV-TOU-5~~	~~EV-TOU-5~~	~~TOU-ELEC~~	~~TOU-ELEC~~
Non-CARE	CARE	Non-CARE	CARE	~~Non-CARE~~	~~CARE~~	~~Non-CARE~~	~~CARE~~

$ 10.77	$ 7.43	$ 10.77	$ 7.43	~~$ 10.77~~	~~$ 7.43~~	~~$ 10.77~~	~~$ 7.43~~
$ 10.77	$ 7.43	$ 10.77	$ 7.43	~~$ 10.77~~	~~$ 7.43~~	~~$ 10.77~~	~~$ 7.43~~
$ 10.77	$ 7.43	$ 10.77	$ 7.43	~~$ 10.77~~	~~$ 7.43~~	~~$ 10.77~~	~~$ 7.43~~
$ 13.14	$ 7.43	$ 13.14	$ 7.43	~~$ 13.14~~	~~$ 7.43~~	~~$ 13.14~~	~~$ 7.43~~
$ 13.14	$ 7.43	$ 13.14	$ 7.43	~~$ 13.14~~	~~$ 7.43~~	~~$ 13.14~~	~~$ 7.43~~
$ 13.14	$ 7.43	$ 13.14	$ 7.43	~~$ 13.14~~	~~$ 7.43~~	~~$ 13.14~~	~~$ 7.43~~
$ 13.14	$ 7.43	$ 13.14	$ 7.43	~~$ 13.14~~	~~$ 7.43~~	~~$ 13.14~~	~~$ 7.43~~

$ 0.090	$ 0.060	$ 0.108	$ 0.071	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
$ -	$ -	$ -	$ -	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~

X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	~~X Highest Demand~~	~~X Highest Demand~~	~~X Highest Demand~~	~~X Highest Demand~~
3	3	3	3	~~3~~	~~3~~	~~3~~	~~3~~
$ -	$ -	$ -	$ -	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~

$ 0.519	$ 0.331	$ 0.837	$ 0.541	~~$ 0.848~~	~~$ 0.548~~	~~$ 0.780~~	~~$ 0.504~~
$ 0.519	$ 0.331	$ 0.524	$ 0.334	~~$ 0.513~~	~~$ 0.327~~	~~$ 0.411~~	~~$ 0.260~~
$ 0.562	$ 0.359	$ 0.359	$ 0.226	~~$ 0.252~~	~~$ 0.155~~	~~$ 0.363~~	~~$ 0.228~~
$ 0.339	$ 0.212	$ 0.598	$ 0.383	~~$ 0.543~~	~~$ 0.347~~	~~$ 0.539~~	~~$ 0.344~~
$ 0.339	$ 0.212	$ 0.514	$ 0.327	~~$ 0.479~~	~~$ 0.305~~	~~$ 0.398~~	~~$ 0.251~~
$ 0.520	$ 0.332	$ 0.489	$ 0.311	~~$ 0.244~~	~~$ 0.149~~	~~$ 0.354~~	~~$ 0.222~~

	$ -		$ -		~~$ -~~		~~$ -~~
	$ -		$ -		~~$ -~~		~~$ -~~
	$ (121,075,241)		$ (121,075,241)		~~$ (121,075,241)~~		~~$ (121,075,241)~~
	$ (100,157,376)		$ (96,179,165)		~~$ (96,851,978)~~		~~$ (93,461,884)~~
	$ (221,232,617)		$ (217,254,406)		~~$ (217,927,218)~~		~~$ (214,537,125)~~

	$ 63,531,039		$ 62,388,623		~~$ 62,581,833~~		~~$ 61,608,305~~
	$ 157,701,577		$ 154,865,783		~~$ 155,345,385~~		~~$ 152,928,820~~

	$ (178,549,476)		$ (178,549,476)		~~$ (178,549,476)~~		~~$ (178,549,476)~~
	24%		22%		~~22%~~		~~20%~~

Bill Impacts

PG&E

			Customer Average Bill Impact ($/mo)										
Income Bracket	Bill Discount		PG&E	P	Q	R	S	T	V	W	X	Y	Z
$0 - $25,000	None	1	$ 0.45	$ (2.97)	$ (2.33)	$ (2.86)	$ (2.14)	$ 1.95	$ (0.87)	$ (2.21)	$ (0.11)	$ (0.19)	$ 2.96
$25,000 - $50,000	None	2	$ (0.39)	$ (2.88)	$ (2.32)	$ (2.89)	$ (2.08)	$ 1.98	$ (0.91)	$ (2.30)	$ (0.11)	$ (0.19)	$ 2.97
$50,000 - $75,000	None	3	$ (0.44)	$ (2.79)	$ (2.28)	$ (2.60)	$ (1.88)	$ 2.01	$ (0.91)	$ (1.94)	$ (0.07)	$ (0.17)	$ 2.96
$75,000 - $100,000	None	4	$ 1.40	$ (0.99)	$ (0.65)	$ (0.58)	$ 0.05	$ 3.67	$ 0.76	$ 0.20	$ 1.60	$ 1.48	$ 4.60
$100,00 - $150,000	None	5	$ 1.65	$ (0.81)	$ (0.55)	$ (0.14)	$ 0.37	$ 3.69	$ 0.80	$ 0.80	$ 1.67	$ 1.48	$ 4.61
$150,000 - $200,000	None	6	$ 1.96	$ (0.46)	$ (0.47)	$ 0.36	$ 0.78	$ 3.71	$ 0.85	$ 1.48	$ 1.75	$ 1.51	$ 4.59
$200,000+	None	7	$ 2.37	$ (0.01)	$ (0.22)	$ 1.13	$ 1.37	$ 3.74	$ 0.86	$ 2.27	$ 2.00	$ 1.56	$ 4.59
$0 - $25,000	CARE	1	$ (0.73)	$ (3.19)	$ (1.97)	$ (2.14)	$ (1.57)	$ 1.26	$ 0.11	$ (1.93)	$ 0.11	$ (2.32)	$ (0.53)
$25,000 - $50,000	CARE	2	$ (0.83)	$ (3.16)	$ (1.97)	$ (2.01)	$ (1.48)	$ 1.27	$ 0.11	$ (1.75)	$ 0.14	$ (2.32)	$ (0.57)
$50,000 - $75,000	CARE	3	$ (0.65)	$ (3.11)	$ (1.85)	$ (1.88)	$ (1.41)	$ 1.28	$ 0.14	$ (1.53)	$ 0.15	$ (2.31)	$ (0.59)
$75,000 - $100,000	CARE	4	$ (0.58)	$ (3.10)	$ (1.62)	$ (1.83)	$ (1.32)	$ 1.29	$ 0.17	$ (1.33)	$ 0.15	$ (2.31)	$ (0.61)
$100,00 - $150,000	CARE	5	$ (0.47)	$ (3.06)	$ (1.93)	$ (1.67)	$ (1.22)	$ 1.30	$ 0.12	$ (1.21)	$ 0.19	$ (2.30)	$ (0.62)
$150,000 - $200,000	CARE	6	$ (0.29)	$ (2.99)	$ (2.02)	$ (1.57)	$ (1.15)	$ 1.29	$ 0.11	$ (0.91)	$ 0.20	$ (2.30)	$ (0.55)
$200,000+	CARE	7	$ (0.04)	$ (2.77)	$ (2.02)	$ (1.37)	$ (1.01)	$ 1.29	$ 0.18	$ (0.79)	$ 0.23	$ (2.30)	$ (1.81)
$0 - $25,000	FERA	1	$ (1.06)	$ (4.60)	$ (3.04)	$ (2.85)	$ (2.24)	$ 1.26	$ (0.26)	$ (2.52)	$ (0.21)	$ (3.47)	$ (0.86)
$25,000 - $50,000	FERA	2	$ (1.10)	$ (4.55)	$ (3.03)	$ (2.53)	$ (2.05)	$ 1.29	$ (0.26)	$ (2.10)	$ (0.16)	$ (3.47)	$ (1.04)
$50,000 - $75,000	FERA	3	$ (0.88)	$ (4.47)	$ (2.79)	$ (2.23)	$ (1.91)	$ 1.30	$ (0.22)	$ (1.66)	$ (0.14)	$ (3.44)	$ (1.12)
$75,000 - $100,000	FERA	4	$ 0.56	$ (3.11)	$ (1.00)	$ (0.78)	$ (0.38)	$ 2.66	$ 1.17	$ 0.05	$ 1.21	$ (2.10)	$ 0.19
$100,00 - $150,000	FERA	5	$ 0.69	$ (3.05)	$ (1.61)	$ (0.46)	$ (0.22)	$ 2.67	$ 1.10	$ 0.26	$ 1.27	$ (2.08)	$ 0.14
$150,000 - $200,000	FERA	6	$ 0.87	$ (2.95)	$ (1.81)	$ (0.28)	$ (0.07)	$ 2.67	$ 1.09	$ 0.71	$ 1.28	$ (2.08)	$ 0.39
$200,000+	FERA	7	$ 1.13	$ (2.63)	$ (1.81)	$ 0.04	$ 0.16	$ 2.67	$ 1.18	$ 0.89	$ 1.34	$ (2.07)	$ (0.62)

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	E-1
Select single counterfactual rate (if applicable)	E-1

Bill Impacts

PG&E

			Customer Average Bill Impact ($/mo)										
Income Bracket	Bill Discount		PG&E	P	Q	R	S	T	V	W	X	Y	Z
$0 - $25,000	None	1	$ 0.22	$ (3.33)	$ (2.62)	$ (3.26)	$ (2.50)	$ 1.78	$ (1.12)	$ (2.63)	$ (0.36)	$ (0.44)	$ 2.81
$25,000 - $50,000	None	2	$ (0.66)	$ (3.23)	$ (2.61)	$ (3.30)	$ (2.44)	$ 1.81	$ (1.16)	$ (2.71)	$ (0.37)	$ (0.44)	$ 2.82
$50,000 - $75,000	None	3	$ (0.72)	$ (3.14)	$ (2.57)	$ (3.00)	$ (2.24)	$ 1.84	$ (1.16)	$ (2.35)	$ (0.32)	$ (0.43)	$ 2.81
$75,000 - $100,000	None	4	$ 1.13	$ (1.34)	$ (0.94)	$ (0.97)	$ (0.30)	$ 3.50	$ 0.52	$ (0.19)	$ 1.36	$ 1.22	$ 4.45
$100,00 - $150,000	None	5	$ 1.39	$ (1.15)	$ (0.83)	$ (0.51)	$ 0.04	$ 3.52	$ 0.56	$ 0.43	$ 1.42	$ 1.23	$ 4.46
$150,000 - $200,000	None	6	$ 1.71	$ (0.78)	$ (0.75)	$ 0.00	$ 0.46	$ 3.54	$ 0.61	$ 1.13	$ 1.51	$ 1.26	$ 4.44
$200,000+	None	7	$ 2.14	$ (0.32)	$ (0.49)	$ 0.79	$ 1.08	$ 3.58	$ 0.62	$ 1.94	$ 1.77	$ 1.31	$ 4.44
$0 - $25,000	CARE	1	$ (0.94)	$ (3.47)	$ (2.17)	$ (2.44)	$ (1.83)	$ 1.14	$ (0.04)	$ (2.24)	$ (0.06)	$ (2.55)	$ (0.69)
$25,000 - $50,000	CARE	2	$ (1.05)	$ (3.44)	$ (2.17)	$ (2.31)	$ (1.74)	$ 1.15	$ (0.04)	$ (2.04)	$ (0.03)	$ (2.55)	$ (0.74)
$50,000 - $75,000	CARE	3	$ (0.86)	$ (3.38)	$ (2.05)	$ (2.17)	$ (1.67)	$ 1.16	$ (0.01)	$ (1.82)	$ (0.01)	$ (2.54)	$ (0.76)
$75,000 - $100,000	CARE	4	$ (0.79)	$ (3.37)	$ (1.81)	$ (2.11)	$ (1.57)	$ 1.17	$ 0.03	$ (1.61)	$ (0.01)	$ (2.54)	$ (0.77)
$100,00 - $150,000	CARE	5	$ (0.68)	$ (3.33)	$ (2.13)	$ (1.95)	$ (1.47)	$ 1.18	$ (0.03)	$ (1.49)	$ 0.02	$ (2.53)	$ (0.79)
$150,000 - $200,000	CARE	6	$ (0.49)	$ (3.26)	$ (2.23)	$ (1.84)	$ (1.39)	$ 1.17	$ (0.04)	$ (1.19)	$ 0.03	$ (2.53)	$ (0.71)
$200,000+	CARE	7	$ (0.22)	$ (3.03)	$ (2.23)	$ (1.64)	$ (1.25)	$ 1.18	$ 0.03	$ (1.06)	$ 0.07	$ (2.53)	$ (1.95)
$0 - $25,000	FERA	1	$ (1.32)	$ (4.95)	$ (3.30)	$ (3.21)	$ (2.56)	$ 1.11	$ (0.44)	$ (2.89)	$ (0.42)	$ (3.76)	$ (1.07)
$25,000 - $50,000	FERA	2	$ (1.37)	$ (4.90)	$ (3.29)	$ (2.89)	$ (2.37)	$ 1.14	$ (0.45)	$ (2.46)	$ (0.37)	$ (3.76)	$ (1.25)
$50,000 - $75,000	FERA	3	$ (1.13)	$ (4.81)	$ (3.04)	$ (2.58)	$ (2.22)	$ 1.15	$ (0.40)	$ (2.01)	$ (0.34)	$ (3.73)	$ (1.32)
$75,000 - $100,000	FERA	4	$ 0.31	$ (3.45)	$ (1.23)	$ (1.12)	$ (0.69)	$ 2.52	$ 0.99	$ (0.28)	$ 1.00	$ (2.39)	$ (0.01)
$100,00 - $150,000	FERA	5	$ 0.44	$ (3.39)	$ (1.86)	$ (0.79)	$ (0.51)	$ 2.53	$ 0.91	$ (0.07)	$ 1.06	$ (2.37)	$ (0.06)
$150,000 - $200,000	FERA	6	$ 0.63	$ (3.29)	$ (2.07)	$ (0.60)	$ (0.37)	$ 2.52	$ 0.90	$ 0.40	$ 1.08	$ (2.37)	$ 0.18
$200,000+	FERA	7	$ 0.91	$ (2.95)	$ (2.07)	$ (0.27)	$ (0.12)	$ 2.53	$ 0.99	$ 0.58	$ 1.14	$ (2.35)	$ (0.81)

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	E-TOU-C
Select single counterfactual rate (if applicable)	E-TOU-C

Bill Impacts

PG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo)										
			PG&E	P	Q	R	S	T	V	W	X	Y	Z
$0 - $25,000	None	1	$ 0.38	$ (3.24)	$ (2.22)	$ (3.49)	$ (2.67)	$ 2.01	$ (0.35)	$ (3.16)	$ (0.19)	$ (0.35)	$ 2.93
$25,000 - $50,000	None	2	$ (0.59)	$ (3.17)	$ (2.22)	$ (3.50)	$ (2.63)	$ 2.02	$ (0.38)	$ (3.20)	$ (0.19)	$ (0.35)	$ 2.94
$50,000 - $75,000	None	3	$ (0.74)	$ (3.11)	$ (2.19)	$ (3.35)	$ (2.51)	$ 2.04	$ (0.38)	$ (3.02)	$ (0.16)	$ (0.35)	$ 2.92
$75,000 - $100,000	None	4	$ 1.07	$ (1.36)	$ (0.56)	$ (1.52)	$ (0.68)	$ 3.69	$ 1.29	$ (1.12)	$ 1.50	$ 1.29	$ 4.57
$100,00 - $150,000	None	5	$ 1.29	$ (1.24)	$ (0.49)	$ (1.29)	$ (0.47)	$ 3.71	$ 1.31	$ (0.80)	$ 1.55	$ 1.29	$ 4.57
$150,000 - $200,000	None	6	$ 1.59	$ (0.99)	$ (0.43)	$ (1.03)	$ (0.21)	$ 3.72	$ 1.35	$ (0.45)	$ 1.60	$ 1.30	$ 4.55
$200,000+	None	7	$ 2.02	$ (0.67)	$ (0.25)	$ (0.63)	$ 0.17	$ 3.74	$ 1.36	$ (0.05)	$ 1.77	$ 1.31	$ 4.55
$0 - $25,000	CARE	1	$ (0.92)	$ (3.24)	$ (1.85)	$ (2.52)	$ (1.92)	$ 1.27	$ 0.25	$ (2.36)	$ 0.03	$ (2.24)	$ (0.31)
$25,000 - $50,000	CARE	2	$ (1.09)	$ (3.22)	$ (1.84)	$ (2.45)	$ (1.86)	$ 1.28	$ 0.25	$ (2.26)	$ 0.05	$ (2.24)	$ (0.38)
$50,000 - $75,000	CARE	3	$ (0.93)	$ (3.19)	$ (1.76)	$ (2.38)	$ (1.82)	$ 1.28	$ 0.27	$ (2.14)	$ 0.06	$ (2.24)	$ (0.42)
$75,000 - $100,000	CARE	4	$ (0.87)	$ (3.18)	$ (1.58)	$ (2.35)	$ (1.76)	$ 1.29	$ 0.29	$ (2.03)	$ 0.06	$ (2.24)	$ (0.44)
$100,00 - $150,000	CARE	5	$ (0.79)	$ (3.16)	$ (1.82)	$ (2.26)	$ (1.71)	$ 1.29	$ 0.26	$ (1.97)	$ 0.08	$ (2.25)	$ (0.47)
$150,000 - $200,000	CARE	6	$ (0.60)	$ (3.12)	$ (1.89)	$ (2.21)	$ (1.66)	$ 1.29	$ 0.25	$ (1.80)	$ 0.09	$ (2.25)	$ (0.35)
$200,000+	CARE	7	$ (0.30)	$ (2.99)	$ (1.89)	$ (2.10)	$ (1.57)	$ 1.29	$ 0.30	$ (1.74)	$ 0.11	$ (2.25)	$ (2.31)
$0 - $25,000	FERA	1	$ (1.30)	$ (4.57)	$ (2.74)	$ (3.47)	$ (2.72)	$ 1.31	$ (0.02)	$ (3.24)	$ (0.28)	$ (3.30)	$ (0.93)
$25,000 - $50,000	FERA	2	$ (1.45)	$ (4.55)	$ (2.73)	$ (3.30)	$ (2.60)	$ 1.33	$ (0.03)	$ (3.01)	$ (0.25)	$ (3.31)	$ (1.38)
$50,000 - $75,000	FERA	3	$ (1.26)	$ (4.50)	$ (2.56)	$ (3.13)	$ (2.52)	$ 1.34	$ 0.01	$ (2.76)	$ (0.23)	$ (3.32)	$ (1.56)
$75,000 - $100,000	FERA	4	$ 0.14	$ (3.14)	$ (0.90)	$ (1.73)	$ (1.06)	$ 2.69	$ 1.38	$ (1.22)	$ 1.11	$ (1.97)	$ (0.31)
$100,00 - $150,000	FERA	5	$ 0.23	$ (3.11)	$ (1.33)	$ (1.55)	$ (0.95)	$ 2.70	$ 1.33	$ (1.10)	$ 1.15	$ (1.98)	$ (0.44)
$150,000 - $200,000	FERA	6	$ 0.44	$ (3.05)	$ (1.47)	$ (1.45)	$ (0.87)	$ 2.69	$ 1.32	$ (0.85)	$ 1.16	$ (1.98)	$ 0.17
$200,000+	FERA	7	$ 0.74	$ (2.87)	$ (1.47)	$ (1.27)	$ (0.72)	$ 2.70	$ 1.38	$ (0.75)	$ 1.20	$ (1.99)	$ (2.31)

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	EV2-A
Select single counterfactual rate (if applicable)	EV2-A

SDG&E

Income Bracket	Bill Discount		SDG&E	Inland	Coastal	Desert	Mountain
			Customer Average Bill Impact ($/mo)				
$0 - $25,000	None	1	$ 0.01	$ 0.03	$ 0.19	$ 0.66	$ (5.76)
$25,000 - $50,000	None	2	$ 0.00	$ (0.24)	$ 0.19	$ 0.33	$ (5.06)
$50,000 - $75,000	None	3	$ (0.03)	$ (0.27)	$ 0.22	$ 1.30	$ (4.85)
$75,000 - $100,000	None	4	$ 2.34	$ 2.16	$ 2.58	$ 4.91	$ (2.24)
$100,00 - $150,000	None	5	$ 2.63	$ 2.60	$ 2.75	$ 4.08	$ (1.46)
$150,000 - $200,000	None	6	$ 3.03	$ 3.22	$ 2.96	$ 10.81	$ (0.38)
$200,000+	None	7	$ 3.70	$ 4.10	$ 3.52	$ 3.74	$ 0.98
$0 - $25,000	CARE	1	$ 1.79	$ 1.08	$ 2.70	$ (6.01)	$ (10.46)
$25,000 - $50,000	CARE	2	$ 1.78	$ 1.10	$ 2.70	$ (6.48)	$ (9.41)
$50,000 - $75,000	CARE	3	$ 1.84	$ 1.13	$ 2.71	N/A	$ (9.58)
$75,000 - $100,000	CARE	4	$ 1.99	$ 1.15	$ 2.75	N/A	$ (10.85)
$100,00 - $150,000	CARE	5	$ 2.10	$ 1.12	$ 2.73	N/A	N/A
$150,000 - $200,000	CARE	6	$ 2.89	N/A	$ 2.89	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ 0.05	$ (0.69)	$ 1.29	$ (8.47)	$ (17.06)
$25,000 - $50,000	FERA	2	$ 0.08	$ (0.65)	$ 1.29	$ (9.59)	$ (15.02)
$50,000 - $75,000	FERA	3	$ 0.19	$ (0.59)	$ 1.31	N/A	$ (15.37)
$75,000 - $100,000	FERA	4	$ 2.27	$ 1.34	$ 3.27	N/A	$ (15.85)
$100,00 - $150,000	FERA	5	$ 2.41	$ 1.28	$ 3.24	N/A	N/A
$150,000 - $200,000	FERA	6	$ 3.55	N/A	$ 3.55	N/A	N/A
$200,000+	FERA	7	N/A	N/A	N/A	N/A	N/A

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	DR
Select single counterfactual rate (if applicable)	DR

SDG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo)				
			SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ (1.36)	$ (1.36)	$ (1.14)	$ (0.76)	$ (8.04)
$25,000 - $50,000	None	2	$ (1.36)	$ (1.67)	$ (1.14)	$ (1.15)	$ (7.21)
$50,000 - $75,000	None	3	$ (1.41)	$ (1.70)	$ (1.10)	$ (0.02)	$ (6.96)
$75,000 - $100,000	None	4	$ 1.04	$ 0.81	$ 1.33	$ 3.85	$ (4.23)
$100,00 - $150,000	None	5	$ 1.37	$ 1.32	$ 1.53	$ 2.88	$ (3.29)
$150,000 - $200,000	None	6	$ 1.85	$ 2.06	$ 1.77	$ 10.63	$ (2.00)
$200,000+	None	7	$ 2.64	$ 3.10	$ 2.43	$ 2.50	$ (0.37)
$0 - $25,000	CARE	1	$ (0.33)	$ (1.15)	$ 0.73	$ (9.21)	$ (13.97)
$25,000 - $50,000	CARE	2	$ (0.34)	$ (1.13)	$ 0.73	$ (9.76)	$ (12.89)
$50,000 - $75,000	CARE	3	$ (0.27)	$ (1.10)	$ 0.74	N/A	$ (13.07)
$75,000 - $100,000	CARE	4	$ (0.10)	$ (1.08)	$ 0.78	N/A	$ (14.37)
$100,00 - $150,000	CARE	5	$ 0.03	$ (1.11)	$ 0.76	N/A	N/A
$150,000 - $200,000	CARE	6	$ 0.95	N/A	$ 0.95	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ (1.07)	$ (1.94)	$ 0.34	$ (10.83)	$ (19.96)
$25,000 - $50,000	FERA	2	$ (1.05)	$ (1.89)	$ 0.34	$ (12.15)	$ (17.87)
$50,000 - $75,000	FERA	3	$ (0.92)	$ (1.82)	$ 0.36	N/A	$ (18.22)
$75,000 - $100,000	FERA	4	$ 1.25	$ 0.17	$ 2.40	N/A	$ (18.72)
$100,00 - $150,000	FERA	5	$ 1.40	$ 0.10	$ 2.36	N/A	N/A
$150,000 - $200,000	FERA	6	$ 2.75	N/A	$ 2.75	N/A	N/A
$200,000+	FERA	7	N/A	N/A	N/A	N/A	N/A

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	TOU-DR1
Select single counterfactual rate (if applicable)	TOU-DR1

SCE

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo)									
			SCE	5	6	8	9	10	13	14	15	16
$0 - $25,000	None	1	$ 1.21	$ 3.51	$ 2.60	$ 1.84	$ 0.21	$ 0.19	$ (1.73)	$ (1.88)	$ (0.87)	$ 2.83
$25,000 - $50,000	None	2	$ 0.74	$ 3.51	$ 2.61	$ 1.80	$ 0.06	$ (0.18)	$ (1.54)	$ (1.77)	$ (1.16)	$ 2.84
$50,000 - $75,000	None	3	$ 0.77	$ 3.51	$ 2.62	$ 1.79	$ 0.04	$ (0.13)	$ (1.20)	$ (1.64)	$ (0.97)	$ 2.86
$75,000 - $100,000	None	4	$ 2.55	$ 5.20	$ 4.33	$ 3.52	$ 1.80	$ 1.72	$ 0.75	$ 0.25	$ 0.90	$ 4.60
$100,00 - $150,000	None	5	$ 2.73	$ 5.20	$ 4.36	$ 3.57	$ 1.87	$ 2.01	$ 1.08	$ 0.45	$ 1.06	$ 4.65
$150,000 - $200,000	None	6	$ 2.93	$ 5.20	$ 4.39	$ 3.65	$ 2.02	$ 2.28	$ 1.32	$ 0.68	$ 1.25	$ 4.70
$200,000+	None	7	$ 3.30	$ 5.20	$ 4.46	$ 3.82	$ 2.23	$ 2.61	$ 1.82	$ 0.96	$ 1.57	$ 4.74
$0 - $25,000	CARE	1	$ 1.35	N/A	$ 3.32	$ 2.56	$ 2.02	$ 0.24	$ (0.30)	$ (0.93)	$ 0.33	$ 1.10
$25,000 - $50,000	CARE	2	$ 1.40	N/A	$ 3.32	$ 2.56	$ 2.02	$ 0.28	$ (0.20)	$ (0.85)	$ 0.44	$ 1.13
$50,000 - $75,000	CARE	3	$ 1.44	N/A	$ 3.32	$ 2.57	$ 2.03	$ 0.34	$ (0.13)	$ (0.80)	$ 0.49	$ 1.12
$75,000 - $100,000	CARE	4	$ 1.44	N/A	$ 3.32	$ 2.57	$ 2.03	$ 0.38	$ (0.05)	$ (0.78)	$ 0.55	$ 1.12
$100,00 - $150,000	CARE	5	$ 1.51	N/A	$ 3.32	$ 2.57	$ 2.03	$ 0.44	$ (0.04)	$ (0.69)	$ 0.58	$ 1.17
$150,000 - $200,000	CARE	6	$ 1.63	N/A	$ 3.32	$ 2.58	$ 2.04	$ 0.56	$ 0.04	$ (0.59)	$ 0.67	$ 1.23
$200,000+	CARE	7	$ 1.82	N/A	$ 3.33	$ 2.59	$ 2.04	$ 0.64	$ 0.17	$ (0.51)	$ 0.83	$ 1.29
$0 - $25,000	FERA	1	$ 1.26	N/A	$ 3.67	$ 2.73	$ 2.08	$ (0.07)	$ (0.86)	$ (1.76)	$ (0.18)	$ 0.37
$25,000 - $50,000	FERA	2	$ 1.31	N/A	$ 3.68	$ 2.73	$ 2.08	$ 0.01	$ (0.65)	$ (1.59)	$ 0.05	$ 0.42
$50,000 - $75,000	FERA	3	$ 1.36	N/A	$ 3.68	$ 2.74	$ 2.08	$ 0.12	$ (0.51)	$ (1.51)	$ 0.17	$ 0.41
$75,000 - $100,000	FERA	4	$ 2.75	N/A	$ 5.07	$ 4.13	$ 3.48	$ 1.57	$ 1.03	$ (0.10)	$ 1.67	$ 1.80
$100,00 - $150,000	FERA	5	$ 2.84	N/A	$ 5.07	$ 4.14	$ 3.48	$ 1.69	$ 1.05	$ 0.07	$ 1.74	$ 1.88
$150,000 - $200,000	FERA	6	$ 3.00	N/A	$ 5.07	$ 4.15	$ 3.48	$ 1.88	$ 1.20	$ 0.23	$ 1.91	$ 1.98
$200,000+	FERA	7	$ 3.21	N/A	$ 5.07	$ 4.16	$ 3.48	$ 2.02	$ 1.42	$ 0.34	$ 2.20	$ 2.08

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	D
Select single counterfactual rate (if applicable)	D

SCE

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo)									
			SCE	5	6	8	9	10	13	14	15	16
$0 - $25,000	None	1	$ (3.53)	$ (1.18)	$ (1.17)	$ (2.29)	$ (4.96)	$ (5.29)	$ (8.15)	$ (8.04)	$ (7.99)	$ (1.38)
$25,000 - $50,000	None	2	$ (4.18)	$ (1.18)	$ (1.16)	$ (2.33)	$ (5.14)	$ (5.76)	$ (7.91)	$ (7.92)	$ (8.25)	$ (1.37)
$50,000 - $75,000	None	3	$ (4.14)	$ (1.18)	$ (1.14)	$ (2.34)	$ (5.16)	$ (5.70)	$ (7.50)	$ (7.78)	$ (8.07)	$ (1.36)
$75,000 - $100,000	None	4	$ (2.33)	$ 0.51	$ 0.57	$ (0.60)	$ (3.40)	$ (3.80)	$ (5.48)	$ (5.86)	$ (6.22)	$ 0.37
$100,00 - $150,000	None	5	$ (2.08)	$ 0.51	$ 0.60	$ (0.54)	$ (3.31)	$ (3.45)	$ (5.07)	$ (5.64)	$ (6.07)	$ 0.40
$150,000 - $200,000	None	6	$ (1.79)	$ 0.51	$ 0.64	$ (0.45)	$ (3.14)	$ (3.10)	$ (4.78)	$ (5.39)	$ (5.90)	$ 0.44
$200,000+	None	7	$ (1.26)	$ 0.51	$ 0.72	$ (0.26)	$ (2.89)	$ (2.68)	$ (4.17)	$ (5.08)	$ (5.61)	$ 0.46
$0 - $25,000	CARE	1	$ (1.82)	N/A	$ 1.23	$ 0.15	$ (0.89)	$ (3.53)	$ (4.45)	$ (5.09)	$ (4.24)	$ (2.19)
$25,000 - $50,000	CARE	2	$ (1.74)	N/A	$ 1.23	$ 0.15	$ (0.89)	$ (3.48)	$ (4.33)	$ (4.99)	$ (4.11)	$ (2.16)
$50,000 - $75,000	CARE	3	$ (1.69)	N/A	$ 1.23	$ 0.16	$ (0.89)	$ (3.41)	$ (4.24)	$ (4.93)	$ (4.04)	$ (2.16)
$75,000 - $100,000	CARE	4	$ (1.70)	N/A	$ 1.23	$ 0.16	$ (0.89)	$ (3.36)	$ (4.15)	$ (4.92)	$ (3.98)	$ (2.16)
$100,00 - $150,000	CARE	5	$ (1.60)	N/A	$ 1.23	$ 0.16	$ (0.89)	$ (3.28)	$ (4.14)	$ (4.81)	$ (3.94)	$ (2.11)
$150,000 - $200,000	CARE	6	$ (1.43)	N/A	$ 1.23	$ 0.17	$ (0.90)	$ (3.14)	$ (4.03)	$ (4.70)	$ (3.84)	$ (2.05)
$200,000+	CARE	7	$ (1.17)	N/A	$ 1.23	$ 0.17	$ (0.90)	$ (3.04)	$ (3.87)	$ (4.61)	$ (3.65)	$ (1.98)
$0 - $25,000	FERA	1	$ (2.57)	N/A	$ 1.12	$ (0.21)	$ (1.47)	$ (4.63)	$ (5.88)	$ (6.82)	$ (5.73)	$ (3.68)
$25,000 - $50,000	FERA	2	$ (2.50)	N/A	$ 1.12	$ (0.21)	$ (1.47)	$ (4.53)	$ (5.62)	$ (6.64)	$ (5.45)	$ (3.63)
$50,000 - $75,000	FERA	3	$ (2.45)	N/A	$ 1.12	$ (0.20)	$ (1.48)	$ (4.40)	$ (5.45)	$ (6.54)	$ (5.32)	$ (3.63)
$75,000 - $100,000	FERA	4	$ (1.06)	N/A	$ 2.52	$ 1.19	$ (0.09)	$ (2.93)	$ (3.87)	$ (5.13)	$ (3.80)	$ (2.24)
$100,00 - $150,000	FERA	5	$ (0.95)	N/A	$ 2.52	$ 1.19	$ (0.10)	$ (2.79)	$ (3.85)	$ (4.94)	$ (3.72)	$ (2.16)
$150,000 - $200,000	FERA	6	$ (0.75)	N/A	$ 2.52	$ 1.20	$ (0.11)	$ (2.56)	$ (3.66)	$ (4.76)	$ (3.52)	$ (2.06)
$200,000+	FERA	7	$ (0.44)	N/A	$ 2.52	$ 1.21	$ (0.13)	$ (2.39)	$ (3.39)	$ (4.63)	$ (3.18)	$ (1.95)

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	TOU-D-4-9
Select single counterfactual rate (if applicable)	TOU-D-4-9