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Witness: John D. Wilson

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance
Demand Flexibility Through Electric Rates

Rulemaking 22-07-005

Errata Direct Testimony of John D. Wilson

On Behalf of Sierra Club

April 7, 2023
Revised April 28, 2023

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I. Introduction and Summary

Q Please state your name, occupation, and business address.

A My name is John D. Wilson. I am the Research Director for Resource Insight, Inc. My business address is 10 Court Street, Arlington, MA.

Q On whose behalf are you testifying?

A I am testifying on behalf of the Sierra Club.

Q Please summarize your professional and educational background.

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

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

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

My professional qualifications are further summarized in Attachment 1.

Q Have you ever testified before this Commission?

A Yes. I have testified before the California Public Utilities Commission ("Commission") in ten proceedings.

Q Have you ever testified before other Commissions?

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

Q What is the purpose of your testimony?

A My testimony proposes an income-graduated fixed charge ("IGFC") for residential rates for all investor-owned electric utilities in accordance with Assembly Bill ("AB") 205, incorporating AB 205's requirements to maintain California Alternate Rates for Energy ("CARE")-exempted charges and create bill savings for low-income customers. My testimony and proposed IGFC attempt to balance opportunities to further equity through a progressive fixed-charge and to further electrification priorities through lower volumetric rates with concerns about maintaining incentives for distributed energy resources and energy efficiency. My proposal is guided by Sierra Club's environmental and equity policy goals and Commission principles on cost-based ratemaking.

Q Please summarize your recommendations.

A I recommend that the Commission adopt five income tiers of progressively larger fixed charges.

I recommend that the IGFC revenue requirement include all costs that do not vary with consumption, except for the Power Cost Indifference Adjustment ("PCIA").

I recommend that the fixed charge include no costs for the lowest tier, solely marginal customer access costs for the second lowest tier, and a progressive distribution of customer access costs, non-marginal distribution costs, and seven non-bypassable charges for the remaining three tiers. The resulting reduction in volumetric rates should be calculated using the uniform factor method.

To support the zero-dollar fixed charge for the lowest tier of customers, which I propose to be CARE/Family Electric Rate Assistance ("FERA") customers, I recommend that a portion of CARE discount funding is used to support this zero-dollar lowest fixed charge tier.

I recommend that the Commission adopt a service line discount and surcharge to remedy inequitable cost allocations between small (shared service line) and larger (dedicated service line) customers.

Q. Please summarize your findings.

A My testimony finds that a progressive fixed charge rooted in fixed costs is on average about $28 in Pacific Gas & Electric ("PG&E") territory, $37 in Southern California Edison ("SCE") territory, and $36~~30~~ in San Diego Gas & Electric ("SDG&E") territory. It finds that it is possible and equitable to include a zero-dollar fixed charge for the lowest income tier, guaranteeing lower bills for low-income customers given the same consumption. It finds that there is a level of fixed charge that will provide bill relief for low-income customers and lower volumetric rates to reward electrification while keeping costs that vary with electric usage in volumetric rates and also maintaining a substantial conservation and energy efficiency incentive. Last, it finds that implementing an IGFC requires the Commission to be thoughtful in setting income thresholds in order to fairly achieve equity and electrification goals in different geographic settings.

Q How is your testimony organized?

A My testimony is organized as follows:

- In Section II, I describe the cost categories that I propose should be recovered through an IGFC, what goals guided the selection of the cost categories, and an estimated revenue requirement.
- In Section III, I describe my proposed rate design for the IGFC. I propose that the Commission adopt five income tiers, with a zero-dollar fixed charge lowest income tier for CARE and FERA customers. I discuss which costs should be assigned to each income tier, how the Commission should direct those charges to be differentiated by type of service drop, and whether the Commission should implement a transition period.
- In Section IV, I discuss application of the IGFC to non-default rates.
- In Section V, I discuss the impacts of my proposed IGFC rate design. As I describe, my proposal will ensure lower average monthly bills for low-income ratepayers, while increasing incentives for electrification and having only modest impacts on conservation and energy efficiency goals.
- In Section VI, I identify certain issues that I have reserved for reply testimony.
- Finally, in Section VII, I conclude my testimony and present the Commission with proposed findings and recommendations.

Q Please describe the attachments to your testimony.

A In addition to Attachment 1, my qualifications, and Attachment 6, referenced data responses, I have attached four reports from the Fixed Charge Tool as directed in Administrative Law Judge ("ALJ") Wang's *Ruling Providing Additional Guidance for Track A Proposals* (March 23,2023).[1]

- Attachment 2 – IGFC Proposal Standard Rates. This 15-page attachment supports the proposal described in Sections <u>II</u>~~II~~ and <u>III</u>~~III~~, including a 12-page report for the three default non-time of use ("TOU") tiered rates and three additional pages providing the heat maps for the default time-of-use rates. Rate design data related to the five electrification rates in this attachment should be disregarded.
- Attachment 3 – IGFC Proposal Electrification Rates. My proposal includes a different IGFC design for electric vehicle ("EV") and electrification rates (generally referred to as electrification rates in my testimony). The differences between the standard and electrification rates are described in Section <u>IV</u>~~IV~~, and are supported by a 15-page attachment, including a 12-page report for the three EV rates and two additional pages providing the heat maps for the electrification rates. Rate design data related to the six non-electrification rates in this attachment should be disregarded.
- Attachment 4 – IGFC Proposal Average Charges. This 9-page attachment supports the average fixed charge per customer and volumetric rate for each utility comparing the impact of the cost categories I propose should be included in the IGFC. This 9-page attachment supports the values shown in <u>Table 4</u>~~Table 4~~. No heat maps are included because the average fixed charge and volumetric rate are not directly included in any of the IGFC rate proposals included in Attachments 2 and 3.
- Attachment 5 – IGFC Proposal Below Average Income ("BAI") Charges. As described in Section <u>III.D.2</u>~~III.D.2~~, the BAI charges are targeted to be approximately equal to the average customer responsibility for marginal customer access costs ("MCACs") as currently defined by the Commission. This 9-page report provides support for this calculation. No heat maps are included because the BAI tier is fully described by the eleven rates included in Attachments 2 and 3.

<u>**Q Please describe the changes you made in your errata testimony.**</u>

<u>A As directed by ALJ Wang, I am submitting errata to reflect results using the E3 Fixed Charge Tool as updated on April 18, 2023. The only substantive impact on my proposal appears to be to SDG&E's fixed-charge weights and rates. I am also correcting several transcription errors and two statutory references. Furthermore, I am providing data inadvertently omitted from Table 6 and Section IV.</u>

[1] ALJ's Ruling Providing Additional Guidance for Track A Proposals, Attach.: Staff Guidance on Using the E3 Fixed Charge Tool to Prepare Opening Test., R.22-07-005 at 4-5 (Mar. 23, 2023) [hereinafter "Staff Guidance Memo on Using the E3 Fixed Charge Tool to Prepare Opening Test."].

II. Cost Categories for Recovery Through a Fixed Charge

A. Standard for Review of Cost Categories

Q What cost components are reasonable to include in an IGFC?

A In laying out what may be included in a fixed charge, AB 205 differentiates between costs that vary with consumption, which may include both variable and certain other fixed utility costs, and costs that are not based on the volume of electricity consumed.[2] Some costs labelled as "fixed costs" may in fact vary with consumption, as supported by Public Utilities Code section 739.9(a), which classifies a "demand charge" among the charges "not based on the volume of electricity consumed." Demand-related costs clearly "vary *with* electricity consumption," as stated in section 14(a)(4); however, they are not "*based on the volume* of electricity consumed" (emphasis added).

Making the distinctions required by AB 205 requires close attention in crafting an IGFC and has significant financial implications. If the California Assembly had intended to authorize or encourage the Commission to recover costs that varied with demand as well as volume of electricity consumed, it would have stated so.

Accordingly, under AB 205, reasonable cost components for an IGFC would include only those *costs that do not vary with electricity consumption*.

Q Should the Commission include all reasonable cost components in the IGFC?

A The Commission should consider including all reasonable cost components in the IGFC, although, as I discuss below, I do not recommend the Commission include all costs that *could* be included in the IGFC.

A reasonable fixed charge can help California achieve some of its energy and climate goals while still protecting incentives to conserve energy and reduce and shift load through

[2] "The current default residential customer rate structure in electrical corporation territories leads to a situation in which rates must rise to recover sufficient revenue to support certain fixed utility costs…" AB 205, section 14(a)(3). These fixed utility costs are described in section 14(a)(4) as "fixed costs that do not vary with electricity consumption."

distributed energy resources ("DERs"). ALJ Wang's proposed decision in this proceeding recommends updating Rate Design Principle #4 to state:

> Rates should encourage economically efficient (i) use of energy, (ii) reduction of greenhouse gas emissions, and (iii) electrification.[3]

As noted in the staff guidance for Phase 1 Track A, "[b]y shifting a portion of [investor-owned utilities'] cost recovery to fixed charges, volumetric rates will be lower, which will increase bill affordability and encourage residential customers to adopt electrification measures."[4] The Commission should approve recovering a *portion* of utility costs in the IGFC, consistent with the statutory standard described above, to reduce volumetric rates and provide an improved economic incentive for fuel-switching.

The Commission should retain flexibility in deciding which eligible costs (i.e. costs that vary with consumption) should be included in the IGFC, and I recommend that the Commission include most, but not all, eligible costs. As my testimony will discuss, the resulting shift in cost recovery to the IGFC will result in lower volumetric rates and encourage residential customers to adopt electrification measures.

My proposal distinguishes between customer-related cost components that the Commission has previously found may be recovered through a fixed charge and other cost components that meet the narrow AB 205 standard of being costs that do not vary with electricity consumption, making them also eligible for recovery through the IGFC. In Decision 17-09-035, the Commission defined "customer-specific" charges for purposes of authorizing residential fixed charges, and that definition is consistent with widely applied regulatory practice in North America.[5]

I recommend that most eligible costs, including "customer-specific" costs and those made eligible for inclusion by AB 205, should be built into the revenue requirement for recovery

[3] ALJ Stephanie Wang, *Proposed Decision Adopting Elec. Rate Design Principles and Demand Flexibility Design Principles* (Mar. 17, 2023), Ordering Para. 1 at 35 [hereinafter "ALJ Wang, *PD Adopting Elec. Rate Design Principles and Demand Flexibility Principles*"]. While the proposed decision has no legal effect until approved by the Commission, the proposed decision states, "Most party comments on this principle supported the addition of GHG emissions reduction and electrification to the principle." *Id.* at 13. It appears uncontroversial that the Commission should update the rate design principles to state that rates should encourage electrification.
[4] Cal. Pub. Utils. Comm'n Energy Div. Staff, Phase 1 Track A: Income-Graduated Fixed Charge Guidance Memo at 1 (Jan. 17, 2022) [hereinafter "Phase 1 Track A: Staff Guidance Memo"].
[5] Decision Identifying Fixed Cost Categories to be Included in a Fixed Charge, D.17-09-035 at 33, Table 2 (Sept. 28, 2017) [hereinafter "D.17-09-035"].

by the IGFC. I propose to use the Commission's existing definition of "customer-specific" costs to set the lowest non-zero tier in the IGFC discussed in Section III.D.2~~III.D.2~~.

In the future, there could be meaningful changes in California's energy policy priorities, the structure of system costs, the relative size of eligible cost components, or circumstances of individual utilities. Accordingly, as the Commission evaluates how well a fixed charge helps to achieve state policy objectives, the Commission may initiate future rulemakings that consider shifting some eligible cost components in the IGFC back to recovery through volumetric rates.

Q Beyond statutory requirements, why is it important that fixed charges not include costs that vary based on consumption?

A Including costs that vary based on consumption would violate the Commission's Electric Rate Design Principles. ALJ Wang's proposed decision in this proceeding recommends a minor clarification to Rate Design Principle #3 to state:

> Rates should be based on cost causation.[6]

Including costs that vary based on consumption in fixed charges is likely to understate the degree to which system costs vary based on long-term consumption. As discussed in a study by the Regulatory Assistance Project ("RAP"), attempting to assign distribution-related costs on a per-customer basis is a flawed approach because it is "unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related and that only the size of the components is demand-related."[7]

A good example of this issue is the ongoing investment in transportation electrification infrastructure. Demand-related distribution infrastructure, including poles, wires, transformers, and related facilities are being upgraded to accommodate increased *loads* related to electric vehicle charging. Distribution systems are built to serve geographic areas

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[6] ALJ Wang, *PD Adopting Elec. Rate Design Principles and Demand Flexibility Principles*, Ordering Para. 1 at 35. While the proposed decision has no legal effect until approved by the Commission, the proposed decision states, "Most party comments on this principle supported the addition of GHG emissions reduction and electrification to the principle." *Id.* at 13. It appears uncontroversial that the Commission should update the rate design principles to state that rates should encourage electrification.

[7] Jim Lazar et al., *Elec. Cost Allocation for a New Era: A Manual,* Regul. Assistance Project at 146 (Mark LeBel ed., 2020), *available at* https://www raponline.org/knowledge-center/electric-cost-allocation-new-era/ [hereinafter "Lazar et al., *Elec. Cost Allocation Manual*"]. The citation (146) is to a discussion on embedded cost analysis. The report states that the issue of whether any of these costs are customer-related is the same for embedded cost analysis and for marginal cost analysis. *Id.* at 203.

because the loads that the utility expects to serve justify the cost of expansion, not because the number of customers (whose load might be minimal) provides a justification. Inappropriately assigning costs not related to the number of customers to customers rather than load could result in inequitable cost recovery and poor investment decisions based on network size for example, rather than load.

It is neither simple nor meaningful to extract some portion of costs that do not vary based on consumption for assignment to fixed charge cost recovery. Ensuring that charges are reflective of costs means that utility investments can be more closely tied to load, i.e. peak demand. As described later in this testimony, California's grid affordability issues cannot be tackled until peak demand is addressed.

B. Generation Costs

Q Should any generation cost components be recovered in the IGFC?

A Yes, the Commission should find that some generation cost components are eligible for recovery in the IGFC because they do not vary with electricity consumption. However, the Commission should exclude generation cost components that are based on the volume of electricity consumed and should also exclude the PCIA due to its volatility.

Q What generation cost components are based on the volume of electricity consumed and thus should be excluded from the IGFC?

A For the most part, generation rates reflect costs that vary based on the volume of electricity consumed. These include the marginal energy cost, the marginal generation capacity cost, and non-marginal generation. Similarly, the New System Generation / Local Generation Charge[8] recovers costs associated with generation resources that benefit all customers, regardless of which load serving entity is responsible for serving their energy requirements. Accordingly, I recommend that the Commission should find that each of these generation-related cost elements should be excluded from the IGFC.

It is worth noting that the New System Generation / Local Generation Charge is one of only three non-bypassable charges that I recommend excluding from the IGFC, as reviewed in

[8] "New System Generation" and "Local Generation" are different names for the same charge, with the former used PG&E and SCE and the latter used by SDG&E.

Section II.E.2~~II.E.2~~ below. It differs from most other non-bypassable charges because the costs are incurred to procure capacity to ensure reliability on behalf of all customers. Since the amount of capacity required for reliability purposes varies from customer to customer, and as each customer's requirements may vary over time, it is a cost that varies based on consumption, and should not be included in an IGFC.

Q What generation cost components no longer vary based on the volume of energy consumed?

A Four non-bypassable charge cost components are related to historical embedded generation costs, and no longer vary based on the volume of energy consumed. These non-bypassable charges include:

- Power Cost Indifference Adjustment ("PCIA"),
- Nuclear Decommissioning,
- Competition Transition Charge ("CTC"), and
- PG&E's Energy Cost Recovery Account.[9]

Each of these charges provides for guaranteed cost recovery of historical generation-related embedded costs or regulatory assets irrespective of whether they are economically used and useful. A fifth non-bypassable charge related to generator costs, the Reliability Services charge, is assessed by the California Independent System Operator ("CAISO") under Federal Energy Regulatory Commission ("FERC") jurisdiction, so it is arguably transmission-related and will be discussed in Section II.D~~II.D~~.

To a large extent, these historical generation-related cost components include stranded costs that became disconnected from the economics of generation supply during the various phases of California's energy market restructuring. Across North American jurisdictions, stranded costs may become the responsibility of utility customers, the public at large, or utility investors, without necessarily being linked to a continuing obligation to serve the same customers' generation requirements. Thus, while these costs are often recovered

[9] Non-bypassable charges are summarized in Decision Revising Net Energy Metering Tariff and Subtariffs, D.22-12-056 at 118-119 (Dec. 15, 2022) [hereinafter "D.22-12-056"].

through a volumetric charge, changes in market structure have disconnected those costs from the requirement to serve customers' demand and energy loads.[10]

Of these four charges, I recommend against including the PCIA charge in the IGFC revenue requirement. The PCIA uses a market benchmark approach to recover the above–market cost of power purchased on a customer's behalf prior to departure from investor-owned utility ("IOU") bundled service. Until recently, the PCIA was assessed against load serving entities such as community choice aggregators, and standby customers, but not to bundled customers. Now, the charge is assessed uniformly against all bundled and unbundled customers. My concern about including the PCIA in the IGFC revenue requirement is that PCIA costs are linked to market capacity costs. As a result, the PCIA is viewed as "highly volatile and unpredictable."[11]

Unfortunately, this proceeding does not provide an opportunity to eliminate the volatility of the PCIA charge. However, the Commission has the choice regarding whether to include that volatility in volumetric rates or in the IGFC. In my view, it is preferable to include that volatility in volumetric rates. Volumetric rates give customers some opportunity to respond to that volatility by adjusting their use of electricity. In contrast, including that volatility in the IGFC would have an immediate and unavoidable impact on customers' bills.

In summary, I recommend that the Commission find that these four generation-related cost components are eligible to be included in the IGFC, but that it should include only the Nuclear Decommissioning, CTC, and PG&E's Energy Cost Recovery Account in the IGFC revenue requirement.

C. Distribution Costs

Q Should any distribution cost components be recovered in the IGFC?

A Yes, the Commission should find that only *customer-related* distribution cost components and distribution-related non-bypassable charges are eligible for recovery in the IGFC and

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[10] For example, in D.97-08-056, the Commission structured the CTC "to not 'fluctuate over time.'" Marin Clean Energy, *White Paper on the Evolution of Non-Bypassable Charges on Cmty. Choice Aggregation* at 26 (Dec. 2017), *available at* https://cleanpowerexchange.org/wp-content/uploads/2018/02/MCE-NonBypass-Charges_Whitepaper_2017-Update-2.1.18.pdf [hereinafter "MCE, *White Paper on the Evolution of Non-Bypassable Charges on Cmty. Choice Aggregation*"].

[11] MCE, *White Paper on the Evolution of Non-Bypassable Charges on Cmty. Choice Aggregation* at 7.

include them in the IGFC because they do not vary with electricity consumption. The Commission should exclude all other distribution cost components, maintaining its prior position that demand-related distribution costs vary with electricity consumption and are properly collected in volumetric rates.

1. Customer-Related Distribution Costs

Q What distribution cost components are clearly customer-related?

A In D.17-09-035, the Commission determined that residential "customer-specific" costs include billing, customer inquiry, and establishing meters, service drops, and final line transformers.[12] It does not appear that AB 205 directs or encourages the Commission to modify its definition of "customer-specific" costs.

The Commission has historically directed that "customer-specific" costs be recovered on a marginal cost basis, either as a fixed charge in some residential tariffs, or as part of distribution rates in other tariffs. The Fixed Charge Tool glossary defines marginal customer access costs ("MCACs") as representing:

> … the incremental costs of connecting an additional (i.e., marginal) customer to the grid that are not driven by volumetric energy usage or demand. The two cost components of MCAC are: 1) the marginal customer equipment costs (MCEC) consisting of final line transformer, service line drop, and meter costs, and 2) the ongoing and variable Revenue Cycle Service (RCS) costs associated with keeping customers connected to the grid, such as customer billing, meter reading, and credit and collections.

Accordingly, I recommend that the Commission continue to use its definition of "customer-specific" MCACs from D.17-09-035. The utilities should recover MCACs through the IGFC.

In addition to MCACs, I propose that the Commission include non-marginal customer access costs in the IGFC.

[12] D.17-09-035 at 33.

Q How should non-marginal customer access costs be determined?

A None of the utilities currently calculate a revenue requirement for or forecast non-marginal customer access costs.[13] However, all three utilities report actual, historical customer access costs on FERC Form 1 for depreciation expense and operation and maintenance (”O&M“) costs. Using these costs, it is possible to allocate historic non-marginal distribution costs between customer access costs and demand-related costs. I used the following method to calculate a non-marginal customer access cost factor (”NMCAC factor”) that I used to estimate the portion of non-marginal distribution costs that represent non-marginal customer access costs:

A. System total distribution revenue requirement (“DRR”), subdivided as MCACs, marginal distribution costs (“MDCs”), and non-marginal distribution costs (“NMDCs”)
B. Residential total DRR, subdivided as MCACs, MDCs and NMDCs
C. Calculate residential revenue requirement percentage for NMDCs as (“B-NMDC”) divided by (“A-NMDC”)
D. System distribution depreciation expense for customer access costs (“CAC”) and demand distribution costs (“DDCs”), from FERC Form 1
E. System distribution O&M expense for CAC and DDC, from FERC Form 1
F. Net plant balance[14] for CAC and DDC, from FERC Form 1
G. Determine system distribution other expenses (presumed to be authorized return, taxes, and other financial adjustments)
H. Allocate system distribution other expenses (G) to CAC and DDC based on net plant balance (F-CAC and F-DDC)
I. Calculate system CACs and DDCs by adding (D), (E), and (H)
J. Calculate system non-marginal customer access costs (“NMCACs”) and non-marginal demand distribution costs (“NMDDCs”) by subtracting (A) from (I)
K. Calculate residential NMCACs and NMDDCs by multiplying (B) times (J) for each cost category
L. Calculate the NMCAC factor by dividing (K-NMCAC) by (B-NMDC)

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[13] PG&E Data Req. Resp. to The Util. Reform Network (“TURN”), Set 04, Question 06; SCE Data Req. Resp. to TURN, Set 04, Question 06; SDG&E Data Req. Resp. to TURN, Set 05, Question 06. (Attach. 6)
[14] Net Plant Balance is calculated as Depreciable Plant minus Accumulated Depreciation.

Q What complications arise when calculating non-marginal customer access costs?

A There are several complications, none of which seriously undermine my recommendations. First, the revenue requirement is unlikely to exactly match the actual costs. This is not particularly concerning because actual utility revenues rarely exactly match actual costs. Nonetheless, there may be ways to improve this aspect of the method I described above.

Second, relying on FERC Form 1 data results in a backward-looking NMCAC factor for use in a forward-looking revenue requirement. Third, in implementing this method, I used FERC Form 1 costs from 2021 along with 2023 revenue requirements from the Fixed Cost Tool. For purposes of using the NMCAC factor in the Fixed Cost Tool, neither of these issues is especially problematic. The Fixed Cost Tool itself uses data from both 2021 and 2022, and the Haas Report[15] relied in part on data from 2019. It is unrealistic to expect that all data sources in such a complex endeavor could be obtained from the same year—even more unrealistic to expect them to align with a future revenue requirement year.

Q Please provide the NMCAC factor you used in the Fixed Charge Tool for each utility.

A I used the NMCAC factors shown below as inputs to the Fixed Charge Tool. For each utility, the NMCAC factor is entered as the "percent to include in customer charge" for the non-marginal distribution cost category. (For all other cost categories, I used either 0% or 100%.) For example, I included 19.93% of PG&E's non-marginal distribution costs in its IGFC revenue requirement. Together with PG&E's MCAC revenue requirement, I believe this reasonably represents all embedded customer access costs and that these costs should be included in the IGFC revenue requirement.

Table 1: Non-Marginal Customer Access Cost (NMCAC) Factors

Utility	**NMCAC Factor**
PG&E	19.93%
SCE	45.79%
SDG&E	39.84%

[15] Severin Borenstein et al., *Paying for Elec. in Cal.: How Residential Rate Design Impacts Equity and Elec., Online App.,* Haas School of Bus. and Energy Inst. at 6 (Sept. 22, 2022), *available at* https://haas.berkeley.edu/wp-content/uploads/WP330Appendix.pdf. [hereinafter "Haas Report"].

2. Distribution-Related Non-Bypassable Charges

Q What are the distribution-related non-bypassable charges?

A There are seven non-bypassable charges that are recovered from all distribution customers and not directly related to generation or transmission system costs. Seven of these charges relate to wildfires, public purpose programs, and regulatory commission costs.

Q Should wildfire-related non-bypassable costs be recovered through the IGFC?

A Yes, the Commission should find that the four wildfire-related non-bypassable charge cost components are eligible for recovery in the IGFC and include them in the IGFC because they do not vary with electricity consumption. These four cost components are:

- Wildfire Fund Non-Bypassable Charge
- Securitized Wildfire Capital Costs
- Recovery Bond Charge/Recovery Bond Credit
- Wildfire Hardening Charge

These wildfire-related non-bypassable charges are related to the recovery of costs related to wildfires (prevention, mitigation, and other costs related to historical events). While wildfires have been sparked by the utilities' electrical facilities, it has not been suggested that simply reducing load would substantially mitigate that risk. In fact, the Public Safety Power Shutoff ("PSPS") process requires complete shutoff of load in elevated risk circumstances. Clearly, it is the existence of the electrical system that drives these costs—the costs do not vary with electrical usage.

Q Should public purpose and regulatory non-bypassable costs be recovered through the IGFC?

A Yes, the Commission should find that the three public purpose and regulatory non-bypassable charge cost components are eligible for recovery in the IGFC and include them in the IGFC because they do not vary with electricity consumption. These three cost components are:

- Public Purpose Programs Charge
- California Energy Commission Fee
- Public Utilities Commission Reimbursement Fee Charge

None of these costs “vary with” (that is, are driven by) electricity consumption.

With respect to the public purpose programs charge, in 2017 the Commission concluded that some of the costs, notably those of energy efficiency programs, “should be equivalent to generation costs in their treatment” because those programs provide alternatives to conventional generation.[16]

The Commission should revisit that finding because even though energy efficiency programs provide alternatives to conventional generation, those program costs do not actually vary with electrical usage. Quite the opposite: with the success of energy efficiency programs, California has avoided substantial increases in load and spending on these programs has only grown. Customers, as a group, have reduced consumption but increased spending. Energy efficiency program costs are annual expenditures, including incentives, that may be ramped up or down from year to year to meet the Commission’s programmatic objectives, independent of whether load increases or decreases, for the most part.[17]

With respect to funding for the two Commissions, a specific point not taken up in D.17-09-035, I believe the case is even stronger that this should be recovered through the IGFC, because it is clear that the revenue requirements for funding the two Commissions do not vary with load.[18]

[16] D.17-09-035 at 32.
[17] On the margin, certain energy efficiency program activities may be sensitive to certain increases or decreases in load, such as those related to temporary business shutdowns during the pandemic. This is an insubstantial distinction.
[18] If any further justification is needed, AB 205 makes a key change that addresses the inequity of proposals to collect these revenue requirements through a uniform fixed charge—proposals that the Commission considered (and rejected) in 2017. Recovering Commission costs through a uniform fixed charge would have amounted to a regressive, per household fee for the services provided by the two Commissions. That would have been an unusual way to fund a state agency, to say the least. Now, however, the authorization of an income graduated fixed charge provides the Commission with the opportunity to ensure that the two Commissions are funded on a progressive basis, by collecting higher amounts of funding from more well-off households and as little as nothing at all for the state’s least financially-secure households.

3. Demand-Related Distribution Costs

Q Should any demand-related distribution cost components be recovered in the IGFC?

A No. Demand-related distribution costs vary with electricity consumption, in the short run to some extent and in the long run to a greater extent. Thus, they are properly collected in volumetric rates, and should be excluded from recovery in the IGFC.

The demand-rated distribution cost components vary slightly by utility, as follows:

- PG&E's Marginal Distribution Capacity Cost – Primary, Secondary, and New Business
- SCE – Marginal Grid and Peak costs
- SDG&E Marginal Demand – Coincident and Non-Coincident Peak costs
- SDG&E's Total Rate Adjustment Component line-item charge, which recovers a small amount of rate tier rate differentials[19]
- All three utilities' Non-Marginal Distribution costs

Q Is there a meaningful distinction between embedded demand-related distribution costs and the historical non-marginal generation costs you stated should be eligible for the IGFC?

A Yes. As discussed above, the historical embedded generation cost components that I recommend the Commission find eligible for inclusion in the IGFC are stranded costs that became disconnected from the economics of generation supply during the various phases of California's energy market restructuring. In contrast, none of the utilities' distribution systems have been restructured.

In general, demand-related distribution costs, whether recovered as marginal or non-marginal costs, have been incurred to serve load. The main exception applies to very thinly settled areas, where "customer-specific plant may include some portion of transformer costs and the percentage of the primary system that consists of line extensions to individual customers."[20] Methods for treating some distribution costs as customer-related were included in the 1992 National Association of Regulatory Utility Commissioners

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[19] It appears that PG&E and SCE recover these costs through distribution rates.

[20] Lazar et al., *Elec. Cost Allocation Manual* at 145. The citation (145) is to a discussion on embedded cost analysis. The report states that the issue of whether any of these costs are customer-related is the same for embedded cost analysis and for marginal cost analysis. *Id.* at 203.

("NARUC") cost allocation manual.[21] However, in D.17-09-035, the Commission appropriately rejected these views, and AB 205 does nothing to buttress them.[22]

The Regulatory Assistance Project's 2020 review of this topic, *Electric Cost Allocation for a New Era: A Manual*, lists eight reasons that distribution system costs are generally insensitive to customer number.[23] In addition to incurring costs to size its equipment to meet peak demand (as measured on the feeder circuit), utilities also incur costs related to the geographic area that a utility serves.

While I will not review each of these eight reasons, I would like to comment on one. The RAP cost allocation manual reminds us that not all distribution system costs are recovered through rates, since new customers may pay costs covering a portion of system extension investment. Under each California utilities' Rule 15, an allowance for distribution line and service extensions is provided to cover costs to serve new accounts. These allowances are based on a revenue-supported method. If the actual loads are lower than expected such that the distribution facilities installed by the utility are more costly than would have been necessary, then the applicant must make additional payments reflecting the shortfall in expected revenue.[24] Thus, the utility determines its cost responsibility for system extensions using new construction *loads*, not number of new customers.

In D.17-09-035, the Commission specifically endorsed the view that demand-related distribution costs are imposed on the system based on customer *usage*.[25] The decision explained that including such costs in a fixed charge would require segmentation of customers by size (presumably as measured by some measure of coincident or peak-period demand). The Commission felt strongly enough about this point that it rejected a proposal to apply the equal percentage of marginal cost ("EPMC") scalar to the marginal customer access costs included in fixed charges because the utility systems of accounts could not then (and still cannot) separate customer-related distribution costs from demand-related distribution costs.[26]

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[21] *Id.* at 146.
[22] D.17-09-035 at 25.
[23] Lazar et al., *Elec. Cost Allocation Manual* at 146-147.
[24] See, for example, PG&E Rule No. 15, Section 7. Similar payments are also required if service is not activated in a timely manner.
[25] D.17-09-035 at 25.
[26] D.17-09-035 at 27.

Based on the Commission's Decision 17-09-035, the reasoning discussed in the RAP cost allocation manual, and the application of Rules 15 and 16 by the utilities, I recommend that the Commission exclude all demand-related distribution costs from the IGFC.

D. Transmission Costs

Q Should any transmission cost components be recovered in the IGFC?

A No. Transmission costs are FERC-jurisdictional and should not be recovered in the IGFC.[27] As with demand-related distribution costs, transmission costs vary with electricity use. In addition to the Base Transmission and Transmission Balancing Accounts identified in the Fixed Charge Tool, the Reliability Services Charge (identified in the Fixed Charge Tool as a line-item charge) is also FERC-jurisdictional and should not be recovered in the IGFC. In D.17-09-035, the Commission noted the lack of evidence that "FERC would accept recovery of transmission costs in a fixed charge," and declined to approve those costs for recovery in a fixed charge.[28]

E. Summary of Proposed IGFC Revenue Requirement

1. Overall Goals of Recommendations

Q How should the Commission determine whether the costs included in the IGFC are consistent with AB 205 and its Electric Rate Design Principles?

A Both AB 205 and the Commission's Electric Rate Design Principles call for a balance between equity, electrification, energy efficiency, and local generation that optimizes the use of existing grid infrastructure. I agree that the Commission should consider all of these factors when determining an appropriate IGFC.

Q How should equity and electrification be considered when determining which costs are reasonable to include in the IGFC?

A A higher IGFC revenue requirement advances equity and encourages economically efficient electrification. Section 739.9(e)(1), as amended by AB 205, requires that an IGFC designed to reduce the bill of low-income ratepayers. Achieving this equity goal requires

[27] PG&E Data Req. Resp. to TURN, Set 04, Question 05; SCE Data Req. Response to TURN, Set 04, Question 05. (Attach. 6)
[28] D.17-09-035 at 30.

(a) that the IGFC revenue requirement recover enough costs that volumetric rates for customers are reduced and (b) that the fixed charge assigned to low-income customers is low enough that customer savings from the volumetric rates are not offset.

In my view, to provide an opportunity for low-income customers to receive meaningful bill reductions, the IGFC revenue requirement must be high enough to meaningfully build in progressivity. My proposal will result in volumetric rate reductions of 15-18% (Section III.A~~III.A~~); combined with a zero-dollar or low IGFC, the rate design changes could reduce lower-income household bills from, for example, 4% to 3.6~~5~~% of annual income (Section V.A~~V.A~~). It is worth noting that while an IGFC can provide bill relief for low-income households, it is not a panacea. The Commission will have to explore other system-wide (e.g. critical peak pricing) and household-specific (e.g. weatherization) solutions in order to reduce energy burdens to acceptable levels.

As noted in the Phase 1 Track A staff guidance memo, "[b]y shifting a portion of IOUs' cost recovery to fixed charges, volumetric rates will be lower, which will increase bill affordability and encourage residential customers to adopt electrification measures."[29] In Section V.B~~V.B~~, I discuss the impact of my proposal on electrification scenarios using the Fixed Charge Tool. In my opinion, my proposal enables bill savings through electrification measures, including fuel switching, and it will not provide electrified customers with an unreasonable windfall.

Q What are the potential drawbacks of setting an IGFC too high?

A Including fewer costs in the IGFC will keep volumetric rates closer to current levels. Higher volumetric rates encourage economically efficient use of energy, reduction of greenhouse gas ("GHG") emissions, and customer investment in distributed energy resources, which may help optimize the use of existing grid infrastructure to reduce long-term electric system costs. Put differently, a high fixed charge may discourage or penalize installation of environmentally beneficial rooftop solar and environmentally and grid-beneficial load-shifting and energy efficiency measures. The Commission should be careful not to grant utilities the means to economically exclude residential customers from choosing to invest in distributed energy resources by approving an average fixed charge

[29] Phase 1 Track A: Staff Guidance Memo at 1.

that is so high as to discourage local energy generation and reduce incentives for conservation and energy efficiency investments.[30] Instead of re-allocating California's growing grid costs through a too high fixed charge, the Commission should push utilities to tackle affordability in a systemic manner, by reducing peak demand through demand response programs, critical peak pricing, and other measures.

Q How should the Commission view impacts of reducing volumetric rates on conservation and energy efficiency?

A Section 739.9(d)(2), as amended by AB 205, requires that the resulting lower volumetric rates shall not "unreasonably impair incentives" to conserve or invest in the more efficient use of energy. As discussed in Section V.C~~V.C~~, a decrease in volumetric rates may support an increase in electricity use in the long run.

In the context of this rate design change, however, the Commission should find that much of that increase is likely to take the form of electrification. As customers implement fuel-switching technologies, their electric bills will rise (offset by savings in natural gas, gasoline, or other fuels).

Furthermore, the Commission should also find that any impairment in conservation or energy is properly considered in the context of California's overall high electricity rates. As shown in Section III.A~~III.A~~, if collected entirely as volumetric rates, customers receiving bundled electric service pay an average of 35 to 51 ¢/kWh for electricity. As the Commission is well aware, these rates are far higher than those in many other jurisdictions and would remain so even with a reduction of 15-18%. Californians will continue to experience rates that are high enough to encourage conservation and substantial investment in energy efficiency.

Q How should the Commission view the impacts of reducing volumetric rates on distributed energy resources?

A In its decision creating the Net Benefits Tariff ("NBT"), the Commission stated that it would consider "how to reform fixed charges for recovery of certain authorized utility costs, including non-bypassable charges"[31] in this rulemaking. The Commission's clear

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[30] Similarly, I view the impacts of rate design on greenhouse gas emissions primarily through the lens of its impacts to energy efficiency and distributed energy resources, which generally result in lower fossil fuel generation.
[31] D.22-12-056 at 117-118.

view that shifting some (undefined) fixed costs into the IGFC would further the goals of its decision in D.22-12-056 should also be informed by the degree to which it may impair the resulting payback period for distributed energy resources (including solar and solar paired with storage). I have not conducted a payback period analysis of my proposal, but will review any evidence on this point submitted by other parties in my reply testimony.

In my view, the Commission should closely monitor the impact of the IGFC along with other elements of the NBT decision. If they unreasonably impair the payback period for distributed energy resources, then the Commission could remove some cost elements from the IGFC, adjust the NBT, or modify the utility electrification tariffs required for NBT customers.

Q Why have you recommended that nearly all eligible costs should be included in the IGFC revenue requirement?

A It's important to note that I believe that only a well-defined bucket of costs, those that do not vary based on consumption, are eligible to be included in an IGFC. I believe that shifting approximately 15-18% of costs from recovery in volumetric rates, by including most eligible costs, into the IGFC strikes the appropriate balance between being large enough to significantly advance equity and electrification goals, without unreasonably impairing the effect of rates on customer conservation and energy efficiency efforts. As noted above, I have not conducted an analysis to determine the potential impact on the NBT. Evidence on this point could cause me to change my opinion and adjust my proposal.

Furthermore, as I have noted, the Commission should monitor the impacts of the IGFC and consider opening a future rulemaking to revisit its guidance. It should consider setting a date for such a rulemaking in coordination with scheduled evaluations of the IGFC itself, energy efficiency programs, and the NBT, and consider whether those evaluations suggest modifications to the IGFC are merited.

2. Non-Bypassable Charges

Q How should the recovery of costs related to non-bypassable charges through the IGFC be reviewed in this proceeding?

A In its decision creating the NBT, the Commission indicated its interest in recovering costs related to non-bypassable charges through the IGFC, stating that it would consider "how to reform fixed charges for recovery of certain authorized utility costs, including non-bypassable charges" in this rulemaking.[32]

In addition to suggesting that it viewed a fixed charge as more equitable than a grid benefits charge, as discussed in Section II.E.1~~II.E.1~~, the Commission also decided not to expand the list of non-bypassable charges that cannot be offset on NBT bills beyond the existing four charges.[33] In that portion of its decision, the Commission did not reference this proceeding.

However, ALJ Wang's December 9, 2022, *Ruling Requesting Track A Briefs on Statutory Interpretation* recognized that AB 205 removed at least some statutory restrictions for specific non-bypassable charges ("NBCs") to be collected in volumetric rates, and raised the question as to whether *any* such restrictions remain. The legislative intent to "help stabilize rates," appears to provide policy direction to the Commission that such non-bypassable charges should be eligible for recovery in the IGFC.[34] Therefore, I assume that AB 205 removes all statutory restrictions on collecting non-bypassable charges through an IGFC.

Q Please summarize your recommendations on the recovery of costs related to non-bypassable charges through the IGFC.

A Based on the amendment to Section 381(a) enacted by AB 205, and for the specific reasons discussed with respect to generation-related (Section II.B~~II.B~~), distribution-related (Section II.C.2~~II.C.2~~), and transmission-related (Section II.D~~II.D~~) non-bypassable charges, I recommend the Commission include all but three non-bypassable charges in the IGFC, as summarized in Table 2~~Table 2~~.

[32] *Id*.
[33] *Id.* at 119-120.
[34] In 2017, the Commission found that non-bypassable charges should not be recovered through a fixed charge. D.17-09-035 at 31. Given the statutory change, I am assuming that this decision no longer binds the Commission.

Table 2: Costs Recovered in Non-bypassable Charges[35]

Charge	Applicable Utilities	NEM / Net Billing NBCs
Recommended for Inclusion in IGFC		
Generation-Related Costs that Do Not Vary by Electrical Usage		
Nuclear Decommissioning Charge	PG&E, SDG&E, SCE	Yes
Competition Transition Charge	PG&E, SDG&E, SCE	Yes
Energy Cost Recovery Account	PG&E	—
Wildfire-Related Costs that Do Not Vary by Electrical Usage		
Wildfire Fund Non-Bypassable Charge	PG&E, SDG&E, SCE	Yes
Securitized Wildfire Capital Costs	PG&E	—
Recovery Bond Charge/Recovery Bond Credit	PG&E	—
Wildfire Hardening Charge	PG&E, SDG&E, SCE[36]	—
Public Purpose and Regulatory Costs that Do Not Vary by Electrical Usage		
Public Purpose Programs Charge	PG&E, SDG&E, SCE	Yes
California Energy Commission Fee	PG&E, SDG&E, SCE	—
PUC Reimbursement Fee Charge	PG&E, SDG&E, SCE	—
Recommended for Exclusion from IGFC		
Generation-Related Costs that Vary by Electrical Usage		
New System Generation / Local Generation Charge	PG&E, SCE / SDG&E	—
Volatile and Unpredictable Generation-Related Costs		
Power Charge Indifference Adjustment Charge	PG&E, SDG&E, SCE	—
FERC Jurisdictional		
Reliability Services Charge	PG&E, SDG&E, SCE	—

Q What will be the impact of including most non-bypassable charges in the IGFC?

A Collecting most non-bypassable charges through the IGFC avoids many of the problems identified by the Commission in 2022 when it rejected including the proposed Grid Benefits Charge in the NBT, as discussed in Section II.E.1~~II.E.1~~. With the exception of the three charges that I recommend excluding, recovering these non-bypassable charges in the IGFC is consistent with the Commission's Electric Rate Design Principles and advances the objectives of AB 205.

[35] D.22-12-056 at 118-119, 120.

[36] D.22-12-056 lists this charge as only applying to SCE, but this is based on comments that stated that this charge "only *currently* applies to SCE," which I interpret to mean that it could also apply to other utilities in future general rate case applications. Joint Opening Comments of S. Cal. Edison. Co. (U 338-E), Pac. Gas and Elec. Co. (U 39-E) and San Diego Gas & Elec. Co. (U 902-E) on the Admin. Law Judge's Ruling Setting Aside Submission of the Record to Take Comment on a Limited Basis Utils., R.20-08-020 at 17 (June 10, 2022).

Shifting non-bypassable charges into the IGFC will result in some customers paying more, and others less than under volumetric rates. This will have a significant impact on NBT customers, some of whom could pay higher bills under my proposal. Lower-income customers with high energy use will pay less, and higher-income customers with low energy use will pay more under my proposal. In my view, my proposal reasonably reflects the direction spelled out in AB 205 and the Commission's decision to defer some aspects of its NBT decision to this proceeding.

Q Do you have any other recommendations related to non-bypassable charges?

A Yes. It is a minor matter, but if my proposal is accepted, the Commission may wish to direct the utilities to refer to non-bypassable charges as "costs," rather than "charges." Since the IGFC will recover costs related to non-bypassable costs through differing monthly charges, it could be simpler to refer to all NBCs as costs rather than charges. Where these costs are recovered through volumetric rates or standby charges, the resulting rate could be referred to as a rate, charge, or fee to distinguish it from the underlying cost.

3. Cost Categories to Include in IGFC Revenue Requirement

Q Please summarize your recommendations on the recovery of costs, as categorized in the Fixed Cost Tool, through the IGFC.

A I have summarized my recommendations in Table 3~~Table 3~~.

Table 3: Inclusion of Cost Components in Proposed IGFC Revenue Requirement

Cost Category	Applicable Utilities	Cost Component (See Fixed Charge Tool Glossary tab for descriptions)	Recommendation
Generation	PG&E, SCE, SDG&E	PCIA	Eligible but exclude
	PG&E, SCE, SDG&E	Marginal Energy	Ineligible
	PG&E, SCE, SDG&E	Marginal Generation Capacity	Ineligible
	PG&E, SCE, SDG&E	Non-Marginal Generation	Ineligible
Distribution	PG&E	**Marginal Customer Access**	**Include**
	SCE	**Marginal - Customer**	**Include**
	SDG&E	**Marginal - Customer**	**Include**
	PG&E	Marginal Distribution Capacity - Primary	Ineligible
	PG&E	Marginal Distribution Capacity - New Business	Ineligible
	PG&E	Marginal Distribution Capacity - Secondary	Ineligible
	SCE	Marginal - Grid	Ineligible
	SCE	Marginal - Peak	Ineligible
	SDG&E	Marginal Demand - Non-Coincident Peak	Ineligible
	SDG&E	Marginal Demand - Coincident Peak	Ineligible
	PG&E, SCE, SDG&E	**Non-Marginal Distribution**	**Include customer access portion**
Transmission	PG&E	Transmission	Ineligible
	SCE, SDG&E	Base Transmission	Ineligible
	SCE	Transmission Balancing Accounts	Ineligible
	SDG&E	Transmission Balancing Accounts	Ineligible
Line Items	PG&E, SCE, SDG&E	**Public Purpose Programs - Self Generation Incentive Program**	**Include**
	PG&E, SCE, SDG&E	**Wildfire Fund Charge**	**Include**
	PG&E, SCE	**Wildfire Hardening Charge**	**Include**
	PG&E, SCE	**Recovery Bond Charge**	**Include**
	PG&E, SCE	**Recovery Bond Credit**	**Include**
	PG&E, SDG&E, SCE	**Public Purpose Programs - Not CARE Exempt**	**Include**
	PG&E, SCE, SDG&E	**Nuclear Decommissioning**	**Include**
	PG&E, SDG&E	**Competition Transition Charge**	**Include**
	PG&E	**Energy Recovery Account**	**Include**
	SDG&E	**Total Rate Adjustment Component - Baseline Adjustment Component**	**Include**
	PG&E, SCE, SDG&E	**Residential CARE Contribution**	**Include**
	SDG&E	Reliability Services	Ineligible
	PG&E, SCE, SDG&E	New System Generation Charge	Ineligible
	PG&E, SCE, SDG&E	GHG Allowances	FC Credit[37]

[37] While the GHG Allowance is technically a cost category, it is actually a fixed charge *credit*, which is provided to all residential customers on a biannual basis. Adjusting this credit on an income-graduated basis does not appear to further AB 205's equity goals. This appears to be recognized by the Energy Division, as this cost category is not used in the Fixed Cost Tool.

4. IGFC Revenue Requirement Estimate

Q Please estimate the total amount of costs, as categorized in the Fixed Cost Tool, that you propose recovery through the IGFC, and their impact on volumetric rates.

A Utilizing the Fixed Cost Tool, I have calculated the total revenue requirement and average charges and rates, as summarized in Table 4~~Table 4~~. The overall costs and current average volumetric rate in Table 4~~Table 4~~ are supported by the Fixed Cost Tool results in Attachment 4. The IGFC proposal rates were developed using PG&E's E-TOU-C, SCE's TOU-D-4-9, and SDG&E's TOU-DR1 rates and are supported by Attachment 2.

Table 4: Cost Recovery in Proposed IGFC

Revenue Requirement	**PG&E**	**SCE**	**SDG&E**
Generation	1,622,741,532	2,570,368,877	321,557,920
Customer	1,535,847,930	1,884,082,015	557,112,036
Other Volumetric	4,141,536,456	3,157,137,865	1,208,877,188
Total Revenue Requirement	**$ 7,300,125,918**	**$ 7,611,588,757**	**$ 2,087,547,144**
Current Average Volumetric Rate	35 ¢/kWh	41 ¢/kWh	51 ¢/kWh
IGFC Proposal			
Average per Customer Charge	**$ 28.48**	**$ 36.65**	**$ 30.94**
Average Volumetric Rate	**30 ¢/kWh**	**34 ¢/kWh**	**51 ¢/kWh**

III. IGFC Rate Design

A. Design of Volumetric Rates

Q How did you design the volumetric rates in your proposal?

A For standard rates, my proposal uses the uniform factor (or constant ratio) method to design the volumetric rates. The Fixed Charge Tool also offered the option of the equal cents differential method. I decided to recommend the uniform factor method for two reasons.

First, I found that the uniform factor method results in greater cost savings for electrification activities conducted by customers on standard TOU rates. Second, in my experience, designing the revenue neutral adder for the rate approved to use in PG&E's

Day-Ahead Hourly Real Time Pricing ("DAHRTP") pilots,[38] the equal cents differential method can have some unintended side-effects that are mitigated through TOU-period specific rate adjustments.

Q What is the impact of your IGFC proposal on volumetric rates?

A As shown in Figure 1~~Figure 1~~, the IGFC proposal reduces volumetric rates by 10-25%, depending on utility and TOU period. The rates illustrated in Figure 1~~Figure 1~~ are PG&E's E-TOU-C, SCE's TOU-D-4-9, and SDG&E's TOU-DR1. Support for these calculations is provided in Attachment 2.

The uniform factor method results in larger *distribution* rate decreases for the highest TOU period rates. Distribution rates are higher in the winter, causing the impact of the IGFC on volumetric rates to be concentrated in the winter.

Another reason the percentage decrease is greater in the winter is that generation rates are higher in the summer (and are unaffected by the IGFC), so total rates are lower in the winter. Thus, the larger impact of the IGFC on winter distribution rates is magnified by comparison to the lower current winter rates.

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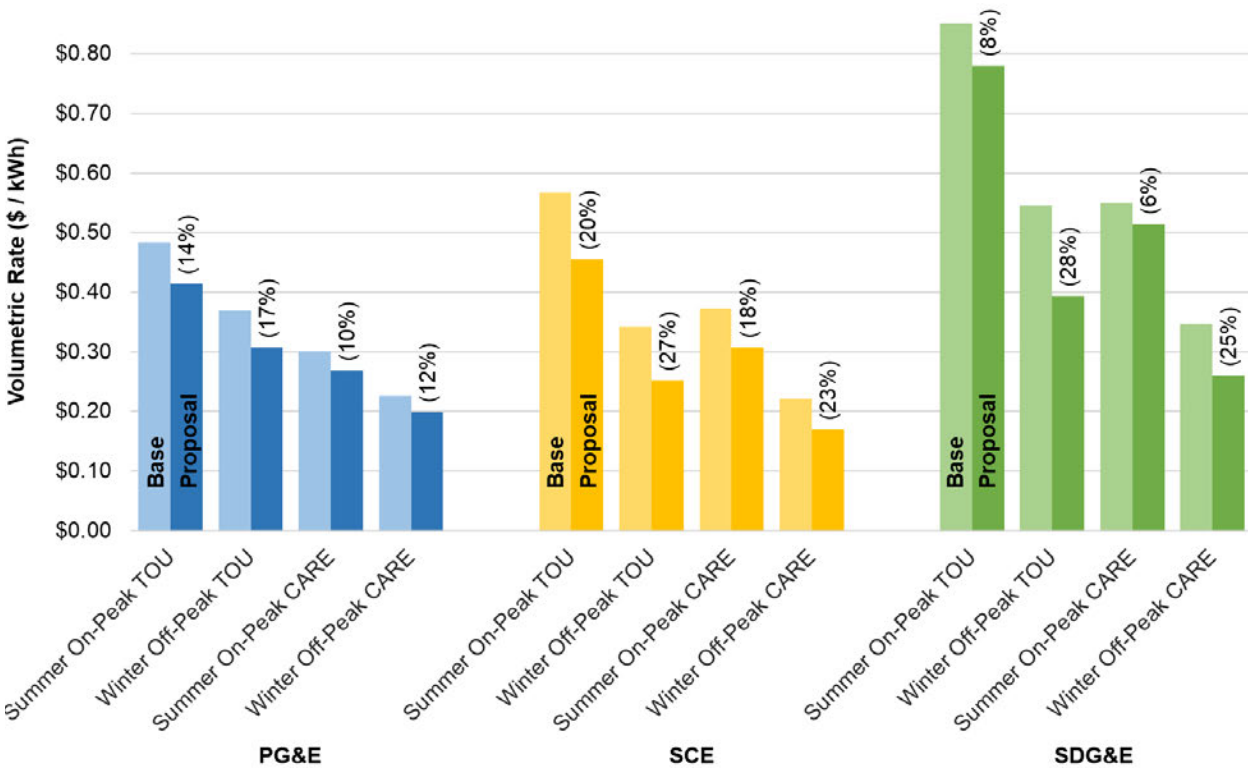
[38] Appl. of Pac. Gas and Elec. Co. to Revise its Elec. Marginal Costs, Revenue Allocation and Rate Design, A.19-11-019 (Nov. 22, 2019); Appl. of Pac. Gas and Elec. Co. (U39M) for Approval of its Proposal for a Day-Ahead Real Time Rate and Pilot to Evaluate Customer Understanding and Supporting Tech., A.20-10-011 (Oct. 23, 2020).

Figure 1: Summer On-Peak and Winter Off-Peak Volumetric Rates, Current vs IGFC Proposal



B. Definition of Income-Graduated Tiers

Q Please describe your overarching goals in creating IGFC income tiers.

A In designing IGFC income tiers, I was guided by principles of equity expressed in both AB 205 and the Commission's Electric Rate Design Principles, while being vigilant to ensure that the income tier design did not impair the achievement of other environmental goals.

I sought to develop a progressive income-graduated tier system for several reasons. First, as discussed in the Commission's 2022 two-day *En Banc* hearing on bill affordability, and as highlighted by the Commission's extensive Affordability Rulemaking (R.18-07-006), California is facing an energy affordability crisis. Energy bills have recently risen above $300 a month in SDG&E[39] and PG&E[40] territories, and, between 2013 and 2021, rates

[39] *SDG&E Hikes Rates: Some Will Pay Double for Nat. Gas, Elec. Rates Also Rise*, E. Cnty. Mag. (Jan. 2023), *available at* https://www.eastcountymagazine.org/sdge-hikes-rates-some-will-pay-double-natural-gas-electric-rates-also-rise.

[40] Julie Johnson, *PG&E Bills Have Topped $300 Per Month This Winter. Here's What's Next,* San Francisco Chron. (Feb. 4, 2023), *available at* https://www.sfchronicle.com/bayarea/article/pg-e-bills-have-topped-300-per-month-this-17763036.php.

grew by 37%, 6%, and 48% for PG&E, SCE, and SDG&E, respectively.[41] Even with the positive effects of the CARE and FERA programs, low-income customers are struggling to afford electricity bills.[42] As shown in Figure 2~~Figure 2~~, without the IGFC, low-income customers pay a substantially higher portion of their bills than higher-income customers.[43] Nationally, low-income households spend three times as much on energy bills than other households.[44] And as many as a quarter of California households are energy insecure, with low-income and communities of color most impacted.[45]

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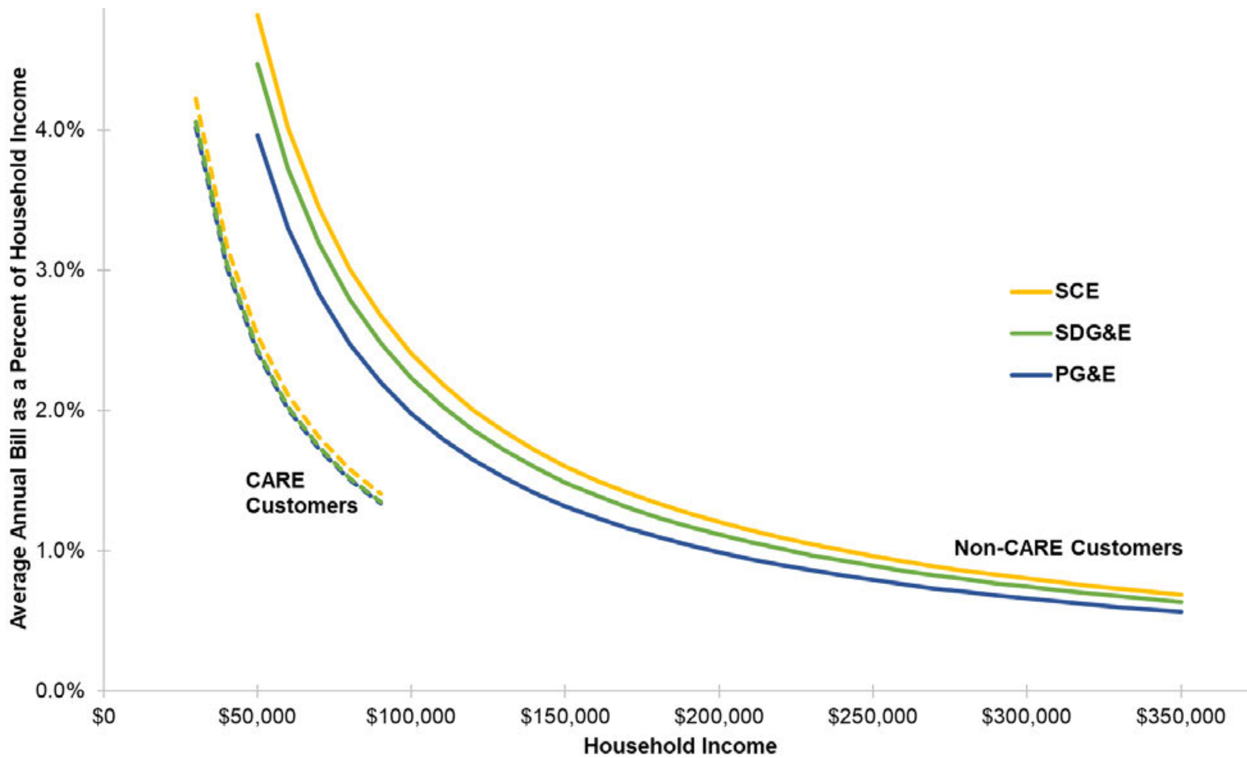
[41] Cal. Pub. Utils. Comm'n, *Util. Costs and Affordability of the Grid of the Future* at 7 (May 2021), *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/en-banc/senate-bill-695-report-2021_en-banc-white-paper.pdf [hereinafter "CPUC, *Util. Costs and Affordability of the Grid of the Future*"].
[42] *See, e.g.,* Cal. Pub. Utils. Comm'n, *2020 Ann. Affordability Report* at 52-53 (Oct. 2022), *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/affordability-proceeding/2020/2020-annual-affordability-report.pdf. ("Low-income households spend a significantly higher percentage of their income after housing costs on essential levels of electricity, natural gas, water, and communications services in these areas, even when the CARE and CAP discounts are applied to their energy and water EUBs.")
[43] Support for the data used to create Figure 2 is found in Attachment 4.
[44] Ariel Drehobl et al., *How High Are Household Energy Burdens?* Am. Council for an Energy-Efficient Econ. at 13 (Sept. 2020), *available at* https://www.aceee.org/sites/default/files/pdfs/u2006.pdf [hereinafter "Drehobl et al., *How High Are Household Energy Burdens?*"].
[45] Gabriela Sandoval & Mark Toney, *Living Without Power: Health Impacts of Util. Shutoffs in Cal.*, The Util. Reform Network at 9 (2018), *available at* https://energyrights.info/content/living-without-power-health-impacts-utility-shutoffs-california.

Figure 2: Regressivity of Current Electric Bills



Many of California's poorest residents live in the San Joaquin Valley and Inland Empire, regions prone to extreme heat. A 2021 Energy Division report found that "in the hotter regions of the state, household bills (electric, natural gas, and gasoline) are forecasted to rise at an annual rate of 4.5 percent, as compared to a 1.9% inflation rate."[46]

Furthermore, low-income customers tend to consume less energy per household, putting less strain on the grid.[47] Historically, they have often had to contend with lower quality of service, lower level of comfort and convenience in their home, and yet they have paid a higher percentage of their income for electricity service.[48] Low-income customers are particularly vulnerable to high volumetric rates, as they are more likely to live in non-weatherized housing[49] and, in California, many low-income customers live in areas with

[46] CPUC, *Util. Costs and Affordability of the Grid of the Future* at 8.
[47] Drehobl et al., *How High Are Household Energy Burdens?*.
[48] Jamal Lewis et. al., *Energy Efficiency as Energy Just.: Addressing Racial Ineqs. Through Invs. in People and Places*, 13 Energy Efficiency 419 at 4 (Aug. 8, 2019), *available at* https://www.greenandhealthyhomes.org/wp-content/uploads/Energy-Efficiency-as-Energy-Justice_Final.pdf.
[49] Ruth Ann Norton et al., *Leading with Equity and Just. in the Clean Energy Transition: Getting to the Starting Line for Residential Bldg. Elec.*, Green & Healthy Homes Initiative at 8-9 (2021), *available at* https://www.greenandhealthyhomes.org/wp-content/uploads/2021-GHHI-Leading-with-equity_wp_Final.pdf.

increasingly extreme weather, including extreme heat, which can result in high energy bills.[50] Low-income customers stand to benefit the most from high-efficiency electric appliances, but they must have access to low enough electricity rates to take full advantage.

To a substantial extent, California's high energy costs are not a result of low-income customers' collective demand for more or higher quality service from the utilities. Rather, many of these high costs are a result of expensive wildfire mitigation and remediation efforts caused by systemic problems with the electric grid (see Section II.C.2~~II.C.2~~). Other costs are stranded costs, expenditures that became disconnected from the economics of generation supply during various phases of California's energy market restructuring (see Section II.B~~II.B~~). Both the California Assembly and the state's energy regulators have made a series of policy decisions that have resulted in these costs being included in electric rates.

This is not the forum to debate the wisdom of those policy choices, but since these costs are more akin to state spending than the purchase of a market-traded commodity, the costs included in my IGFC proposal should be reasonably collected on an income-graduated basis. As California aspires to a progressive revenue system for state government funding, so too should its energy finance and policy objectives be funded in a progressive manner.

Q Please summarize your proposed IGFC tiers.

A I am proposing five tiers. For each tier, I am providing a formal definition, a proposed near-term simplification, and an approximation for modeling purposes.

[50] In 2021, Los Angeles County averaged 23 extreme heat days. By 2050, the state estimates that the county will see 51 extreme heat days a year. Cal. Energy Comm'n, *Local Climate Change Snapshot for Los Angeles Cnty. Cal.,* Cal-Adapt, *available at* https://cal-adapt.org/tools/local-climate-change-snapshot.

Table 5: Proposed IGFC Tiers

Tier	Definition	Near-Term Simplification	Approximation for Modeling
CARE/FERA	Customers enrolled in CARE/FERA programs	n/a	CARE enrollment up to $100,000 annual income[51] or income below $50,000
Below Average Income	Households with less than 80% AMI	Households with less than 4x FPL	Income up to $100,000
Moderate Income	Households with less than 125% AMI	Households with less than 6x FPL	Income up to $150,000
High Income	Households with less than 200% AMI	Households with less than 8x FPL	Income up to $200,000
Upper Income	Households above 200% AMI	Households with more than 8x FPL	Income above $200,000

Q What information will be needed to assign a household to an IGFC tier?

A Because my proposal includes the use of area median income ("AMI"), the utility (or a third-party verification agent) will need information related to household income, household size, and the geographic location of each residential customer, although exact information may not be necessary. Currently, the eligibility requirements for CARE and FERA also require information on household income and household size, but they are not sensitive to geographic location.

Q Please describe your CARE/FERA IGFC tier.

A I proposed a CARE/FERA tier because it is the most straightforward approach for enrolling and verifying customers in the lowest tier.

Q Why does your CARE/FERA IGFC tier include non-CARE customers with incomes below $50,000 and exclude CARE participants with incomes above $100,000 from your modeling?

A I believe there is a mismatch between the CARE enrollment data in the Fixed Charge Tool and CARE/FERA enrollment that is likely to occur when the IGFC is implemented. As

[51] Customers modeled as CARE customers with incomes over $100,000 are modeled as having approximately the same IGFC as non-CARE customers.

noted in the Haas Report used to supply the relationship between income, electricity usage, and CARE enrollment status:

> As expected, CARE participation rates are much higher among lower-income groups. However, not all eligible (based on income) CARE households participate. At the other end of the income distribution, some presumably ineligible households in higher income categories are CARE customers.[52]

Because of likely under-enrollment, I assumed that all non-CARE customers with incomes up to $50,000 are CARE- or FERA-eligible, and thus modeled all such customers as if they are CARE-enrolled. Similarly, I am skeptical of the Haas Report's inferred estimates of CARE participation levels in the highest income groups.[53] While I accept the Haas data as the best available resource for evaluating the overall income distribution and CARE participation levels, these two issues suggest that the Fixed Charge Tool may include significant errors in its forecast of CARE enrollment.

These CARE enrollment forecast issues are likely to be magnified with the rollout of the IGFC. As unenrolled CARE-eligible customers become aware that all customers' rates will be differentiated by household income, it seems probable that many will take the opportunity to enroll.

To partially address these forecast issues, I set the monthly IGFC amounts for "CARE" customers earning over $100,000 equal to IGFC amounts for non-CARE customers earning over $100,000.[54] An improved CARE/FERA participation forecast could take into account the increased visibility of bill savings opportunities available to low-income customers (boosting enrollment).

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[52] Haas Report at 6.

[53] According to the Haas Report, households with income above $150,000 participate in CARE at a rate of 1% to 6%, depending on the income range. These income data are based on California's 2019 Residential Appliance Saturation Study, which are linked to CARE program participation data using a combination of household-level electricity consumption and census block location. It is easy to imagine how such a method might miscode a small number of high-income households in high CARE-participation neighborhoods. But it appears that about 171 respondents (out of 28,800 who provided household income) are coded higher-income, CARE participants. It is hard to attach much statistical significance to this number without further resources and access to raw data. Haas Report at 5-6.

[54] Manually aligning the monthly IGFC amounts for higher-income CARE customers with non-CARE customers does not fully account for other CARE-related accounting in the Fixed Charge Tool. To fully account for CARE credits, the skewed CARE enrollment forecast would need to be adjusted. I did not have sufficient basis to select a specific enrollment forecast.

Overall, I suspect that CARE-eligible sales may be overstated by the data in the Fixed Charge Tool. The 2023 forecast billing determinants in the tool indicate that 28% of residential sales can be attributed to CARE customers, but the Commission's 2021 Low Income Energy Efficiency Potential Study estimates that 18-23% of residential energy consumption can be attributed to this population.[55] There are many potential explanations for the mismatch between these two findings. In implementing the Commission's decision, the utilities may find that actual CARE/FERA participation differs substantially from modeled data.

Q Why are you proposing to use AMI to assign customers to the other IGFC tiers?

A While any income threshold approach is likely to have pros and cons, I am proposing to use AMI for several reasons. First, AB 205 does not define "low-income customers." However, in Section 739.9(e)(1), AB 205 requires that "a low-income ratepayer *in each baseline territory* would realize a lower monthly average bill …" (emphasis added). This implies some degree of geographic differentiation in rate design.

Second, the Commission's definition of low-income household in its Environmental and Social Justice Plan 2.0 identifies a "low-income household" as a household with income at or below 80% of the AMI (80% AMI).[56] The Commission's definition came from another bill focused on energy equity, AB 1550, which directed the California Environmental Protection Agency to identify disadvantaged communities for funding purposes. Given the Commission's established use of this definition and consensus around its usage across state agencies, I recommend that the Commission use AMI as its primary definition in designing IGFC tiers.[57]

Finally, use of AMI advances the Commission's equity goals because it reflects regional variation in income. California has a particularly large variation in income across its 51 U.S. Department of Housing and Urban Development ("HUD") Fair Market Rent Areas

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[55] Guidehouse, *Low Income Program Energy Efficiency Potential Study* at 14 (Apr. 16, 2021), *available at* https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2021-potential-goals-study/low-income-report.pdf.

[56] Cal. Pub. Utils. Comm'n, *Env't and Social Just. Action Plan, Version 2.0* at 2 (Apr. 7, 2022), *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf.

[57] *See also* Opening Br. of Sierra Club and the Cal. Env't Just. All. at 10 (Jan. 23, 2023) [hereinafter "Opening Br. of Sierra Club & CEJA"].

(primarily county and metropolitan statistical areas, with no area smaller than an individual county). The 80% of AMI value for three-person households varies from $56,133 to $134,267 across those 51 areas.[58] While it is reasonable to assign a three-person household with an income of $125,000 to a low-income tier in some counties, across much of the state, that would be unreasonable.

My proposal assumes that the utilities would rely on AMI values published by HUD for its Fair Market Rent Areas, which are no smaller than individual counties. Baselines developed at a sub-county level could potentially produce unjust outcomes, such as a household earning $60k a year in a low-income county falling into a moderate-income tier because of local AMI. I recommend that in considering where to set the highest income threshold, the Commission considers geographic variation in cost-of-living and the risks of placing middle-income households into the highest income tier without a high enough threshold.

My proposed geographic baselining differs from the current CARE program approach; eligibility for the CARE program is set at 200% of the statewide federal poverty level ("FPL"). The CARE approach is simpler, but AB 1550 and AB 205 have increased the emphasis on ensuring equity in California's rate design. Households whose income is above the statewide FPL threshold and are thus ineligible for CARE may reside in areas where the AMI is so high that their household qualifies for housing assistance. While CARE eligibility is linked to an FPL threshold at the present time, California may want to unify its energy equity policies around the more equitable AMI threshold.

Q Please explain how you designed the proposed AMI-based income-graduated tiers.

A I began with the design of the Below Average Income ("BAI") tier. This tier is tied to the Commission's definition of low-income household as having an income at or below 80% of the AMI ("80% AMI").

For modeling purposes, I determined that the most appropriate representation of the BAI tier would be household incomes up to $100,000. This is a modest departure from the

[58] U.S. Dep't of Hous. and Urb. Dev., *Tables for HUD 30% Income Levels* (Apr. 18, 2022), *available at* https://www huduser.gov/portal/datasets/il html.

Energy Division staff proposal for modeling AMI thresholds.[59] The statewide 80% AMI for a three-person household is $72,600 for 2022. For modeling purposes, I selected $100,000 rather than $75,000 as a reasonable equivalent for two reasons. First, incomes are likely to be higher in 2023. Second, the average AMI in the IOU service territories is likely to be higher than the statewide average.

After setting the BAI tier at $100,000, I determined that to achieve the goal of developing progressive IGFC values, I would need at least three additional tiers. Since the Fixed Charge Tool offered household income tiers of $100-150,000, $150-200,000, and greater than $200,000, the design of the Fixed Charge Tool effectively drove my proposed tiers.

I then developed proposed AMI tiers that are roughly aligned with the Fixed Charge Tool tiers. I also developed FPL tiers for potential use as a near-term simplification.

Q Please summarize your proposed near-term simplification.

A I view it as the highest priority for the utilities to implement some form of income-graduated fixed rates. It may be necessary for the utilities to phase-in some details of the income verification and re-verification process. If that is necessary, then I have provided alternative guidelines for use with the FPL that are roughly equivalent to the AMI guidelines on a statewide basis. However, the FPL guidelines do not address the substantial geographic variation in affordability.

Q Did you consider any other income tiers?

A Yes. I also considered an additional upper income tier that would capture only the top 3% of earners in California. However, I determined that the Fixed Cost Tool did not allow for the creation of such a tier, because the upper income limit within the tool is for incomes over $200,000. An upper-plus income tier could be used to increase the progressivity of the IGFC, lower fixed charges for other income tiers, and increase equity. While I was not able to quantify an IGFC by creating such a tier, if the Commission would like to maintain a progressive fixed charge but with lower fixed charges for the currently modelled five

[59] ALJ Wang's ruling of March 23, 2023 directed parties to follow certain guidance for IGFC proposals, as described in an attached staff guidance memo. Staff acknowledge that the Fixed Charge Tool's "requirement that income thresholds be specified on an absolute basis at the household level does not allow for direct modeling of thresholds that are dependent on household size" or by region. Staff Guidance Memo on Using the E3 Fixed Charge Tool to Prepare Opening Test. at 4-5.

income tiers, it could direct the utilities to reassign a substantial portion of the revenue requirement to the wealthiest Californians by creating an upper-plus income tier.

C. Implementation of Zero-Dollar IGFC for CARE Customers

Q How did you model the proposed zero-dollar IGFC for CARE customers?

A The rate design I propose provides the CARE/FERA customers with a zero-dollar fixed charge, without a substantial net effect on the CARE/FERA costs included in non-residential customer rates.[60]

In order to ensure that non-residential CARE program contributions remain unchanged with respect to the IGFC, I matched the total CARE credits in a base case (no IGFC) with my proposal.[61] As a result, my proposal includes the recommendation that CARE program funding should be used to support a portion of the zero-dollar IGFC charge for CARE customers, as shown in Table 6~~Table 6~~.

Table 6: CARE Program Funding Used to Support the Zero-Dollar IGFC for CARE Customers[62]

Utility	**CARE Program Funding** ($ per CARE customer)	**Electrification Rates CARE Program Funding (Section IV~~IVIV~~)**
PG&E	$ 7.00	$ 8.50
SCE	$ 9.50	$ 10.20
SDG&E	$ 9.00	$ 10.40

Q Why is it reasonable to use CARE/FERA program funding to support the zero-dollar IGFC for CARE/FERA customers?

A It does not appear that AB 205 provides the Commission with direction regarding how to ensure full revenue recovery if it decides to provide CARE/FERA customers with a zero-dollar IGFC. However, I see nothing in AB 205 that suggests that the California Assembly

[60] The Fixed Charge Tool does not include FERA-specific cost estimates or the means to control FERA costs. For the remainder of this discussion, I focus on CARE only to reflect the information included in the Fixed Charge Tool. My proposal, however, treats CARE and FERA customers identically, and implementation by the utilities should address program-specific funding allocation.

[61] These values can be found on the Rate Design Dashboard, row 170. Because matching the values between the base case and my proposal required manual iteration, I did not solve for an exact match. As an example, PG&E's E-TOU-C rate has $985.4 million in total CARE credits in the base case, and $986.2 million in my proposal.

[62] These values are supported in Attachment 2.

anticipated that implementing the IGFC might result in an increased share of CARE/FERA program costs being recovered from non-residential customers. By holding total CARE credits unchanged between a no-IGFC case and my proposal, this ensures that non-residential customers are not held responsible for any costs in the IGFC revenue requirement.

D. Income-Based Graduation of Fixed Charge Levels

Q Please summarize your proposal for income-based graduation of fixed charge levels.

A I recommend that the Commission set the CARE/FERA IGFC at zero dollars, adopt a cost-based definition for the Below Average Income (BAI) tier, and allocate the remaining IGFC revenue requirement to the upper three tiers using utility-specific weights, as summarized in Table 7~~Table 7~~.

Table 7: Proposed IGFC Method

<table>
<tr><th>Tier</th><th>Definition</th><th colspan="4">Costs Included</th></tr>
<tr><td>CARE/FERA</td><td>Customers enrolled in CARE/FERA programs</td><td colspan="4">None</td></tr>
<tr><td>Below Average Income (BAI)</td><td>Households with less than 80% AMI</td><td colspan="4">Average per system customer (unweighted) of marginal customer access costs (MCAC)</td></tr>
<tr><td>Moderate Income</td><td>Households with less than 125% AMI</td><td rowspan="3">All IGFC costs not collected from the CARE/FERA and BAI tiers, weighted relative to the BAI tier, as follows:[63]</td><td>PG&E</td><td>SCE</td><td>SDG&E</td></tr>
<tr><td>High Income</td><td>Households with less than 200% AMI</td><td>1.0
2.0</td><td>1.0
2.5</td><td>1.0
2.0</td></tr>
<tr><td>Upper Income</td><td>Households above 200% AMI</td><td>6.00
12.50</td><td>9.00
24.00</td><td>5.50
12.00</td></tr>
<tr><td>Dedicated service connection surcharge</td><td>Customers with dedicated service drop</td><td colspan="4">Calculated as: MCAC for dedicated single-phase service drop – Average residential MCAC</td></tr>
<tr><td>Shared service connection discount</td><td>Customers with shared service connection</td><td colspan="4">Calculated as: MCAC for multi-family shared service drop – Average residential MCAC</td></tr>
</table>

[63] These values are applied in Attachment 2.

1. Lower Bills for Low-Income Customers

Q Why do you recommend that CARE/FERA customers be permanently assigned a zero-dollar IGFC?

A A zero-dollar IGFC for CARE/FERA customers is essential to meeting the requirements of AB 205,[64] which requires that the fixed charge be established so that ”a low-income ratepayer in each baseline territory [realizes] a lower average monthly bill without making any changes in usage.”[65] For thrifty low-income consumers, the only way to ensure that their bills will be lower with an IGFC is to set the IGFC at an amount that is lower than the current monthly bill of *all* low-income consumers. To ensure that the bill savings are meaningful for *all* low-income customers, and in the interests of expediency, I recommend the zero-dollar IGFC.

Furthermore, low-income customers tend to have less opportunity to control their electricity bill than higher-income customers. For instance, they may be renters or may only be able to afford residences that are not easily or cost-effectively upgraded to include more efficient technologies and building envelope improvements. As a consequence, low-income customers often pay a higher share of fixed costs that do not vary with electricity consumption than similarly situated customers with higher incomes. This historic inequity can be remedied by providing low-income customers with a zero-dollar fixed charge.

Q Is your proposal for a zero-dollar IGFC in conflict with any requirements in the CARE program?

A No. The CARE program establishes an overall bill discount whose cost is allocated to all customers. The IGFC policy allows the Commission to select costs to include in an IGFC to collect those from customers on an income-graduated basis. Like the CARE program, the IGFC policy will result in utilities collecting less revenue from a low-income residential customer than a higher-income residential customer. Unlike the CARE program, that revenue shortfall will need to be collected from higher-income residential customers—AB 205 does not state that the revenue shortfall should be included in the CARE program cost recovery mechanism established in Section 739.1.

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[64] Opening Br. of Sierra Club & CEJA at 9.
[65] Section 739.9(e)(1).

2. Minimum-cost Fixed Charges for Below-Average Income Customers

Q Why do you recommend that customers with below average income (the BAI tier) pay only MCAC and non-bypassable public purpose and regulatory charge costs?

A For the BAI tier to be charged a non-zero IGFC, I recommend that the Commission assign cost responsibility consistent with the average customer's "customer-specific" MCACs as defined in D.17-09-035 (see Section II.C.1~~II.C.1~~). It is reasonable to ensure that the BAI tier charge include MCACs because the Commission's policy since issuing D.17-09-035 has been to allow the customer charge to recover "customer-specific" costs including billing, customer inquiry, and establishing meters, service drops, and final line transformers.[66] I am recommending that this tier of customers be exempted from responsibility for other costs that are eligible for recovery in the IGFC. Those other costs should be recovered from customers with above-average income.

Q Please describe the method that the utilities should use to set the IGFC for customers in the BAI tier.

A In each general rate case ("GRC") application (Phase 2), utilities propose MCACs (calculated on a $/customer basis). The approved residential MCAC should be used as the IGFC for the BAI tier.

3. Weighted-Customer Method for Top Three IGFC Customer Tiers

Q Please describe your proposal for setting the IGFC for the top three income tiers.

A After forecasting the IGFC revenues for the below average income tier group, the utility should determine the remaining revenue requirement for the costs included in the IGFC. The utility will also need to forecast the number of customers in each of the top three income tiers. Using these data, the utility should allocate the costs on a weighted per-customer basis to each tier, and then determine the per-customer charge to recover those costs.

I have provided an example calculation in Table 8~~Table 8~~. I believe this method is functionally similar to E3's Fixed Charge Tool.

[66] D.17-09-035 at 32-33.

Table 8: Example Calculation of IGFC Using Weighted Customer Counts

Tier	**Customer Count**	**Weight**	**Weighted Customer Count**	**Cost per Weighted Customer**	**Annual IGFC (Cost per Customer)**
	(a)	(b)	(c)	(d)	(e)
Source:	Utility Forecast	Table 7~~Table 7~~	(a) x (b)	Total Revenue Req. / Total (c)	(d) x (c) / (a)
Moderate Income	100,000	2	200,000		$ 24
High Income	50,000	5	250,000		$ 60
Upper Income	10,000	15	150,000		$ 180
Total	160,000	n/a	600,000	$ 12	

Total Revenue Requirement = IGFC Revenue Requirement – Forecast BAI Tier IGFC Revenue

4. Lower Bills for Small Customers

Q Please summarize your proposal for a dedicated service connection surcharge and shared service connection discount.

A PUC Section 739.9(d)(1) ~~of AB 205~~ states that the fixed charge shall "[r]easonably reflect an appropriate portion of the different costs of serving small and large customers." Differentiating costs between small and large customers can be achieved by assessing the service drop provided to the customer. The vast majority of residential customers are on either shared service drops (usually multi-family residences) or dedicated single-phase service (usually single-family residences).[67] A very small number may receive the more costly three-phase service (for exceptionally high demand) or a dedicated transformer and service drop (potentially due to isolated location).

I recommend that the Commission direct the utilities to include a determination of MCACs for all customers, those with shared service drops and those with dedicated single-phase service, in their GRC Phase 2 applications.[68] The surcharge and discount for the IGFC would be the difference between the relevant charge for the customer type (shared or dedicated service) and the average customer.

As an alternative, the Commission could designate either shared or dedicated service as standard service, and then have either a surcharge or a discount reflecting the relative cost difference. This alternative would have the same resulting fixed charge but would simplify the tariff presentation.

The Commission should also direct the utilities to investigate whether or not establishing further cost differentiation for three-phase service or a dedicated transformer and service drop may be worthwhile. Such differentiation may be justified if there is a significant equity issue (a meaningful number of customers enjoying a very substantial, unwarranted discount) or a cost-allocation issue that results in a materially inequitable cost allocation between customer groups with different types of service. Using reasonable estimates of the

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[67] SDG&E states that it "does not gather or store data in this manner." PG&E and SDG&E provided data on single- and multi-family residential customer counts, with different degrees of data confidence. PGE&E Data Req. Resp. to Sierra Club, Set 01, Question 02, Supplement; SCE Data Req. Resp. to Sierra Club, Set 01, Question 02; SDG&E Data Req. Resp. to Sierra Club, Set 01, Question 2. (Attach. 6)

[68] SCE's data response is unclear as to whether it has or could calculate cost-based MCACs for dedicated- and shared-service drop customers. SCE Data Req. Resp. to Sierra Club, Set 01, Question 02. (Attach. 6)

MCACs for each type of service and the number of customers likely to be served using each method, this should be a fairly straightforward analysis that would inform the Commission regarding whether each utility should implement further cost differentiation.

Q Are there any challenges to implementing a fixed charge that distinguishes between dedicated and shared service?

A Yes. In response to data requests and informal consultation, I learned that the utilities do not believe they have billing-quality data that would allow them to accurately assign customers as having dedicated or shared service.

In spite of these concerns, I believe the Commission should implement my recommendation, not only because it is more equitable for customers on a shared service drop but also because Section 739.9(d)(1) appears to require that the Commission factor this information into any fixed charge. Because the utilities claim not to have the billing data quality necessary for immediate implementation, I recommend that the Commission allow the utilities to assume that all residential customers have dedicated service unless they are able to associate the account with information that is considered highly likely to indicate that the account is served by a shared service drop.

To improve this billing data, the utilities should identify opportunities in its standard business practices, such as in-person service calls, to update account information to reflect the existence of shared service drops. The utilities should also develop a cost-effective method for responding to customer complaints that they have not received the shared service discount for which they are eligible. The utilities should have leeway to schedule such investigations to minimize the cost of investigation in whatever manner their business practices may allow. In the interests of fairness to mis-classified customers, and to recognize that the compliant resolution process may be time consuming, the utilities should be directed to provide a standard-length rebate (e.g., two years) when a customer complaint is verified.

5. Proposed IGFCs Based on Fixed Charge Tool Calculations

Q What are the IGFCs that result from your proposal?

A Using the fixed charge tool, I calculated the IGFCs shown in Table 9~~Table 9~~ and as supported in Attachment 2. If adopted by the Commission, these values should be updated in a compliance filing by the utilities to reflect updates and details that may not be available in the Fixed Charge Tool. Furthermore, these values do not reflect my proposal for a discount/surcharge to reflect cost differences between smaller and larger customers, as discussed in Section III.D.4~~III.D.4~~.

Table 9: Proposed Income-Graduated Fixed Charges (IGFCs) for Standard Rates

IGFC Tiers	**PG&E**	**SCE**	**SDG&E**
CARE/FERA Customers	$ 0.00	$ 0.00	$ 0.00
Below Average Income (BAI)	$ 7.59	$ 7.89	$ 11.35
Moderate Income (MI)	$ 15.08	$ 19.71	$ 22.69
High Income (HI)	$ 45.23	$ 70.97	$ 62.40
Upper Income (UI)	$ 94.22	$ 189.26	$ 136.14
Average Charge per Customer	$ 28.48	$ 36.65	$ 36.44

Q Why do the fixed charges differ among the utilities?

A There are two main underlying causes of the differences. First is cost: consistent with the Commission's Electric Rate Design Principles, I am proposing cost-based rate design. I recommend that the Commission adopt my proposed *method* (IGFCs modeled with this method, above), and direct the utilities to calculate the actual IGFCs in a compliance filing.

Second is different income distribution by utility service territory. It appears that PG&E has a higher percentage of customers in the Upper Income tier than the other IOUs. In determining the weighting factors that I recommend the Commission adopt, I reviewed the progressivity of the IGFC for each tier. Given differences in utility costs and household income distribution, it was not possible to use equal weights to achieve a reasonably progressive outcome.

Q What do you mean by "progressive"?

A The progressive outcome I sought was that the IGFCs would be set so that households in higher income tiers would be charged a larger percentage of their income than those in lower income tiers. Examples of these percentages for certain representative annual incomes are shown in Table 10~~Table 10~~, as supported by Attachment 2.

I wish to emphasize that Table 10~~Table 10~~ only reflects the IGFC portion of a customer's bill. In Section V.A~~V.A~~, I will illustrate the relationship between household income and *total* bill impacts (in particular, see Figure 5~~Figure 5~~).

Table 10: Percent of Household Income Represented by Proposed Income-Graduated Fixed Charges

IGFC Tiers	Representative Annual Income	PG&E	SCE	SDG&E
CARE/FERA Customers	$ 50,000	0.00 %	0.00 %	0.00 %
Below Average Income (BAI)	$ 75,000	0.12 %	0.13 %	0.18 %
Moderate Income (MI)	$125,000	0.14 %	0.19 %	0.22 %
High Income (HI)	$175,000	0.31 %	0.49 %	0.43 %
Upper Income (UI)	$225,000	0.50 %	1.01 %	0.73 %

E. Transition Period for Fixed Charge

Q Should there be any transition period for the fixed charge?

A In general, no. However, there may be a need to delay two elements of my proposal for implementation as part of each utility's next Phase 2 GRC.

First, in Section III.B~~III.B~~, I acknowledge that it may be necessary for the utilities to phase-in some details of the income verification and re-verification process. If necessary, then I have provided alternative guidelines for FPL-based tiers that are roughly equivalent to the AMI-based tiers that I recommend be used in the final IGFC. This temporary approach will not address the substantial geographic variation in affordability evident in California.

Second, in Section III.D.4~~III.D.4~~, I recommend that the utilities develop marginal costs for small (shared service drop) and larger (dedicated service drop) customers. The primary purpose of this and any other reason for delay should be to gather more accurate information and ease the process for building the necessary billing system enhancements to enable implementation.

IV. Application of IGFC to Non-Default Rates

Q Are there any non-default rates that should be treated in a non-standard manner?

A Yes. Certain electrification rates have a non-zero fixed charge. It would be unreasonable to modify these rates to worsen their electrification attributes, and I am assuming that revisiting the rate design for these rates is beyond the scope of the instant proceeding.

For all customers served on these rates, the distribution component of the fixed charges currently included in the electrification rates should continue to be collected in those rates until those rates are updated in the utilities' GRC Phase 2 proceedings.

I will note that for these rates, CARE and FERA customers will pay a fixed charge set to recover the distribution component of the current fixed charge. According to all the electrification rate tariffs, the existing fixed charge is discounted for CARE customers.

Q Should the Commission make specific determinations regarding fixed charges in the utilities' electrification rates?

A No, other than leaving the status quo unaffected, the Commission should address the rate design in the utilities' next GRC Phase 2 proceedings. In particular, the scope of this proceeding does not include an opportunity to obtain and review evidence regarding the need for distribution costs to be recovered in the fixed charges of customers who subscribe to electrification rates. Furthermore, in such a review, the Commission should continue to review the applicable TOU periods to ensure that they are well-aligned and that volumetric rate differentials are appropriately designed.

My opinion is that the IGFC should largely address the motivations for establishing electrification rates. There may be a continuing need for both electrification and non-electrification rates, but if my proposal is adopted, it will largely address what I understand to be the motivations for designing those rates.

Q How did you determine the fixed charges for the electrification rates?

A Unfortunately, information about the cost components of the revenue requirements for the fixed charges in the utilities' electrification rates is not included in the Fixed Charge Tool or any discovery responses from the utilities.

I estimated the distribution cost by comparing each electrification rate's current fixed charge with the minimum bill amount for a non-electrification rate. I assumed that the difference represented the distribution cost portion of the fixed charge.[69]

The distribution cost portion of the fixed charge is discounted for CARE customers, but not for FERA customers who are charged at the higher non-CARE rate. As a result, for electrification rates only, the IGFC will differ for CARE and FERA customers by a small amount.

The estimated distribution portion of current electrification rates is shown in Table 11~~Table 11~~, as supplied in E3's Fixed Cost Tool without modification.

Table 11: Distribution Portion of Current Electrification Rates

Current Average Monthly Charges	**PG&E**	**SCE**	**SDG&E**
Non-CARE Customers			
Minimum Bill	$ 10.59	$ 10.52	$ 11.56
Customer Charge	$ 14.98	$ 13.32	$ 16.21
Distribution Portion	$ 4.39	$ 2.80	$ 4.65
CARE Customers			
Minimum Bill	$ 6.89	$ 7.10	$ 7.63
Customer Charge	$ 9.74	$ 8.99	$ 10.70
Distribution Portion	$ 2.85	$ 1.89	$ 3.07

I then calculated proposed IGFCs (Table 12~~Table 12~~) for electrification rates by adding the distribution portion of current fixed charges (Table 11~~Table 11~~) to the proposed IGFCs for standard rates (Table 9~~Table 9~~). As discussed in Section III.C~~III.C~~, in order to ensure that non-residential CARE program contributions remain unchanged with respect to the IGFC, I matched the total CARE credits in a base case (no IGFC) with my proposal. The resulting CARE program funding used to support the zero-dollar IGFC for CARE customers on electrification rates is shown in Table 6~~Table 6Table 6~~.

[69] I may update this calculation in reply testimony with more accurate data from the utilities.

***Table 12: Proposed Income-Graduated Fixed Charges (IGFCs) for Electrification Rates*[70]**

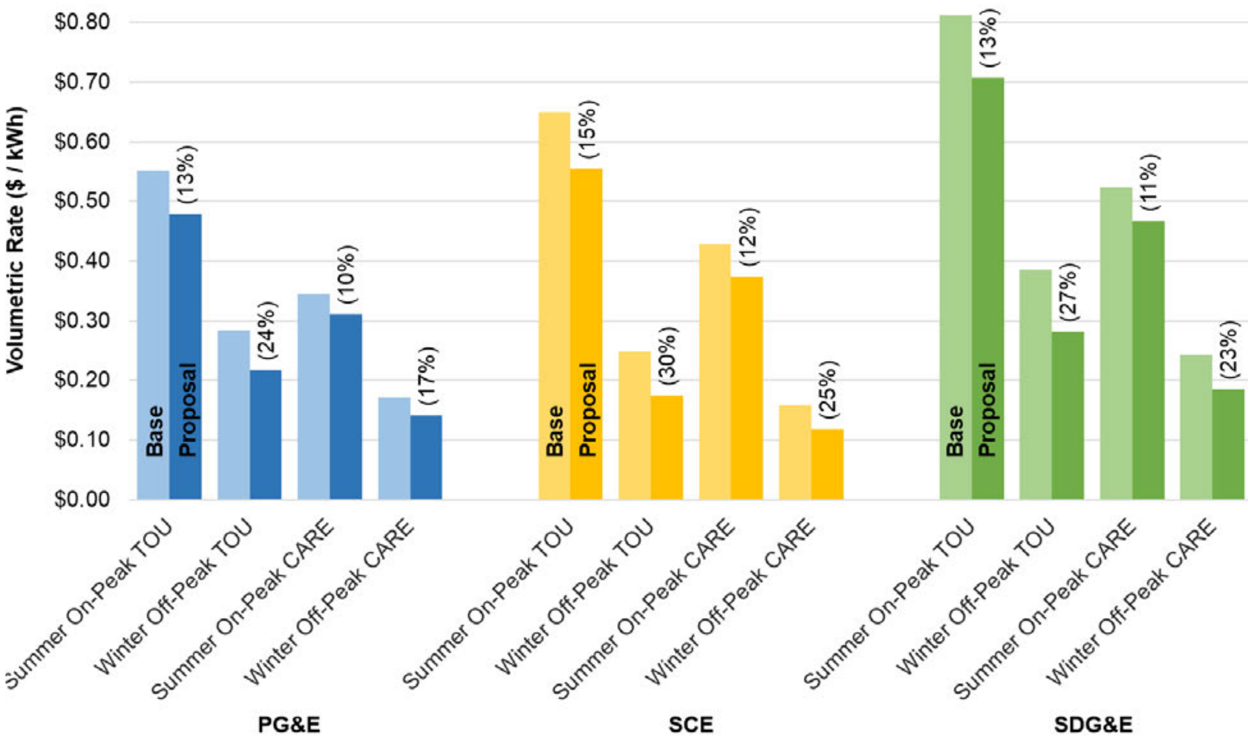
IGFC Tiers	PG&E	SCE	SDG&E
CARE/FERA Customers	$ 2.85	$ 1.89	$ 3.07
Below Average Income (BAI)	$ 11.98	$ 10.68	$ 15.86
Moderate Income (MI)	$ 19.47	$ 22.51	$ 21.47
High Income (HI)	$ 49.62	$ 73.77	$ 55.09
Upper Income (UI)	$ 98.61	$ 192.05	$ 127.95
Average Charge per Customer	$ 32.87	$ 39.45	$ 35.59

Q What are the resulting volumetric rates for electrification tariffs?

A The resulting volumetric rates are shown in Figure 3~~Figure 3~~ for PG&E's E-ELEC, SCE's TOU-PRIME, and SDG&E's TOU-ELEC tariffs. For the utilities' electrification rates, there is little or no differentiation in the distribution portion of the volumetric rates, so there is no significant difference between the uniform factor (which I used for these rates as well as standard rates) and equal cents differential methods. Similar to the standard rates, the volumetric reduction is greater in the winter.

[70] The Electrification Rate IGFCs should apply to all five electric vehicle and electrification rates included in the Fixed Cost Tool, plus any future rates designed to include a portion of demand-related distribution costs in the fixed charge.

Figure 3: Summer On-Peak and Winter Off-Peak Volumetric Rates, Current vs IGFC Proposal for Electrification Rates



V. Impacts of IGFC Proposal

A. Lower Average Monthly Bills for Low-Income Ratepayers

Q Will your proposal achieve lower average monthly bills for low-income ratepayers?

A Yes. Because my proposal has a zero-dollar IGFC for CARE/FERA customers, and lowers volumetric rates for all customers, all CARE/FERA customers will have lower average monthly bills given the same consumption.

Furthermore, because my proposal has a low IGFC for customers with below average income, most of those customers will also benefit from substantially lower average monthly bills.

Q What are anticipated bill impacts for each of the five proposed income tiers?

A Bills will be reduced for the lowest three income tiers and increased for the top two income tiers, as shown in Figure 4~~Figure 4~~. Similarly, bills as a percentage of income will be reduced for households with lower incomes, but increased for higher income households, as shown in Figure 5~~Figure 5~~.[71]

[71] These figures are based on data from Attachments 2 and 4.

Figure 4: Bill Impacts of Proposed IGFC by Utility and Tier[72]

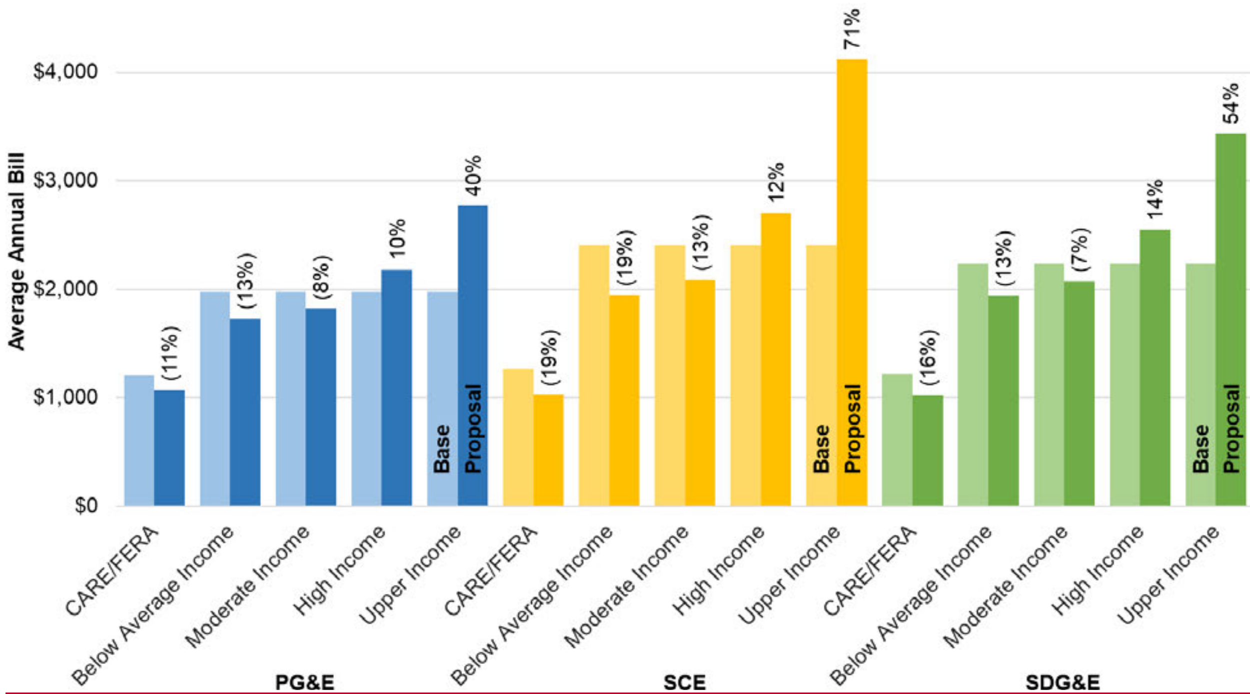
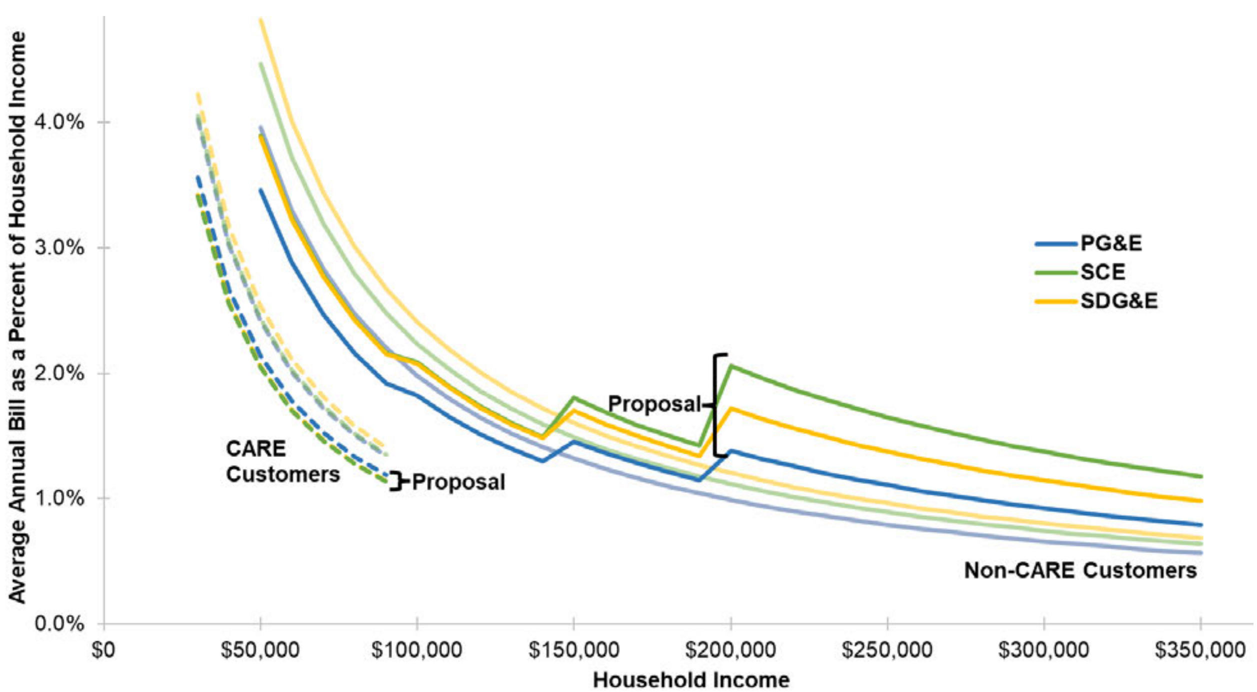


Figure 5: Progressive Impact of Proposed IGFC on Bills Relative to Household Income[73]



[72] Bill impacts are for an average Non-NEM, bundled customer, from the Fixed Charge Tool. PG&E: E-TOU-C, Inland (Zone X). SCE: TOU-D-4-9, Inland (Zone 9). SDG&E: TOU-DR1, Coastal.
[73] Bill impacts are for an average Non-NEM, bundled customer, from the Fixed Charge Tool. PG&E: E-TOU-C, Inland (Zone X). SCE: TOU-D-4-9, Inland (Zone 9). SDG&E: TOU-DR1, Coastal.

B. Increased Incentives for Electrification

Q Why does a fixed charge incentivize electrification?

A As I discussed above, when a portion of the utility's costs are recovered through a fixed charge, the volumetric rate can be correspondingly lowered. A lower volumetric rate generally encourages customers to use more electricity. Because California has a policy to encourage electrification, lowering the volumetric rate can help achieve California's goals.

Q How does the Fixed Charge Tool evaluate the impact of the IGFC on electrification?

A Instead of using economic methods (e.g., cross-price elasticities), the Fixed Charge Tool uses a price scenario to represent the type of analysis that a household might undertake to determine what the energy cost savings might be for various electrification scenarios. Using these methods, the rates resulting from my IGFC proposal will mean greater savings for customers who choose to electrify.

As a strong initial caveat, I have not examined the assumptions and methods in the Fixed Charge Tool's electrification scenarios in depth. They appear to be a reasonable approach, but it is entirely possible (even likely) that the data may not reflect how consumers are viewing electrification investment decisions. Furthermore, if the electrification scenarios understate future costs of natural gas or gasoline, then electrification would have greater benefits than estimated by the Fixed Charge Tool.

For these reasons, I urge the Commission to view the results of the Fixed Charge Tool as providing directionally useful information, and not to consider the evaluations as an indication that consumers will or will not be incentivized *en mass* to invest in electrification based on the tool's outputs.

Q How does the proposed IGFC impact electrification for each of the income tiers and overall?

A The proposed IGFC is more financially advantageous for electrification projects than current rates, as modeled in the Fixed Charge Tool. I reviewed the tool's findings for a variety of scenarios, and did not observe any instances in which the proposed IGFC worsens the bill impact of any electrification project scenarios.

Figure 6~~Figure 6~~ illustrates the potential impact of the IGFC on average monthly household energy bills without electrification and with three electrification scenarios, as estimated in the Fixed Charge Tool.[74] The bills shown are for moderate income tier customers (household income of $100-150,000), calculated as follows:

- PG&E: E-ELEC rate, Inland region
- SCE: TOU-D-PRIME rate, Inland region
- SDG&E: TOU-ELEC rate, Coastal region

In each case studied except for the SDG&E "No Electrification" scenario, the IFGC results in cost savings relative to the current rate (as modeled by the Fixed Charge Tool). The difference is illustrated by the lighter bar which shows the higher bill under current rates as compared to the darker bar with the bill using my proposed IGFC rates.

The benefits of the IGFC in the electrification scenarios vary by utility. For PG&E, electrification on the IGFC results in bills that would be $14-33~~10-25~~ less per month than on the existing electrification rate—$31-58~~28-53~~ for SCE and $3-33~~7-31~~ for SDG&E.

Figure 6~~Figure 6~~ also shows the amount of the IGFC bill savings relative to "No Electrification" for each electrification scenarios from the tool: space and water heating, full building, and full building plus vehicle electrification (unmanaged charging). For all three utilities, the IGFC improves electrification benefits by $4-39~~3-31~~ per month, depending on the scenario.

For PG&E and SCE, the Fixed Charge Tool suggests substantial monthly bill savings due to electrification. For those two utilities, total monthly household energy bills are lower by $19~~17~~ to $51~~46~~ with the proposed IGFC rates, depending on electrification scenario, or $230~~210~~-$617~~553~~ per year.

Due to SDG&E's overall higher residential volumetric rates (compared to the other utilities), the Fixed Charge Tool results suggest that SDG&E customer households would not see a reduced monthly household energy bill due to electrification, except in the space ~~&~~and water heating scenario. However, the IGFC does provide progressively greater benefits as compared to current rates. As noted above, the benefits of electrification would be greater under higher assumed natural gas or gasoline costs.

[74] Support for Figure 6~~Figure 6~~ is provided in Attachment 2.

Figure 6: Average Monthly Household Energy Bills Under Four Electrification Scenarios, Current Rates vs Proposed IGFC, with Net Savings (Costs) on IGFC Rate

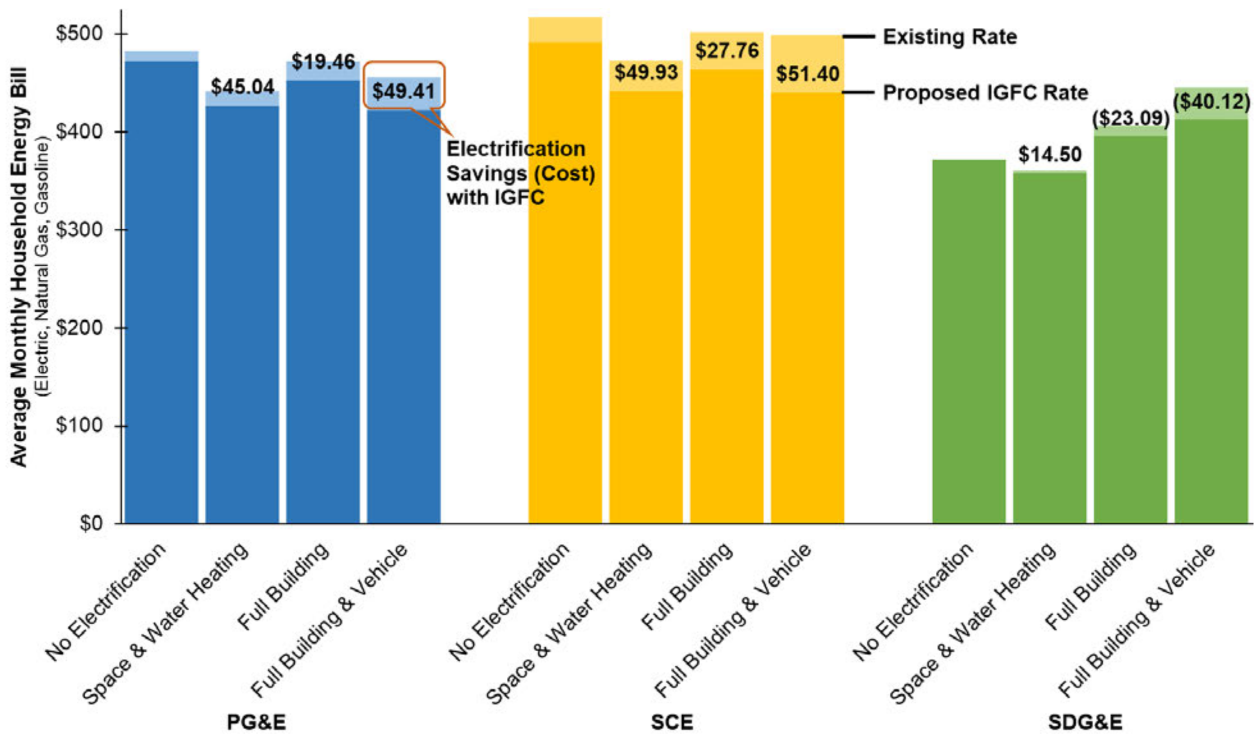
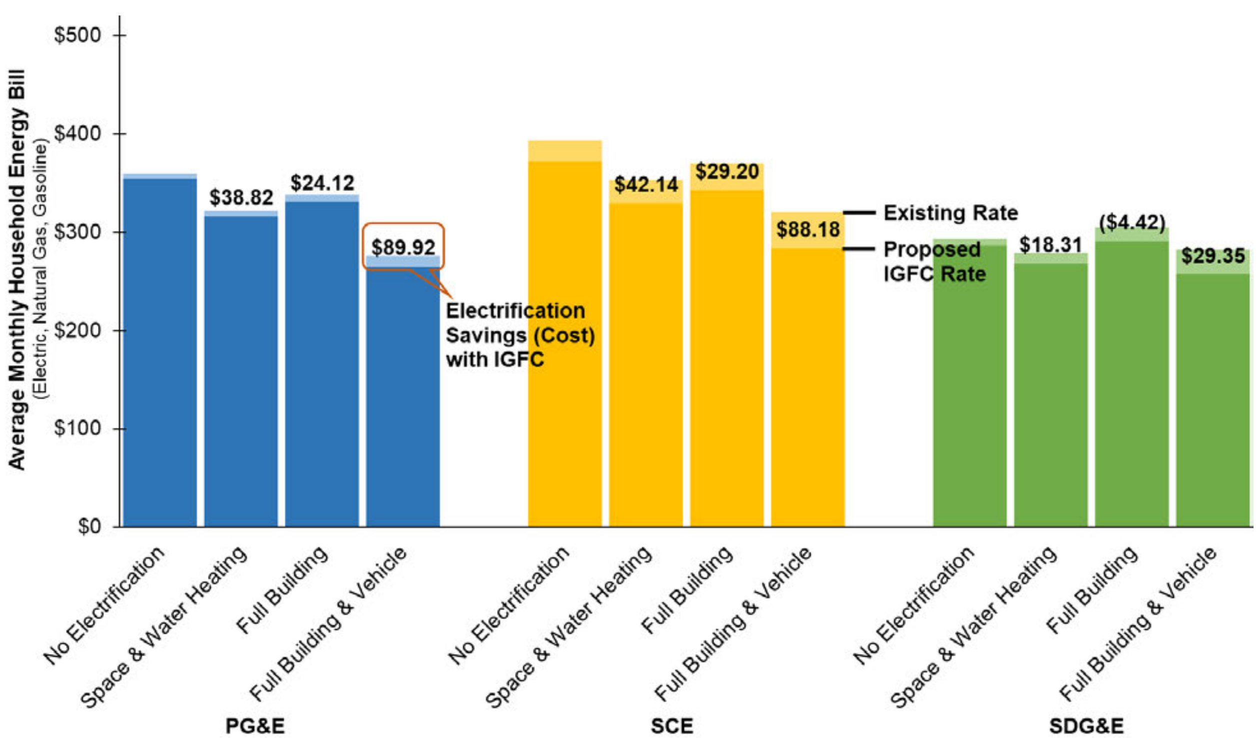


Figure 7: Average Monthly CARE Customer Household Energy Bills Under Four Electrification Scenarios, Current Rates vs Proposed IGFC, with Net Savings (Costs) on IGFC Rate



With the exception of the findings for SDG&E, these results are consistent with those found in a recent study by Rewiring America. The Rewiring America study found that in California, 12.9 million out of 13 million households would see bill savings from fuel-switching from gas to electric today with an average annual savings of over $270 on energy bills.[75] Switching to highly efficient heat pump space heaters and heat pump water heaters would save low- and moderate-income households an average of $302 a year.[76]

Rewiring America also found that fuel-switching savings are concentrated at the bottom: "savings are particularly meaningful for low- and moderate income (LMI) households. LMI households have 3x the energy burden (the portion of their income spent on home energy) as other households."[77] Rewiring America's findings are consistent with the income regressivity illustrated in Figure 2~~Figure 2~~.

Q Under the proposal, will low-income customers likely see bill savings from fuel-switching?

A Yes, low-income customers benefit more from my IGFC proposal than moderate income customers. As shown in Figure 7~~Figure 7~~, compared with non-CARE customers, CARE customers would see lower monthly bills under each of the four electrification scenarios *and* greater electrification savings on the IGFC rate.[78]

C. Modest Impacts on Conservation and Energy Efficiency

Q How will the proposed IGFC impact incentives for energy conservation and energy efficiency?

A The proposed IGFC will have a modest impact on conservation and energy efficiency. By design, the IGFC will lead to a decrease in volumetric rates. The theory of price elasticity, as supported by many economic studies, indicates that such a decrease in the electricity price will lead to an increase in its use. However, the response of customers to such price changes is difficult to measure independent of other relevant factors.

[75] Rewiring America, *Cal.: The IRA Will Deliver Huge Savings* at 2 (July 2022), *available at* https://pdf.rewiringamerica.org/fact-sheet/06/print.
[76] *Id.*
[77] *Id.* at 1; *see also* Sherri Billimoria et. al., *The Econ. of Elec. Bldgs*., RMI at 29-31 (2018), *available at* https://rmi.org/insight/the-economics-of-electrifying-buildings/.
[78] Support for Figure 7~~Figure 7~~ is provided in Attachment 3.

One relevant factor is wealth, as "[m]ore wealthy consumers generally are less responsive to changes in electricity prices, when compared with lower-income consumers."[79] Another possible factor is the likelihood that the increase in electricity use will be realized in the form of accelerated electrification. There is no iron law that suggests that the increased electricity use will be realized through greater use of existing technologies. Customers may go out and purchase a second (or fourth) television, but they may also switch from a gas to an electric heat pump hot water heater. Both of these actions would appear as an increase in electricity use, but only one would also appear as a decrease in natural gas consumption.

Q Can you quantify the effect of lower volumetric rates on electricity use?

A Yes. To address this question, I considered the long-run price elasticity of residential electricity use, which captures the potential price responsiveness of customers to a decrease in volumetric rates.

By reducing volumetric rates by ~~10-25~~15-18%% (see Section III.A~~III.A~~), and assuming a short-run elasticity of -0.13, electricity demand could increase by about 2~~-3~~%.[80] This modest effect is not enough to offset the overall bill savings shown in Figure 4~~Figure 4~~. However, as discussed above, much of this future increase electricity use could be in the form of electrification, with offsetting bill savings due to reduced natural gas and motor fuel use.

The effect of lower electricity prices stimulating higher electricity demand in an electrification context is illustrated in the Fixed Charge Tool's building electrification impacts. In Table 13~~Table 13~~, the electricity bill rises in each of the four levels of electrification, but the total fuel bill is lower in each compared to the no electrification option. This example is for a particular customer type—it depends on the assumptions

[79] Cal. Senate Off. of Rsch., *Pricing Strategies Can be Effective in Reducing Residential Elec. Demand* at 2 (Aug. 2017), *available at* https://sor.senate.ca.gov/sites/sor.senate.ca.gov/files/REDUCING%20RESIDENTIAL%20ELECTRICITY%20DEMAND.pdf.

[80] In the long run, assuming a price elasticity of -0.5 may increase electricity use by 8-9~~9-12~~%. That level of increased electricity use would significantly reduce overall bill savings. The US EIA recommends a residential price elasticities of -0.5 (long run) and -0.13 (1 year). U.S. Energy Info. Admin., *Price Elasticity for Energy Use in Bldgs. in the United States*, Table 1, at 3 (Jan. 2021), *available at* https://www.eia.gov/analysis/studies/buildings/energyuse/.

supplied by E3 in the Fixed Charge Tool, but I believe them to be directionally consistent with the anticipated effect.

Table 13: Fuel Bill Changes for Customers Adopting Varying Levels of Electrification *(SCE, TOU-D-PRIME, IGFC Proposal, Inland non-CARE customer, $100-150,000 household income)*[81]

Mixed Fuel Bill	**No Electrification**	**Space and Water Heating**	**Full Building Electrification**	**Full Building Electrification & Electric Vehicle**
Electricity	$ 301	$ 324	$ 370	$ 499
Natural Gas	$ ~~80~~84	$ 16	$ -	$ -
Gasoline	$ 132	$ 132	$ 132	$ -
Total	$ ~~513~~518	$ ~~472~~473	$ 502	$ 499

Q Should the Commission find that my proposed IGFC would unreasonably impair conservation and energy efficiency?

A No. In addition to the possibility that much of long-run increase in electricity use will be desirable electrification investment, the Commission should also find that any impairment in conservation or energy is properly considered in the context of California's overall high electricity rates. As shown in Section III.A~~III.A~~, if collected entirely as volumetric rates, customers receiving bundled electric service pay an average of 35 to 51 ¢/kWh for electricity. As the Commission is well aware, these rates are far higher than those in many other jurisdictions and would remain so even with a reduction of 15-18%. Californians will continue to experience rates that are high enough to encourage conservation and substantial investment in energy efficiency.

VI. Issues Reserved for Reply Testimony

Q Please summarize the issues that you are reserving for reply testimony.

A Although I have briefly touched on some of these topics, I have not addressed the following issues in depth.

1. The potential impact of the IGFC on the Net Billing Tariff.
2. The processes that should be used to verify and reverify customers' income.
3. The costs and timeline associated with implementation of an IGFC.

[81] Table 13~~Table 13~~ is supported by Attachment 3.

4. The process for rate adjustments to achieve revenue neutrality.
5. Future evaluation of the effectiveness of the design and implementation of an IGFC, including appropriate income thresholds for the highest tier.

I reserve these issues for possible discussion in reply testimony.

VII. Conclusion

Q Please restate your recommendations.

A I recommend that the Commission reach the following findings:

1) Generation-related costs that vary based on the volume of electricity consumed should be excluded from the IGFC.
2) Generation-related costs that provide for guaranteed cost recovery of historical embedded generation costs are stranded costs that became disconnected from the economics of generation supply during the various phases of market restructuring, and are collected through non-bypassable charges.
3) Those generation-related costs, collected through non-bypassable charges, should be eligible for recovery through the IGFC.
4) The Power Cost Indifference Adjustment charge has been highly volatile and unpredictable because its costs are linked to market capacity costs. Because including it in the IGFC could result in significant volatility in the fixed charge, PCIA costs should be excluded from recovery in the IGFC.
5) AB 205 does not direct or encourage the Commission to modify its definition of "customer-specific" costs, and it is reasonable to retain the definition of ~~marginal customer access costs (~~MCACs~~)~~ established in D.17-09-035.
6) AB 205 does not restrict the Commission from including non-marginal customer access costs in the IGFC. Because those customer-specific distribution costs were incurred on a per-customer basis, both marginal and non-marginal customer access costs should be recovered through the IGFC.
7) Based on Commission precedent and widely accepted practice across North America, customer-specific distribution costs, which vary with customer count, should be recovered thorough the IGFC.
8) The California Assembly's amendments to Section 381(a) in AB 205 removed statutory restrictions for collecting specific ~~non-bypassable charges (~~NBCs~~)~~ in volumetric rates.
9) The four distribution-related NBCs are related to the recovery of costs related to wildfires, and those costs do not vary significantly with electricity consumption (other than the drastic step of shutting off power). Accordingly, those costs should be eligible for recovery through the IGFC.
10) The costs to fund public purpose programs and regulatory commissions are more similar in nature to the costs of other state agency programs than they are to other costs of electric service.

11) Commission-approved public purpose program costs do not vary with electrical usage. In the case of energy efficiency, the relationship is usually in the opposite direction: electrical usage varies with energy efficiency spending.

12) Energy efficiency costs are, for the most part, not fixed costs, but rather costs that may vary based on Commission policy, and should be recovered through the IGFC.

13) Regulatory commission costs do not vary with electrical usage and should be recovered through the IGFC.

14) Because the income-graduated fixed charge establishes a funding mechanism which may be assessed on a progressive basis in a manner similar to California's tax system, the IGFC should be used to recover the costs to fund public purpose programs and regulatory commissions.

15) Other distribution costs that should be considered eligible for recovery through the IGFC are those whose fixed costs do not vary with electricity consumption, as stated in AB 205 Section 14(a)(4). It is reasonable for the Commission to retain discretion as to whether such costs should or should not be included in the IGFC as circumstances may change.

16) Because demand-related distribution costs vary with electricity consumption, they are properly collected in volumetric rates and should be excluded from recovery through the IGFC.

17) FERC-jurisdictional transmission and other reliability costs should not be recovered in the IGFC because of the lack of evidence that FERC would accept recovery of these charges in a fixed charge.

18) Because the uniform factor method results in greater cost savings for electrification activities, it should be used to determine the adjustments to volumetric rates that result from recovering costs through the IGFC.

19) It is reasonable to establish five tiers for the IGFC, including (a) CARE/FERA customers, (b) below average income, (c) moderate income, (d) high income, and (e) upper income, as defined using CARE/FERA eligibility criteria and area median income (AMI) thresholds set out in Table 5~~Table 5~~. In the future, the Commission may revisit the thresholds used to define the tiers, including potentially adding an upper-plus income tier.

20) Because it will be challenging to implement geographically-specific AMI tiers immediately, it is reasonable to defer use of AMI in favor of FPL tiers until the utilities are able to implement AMI tiers, as set out in Table 5~~Table 5~~. Both the temporary FPL-based tiers and the final AMI-based tiers will require the utilities (or a designated third-party) to determine household size and income with sufficient precision to assign customers to the correct tier.

21) CARE/FERA customers should be assigned a zero-dollar IGFC to ensure that all low-income customers realize a lower average monthly bill, as required by Section 739.9(e)(1).

22) To support the zero-dollar IGFC without affecting the amount of non-residential CARE program contributions, CARE program funding should be used to support a portion of the zero-dollar IGFC charge for CARE customers, as shown in Table 6~~Table 6~~.

23) The IGFC for below-average income customers should recover revenue for costs that the Commission has previously determined to be "customer-specific" (MCACs) and not for other costs that are only eligible for recovery in an IGFC.

24) All costs that should be recovered or are eligible for recovery in an IGFC should be recovered through the top three income tiers to reduce inequities among customers, as required by AB 205 Section 14(a)(4) and to assist with achieving California's climate change goals, as required by AB 205 Section 14(b)(2).
25) A reasonable progressive weighting method is illustrated in Table 8~~Table 8~~ and should be used to allocate costs between the top three income tiers.
26) To reflect the different costs of serving small and large customers as required by Section 739.9(d)(1), the IGFC should provide for different MCACs for customers served by shared service drops as compared to customers served by dedicated service drops.
27) The utilities do not have billing quality data to determine which accounts are served by shared or dedicated service drops, but they do have some data that may be used for initial assignments. It is reasonable for the utilities to gradually improve these data over time and provide customers with information and incentive to identify misclassifications.
28) The utilities do not have information regarding the costs or number of residential customers served by more costly three-phase or dedicated transformer services.
29) The demand-related distribution costs included in the fixed charges of approved electrification rates should be retained until each utility's next GRC Phase 2 in the interests of maintaining consistency in those rate designs.
30) Because electrification rates are designed differently than other optional rates, those optional rates will include small fixed charges for CARE and FERA customers.

I recommend that the Commission direct the utilities to take the following actions in a compliance filing:

1) Provide an initial best-available-evidence estimate of non-marginal customer access costs for use in the IGFC.
2) Propose a plan for filing an improved non-marginal customer access revenue requirement in the utilities' next Phase 1 GRC.
3) Propose a plan for implementing geographically-specific AMI tiers.
4) Update each residential tariff's volumetric rates after removing the recovery of revenues related to the costs that will be recovered in the IGFC.
5) Determine the total amount of costs to be recovered in the IGFC, less the costs to be recovered from the below-average-income customer tier. The IGFC for each of the remaining three tiers should be determined using these costs, based on the weighted cost method illustrated in Table 8~~Table 8~~.
6) Utilize available information to estimate the difference in MCACs for customers served by shared or dedicated service drops, and apply those price differentials to the IGFC.
7) Propose a plan for utilizing the best-available-information for initially assigning residential customer accounts to shared or dedicated service drop rates.
8) Propose a plan for gradually improving the accuracy of account data reflecting the service drop for each residential customer account in the utility's billing system.
9) Provide an analysis of further cost differentiation for customers served by three-phase service or dedicated transformers from the perspective of equity and the reasonableness

of cost-allocation, including a discussion of the actions required to implement such cost differentiation.

Q Does this conclude your testimony?

A Yes.

Docket No: R.22-07-005

Sierra Club
Direct Testimony of John D. Wilson

Attachment 1
Qualifications for John D. Wilson

John D. Wilson

Resource Insight, Inc.
10 Court Street, PO Box 232
Arlington MA 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

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

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

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

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

EDUCATION

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

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

PUBLICATIONS

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

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

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

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

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

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"Implementing All-Source Procurement in the Carolinas," prepared for Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy, South Carolina Coastal

Conservation League and Upstate Forever, for submission in NCUC Docket E-100, Sub 165, and SCPSC Dockets 2019-224-E and 2019-225-E, February 2021.

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"MGCC Pricing Formula for PG&E's Day-Ahead Hourly Real Time Pricing (DAHRTP) Rates," joint report prepared by PG&E, Small Business Utility Advocates, CPUC Public Advocates Office, California Large Energy Consumers Association, and Enel X, CPUC Dockets A.20-10-011 and A.19-11-019, March 2022.

PRESENTATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"Resource Adequacy, Reserve Margin, & Seasonal Planning," 2022 Georgia IRP Training and Roundtable Series, February 2022.

"Six Lessons from the PG&E Real Time Pricing Rate Proceeding," 45th Peak Load Management Alliance Conference, April 2022.

EXPERT TESTIMONY

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

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

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

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

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

Georgia PSC Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

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

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

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

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

South Carolina PSC Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

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

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

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

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

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

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

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

Nova Scotia UARB Matter No. M09707, direct testimony with Paul Chernick on Nova Scotia Power's 2020 Load Forecast on behalf of the Nova Scotia

Consumer Advocate. Impacts of recession, application of end-use studies, improvements to forecast components, and impact of time-varying pricing.

California PUC Docket A.19-10-012, direct and rebuttal testimony with Paul Chernick in San Diego Gas & Electric's application for the Power Your Drive Electric Vehicle Charging Program on behalf of the Small Business Utility Advocates. Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

California PUC Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 2) on behalf of the Small Business Utility Advocates. Reasonableness of remedial software costs to be included in authorized revenue requirement.

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

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

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

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

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

Nova Scotia UARB Matter No. M09920, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2021 on behalf of the Nova Scotia

Consumer Advocate. Cost minimization. Project contingency. Economic analysis model. Analysis of specific projects.

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

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

California PUC Docket A.20-10-011, direct and reply testimony with Paul Chernick in Pacific Gas & Electric's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot on behalf of the Small Business Utility Advocates. Rate design for real time pricing tariff. Marketing to small businesses. Evaluation plan.

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

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

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

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

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

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

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

2022 **California PUC** Docket A.21-05-017, direct testimony with Paul Chernick in Liberty Utilities Calpeco 2022 general rate case on behalf of the Small Business Utility Advocates. Marginal cost study, revenue allocation, rate design.

Nova Scotia UARB Matter No. M10366, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2022 on behalf of the Nova Scotia Consumer Advocate. Alignment with IRP and new regulation. Cost minimization. Project contingency. Post-project review. Total cost of ownership. Economic analysis model. Decommissioning. Analysis of specific projects.

California PUC Docket A.21-10-010, direct testimony on Pacific Gas and Electric's proposed Electric Vehicle Charge 2 Program on behalf of the Small Business Utility Advocates. Program scale and unit costs. Cost controls. Cost Allocation.

Nova Scotia UARB Matter No. M10400, direct testimony on Nova Scotia Power's Work Management and Scheduling & Dispatch Application on behalf of the Nova Scotia Consumer Advocate. Economic Analysis. Additional Applications for Software. Contingency Guidelines. Total Cost of Ownership.

Massachusetts DPU Docket No. 22-22, direct, surrebuttal and supplemental testimony on Eversource Energy's 2022 Base Distribution Rate Case on behalf of the Cape Light Compact. Allocation of Distribution Revenue Requirement.

Nova Scotia UARB Matter No. M10431, direct testimony on Nova Scotia Power's 2022 General Rate Application on behalf of the Nova Scotia Consumer Advocate. Board Directives. Fuel Costs. Capital Project Revenue Requirements. Deferral Accounts and Riders. Cost Allocation. Residential Customer Charge.

2023 **Nova Scotia UARB** Matter No. M10959, direct testimony on Nova Scotia Power's 2023 Application for Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Seasonal and Time-Varying Rates. Impact of Maritime Link Power Delivery. Cost of Service Study Updates.

Docket No: R.22-07-005

Sierra Club
Direct Testimony of John D. Wilson

Attachment 2
IGFC Proposal Standard Rates

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

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
Phone: 415-391-5100

Model Release Date: April 13, 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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 538,263,216	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 218,481,550	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 865,996,766	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal Customer Access	$ 454,792,861	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Distribution Capacity Cost - Primary	$ 439,382,040	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Distribution Capacity Cost - New Business	$ 476,043,853	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Distribution Capacity Cost - Secondary	$ 29,945,145	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,833,578,625	FALSE	FALSE	19.93%	0.00%	80.07%
Transmission	Transmission	$ 1,447,654,612	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 58,854,252	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 63,120,120	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Hardening Charge	$ 68,921,008	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ 215,256,658	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Credit	$ (215,256,658)	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 230,732,710	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 37,938,712	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 96,956,158	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Competition Transition Charge	$ 8,518,646	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Energy Cost Recovery Account	$ (19,846,861)	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 606,708,166	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 584,831,167	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 1,378,829,544	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 427,567,610	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal - Grid	$ 888,543,196	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal - Peak	$ 503,372,326	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,845,967,040	FALSE	FALSE	45.79%	0.00%	54.21%
Transmission	Base Transmission	$ 599,320,433	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (1,839,212)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 23,619,309	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 103,390,404	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Hardening Charge	$ 17,556,861	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ -	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Credit	$ (40,575,857)	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 313,291,510	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 2,364,701	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 148,976,188	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 100,915,850	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 57,547,258	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 163,094,812	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 183,005,936	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Demand - Non-Coincident Peak	$ 198,205,378	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Demand - Coincident Peak	$ 26,974,391	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 490,650,411	FALSE	FALSE	39.84%	0.00%	60.16%
Transmission	Base Transmission	$ 537,401,722	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (111,012,377)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 8,781,000	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 29,143,070	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 61,433,000	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 526,530	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Local Generation Charge/New System Generation Cha	$ 81,949,029	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Competition Transition Charge	$ 11,052,908	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Total Rate Adjustment Component - Baseline adjustme	$ 1,000,000	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Reliability Services	$ 177,809	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.0000	1.0000	1.0000
	[100,150]	1.0000	1.0000	1.0000
	[150,200]	1.0000	1.0000	1.0000
	200+	1.0000	1.0000	1.0000
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	-	-	-
	[25,50]	-	-	-
	[50,75]	-	-	-
	[75,100]	-	-	-
	[100,150]	15.0751	19.7143	22.6909
	[150,200]	45.2253	70.9715	62.4000
	200+	94.2194	189.2572	136.1454
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	-	-	-
	[25,50]	-	-	-
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.0000	1.0000	1.0000
	[100,150]	2.0000	2.5000	2.0000
	[150,200]	6.0000	9.0000	5.5000
	200+	12.5000	24.0000	12.0000
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ 7.0000	$ 9.5000	$ 9.0000
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	$ 3.0000	$ 3.0000	$ 3.0000
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
$ 1,077,568,288	$ -	$ 4,141,536,456

Based on CARE program size from E-TOU-C

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 458,279,641	$ -	$ -

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 2,413,517,443
NBCs	$ -
Non-Dist	$ 1,728,019,013

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

SDG&E

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 452,493,498	$ -	$ 1,208,877,188

Based on CARE program size from TOU-DR1

Delivery - CARE-exempt			
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric	
$ 104,618,538	$ -	$ -	$ 557,112,036

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 520,355,055
NBCs	$ -
Non-Dist	$ 688,522,133

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

SCE

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 1,588,466,398	$ -	$ 3,157,163,596

Based on CARE program size from TOU-D-4-9

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 295,590,440	$ -	$ -

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 2,392,639,984
NBCs	$ -
Non-Dist	$ 764,523,612

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

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]	$ -	$ -	$ -	$ -	$ -	$ -
[25,50]	$ -	$ -	$ -	$ -	$ -	$ -
[50,75]	$ 7.5501	$ -	$ 7.5376	$ -	$ 7.5304	$ -
[75,100]	$ 7.5501	$ -	$ 7.5376	$ -	$ 7.5304	$ -
[100,150]	$ 15.1002	$ 15.0751	$ 15.0752	$ 15.0751	$ 15.0609	$ 15.0751
[150,200]	$ 45.3005	$ 45.2253	$ 45.2256	$ 45.2253	$ 45.1826	$ 45.2253
200+	$ 94.3761	$ 94.2194	$ 94.2199	$ 94.2194	$ 94.1304	$ 94.2194
Tier Credits/Charges ($/kWh)						
Baseline Credit	$ 0.0651	$ 0.0423	$ 0.0651	$ 0.0423	$ -	$ -
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	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
Demand Charge ($/kW-mo)	$ -	$ -	$ -	$ -	$ -	$ -
Energy Charges ($/kWh)						
Summer - Peak	$ 0.3276	$ 0.2129	$ 0.4142	$ 0.2692	$ 0.4659	$ 0.3028
Summer - Part-Peak	$ 0.3276	$ 0.2129	$ -	$ -	$ 0.3684	$ 0.2394
Summer - Off-Peak	$ 0.3276	$ 0.2129	$ 0.3522	$ 0.2290	$ 0.1981	$ 0.1287
Winter - Peak	$ 0.3276	$ 0.2129	$ 0.3243	$ 0.2108	$ 0.3526	$ 0.2292
Winter - Part-Peak	$ 0.3276	$ 0.2129	$ -	$ -	$ 0.3368	$ 0.2189
Winter - Off-Peak	$ 0.3276	$ 0.2129	$ 0.3073	$ 0.1997	$ 0.1967	$ 0.1279
Total CARE Program Funding - Modeled						
Customer		$ (115,871,238)		$ (115,871,238)		$ (115,871,238)
Demand		$ -		$ -		$ -
Volumetric - Delivery		$ (446,794,957)		$ (446,794,957)		$ (446,794,957)
Volumetric - Generation		$ (431,894,113)		$ (423,536,307)		$ (418,748,960)
Total CARE Credits		$ (994,560,307)		$ (986,202,502)		$ (981,415,154)
Residential CARE Funding		$ 269,650,273		$ 267,384,262		$ 266,086,292
Non-Res CARE Funding		$ 724,910,035		$ 718,818,241		$ 715,328,863
Total IOU forecast CARE program size						
2023 Forecast (Existing Rates)		$ (891,914,356)		$ (891,914,356)		$ (891,914,356)
Modeled Credits as % of Forecast		12%		11%		10%

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
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 7.5099	$ -	$ 7.8757	$ -	$ 7.8856	$ -	$ 7.8946	$ -
$ 7.5099	$ -	$ 7.8757	$ -	$ 7.8856	$ -	$ 7.8946	$ -
$ 15.0199	$ 15.0751	$ 19.6892	$ 19.7143	$ 19.7141	$ 19.7143	$ 19.7364	$ 19.7143
$ 45.0596	$ 45.2253	$ 70.8812	$ 70.9715	$ 70.9707	$ 70.9715	$ 71.0510	$ 70.9715
$ 93.8741	$ 94.2194	$ 189.0165	$ 189.2572	$ 189.2553	$ 189.2572	$ 189.4692	$ 189.2572
$ -	$ -	$ 0.0548	$ 0.0370	$ 0.0600	$ 0.0405	$ -	$ -
$ -	$ -	$ 0.0617	$ 0.0417	$ -	$ -	$ -	$ -
X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.4937	$ 0.3209	$ 0.3071	$ 0.2073	$ 0.4555	$ 0.3074	$ 0.5625	$ 0.3797
$ 0.3303	$ 0.2147	$ 0.2160	$ 0.1458	$ 0.3471	$ 0.2343	$ 0.3048	$ 0.2057
$ 0.2733	$ 0.1776	$ 0.2160	$ 0.1458	$ 0.2563	$ 0.1730	$ 0.1984	$ 0.1339
$ 0.2605	$ 0.1693	$ 0.3071	$ 0.2073	$ 0.3875	$ 0.2616	$ 0.5039	$ 0.3401
$ 0.2383	$ 0.1549	$ 0.2160	$ 0.1458	$ 0.2810	$ 0.1897	$ 0.1790	$ 0.1208
$ 0.2245	$ 0.1459	$ 0.2160	$ 0.1458	$ 0.2515	$ 0.1697	$ 0.1790	$ 0.1208
	$ (115,871,238)		$ (133,590,131)		$ (133,590,131)		$ (133,590,131)
	$ -		$ -		$ -		$ -
	$ (446,794,957)		$ (264,260,551)		$ (264,260,551)		$ (264,260,551)
	$ (405,034,979)		$ (339,559,859)		$ (347,681,851)		$ (354,957,511)
	$ (967,701,173)		$ (737,410,541)		$ (745,532,532)		$ (752,808,193)
	$ 262,368,087		$ 189,512,394		$ 191,599,722		$ 193,469,546
	$ 705,333,087		$ 547,898,148		$ 553,932,810		$ 559,338,647
	$ (891,914,356)		$ (660,034,291)		$ (660,034,291)		$ (660,034,291)
	8%		12%		13%		14%

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
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 11.3699	$ -	$ 11.3450	$ -	$ 11.3492	$ -	$ 11.3280	$ -
$ 11.3699	$ -	$ 11.3450	$ -	$ 11.3492	$ -	$ 11.3280	$ -
$ 22.7399	$ 22.6909	$ 22.6901	$ 22.6909	$ 22.6985	$ 22.6909	$ 22.6561	$ 22.6909
$ 62.5346	$ 62.4000	$ 62.3977	$ 62.4000	$ 62.4209	$ 62.4000	$ 62.3042	$ 62.4000
$ 136.4392	$ 136.1454	$ 136.1405	$ 136.1454	$ 136.1910	$ 136.1454	$ 135.9364	$ 136.1454
$ 0.0877	$ 0.0579	$ 0.0877	$ 0.0579	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.4894	$ 0.3230	$ 0.7798	$ 0.5147	$ 0.7725	$ 0.5099	$ 0.7196	$ 0.4750
$ 0.4894	$ 0.3230	$ 0.4663	$ 0.3078	$ 0.4375	$ 0.2888	$ 0.3504	$ 0.2313
$ 0.5200	$ 0.3432	$ 0.3017	$ 0.1991	$ 0.2198	$ 0.1451	$ 0.3018	$ 0.1992
$ 0.3088	$ 0.2038	$ 0.5028	$ 0.3319	$ 0.4677	$ 0.3087	$ 0.4786	$ 0.3159
$ 0.3088	$ 0.2038	$ 0.4183	$ 0.2761	$ 0.4040	$ 0.2666	$ 0.3372	$ 0.2225
$ 0.4408	$ 0.2909	$ 0.3938	$ 0.2599	$ 0.2115	$ 0.1396	$ 0.2930	$ 0.1934
	$ (36,417,564)		$ (36,417,564)		$ (36,417,564)		$ (36,417,564)
	$ -		$ -		$ -		$ -
	$ (99,651,820)		$ (99,651,820)		$ (99,651,820)		$ (99,651,820)
	$ (100,157,376)		$ (96,179,165)		$ (96,851,978)		$ (93,461,884)
	$ (236,226,761)		$ (232,248,550)		$ (232,921,362)		$ (229,531,269)
	$ 67,836,885		$ 66,694,468		$ 66,887,679		$ 65,914,151
	$ 168,389,875		$ 165,554,081		$ 166,033,683		$ 163,617,118
	$ (178,549,476)		$ (178,549,476)		$ (178,549,476)		$ (178,549,476)
	32%		30%		30%		29%

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	$ (25.78)	$ (38.77)	$ (35.27)	$ (39.14)	$ (36.33)	$ (19.89)	$ (29.79)	$ (37.36)	$ (27.92)	$ (28.46)	$ (16.47)
$25,000 - $50,000	None	2	$ (29.16)	$ (38.54)	$ (35.25)	$ (39.22)	$ (36.17)	$ (19.83)	$ (29.88)	$ (37.57)	$ (27.92)	$ (28.46)	$ (16.45)
$50,000 - $75,000	None	3	$ (22.06)	$ (30.79)	$ (27.62)	$ (30.97)	$ (28.12)	$ (12.23)	$ (22.34)	$ (29.13)	$ (20.28)	$ (20.92)	$ (8.95)
$75,000 - $100,000	None	4	$ (21.42)	$ (30.41)	$ (27.63)	$ (30.05)	$ (27.37)	$ (12.18)	$ (22.25)	$ (27.83)	$ (20.20)	$ (20.92)	$ (8.94)
$100,00 - $150,000	None	5	$ (13.07)	$ (22.44)	$ (19.85)	$ (21.43)	$ (18.99)	$ (4.59)	$ (14.62)	$ (18.75)	$ (12.51)	$ (13.38)	$ (1.38)
$150,000 - $200,000	None	6	$ 18.13	$ 8.57	$ 10.49	$ 9.95	$ 12.22	$ 25.60	$ 15.65	$ 13.14	$ 17.84	$ 16.78	$ 28.72
$200,000+	None	7	$ 68.59	$ 58.65	$ 60.11	$ 60.82	$ 62.74	$ 74.69	$ 64.67	$ 64.17	$ 67.41	$ 65.78	$ 77.72
$0 - $25,000	CARE	1	$ (13.62)	$ (19.09)	$ (15.86)	$ (17.36)	$ (15.84)	$ (8.61)	$ (11.24)	$ (17.08)	$ (11.36)	$ (16.97)	$ (13.02)
$25,000 - $50,000	CARE	2	$ (13.96)	$ (19.03)	$ (15.85)	$ (17.11)	$ (15.66)	$ (8.58)	$ (11.25)	$ (16.70)	$ (11.30)	$ (16.97)	$ (13.10)
$50,000 - $75,000	CARE	3	$ (13.54)	$ (18.92)	$ (15.62)	$ (16.84)	$ (15.52)	$ (8.57)	$ (11.16)	$ (16.27)	$ (11.28)	$ (16.96)	$ (13.14)
$75,000 - $100,000	CARE	4	$ (13.38)	$ (18.90)	$ (15.17)	$ (16.74)	$ (15.33)	$ (8.54)	$ (11.08)	$ (15.86)	$ (11.28)	$ (16.96)	$ (13.17)
$100,00 - $150,000	CARE	5	$ 1.94	$ (3.76)	$ (0.70)	$ (1.34)	$ (0.07)	$ 6.55	$ 3.87	$ (0.55)	$ 3.87	$ (1.88)	$ 1.87
$150,000 - $200,000	CARE	6	$ 32.55	$ 26.52	$ 29.26	$ 29.01	$ 30.23	$ 36.69	$ 34.00	$ 30.18	$ 34.04	$ 28.27	$ 32.16
$200,000+	CARE	7	$ 82.23	$ 75.94	$ 78.26	$ 78.38	$ 79.51	$ 85.69	$ 83.15	$ 79.42	$ 83.10	$ 77.27	$ 78.84
$0 - $25,000	FERA	1	$ (26.05)	$ (37.82)	$ (31.49)	$ (33.53)	$ (30.89)	$ (17.11)	$ (22.26)	$ (32.83)	$ (22.41)	$ (33.92)	$ (25.95)
$25,000 - $50,000	FERA	2	$ (26.47)	$ (37.71)	$ (31.46)	$ (32.73)	$ (30.43)	$ (17.05)	$ (22.28)	$ (31.75)	$ (22.27)	$ (33.92)	$ (26.46)
$50,000 - $75,000	FERA	3	$ (19.57)	$ (31.35)	$ (24.72)	$ (25.80)	$ (23.90)	$ (10.82)	$ (15.93)	$ (24.44)	$ (16.03)	$ (27.74)	$ (20.48)
$75,000 - $100,000	FERA	4	$ (19.32)	$ (31.32)	$ (23.66)	$ (25.53)	$ (23.43)	$ (10.77)	$ (15.77)	$ (23.49)	$ (16.03)	$ (27.74)	$ (20.59)
$100,00 - $150,000	FERA	5	$ (12.78)	$ (25.02)	$ (18.91)	$ (18.55)	$ (16.82)	$ (4.56)	$ (9.85)	$ (16.78)	$ (9.70)	$ (21.56)	$ (14.55)
$150,000 - $200,000	FERA	6	$ 12.67	$ (0.08)	$ 5.34	$ 6.63	$ 8.26	$ 20.14	$ 14.84	$ 9.12	$ 15.06	$ 3.17	$ 10.87
$200,000+	FERA	7	$ 53.89	$ 40.78	$ 45.52	$ 47.62	$ 49.04	$ 60.33	$ 55.32	$ 49.75	$ 55.38	$ 43.35	$ 48.22

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

SDG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ (36.33)	$ (37.94)	$ (35.31)	$ (38.15)	$ (55.52)
$25,000 - $50,000	None	2	$ (36.44)	$ (38.45)	$ (35.31)	$ (38.69)	$ (54.10)
$50,000 - $75,000	None	3	$ (25.45)	$ (27.16)	$ (23.91)	$ (25.76)	$ (42.32)
$75,000 - $100,000	None	4	$ (25.38)	$ (26.91)	$ (23.83)	$ (23.64)	$ (41.70)
$100,00 - $150,000	None	5	$ (13.54)	$ (14.73)	$ (12.22)	$ (13.66)	$ (28.74)
$150,000 - $200,000	None	6	$ 26.97	$ 26.19	$ 27.81	$ 37.00	$ 13.17
$200,000+	None	7	$ 102.07	$ 101.64	$ 102.42	$ 99.25	$ 89.71
$0 - $25,000	CARE	1	$ (18.46)	$ (20.35)	$ (16.12)	$ (36.75)	$ (46.31)
$25,000 - $50,000	CARE	2	$ (18.51)	$ (20.31)	$ (16.12)	$ (37.95)	$ (44.53)
$50,000 - $75,000	CARE	3	$ (18.37)	$ (20.26)	$ (16.10)	N/A	$ (44.82)
$75,000 - $100,000	CARE	4	$ (18.00)	$ (20.22)	$ (16.02)	N/A	$ (46.97)
$100,00 - $150,000	CARE	5	$ 4.98	$ 2.41	$ 6.64	N/A	N/A
$150,000 - $200,000	CARE	6	$ 46.69	N/A	$ 46.69	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ (29.08)	$ (31.74)	$ (25.20)	$ (54.30)	$ (71.82)
$25,000 - $50,000	FERA	2	$ (29.14)	$ (31.67)	$ (25.20)	$ (56.96)	$ (68.31)
$50,000 - $75,000	FERA	3	$ (19.62)	$ (22.28)	$ (15.87)	N/A	$ (59.61)
$75,000 - $100,000	FERA	4	$ (19.06)	$ (22.22)	$ (15.76)	N/A	$ (63.70)
$100,00 - $150,000	FERA	5	$ (9.27)	$ (13.01)	$ (6.51)	N/A	N/A
$150,000 - $200,000	FERA	6	$ 26.51	N/A	$ 26.51	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

			Customer Average Bill Impact ($/mo)									
Income Bracket	Bill Discount		SCE	5	6	8	9	10	13	14	15	16
$0 - $25,000	None	1	$ (41.14)	$ (41.02)	$ (33.21)	$ (36.07)	$ (45.07)	$ (46.93)	$ (55.41)	$ (53.23)	$ (59.49)	$ (36.83)
$25,000 - $50,000	None	2	$ (42.82)	$ (41.02)	$ (33.18)	$ (36.17)	$ (45.51)	$ (48.15)	$ (54.80)	$ (52.90)	$ (60.23)	$ (36.80)
$50,000 - $75,000	None	3	$ (34.72)	$ (33.13)	$ (25.25)	$ (28.29)	$ (37.66)	$ (40.11)	$ (45.81)	$ (44.60)	$ (51.84)	$ (28.89)
$75,000 - $100,000	None	4	$ (34.34)	$ (33.13)	$ (25.22)	$ (28.21)	$ (37.50)	$ (39.59)	$ (44.96)	$ (43.97)	$ (51.38)	$ (28.79)
$100,00 - $150,000	None	5	$ (21.81)	$ (21.30)	$ (13.31)	$ (16.25)	$ (25.45)	$ (26.83)	$ (32.06)	$ (31.51)	$ (39.13)	$ (16.86)
$150,000 - $200,000	None	6	$ 30.28	$ 29.96	$ 38.04	$ 35.21	$ 26.21	$ 25.32	$ 19.96	$ 20.47	$ 12.61	$ 34.50
$200,000+	None	7	$ 150.07	$ 148.24	$ 156.51	$ 153.94	$ 145.10	$ 144.70	$ 139.86	$ 139.66	$ 131.74	$ 152.86
$0 - $25,000	CARE	1	$ (22.04)	N/A	$ (14.31)	$ (16.69)	$ (20.08)	$ (26.31)	$ (28.79)	$ (29.42)	$ (30.96)	$ (23.18)
$25,000 - $50,000	CARE	2	$ (21.80)	N/A	$ (14.31)	$ (16.68)	$ (20.08)	$ (26.19)	$ (28.51)	$ (29.17)	$ (30.61)	$ (23.10)
$50,000 - $75,000	CARE	3	$ (21.67)	N/A	$ (14.30)	$ (16.68)	$ (20.08)	$ (26.02)	$ (28.30)	$ (29.03)	$ (30.42)	$ (23.12)
$75,000 - $100,000	CARE	4	$ (21.67)	N/A	$ (14.30)	$ (16.67)	$ (20.08)	$ (25.92)	$ (28.08)	$ (29.00)	$ (30.24)	$ (23.12)
$100,00 - $150,000	CARE	5	$ (1.72)	N/A	$ 5.42	$ 3.05	$ (0.36)	$ (6.01)	$ (8.34)	$ (9.02)	$ (10.41)	$ (3.28)
$150,000 - $200,000	CARE	6	$ 49.94	N/A	$ 56.69	$ 54.32	$ 50.90	$ 45.57	$ 43.17	$ 42.51	$ 41.13	$ 48.13
$200,000+	CARE	7	$ 168.86	N/A	$ 174.97	$ 172.63	$ 169.19	$ 164.10	$ 161.83	$ 161.00	$ 159.95	$ 166.59
$0 - $25,000	FERA	1	$ (33.21)	N/A	$ (22.16)	$ (25.61)	$ (30.75)	$ (39.53)	$ (43.07)	$ (44.26)	$ (46.95)	$ (36.01)
$25,000 - $50,000	FERA	2	$ (33.00)	N/A	$ (22.15)	$ (25.60)	$ (30.76)	$ (39.29)	$ (42.38)	$ (43.75)	$ (46.10)	$ (35.86)
$50,000 - $75,000	FERA	3	$ (26.41)	N/A	$ (15.68)	$ (19.12)	$ (24.30)	$ (32.48)	$ (35.46)	$ (37.01)	$ (39.22)	$ (29.42)
$75,000 - $100,000	FERA	4	$ (26.43)	N/A	$ (15.67)	$ (19.12)	$ (24.31)	$ (32.27)	$ (34.97)	$ (36.95)	$ (38.83)	$ (29.42)
$100,00 - $150,000	FERA	5	$ (16.43)	N/A	$ (5.96)	$ (9.40)	$ (14.61)	$ (22.21)	$ (25.22)	$ (26.74)	$ (28.88)	$ (19.50)
$150,000 - $200,000	FERA	6	$ 26.15	N/A	$ 36.08	$ 32.66	$ 27.40	$ 20.42	$ 17.33	$ 15.81	$ 13.75	$ 22.79
$200,000+	FERA	7	$ 124.02	N/A	$ 133.08	$ 129.68	$ 124.37	$ 117.85	$ 115.05	$ 113.15	$ 111.79	$ 120.07

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

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
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 11.3699	$ -	$ 11.3450	$ -	$ 11.3492	$ -	$ 11.3280	$ -
$ 11.3699	$ -	$ 11.3450	$ -	$ 11.3492	$ -	$ 11.3280	$ -
$ 22.7399	$ 22.6909	$ 22.6901	$ 22.6909	$ 22.6985	$ 22.6909	$ 22.6561	$ 22.6909
$ 62.5346	$ 62.4000	$ 62.3977	$ 62.4000	$ 62.4209	$ 62.4000	$ 62.3042	$ 62.4000
$ 136.4392	$ 136.1454	$ 136.1405	$ 136.1454	$ 136.1910	$ 136.1454	$ 135.9364	$ 136.1454
$ 0.0877	$ 0.0579	$ 0.0877	$ 0.0579	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.4894	$ 0.3230	$ 0.7798	$ 0.5147	$ 0.7725	$ 0.5099	$ 0.7196	$ 0.4750
$ 0.4894	$ 0.3230	$ 0.4663	$ 0.3078	$ 0.4375	$ 0.2888	$ 0.3504	$ 0.2313
$ 0.5200	$ 0.3432	$ 0.3017	$ 0.1991	$ 0.2198	$ 0.1451	$ 0.3018	$ 0.1992
$ 0.3088	$ 0.2038	$ 0.5028	$ 0.3319	$ 0.4677	$ 0.3087	$ 0.4786	$ 0.3159
$ 0.3088	$ 0.2038	$ 0.4183	$ 0.2761	$ 0.4040	$ 0.2666	$ 0.3372	$ 0.2225
$ 0.4408	$ 0.2909	$ 0.3938	$ 0.2599	$ 0.2115	$ 0.1396	$ 0.2930	$ 0.1934
	$ (36,417,564)		$ (36,417,564)		$ (36,417,564)		$ (36,417,564)
	$ -		$ -		$ -		$ -
	$ (99,651,820)		$ (99,651,820)		$ (99,651,820)		$ (99,651,820)
	$ (100,157,376)		$ (96,179,165)		$ (96,851,978)		$ (93,461,884)
	$ (236,226,761)		$ (232,248,550)		$ (232,921,362)		$ (229,531,269)
	$ 67,836,885		$ 66,694,468		$ 66,887,679		$ 65,914,151
	$ 168,389,875		$ 165,554,081		$ 166,033,683		$ 163,617,118
	$ (178,549,476)		$ (178,549,476)		$ (178,549,476)		$ (178,549,476)
	32%		30%		30%		29%

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	$ (25.46)	$ (38.24)	$ (35.15)	$ (38.14)	$ (35.53)	$ (19.75)	$ (29.62)	$ (36.17)	$ (27.56)	$ (28.20)	$ (16.30)
$25,000 - $50,000	None	2	$ (28.70)	$ (38.03)	$ (35.13)	$ (38.22)	$ (35.38)	$ (19.70)	$ (29.70)	$ (36.39)	$ (27.57)	$ (28.20)	$ (16.29)
$50,000 - $75,000	None	3	$ (21.55)	$ (30.27)	$ (27.49)	$ (29.97)	$ (27.33)	$ (12.09)	$ (22.15)	$ (27.94)	$ (19.92)	$ (20.65)	$ (8.77)
$75,000 - $100,000	None	4	$ (20.94)	$ (29.91)	$ (27.51)	$ (29.07)	$ (26.59)	$ (12.04)	$ (22.07)	$ (26.65)	$ (19.84)	$ (20.65)	$ (8.76)
$100,00 - $150,000	None	5	$ (12.61)	$ (21.94)	$ (19.72)	$ (20.46)	$ (18.23)	$ (4.45)	$ (14.43)	$ (17.57)	$ (12.15)	$ (13.10)	$ (1.19)
$150,000 - $200,000	None	6	$ 18.60	$ 9.08	$ 10.66	$ 10.95	$ 13.00	$ 25.79	$ 15.88	$ 14.36	$ 18.24	$ 17.09	$ 28.96
$200,000+	None	7	$ 69.05	$ 59.19	$ 60.33	$ 61.86	$ 63.56	$ 74.95	$ 64.98	$ 65.44	$ 67.86	$ 66.16	$ 78.04
$0 - $25,000	CARE	1	$ (13.16)	$ (18.70)	$ (15.77)	$ (16.56)	$ (15.20)	$ (8.49)	$ (11.10)	$ (16.16)	$ (11.11)	$ (16.75)	$ (12.89)
$25,000 - $50,000	CARE	2	$ (13.45)	$ (18.65)	$ (15.77)	$ (16.31)	$ (15.03)	$ (8.46)	$ (11.11)	$ (15.79)	$ (11.05)	$ (16.75)	$ (12.99)
$50,000 - $75,000	CARE	3	$ (13.05)	$ (18.55)	$ (15.55)	$ (16.05)	$ (14.90)	$ (8.44)	$ (11.03)	$ (15.36)	$ (11.03)	$ (16.74)	$ (13.03)
$75,000 - $100,000	CARE	4	$ (12.90)	$ (18.53)	$ (15.11)	$ (15.95)	$ (14.71)	$ (8.42)	$ (10.96)	$ (14.97)	$ (11.03)	$ (16.74)	$ (13.06)
$100,00 - $150,000	CARE	5	$ 2.40	$ (3.39)	$ (0.62)	$ (0.56)	$ 0.54	$ 6.67	$ 4.00	$ 0.34	$ 4.11	$ (1.66)	$ 1.97
$150,000 - $200,000	CARE	6	$ 32.97	$ 26.88	$ 29.35	$ 29.78	$ 30.85	$ 36.81	$ 34.13	$ 31.07	$ 34.28	$ 28.49	$ 32.29
$200,000+	CARE	7	$ 82.58	$ 76.27	$ 78.35	$ 79.15	$ 80.11	$ 85.81	$ 83.26	$ 80.31	$ 83.34	$ 77.49	$ 78.62
$0 - $25,000	FERA	1	$ (25.57)	$ (37.40)	$ (31.43)	$ (32.60)	$ (30.16)	$ (16.99)	$ (22.13)	$ (31.74)	$ (22.13)	$ (33.71)	$ (25.86)
$25,000 - $50,000	FERA	2	$ (25.94)	$ (37.30)	$ (31.41)	$ (31.82)	$ (29.70)	$ (16.92)	$ (22.15)	$ (30.67)	$ (22.00)	$ (33.71)	$ (26.45)
$50,000 - $75,000	FERA	3	$ (19.05)	$ (30.94)	$ (24.67)	$ (24.89)	$ (23.17)	$ (10.69)	$ (15.80)	$ (23.36)	$ (15.75)	$ (27.53)	$ (20.49)
$75,000 - $100,000	FERA	4	$ (18.81)	$ (30.91)	$ (23.65)	$ (24.62)	$ (22.72)	$ (10.64)	$ (15.65)	$ (22.42)	$ (15.76)	$ (27.53)	$ (20.61)
$100,00 - $150,000	FERA	5	$ (12.28)	$ (24.60)	$ (18.84)	$ (17.64)	$ (16.11)	$ (4.42)	$ (9.70)	$ (15.71)	$ (9.42)	$ (21.35)	$ (14.59)
$150,000 - $200,000	FERA	6	$ 13.17	$ 0.36	$ 5.46	$ 7.57	$ 9.00	$ 20.32	$ 15.03	$ 10.22	$ 15.38	$ 3.41	$ 10.98
$200,000+	FERA	7	$ 54.40	$ 41.24	$ 45.70	$ 48.61	$ 49.83	$ 60.58	$ 55.55	$ 50.91	$ 55.76	$ 43.65	$ 47.97

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

SDG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ (35.29)	$ (36.90)	$ (34.29)	$ (37.09)	$ (53.90)
$25,000 - $50,000	None	2	$ (35.41)	$ (37.38)	$ (34.30)	$ (37.60)	$ (52.57)
$50,000 - $75,000	None	3	$ (24.38)	$ (26.06)	$ (22.88)	$ (24.75)	$ (40.80)
$75,000 - $100,000	None	4	$ (24.32)	$ (25.83)	$ (22.81)	$ (22.77)	$ (40.22)
$100,00 - $150,000	None	5	$ (12.50)	$ (13.68)	$ (11.19)	$ (12.67)	$ (27.34)
$150,000 - $200,000	None	6	$ 28.05	$ 27.25	$ 28.90	$ 37.35	$ 14.51
$200,000+	None	7	$ 103.24	$ 102.75	$ 103.61	$ 100.52	$ 91.02
$0 - $25,000	CARE	1	$ (17.71)	$ (19.52)	$ (15.46)	$ (35.27)	$ (44.61)
$25,000 - $50,000	CARE	2	$ (17.76)	$ (19.48)	$ (15.46)	$ (36.41)	$ (42.85)
$50,000 - $75,000	CARE	3	$ (17.63)	$ (19.43)	$ (15.44)	N/A	$ (43.13)
$75,000 - $100,000	CARE	4	$ (17.27)	$ (19.40)	$ (15.37)	N/A	$ (45.26)
$100,00 - $150,000	CARE	5	$ 5.70	$ 3.24	$ 7.29	N/A	N/A
$150,000 - $200,000	CARE	6	$ 47.32	N/A	$ 47.32	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ (28.22)	$ (30.80)	$ (24.46)	$ (52.67)	$ (69.82)
$25,000 - $50,000	FERA	2	$ (28.28)	$ (30.74)	$ (24.46)	$ (55.19)	$ (66.34)
$50,000 - $75,000	FERA	3	$ (18.76)	$ (21.34)	$ (15.11)	N/A	$ (57.61)
$75,000 - $100,000	FERA	4	$ (18.21)	$ (21.29)	$ (15.01)	N/A	$ (61.66)
$100,00 - $150,000	FERA	5	$ (8.41)	$ (12.04)	$ (5.73)	N/A	N/A
$150,000 - $200,000	FERA	6	$ 27.30	N/A	$ 27.30	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

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	$ (37.59)	$ (38.20)	$ (30.65)	$ (33.07)	$ (41.20)	$ (42.38)	$ (50.47)	$ (48.26)	$ (53.43)	$ (34.08)
$25,000 - $50,000	None	2	$ (39.13)	$ (38.20)	$ (30.61)	$ (33.20)	$ (41.72)	$ (43.72)	$ (49.78)	$ (47.82)	$ (54.59)	$ (34.00)
$50,000 - $75,000	None	3	$ (31.02)	$ (30.32)	$ (22.68)	$ (25.33)	$ (33.88)	$ (35.67)	$ (40.64)	$ (39.42)	$ (45.93)	$ (26.05)
$75,000 - $100,000	None	4	$ (30.60)	$ (30.32)	$ (22.64)	$ (25.23)	$ (33.70)	$ (35.10)	$ (39.68)	$ (38.60)	$ (45.22)	$ (25.80)
$100,00 - $150,000	None	5	$ (18.09)	$ (18.51)	$ (10.73)	$ (13.25)	$ (21.62)	$ (22.27)	$ (26.65)	$ (25.96)	$ (32.75)	$ (13.73)
$150,000 - $200,000	None	6	$ 33.94	$ 32.68	$ 40.58	$ 38.19	$ 30.05	$ 29.89	$ 25.42	$ 26.17	$ 19.21	$ 37.74
$200,000+	None	7	$ 153.52	$ 150.82	$ 158.96	$ 156.87	$ 148.90	$ 149.23	$ 145.38	$ 145.48	$ 138.67	$ 156.07
$0 - $25,000	CARE	1	$ (19.82)	N/A	$ (12.97)	$ (15.09)	$ (18.09)	$ (23.57)	$ (25.70)	$ (26.40)	$ (27.62)	$ (21.05)
$25,000 - $50,000	CARE	2	$ (19.57)	N/A	$ (12.95)	$ (15.08)	$ (18.08)	$ (23.44)	$ (25.37)	$ (26.08)	$ (27.17)	$ (20.93)
$50,000 - $75,000	CARE	3	$ (19.42)	N/A	$ (12.94)	$ (15.06)	$ (18.06)	$ (23.23)	$ (25.14)	$ (25.90)	$ (26.94)	$ (20.94)
$75,000 - $100,000	CARE	4	$ (19.40)	N/A	$ (12.93)	$ (15.05)	$ (18.05)	$ (23.11)	$ (24.88)	$ (25.86)	$ (26.71)	$ (20.95)
$100,00 - $150,000	CARE	5	$ 0.55	N/A	$ 6.80	$ 4.68	$ 1.68	$ (3.18)	$ (5.13)	$ (5.79)	$ (6.85)	$ (1.05)
$150,000 - $200,000	CARE	6	$ 52.21	N/A	$ 58.08	$ 55.98	$ 52.99	$ 48.47	$ 46.41	$ 45.83	$ 44.77	$ 50.44
$200,000+	CARE	7	$ 171.09	N/A	$ 176.37	$ 174.31	$ 171.33	$ 167.04	$ 165.14	$ 164.39	$ 163.73	$ 168.98
$0 - $25,000	FERA	1	$ (30.42)	N/A	$ (20.47)	$ (23.60)	$ (28.25)	$ (36.07)	$ (39.09)	$ (40.36)	$ (42.62)	$ (33.27)
$25,000 - $50,000	FERA	2	$ (30.17)	N/A	$ (20.44)	$ (23.57)	$ (28.23)	$ (35.78)	$ (38.32)	$ (39.71)	$ (41.61)	$ (33.06)
$50,000 - $75,000	FERA	3	$ (23.54)	N/A	$ (13.98)	$ (17.08)	$ (21.74)	$ (28.93)	$ (31.34)	$ (32.90)	$ (34.65)	$ (26.63)
$75,000 - $100,000	FERA	4	$ (23.52)	N/A	$ (13.96)	$ (17.06)	$ (21.72)	$ (28.69)	$ (30.79)	$ (32.82)	$ (34.18)	$ (26.64)
$100,00 - $150,000	FERA	5	$ (13.51)	N/A	$ (4.24)	$ (7.34)	$ (12.02)	$ (18.58)	$ (21.04)	$ (22.48)	$ (24.19)	$ (16.63)
$150,000 - $200,000	FERA	6	$ 29.05	N/A	$ 37.76	$ 34.71	$ 30.03	$ 24.09	$ 21.51	$ 20.15	$ 18.50	$ 25.73
$200,000+	FERA	7	$ 126.77	N/A	$ 134.64	$ 131.66	$ 126.97	$ 121.47	$ 119.21	$ 117.48	$ 116.63	$ 123.01

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

Docket No: R.22-07-005

Sierra Club
Direct Testimony of John D. Wilson

Attachment 3
IGFC Proposal Electrification Rates

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.

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Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
Phone: 415-391-5100

Model Release Date: April 13, 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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 538,263,216	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 218,481,550	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 865,996,766	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal Customer Access	$ 454,792,861	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Distribution Capacity Cost - Primary	$ 439,382,040	FALSE	FALSE	9.96%	0.00%	90.04%
Distribution	Marginal Distribution Capacity Cost - New Business	$ 476,043,853	FALSE	FALSE	9.96%	0.00%	90.04%
Distribution	Marginal Distribution Capacity Cost - Secondary	$ 29,945,145	FALSE	FALSE	9.96%	0.00%	90.04%
Distribution	Non-Marginal Distribution	$ 1,833,578,625	FALSE	FALSE	27.90%	0.00%	72.10%
Transmission	Transmission	$ 1,447,654,612	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 58,854,252	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 63,120,120	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Hardening Charge	$ 68,921,008	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ 215,256,658	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Credit	$ (215,256,658)	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 230,732,710	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 37,938,712	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 96,956,158	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Competition Transition Charge	$ 8,518,646	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Energy Cost Recovery Account	$ (19,846,861)	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 606,708,166	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 584,831,167	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 1,378,829,544	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 427,567,610	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal - Grid	$ 888,543,196	FALSE	FALSE	9.70%	0.00%	90.30%
Distribution	Marginal - Peak	$ 503,372,326	FALSE	FALSE	9.70%	0.00%	90.30%
Distribution	Non-Marginal Distribution	$ 1,845,967,040	FALSE	FALSE	45.68%	0.00%	54.32%
Transmission	Base Transmission	$ 599,320,433	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (1,839,212)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 23,619,309	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 103,390,404	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Hardening Charge	$ 17,556,861	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ -	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Credit	$ (40,575,857)	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 313,291,510	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 2,364,701	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 148,976,188	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 100,915,850	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 57,547,258	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 163,094,812	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 183,005,936	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Demand - Non-Coincident Peak	$ 198,205,378	FALSE	FALSE	13.42%	0.00%	86.59%
Distribution	Marginal Demand - Coincident Peak	$ 26,974,391	FALSE	FALSE	13.42%	0.00%	86.59%
Distribution	Non-Marginal Distribution	$ 490,650,411	FALSE	FALSE	47.91%	0.00%	52.09%
Transmission	Base Transmission	$ 537,401,722	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (111,012,377)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 8,781,000	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 29,143,070	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 61,433,000	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 526,530	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Local Generation Charge/New System Generation Cha	$ 81,949,029	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Competition Transition Charge	$ 11,052,908	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Total Rate Adjustment Component - Baseline adjustme	$ 1,000,000	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Reliability Services	$ 177,809	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.0000	1.0000	1.0000
	[100,150]	1.0000	1.0000	1.0000
	[150,200]	1.0000	1.0000	1.0000
	200+	1.0000	1.0000	1.0000
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	2.8514	1.8872	3.0701
	[25,50]	2.8514	1.8872	3.0701
	[50,75]	2.8514	1.8872	3.0701
	[75,100]	2.8514	1.8872	3.0701
	[100,150]	19.4671	22.5101	27.3417
	[150,200]	49.6173	73.7673	67.0494
	200+	98.6114	192.0530	140.7921
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	4.2022	5.6600	5.2105
	[75,100]	4.2022	5.6600	5.2105
	[100,150]	6.8272	11.9279	8.9058
	[150,200]	17.4011	39.0885	21.8395
	200+	34.5837	101.7668	45.8591
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ 8.5000	$ 10.2000	$ 10.4000
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	$ 3.0000	$ 3.0000	$ 3.0000
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

Based on CARE program size from E-TOU-C

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 1,317,954,626	$ -	$ 3,901,150,119

Delivery - CARE-exempt			
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric	
$ 457,980,407	$ -	$ -	$ 1,775,935,033

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 2,173,131,106
NBCs	$ -
Non-Dist	$ 1,728,019,013

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

SDG&E

Based on CARE program size from TOU-DR1

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 522,299,128	$ -	$ 1,139,071,558

Delivery - CARE-exempt			
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric	
$ 104,592,877	$ -	$ -	$ 626,892,006
			$ 1,139,071,558

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 450,549,425
NBCs	$ -
Non-Dist	$ 688,522,133

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

SCE

Based on CARE program size from TOU-D-4-9

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 1,721,394,671	$ -	$ 3,024,235,323

Delivery - CARE-exempt			
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric	
$ 295,260,747	$ -	$ -	$ 2,016,655,418
			$ 3,024,235,323

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 2,259,711,711
NBCs	$ -
Non-Dist	$ 764,523,612

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

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]	$ 2.8264	$ 2.8514	$ 2.8223	$ 2.8514	$ 2.8199	$ 2.8514
[25,50]	$ 2.8264	$ 2.8514	$ 2.8223	$ 2.8514	$ 2.8199	$ 2.8514
[50,75]	$ 11.8771	$ 2.8514	$ 11.8596	$ 2.8514	$ 11.8496	$ 2.8514
[75,100]	$ 11.8771	$ 2.8514	$ 11.8596	$ 2.8514	$ 11.8496	$ 2.8514
[100,150]	$ 19.2967	$ 19.4671	$ 19.2683	$ 19.4671	$ 19.2519	$ 19.4671
[150,200]	$ 49.1832	$ 49.6173	$ 49.1106	$ 49.6173	$ 49.0690	$ 49.6173
200+	$ 97.7486	$ 98.6114	$ 97.6043	$ 98.6114	$ 97.5217	$ 98.6114
Tier Credits/Charges ($/kWh)						
Baseline Credit	$ 0.0632	$ 0.0411	$ 0.0632	$ 0.0411	$ -	$ -
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	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
Demand Charge ($/kW-mo)	$ -	$ -	$ -	$ -	$ -	$ -
Energy Charges ($/kWh)						
Summer - Peak	$ 0.3179	$ 0.2066	$ 0.4014	$ 0.2609	$ 0.4462	$ 0.2900
Summer - Part-Peak	$ 0.3179	$ 0.2066	$ -	$ -	$ 0.3539	$ 0.2301
Summer - Off-Peak	$ 0.3179	$ 0.2066	$ 0.3403	$ 0.2212	$ 0.1965	$ 0.1277
Winter - Peak	$ 0.3179	$ 0.2066	$ 0.3156	$ 0.2051	$ 0.3385	$ 0.2201
Winter - Part-Peak	$ 0.3179	$ 0.2066	$ -	$ -	$ 0.3230	$ 0.2100
Winter - Off-Peak	$ 0.3179	$ 0.2066	$ 0.2988	$ 0.1942	$ 0.1946	$ 0.1265
Total CARE Program Funding - Modeled						
Customer		$ (140,700,789)		$ (140,700,789)		$ (140,700,789)
Demand		$ -		$ -		$ -
Volumetric - Delivery		$ (420,861,730)		$ (420,861,730)		$ (420,861,730)
Volumetric - Generation		$ (431,894,113)		$ (423,536,307)		$ (418,748,960)
Total CARE Credits		$ (993,456,632)		$ (985,098,827)		$ (980,311,479)
Residential CARE Funding		$ 269,351,038		$ 267,085,028		$ 265,787,057
Non-Res CARE Funding		$ 724,105,593		$ 718,013,799		$ 714,524,422
Total IOU forecast CARE program size						
2023 Forecast (Existing Rates)		$ (891,914,356)		$ (891,914,356)		$ (891,914,356)
Modeled Credits as % of Forecast		11%		10%		10%

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
$ 2.8130	$ 2.8514	$ 1.8736	$ 1.8872	$ 1.8758	$ 1.8872	$ 1.8778	$ 1.8872
$ 2.8130	$ 2.8514	$ 1.8736	$ 1.8872	$ 1.8758	$ 1.8872	$ 1.8778	$ 1.8872
$ 11.8208	$ 2.8514	$ 10.6044	$ 1.8872	$ 10.6171	$ 1.8872	$ 10.6284	$ 1.8872
$ 11.8208	$ 2.8514	$ 10.6044	$ 1.8872	$ 10.6171	$ 1.8872	$ 10.6284	$ 1.8872
$ 19.2052	$ 19.4671	$ 22.3475	$ 22.5101	$ 22.3742	$ 22.5101	$ 22.3982	$ 22.5101
$ 48.9499	$ 49.6173	$ 73.2345	$ 73.7673	$ 73.3220	$ 73.7673	$ 73.4004	$ 73.7673
$ 97.2849	$ 98.6114	$ 190.6659	$ 192.0530	$ 190.8937	$ 192.0530	$ 191.0977	$ 192.0530
$ -	$ -	$ 0.0544	$ 0.0367	$ 0.0596	$ 0.0402	$ -	$ -
$ -	$ -	$ 0.0612	$ 0.0413	$ -	$ -	$ -	$ -
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
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.4787	$ 0.3112	$ 0.3017	$ 0.2037	$ 0.4493	$ 0.3033	$ 0.5551	$ 0.3747
$ 0.3217	$ 0.2091	$ 0.2157	$ 0.1456	$ 0.3410	$ 0.2302	$ 0.2974	$ 0.2007
$ 0.2659	$ 0.1728	$ 0.2157	$ 0.1456	$ 0.2517	$ 0.1699	$ 0.1942	$ 0.1311
$ 0.2526	$ 0.1642	$ 0.3017	$ 0.2037	$ 0.3814	$ 0.2575	$ 0.4962	$ 0.3350
$ 0.2307	$ 0.1499	$ 0.2157	$ 0.1456	$ 0.2764	$ 0.1866	$ 0.1751	$ 0.1182
$ 0.2168	$ 0.1409	$ 0.2157	$ 0.1456	$ 0.2474	$ 0.1670	$ 0.1751	$ 0.1182
	$ (140,700,789)		$ (143,433,614)		$ (143,433,614)		$ (143,433,614)
	$ -		$ -		$ -		$ -
	$ (420,861,730)		$ (253,134,204)		$ (253,134,204)		$ (253,134,204)
	$ (405,034,979)		$ (339,559,859)		$ (347,681,851)		$ (354,957,511)
	$ (966,597,498)		$ (736,127,677)		$ (744,249,668)		$ (751,525,329)
	$ 262,068,853		$ 189,182,701		$ 191,270,030		$ 193,139,854
	$ 704,528,645		$ 546,944,976		$ 552,979,639		$ 558,385,475
	$ (891,914,356)		$ (660,034,291)		$ (660,034,291)		$ (660,034,291)
	8%		12%		13%		14%

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
$ 3.0588	$ 3.0701	$ 3.0527	$ 3.0701	$ 3.0537	$ 3.0701	$ 3.0485	$ 3.0701
$ 3.0588	$ 3.0701	$ 3.0527	$ 3.0701	$ 3.0537	$ 3.0701	$ 3.0485	$ 3.0701
$ 15.9378	$ 3.0701	$ 15.9061	$ 3.0701	$ 15.9114	$ 3.0701	$ 15.8844	$ 3.0701
$ 15.9378	$ 3.0701	$ 15.9061	$ 3.0701	$ 15.9114	$ 3.0701	$ 15.8844	$ 3.0701
$ 27.2411	$ 27.3417	$ 27.1868	$ 27.3417	$ 27.1960	$ 27.3417	$ 27.1498	$ 27.3417
$ 66.8026	$ 67.0494	$ 66.6695	$ 67.0494	$ 66.6920	$ 67.0494	$ 66.5786	$ 67.0494
$ 140.2739	$ 140.7921	$ 139.9944	$ 140.7921	$ 140.0417	$ 140.7921	$ 139.8035	$ 140.7921
$ 0.0868	$ 0.0573	$ 0.0868	$ 0.0573	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.4887	$ 0.3226	$ 0.7754	$ 0.5118	$ 0.7557	$ 0.4987	$ 0.7079	$ 0.4672
$ 0.4887	$ 0.3226	$ 0.4620	$ 0.3049	$ 0.4207	$ 0.2776	$ 0.3386	$ 0.2235
$ 0.5152	$ 0.3400	$ 0.2973	$ 0.1962	$ 0.2183	$ 0.1441	$ 0.2900	$ 0.1914
$ 0.3081	$ 0.2034	$ 0.4850	$ 0.3201	$ 0.4509	$ 0.2976	$ 0.4668	$ 0.3081
$ 0.3081	$ 0.2034	$ 0.4005	$ 0.2643	$ 0.3871	$ 0.2555	$ 0.3254	$ 0.2148
$ 0.4224	$ 0.2788	$ 0.3759	$ 0.2481	$ 0.2100	$ 0.1386	$ 0.2812	$ 0.1856
	$ (42,082,518)		$ (42,082,518)		$ (42,082,518)		$ (42,082,518)
	$ -		$ -		$ -		$ -
	$ (93,897,507)		$ (93,897,507)		$ (93,897,507)		$ (93,897,507)
	$ (100,157,376)		$ (96,179,165)		$ (96,851,978)		$ (93,461,884)
	$ (236,137,402)		$ (232,159,191)		$ (232,832,003)		$ (229,441,910)
	$ 67,811,224		$ 66,668,807		$ 66,862,018		$ 65,888,490
	$ 168,326,177		$ 165,490,383		$ 165,969,985		$ 163,553,420
	$ (178,549,476)		$ (178,549,476)		$ (178,549,476)		$ (178,549,476)
	32%		30%		30%		29%

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	$ (27.79)	$ (35.92)	$ (33.51)	$ (36.04)	$ (34.39)	$ (24.14)	$ (29.83)	$ (35.06)	$ (29.09)	$ (29.79)	$ (22.24)
$25,000 - $50,000	None	2	$ (29.90)	$ (35.84)	$ (33.50)	$ (36.07)	$ (34.33)	$ (24.12)	$ (29.86)	$ (35.15)	$ (29.09)	$ (29.79)	$ (22.23)
$50,000 - $75,000	None	3	$ (21.23)	$ (26.76)	$ (24.46)	$ (26.80)	$ (25.11)	$ (15.09)	$ (20.85)	$ (25.78)	$ (20.05)	$ (20.80)	$ (13.24)
$75,000 - $100,000	None	4	$ (20.92)	$ (26.62)	$ (24.47)	$ (26.47)	$ (24.81)	$ (15.08)	$ (20.82)	$ (25.25)	$ (20.02)	$ (20.82)	$ (13.23)
$100,00 - $150,000	None	5	$ (13.11)	$ (19.09)	$ (16.99)	$ (18.68)	$ (17.09)	$ (7.68)	$ (13.41)	$ (17.24)	$ (12.59)	$ (13.44)	$ (5.84)
$150,000 - $200,000	None	6	$ 17.23	$ 10.96	$ 12.82	$ 11.51	$ 13.08	$ 22.08	$ 16.37	$ 13.21	$ 17.22	$ 16.26	$ 23.87
$200,000+	None	7	$ 66.38	$ 59.69	$ 61.38	$ 60.54	$ 62.02	$ 70.44	$ 64.71	$ 62.37	$ 65.74	$ 64.51	$ 72.21
$0 - $25,000	CARE	1	$ (11.99)	$ (13.97)	$ (12.69)	$ (13.44)	$ (12.88)	$ (10.07)	$ (10.99)	$ (13.36)	$ (11.09)	$ (13.22)	$ (11.86)
$25,000 - $50,000	CARE	2	$ (12.15)	$ (13.96)	$ (12.68)	$ (13.38)	$ (12.84)	$ (10.07)	$ (10.99)	$ (13.27)	$ (11.07)	$ (13.22)	$ (11.88)
$50,000 - $75,000	CARE	3	$ (12.01)	$ (13.94)	$ (12.64)	$ (13.33)	$ (12.81)	$ (10.06)	$ (10.96)	$ (13.17)	$ (11.07)	$ (13.22)	$ (11.89)
$75,000 - $100,000	CARE	4	$ (11.96)	$ (13.94)	$ (12.55)	$ (13.30)	$ (12.77)	$ (10.06)	$ (10.94)	$ (13.08)	$ (11.07)	$ (13.22)	$ (11.90)
$100,00 - $150,000	CARE	5	$ 4.73	$ 2.69	$ 3.95	$ 3.38	$ 3.89	$ 6.56	$ 5.64	$ 3.59	$ 5.56	$ 3.39	$ 4.70
$150,000 - $200,000	CARE	6	$ 35.05	$ 32.85	$ 34.06	$ 33.57	$ 34.07	$ 36.71	$ 35.78	$ 33.87	$ 35.72	$ 33.54	$ 34.90
$200,000+	CARE	7	$ 84.31	$ 81.91	$ 83.05	$ 82.65	$ 83.13	$ 85.71	$ 84.82	$ 82.92	$ 84.73	$ 82.53	$ 83.19
$0 - $25,000	FERA	1	$ (25.49)	$ (32.27)	$ (28.33)	$ (30.16)	$ (28.53)	$ (20.08)	$ (23.00)	$ (29.82)	$ (23.19)	$ (30.11)	$ (26.07)
$25,000 - $50,000	FERA	2	$ (25.85)	$ (32.25)	$ (28.33)	$ (29.86)	$ (28.35)	$ (20.05)	$ (23.01)	$ (29.39)	$ (23.14)	$ (30.13)	$ (26.43)
$50,000 - $75,000	FERA	3	$ (18.09)	$ (24.82)	$ (20.76)	$ (22.18)	$ (20.83)	$ (12.65)	$ (15.53)	$ (21.54)	$ (15.73)	$ (22.79)	$ (19.18)
$75,000 - $100,000	FERA	4	$ (17.98)	$ (24.81)	$ (20.41)	$ (22.08)	$ (20.65)	$ (12.62)	$ (15.45)	$ (21.15)	$ (15.73)	$ (22.78)	$ (19.25)
$100,00 - $150,000	FERA	5	$ (11.77)	$ (18.73)	$ (14.82)	$ (15.72)	$ (14.43)	$ (6.56)	$ (9.53)	$ (14.89)	$ (9.62)	$ (16.77)	$ (13.30)
$150,000 - $200,000	FERA	6	$ 13.06	$ 5.71	$ 9.41	$ 8.85	$ 10.09	$ 17.83	$ 14.84	$ 9.98	$ 14.79	$ 7.62	$ 11.58
$200,000+	FERA	7	$ 53.34	$ 45.50	$ 49.05	$ 48.80	$ 49.96	$ 57.47	$ 54.64	$ 49.80	$ 54.48	$ 47.23	$ 49.25

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-ELEC
Select single counterfactual rate (if applicable)	E-ELEC

SDG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ (37.65)	$ (39.49)	$ (36.82)	$ (40.70)	$ (49.76)
$25,000 - $50,000	None	2	$ (37.80)	$ (39.72)	$ (36.82)	$ (40.80)	$ (49.05)
$50,000 - $75,000	None	3	$ (25.31)	$ (26.90)	$ (23.96)	$ (27.68)	$ (36.00)
$75,000 - $100,000	None	4	$ (25.32)	$ (26.79)	$ (23.94)	$ (27.30)	$ (35.68)
$100,00 - $150,000	None	5	$ (13.86)	$ (15.16)	$ (12.59)	$ (16.28)	$ (23.61)
$150,000 - $200,000	None	6	$ 25.95	$ 24.81	$ 26.94	$ 25.11	$ 16.93
$200,000+	None	7	$ 99.82	$ 98.80	$ 100.44	$ 96.28	$ 91.56
$0 - $25,000	CARE	1	$ (18.33)	$ (19.54)	$ (16.95)	$ (28.80)	$ (30.60)
$25,000 - $50,000	CARE	2	$ (18.39)	$ (19.52)	$ (16.95)	$ (29.32)	$ (30.50)
$50,000 - $75,000	CARE	3	$ (18.33)	$ (19.49)	$ (16.94)	N/A	$ (30.52)
$75,000 - $100,000	CARE	4	$ (18.10)	$ (19.47)	$ (16.90)	N/A	$ (30.63)
$100,00 - $150,000	CARE	5	$ 6.34	$ 4.77	$ 7.36	N/A	N/A
$150,000 - $200,000	CARE	6	$ 47.27	N/A	$ 47.27	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ (30.13)	$ (32.11)	$ (27.55)	$ (47.39)	$ (51.12)
$25,000 - $50,000	FERA	2	$ (30.25)	$ (32.09)	$ (27.55)	$ (48.42)	$ (50.85)
$50,000 - $75,000	FERA	3	$ (19.64)	$ (21.53)	$ (17.02)	N/A	$ (40.37)
$75,000 - $100,000	FERA	4	$ (19.25)	$ (21.50)	$ (16.97)	N/A	$ (40.69)
$100,00 - $150,000	FERA	5	$ (9.69)	$ (12.30)	$ (7.76)	N/A	N/A
$150,000 - $200,000	FERA	6	$ 24.75	N/A	$ 24.75	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-ELEC
Select single counterfactual rate (if applicable)	TOU-ELEC

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	$ (39.89)	$ (42.03)	$ (34.50)	$ (36.19)	$ (42.22)	$ (43.90)	$ (49.00)	$ (46.96)	$ (53.55)	$ (37.79)
$25,000 - $50,000	None	2	$ (40.84)	$ (42.03)	$ (34.49)	$ (36.23)	$ (42.41)	$ (44.51)	$ (48.69)	$ (46.80)	$ (53.82)	$ (37.80)
$50,000 - $75,000	None	3	$ (31.94)	$ (33.28)	$ (25.73)	$ (27.49)	$ (33.68)	$ (35.68)	$ (39.40)	$ (37.85)	$ (44.89)	$ (29.05)
$75,000 - $100,000	None	4	$ (31.71)	$ (33.28)	$ (25.71)	$ (27.45)	$ (33.61)	$ (35.42)	$ (38.98)	$ (37.56)	$ (44.72)	$ (29.05)
$100,00 - $150,000	None	5	$ (19.55)	$ (21.51)	$ (13.92)	$ (15.63)	$ (21.74)	$ (23.19)	$ (26.68)	$ (25.48)	$ (32.79)	$ (17.29)
$150,000 - $200,000	None	6	$ 31.93	$ 29.49	$ 37.12	$ 35.45	$ 29.44	$ 28.26	$ 24.70	$ 25.86	$ 18.39	$ 33.71
$200,000+	None	7	$ 150.52	$ 147.19	$ 154.89	$ 153.31	$ 147.40	$ 146.50	$ 143.20	$ 143.99	$ 136.40	$ 151.40
$0 - $25,000	CARE	1	$ (20.78)	N/A	$ (16.53)	$ (17.68)	$ (19.86)	$ (23.12)	$ (24.60)	$ (24.41)	$ (26.89)	$ (21.43)
$25,000 - $50,000	CARE	2	$ (20.64)	N/A	$ (16.53)	$ (17.68)	$ (19.87)	$ (23.07)	$ (24.48)	$ (24.32)	$ (26.72)	$ (21.40)
$50,000 - $75,000	CARE	3	$ (20.58)	N/A	$ (16.53)	$ (17.68)	$ (19.87)	$ (23.00)	$ (24.39)	$ (24.26)	$ (26.64)	$ (21.41)
$75,000 - $100,000	CARE	4	$ (20.58)	N/A	$ (16.53)	$ (17.68)	$ (19.87)	$ (22.96)	$ (24.29)	$ (24.25)	$ (26.56)	$ (21.41)
$100,00 - $150,000	CARE	5	$ 0.15	N/A	$ 4.10	$ 2.94	$ 0.75	$ (2.26)	$ (3.66)	$ (3.53)	$ (5.88)	$ (0.74)
$150,000 - $200,000	CARE	6	$ 51.61	N/A	$ 55.36	$ 54.20	$ 51.99	$ 49.13	$ 47.70	$ 47.84	$ 45.51	$ 50.56
$200,000+	CARE	7	$ 170.21	N/A	$ 173.65	$ 172.49	$ 170.27	$ 167.52	$ 166.15	$ 166.21	$ 164.04	$ 168.91
$0 - $25,000	FERA	1	$ (32.51)	N/A	$ (25.55)	$ (27.52)	$ (31.25)	$ (36.57)	$ (38.79)	$ (38.81)	$ (42.75)	$ (33.97)
$25,000 - $50,000	FERA	2	$ (32.40)	N/A	$ (25.55)	$ (27.52)	$ (31.26)	$ (36.46)	$ (38.45)	$ (38.57)	$ (42.30)	$ (33.91)
$50,000 - $75,000	FERA	3	$ (25.18)	N/A	$ (18.37)	$ (20.34)	$ (24.10)	$ (29.12)	$ (31.05)	$ (31.26)	$ (34.91)	$ (26.75)
$75,000 - $100,000	FERA	4	$ (25.19)	N/A	$ (18.37)	$ (20.34)	$ (24.11)	$ (29.02)	$ (30.80)	$ (31.24)	$ (34.70)	$ (26.75)
$100,00 - $150,000	FERA	5	$ (15.40)	N/A	$ (8.72)	$ (10.69)	$ (14.47)	$ (19.20)	$ (21.12)	$ (21.34)	$ (24.91)	$ (17.02)
$150,000 - $200,000	FERA	6	$ 26.72	N/A	$ 33.11	$ 31.14	$ 27.32	$ 22.91	$ 20.96	$ 20.72	$ 17.23	$ 24.90
$200,000+	FERA	7	$ 123.74	N/A	$ 129.62	$ 127.65	$ 123.79	$ 119.63	$ 117.83	$ 117.40	$ 114.30	$ 121.52

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-PRIME
Select single counterfactual rate (if applicable)	TOU-D-PRIME

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	$ (26.13)	$ (40.91)	$ (36.29)	$ (42.37)	$ (39.08)	$ (19.26)	$ (29.00)	$ (41.26)	$ (28.53)	$ (29.01)	$ (15.42)
$25,000 - $50,000	None	2	$ (30.21)	$ (40.75)	$ (36.28)	$ (42.41)	$ (38.98)	$ (19.23)	$ (29.07)	$ (41.37)	$ (28.54)	$ (29.01)	$ (15.40)
$50,000 - $75,000	None	3	$ (21.94)	$ (31.57)	$ (27.18)	$ (33.04)	$ (29.60)	$ (10.16)	$ (20.04)	$ (31.88)	$ (19.44)	$ (20.01)	$ (6.42)
$75,000 - $100,000	None	4	$ (21.38)	$ (31.30)	$ (27.19)	$ (32.61)	$ (29.10)	$ (10.14)	$ (19.97)	$ (31.24)	$ (19.38)	$ (20.05)	$ (6.40)
$100,00 - $150,000	None	5	$ (13.18)	$ (23.59)	$ (19.61)	$ (24.69)	$ (21.14)	$ (2.70)	$ (12.50)	$ (23.06)	$ (11.88)	$ (12.67)	$ 1.04
$150,000 - $200,000	None	6	$ 17.77	$ 6.84	$ 10.34	$ 5.70	$ 9.39	$ 27.14	$ 17.41	$ 7.62	$ 18.06	$ 17.08	$ 30.76
$200,000+	None	7	$ 67.86	$ 56.05	$ 59.24	$ 55.04	$ 58.86	$ 75.64	$ 65.88	$ 57.08	$ 66.89	$ 65.38	$ 79.22
$0 - $25,000	CARE	1	$ (13.79)	$ (19.91)	$ (15.82)	$ (18.63)	$ (16.84)	$ (7.39)	$ (10.17)	$ (18.32)	$ (10.90)	$ (17.07)	$ (11.99)
$25,000 - $50,000	CARE	2	$ (14.38)	$ (19.88)	$ (15.81)	$ (18.52)	$ (16.74)	$ (7.38)	$ (10.18)	$ (18.16)	$ (10.86)	$ (17.08)	$ (12.22)
$50,000 - $75,000	CARE	3	$ (13.97)	$ (19.84)	$ (15.63)	$ (18.42)	$ (16.67)	$ (7.37)	$ (10.12)	$ (17.98)	$ (10.85)	$ (17.11)	$ (12.33)
$75,000 - $100,000	CARE	4	$ (13.84)	$ (19.83)	$ (15.28)	$ (18.37)	$ (16.56)	$ (7.36)	$ (10.07)	$ (17.81)	$ (10.85)	$ (17.11)	$ (12.40)
$100,00 - $150,000	CARE	5	$ 2.98	$ (3.18)	$ 0.87	$ (1.63)	$ 0.15	$ 9.27	$ 6.46	$ (1.09)	$ 5.81	$ (0.51)	$ 4.12
$150,000 - $200,000	CARE	6	$ 33.70	$ 27.02	$ 30.87	$ 28.60	$ 30.39	$ 39.41	$ 36.60	$ 29.30	$ 35.97	$ 29.63	$ 34.66
$200,000+	CARE	7	$ 83.57	$ 76.19	$ 79.86	$ 77.75	$ 79.53	$ 88.41	$ 85.69	$ 78.40	$ 85.00	$ 78.61	$ 77.24
$0 - $25,000	FERA	1	$ (27.47)	$ (39.93)	$ (32.39)	$ (36.75)	$ (33.52)	$ (16.77)	$ (22.07)	$ (36.11)	$ (23.02)	$ (35.22)	$ (26.77)
$25,000 - $50,000	FERA	2	$ (28.27)	$ (39.89)	$ (32.37)	$ (36.32)	$ (33.23)	$ (16.73)	$ (22.09)	$ (35.50)	$ (22.94)	$ (35.25)	$ (28.43)
$50,000 - $75,000	FERA	3	$ (20.19)	$ (32.40)	$ (24.53)	$ (28.51)	$ (25.60)	$ (9.30)	$ (14.55)	$ (27.46)	$ (15.49)	$ (28.00)	$ (21.67)
$75,000 - $100,000	FERA	4	$ (20.02)	$ (32.38)	$ (23.72)	$ (28.36)	$ (25.30)	$ (9.27)	$ (14.43)	$ (26.93)	$ (15.49)	$ (27.97)	$ (22.02)
$100,00 - $150,000	FERA	5	$ (13.69)	$ (26.26)	$ (18.75)	$ (21.86)	$ (18.96)	$ (3.18)	$ (8.56)	$ (20.56)	$ (9.32)	$ (22.00)	$ (16.42)
$150,000 - $200,000	FERA	6	$ 11.64	$ (1.71)	$ 5.33	$ 2.83	$ 5.71	$ 21.26	$ 15.87	$ 4.55	$ 15.15	$ 2.44	$ 10.28
$200,000+	FERA	7	$ 52.63	$ 38.34	$ 45.07	$ 43.00	$ 45.83	$ 61.00	$ 55.83	$ 44.53	$ 54.98	$ 42.10	$ 40.89

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	$ (38.16)	$ (39.94)	$ (37.31)	$ (41.37)	$ (50.63)
$25,000 - $50,000	None	2	$ (38.31)	$ (40.25)	$ (37.31)	$ (41.55)	$ (49.69)
$50,000 - $75,000	None	3	$ (25.80)	$ (27.42)	$ (24.43)	$ (28.18)	$ (36.55)
$75,000 - $100,000	None	4	$ (25.78)	$ (27.28)	$ (24.38)	$ (27.50)	$ (36.14)
$100,00 - $150,000	None	5	$ (14.21)	$ (15.49)	$ (12.95)	$ (16.65)	$ (23.80)
$150,000 - $200,000	None	6	$ 25.80	$ 24.73	$ 26.73	$ 26.35	$ 17.16
$200,000+	None	7	$ 100.02	$ 99.10	$ 100.57	$ 96.02	$ 92.34
$0 - $25,000	CARE	1	$ (18.75)	$ (20.07)	$ (17.28)	$ (29.85)	$ (31.19)
$25,000 - $50,000	CARE	2	$ (18.81)	$ (20.03)	$ (17.28)	$ (30.60)	$ (31.31)
$50,000 - $75,000	CARE	3	$ (18.74)	$ (19.99)	$ (17.26)	N/A	$ (31.29)
$75,000 - $100,000	CARE	4	$ (18.48)	$ (19.96)	$ (17.20)	N/A	$ (31.14)
$100,00 - $150,000	CARE	5	$ 5.95	$ 4.27	$ 7.04	N/A	N/A
$150,000 - $200,000	CARE	6	$ 47.06	N/A	$ 47.06	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ (30.65)	$ (32.74)	$ (27.97)	$ (48.45)	$ (51.72)
$25,000 - $50,000	FERA	2	$ (30.77)	$ (32.69)	$ (27.97)	$ (50.04)	$ (51.86)
$50,000 - $75,000	FERA	3	$ (20.12)	$ (22.07)	$ (17.40)	N/A	$ (41.30)
$75,000 - $100,000	FERA	4	$ (19.68)	$ (22.03)	$ (17.31)	N/A	$ (41.13)
$100,00 - $150,000	FERA	5	$ (10.11)	$ (12.85)	$ (8.10)	N/A	N/A
$150,000 - $200,000	FERA	6	$ 24.66	N/A	$ 24.66	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)	EV-TOU-5
Select single counterfactual rate (if applicable)	EV-TOU-5

Docket No: R.22-07-005

Sierra Club
Direct Testimony of John D. Wilson

Attachment 4
IGFC Proposal Average 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.

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Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
Phone: 415-391-5100

Model Release Date: April 13, 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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 538,263,216	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 218,481,550	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 865,996,766	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal Customer Access	$ 454,792,861	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Distribution Capacity Cost - Primary	$ 439,382,040	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Distribution Capacity Cost - New Business	$ 476,043,853	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Distribution Capacity Cost - Secondary	$ 29,945,145	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,833,578,625	FALSE	FALSE	19.93%	0.00%	80.07%
Transmission	Transmission	$ 1,447,654,612	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 58,854,252	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 63,120,120	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Hardening Charge	$ 68,921,008	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ 215,256,658	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Credit	$ (215,256,658)	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 230,732,710	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 37,938,712	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 96,956,158	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Competition Transition Charge	$ 8,518,646	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Energy Cost Recovery Account	$ (19,846,861)	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 606,708,166	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 584,831,167	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 1,378,829,544	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 427,567,610	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal - Grid	$ 888,543,196	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal - Peak	$ 503,372,326	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,845,967,040	FALSE	FALSE	45.79%	0.00%	54.21%
Transmission	Base Transmission	$ 599,320,433	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (1,839,212)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 23,619,309	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 103,390,404	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Hardening Charge	$ 17,556,861	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ -	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Credit	$ (40,575,857)	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 313,291,510	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 2,364,701	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 148,976,188	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 100,915,850	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 57,547,258	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 163,094,812	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 183,005,936	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Demand - Non-Coincident Peak	$ 198,205,378	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Demand - Coincident Peak	$ 26,974,391	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 490,650,411	FALSE	FALSE	39.84%	0.00%	60.16%
Transmission	Base Transmission	$ 537,401,722	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (111,012,377)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 8,781,000	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 29,143,070	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 61,433,000	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 526,530	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Local Generation Charge/New System Generation Cha	$ 81,949,029	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Competition Transition Charge	$ 11,052,908	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Total Rate Adjustment Component - Baseline adjustme	$ 1,000,000	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Reliability Services	$ 177,809	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	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		Uniform Weights	Uniform Weights	Uniform Weights
Customer Charge Weighting is used when Customer Charge Option is set to "Uniform Weights"				
Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.0000	1.0000	1.0000
	[100,150]	1.0000	1.0000	1.0000
	[150,200]	1.0000	1.0000	1.0000
	200+	1.0000	1.0000	1.0000
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	5.0000	5.0000	5.0000
	[25,50]	5.0000	5.0000	5.0000
	[50,75]	5.0000	5.0000	5.0000
	[75,100]	5.0000	5.0000	5.0000
	[100,150]	5.0000	5.0000	5.0000
	[150,200]	5.0000	5.0000	5.0000
	200+	5.0000	5.0000	5.0000
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	2.0000	2.0000	2.0000
	[100,150]	2.0000	2.0000	2.0000
	[150,200]	2.0000	2.0000	2.0000
	200+	2.0000	2.0000	2.0000
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ 5.0000	$ 5.0000	$ 5.0000
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	$ 3.0000	$ 3.0000	$ 3.0000
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
$ 1,077,568,288	$ -	$ 4,141,536,456

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 2,413,517,443
NBCs	$ -
Non-Dist	$ 1,728,019,013

Based on CARE program size from E-TOU-C

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 455,112,080	$ -	$ -

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

SDG&E

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 452,493,498	$ -	$ 1,208,877,188

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 520,355,055
NBCs	$ -
Non-Dist	$ 688,522,133

Based on CARE program size from TOU-DR1

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 105,156,114	$ -	$ -

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

SCE

Delivery - excluding CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 1,588,466,398	$ -	$ 3,157,163,596

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 2,392,639,984
NBCs	$ -
Non-Dist	$ 764,523,612

Based on CARE program size from TOU-D-4-9

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ 295,659,369	$ -	$ -

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ -
Non-Dist	$ -

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]	$ 28.5301	$ 11.6892	$ 28.4779	$ 11.6892	$ 28.4480	$ 11.6892
[25,50]	$ 28.5301	$ 11.6892	$ 28.4779	$ 11.6892	$ 28.4480	$ 11.6892
[50,75]	$ 28.5301	$ 11.6892	$ 28.4779	$ 11.6892	$ 28.4480	$ 11.6892
[75,100]	$ 28.5301	$ 11.6892	$ 28.4779	$ 11.6892	$ 28.4480	$ 11.6892
[100,150]	$ 28.5301	$ 11.6892	$ 28.4779	$ 11.6892	$ 28.4480	$ 11.6892
[150,200]	$ 28.5301	$ 11.6892	$ 28.4779	$ 11.6892	$ 28.4480	$ 11.6892
200+	$ 28.5301	$ 11.6892	$ 28.4779	$ 11.6892	$ 28.4480	$ 11.6892
Tier Credits/Charges ($/kWh)						
Baseline Credit	$ 0.0651	$ 0.0423	$ 0.0651	$ 0.0423	$ -	$ -
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	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
Demand Charge ($/kW-mo)	$ -	$ -	$ -	$ -	$ -	$ -
Energy Charges ($/kWh)						
Summer - Peak	$ 0.3276	$ 0.2129	$ 0.4142	$ 0.2692	$ 0.4659	$ 0.3028
Summer - Part-Peak	$ 0.3276	$ 0.2129	$ -	$ -	$ 0.3684	$ 0.2394
Summer - Off-Peak	$ 0.3276	$ 0.2129	$ 0.3522	$ 0.2290	$ 0.1981	$ 0.1287
Winter - Peak	$ 0.3276	$ 0.2129	$ 0.3243	$ 0.2108	$ 0.3526	$ 0.2292
Winter - Part-Peak	$ 0.3276	$ 0.2129	$ -	$ -	$ 0.3368	$ 0.2189
Winter - Off-Peak	$ 0.3276	$ 0.2129	$ 0.3073	$ 0.1997	$ 0.1967	$ 0.1279
Total CARE Program Funding - Modeled						
Customer		$ (104,188,213)		$ (104,188,213)		$ (104,188,213)
Demand		$ -		$ -		$ -
Volumetric - Delivery		$ (446,794,957)		$ (446,794,957)		$ (446,794,957)
Volumetric - Generation		$ (431,894,113)		$ (423,536,307)		$ (418,748,960)
Total CARE Credits		$ (982,877,283)		$ (974,519,478)		$ (969,732,130)
Residential CARE Funding		$ 266,482,711		$ 264,216,700		$ 262,918,730
Non-Res CARE Funding		$ 716,394,572		$ 710,302,777		$ 706,813,400
Total IOU forecast CARE program size						
2023 Forecast (Existing Rates)		$ (891,914,356)		$ (891,914,356)		$ (891,914,356)
Modeled Credits as % of Forecast		10%		9%		9%

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
$ 28.3622	$ 11.6892	$ 36.5975	$ 19.7704	$ 36.6494	$ 19.7704	$ 36.6960	$ 19.7704
$ 28.3622	$ 11.6892	$ 36.5975	$ 19.7704	$ 36.6494	$ 19.7704	$ 36.6960	$ 19.7704
$ 28.3622	$ 11.6892	$ 36.5975	$ 19.7704	$ 36.6494	$ 19.7704	$ 36.6960	$ 19.7704
$ 28.3622	$ 11.6892	$ 36.5975	$ 19.7704	$ 36.6494	$ 19.7704	$ 36.6960	$ 19.7704
$ 28.3622	$ 11.6892	$ 36.5975	$ 19.7704	$ 36.6494	$ 19.7704	$ 36.6960	$ 19.7704
$ 28.3622	$ 11.6892	$ 36.5975	$ 19.7704	$ 36.6494	$ 19.7704	$ 36.6960	$ 19.7704
$ 28.3622	$ 11.6892	$ 36.5975	$ 19.7704	$ 36.6494	$ 19.7704	$ 36.6960	$ 19.7704
$ -	$ -	$ 0.0548	$ 0.0370	$ 0.0600	$ 0.0405	$ -	$ -
$ -	$ -	$ 0.0617	$ 0.0417	$ -	$ -	$ -	$ -
X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.4937	$ 0.3209	$ 0.3071	$ 0.2073	$ 0.4555	$ 0.3074	$ 0.5625	$ 0.3797
$ 0.3303	$ 0.2147	$ 0.2160	$ 0.1458	$ 0.3471	$ 0.2343	$ 0.3048	$ 0.2057
$ 0.2733	$ 0.1776	$ 0.2160	$ 0.1458	$ 0.2563	$ 0.1730	$ 0.1984	$ 0.1339
$ 0.2605	$ 0.1693	$ 0.3071	$ 0.2073	$ 0.3875	$ 0.2616	$ 0.5039	$ 0.3401
$ 0.2383	$ 0.1549	$ 0.2160	$ 0.1458	$ 0.2810	$ 0.1897	$ 0.1790	$ 0.1208
$ 0.2245	$ 0.1459	$ 0.2160	$ 0.1458	$ 0.2515	$ 0.1697	$ 0.1790	$ 0.1208
	$ (104,188,213)		$ (133,858,340)		$ (133,858,340)		$ (133,858,340)
	$ -		$ -		$ -		$ -
	$ (446,794,957)		$ (264,260,551)		$ (264,260,551)		$ (264,260,551)
	$ (405,034,979)		$ (339,559,859)		$ (347,681,851)		$ (354,957,511)
	$ (956,018,149)		$ (737,678,750)		$ (745,800,741)		$ (753,076,402)
	$ 259,200,526		$ 189,581,323		$ 191,668,651		$ 193,538,475
	$ 696,817,623		$ 548,097,428		$ 554,132,090		$ 559,537,927
	$ (891,914,356)		$ (660,034,291)		$ (660,034,291)		$ (660,034,291)
	7%		12%		13%		14%

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
$ 36.5357	$ 18.3686	$ 36.4421	$ 18.3686	$ 36.4579	$ 18.3686	$ 36.3782	$ 18.3686
$ 36.5357	$ 18.3686	$ 36.4421	$ 18.3686	$ 36.4579	$ 18.3686	$ 36.3782	$ 18.3686
$ 36.5357	$ 18.3686	$ 36.4421	$ 18.3686	$ 36.4579	$ 18.3686	$ 36.3782	$ 18.3686
$ 36.5357	$ 18.3686	$ 36.4421	$ 18.3686	$ 36.4579	$ 18.3686	$ 36.3782	$ 18.3686
$ 36.5357	$ 18.3686	$ 36.4421	$ 18.3686	$ 36.4579	$ 18.3686	$ 36.3782	$ 18.3686
$ 36.5357	$ 18.3686	$ 36.4421	$ 18.3686	$ 36.4579	$ 18.3686	$ 36.3782	$ 18.3686
$ 36.5357	$ 18.3686	$ 36.4421	$ 18.3686	$ 36.4579	$ 18.3686	$ 36.3782	$ 18.3686
$ 0.0877	$ 0.0579	$ 0.0877	$ 0.0579	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.4894	$ 0.3230	$ 0.7798	$ 0.5147	$ 0.7725	$ 0.5099	$ 0.7196	$ 0.4750
$ 0.4894	$ 0.3230	$ 0.4663	$ 0.3078	$ 0.4375	$ 0.2888	$ 0.3504	$ 0.2313
$ 0.5200	$ 0.3432	$ 0.3017	$ 0.1991	$ 0.2198	$ 0.1451	$ 0.3018	$ 0.1992
$ 0.3088	$ 0.2038	$ 0.5028	$ 0.3319	$ 0.4677	$ 0.3087	$ 0.4786	$ 0.3159
$ 0.3088	$ 0.2038	$ 0.4183	$ 0.2761	$ 0.4040	$ 0.2666	$ 0.3372	$ 0.2225
$ 0.4408	$ 0.2909	$ 0.3938	$ 0.2599	$ 0.2115	$ 0.1396	$ 0.2930	$ 0.1934
	$ (38,289,552)		$ (38,289,552)		$ (38,289,552)		$ (38,289,552)
	$ -		$ -		$ -		$ -
	$ (99,651,820)		$ (99,651,820)		$ (99,651,820)		$ (99,651,820)
	$ (100,157,376)		$ (96,179,165)		$ (96,851,978)		$ (93,461,884)
	$ (238,098,749)		$ (234,120,538)		$ (234,793,351)		$ (231,403,257)
	$ 68,374,461		$ 67,232,044		$ 67,425,255		$ 66,451,727
	$ 169,724,288		$ 166,888,494		$ 167,368,095		$ 164,951,530
	$ (178,549,476)		$ (178,549,476)		$ (178,549,476)		$ (178,549,476)
	33%		31%		32%		30%

Docket No: R.22-07-005

Sierra Club
Direct Testimony of John D. Wilson

Attachment 5
IGFC Proposal Below Average Income 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.

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Energy+Environmental Economics

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
Phone: 415-391-5100

Model Release Date: April 13, 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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 538,263,216	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 218,481,550	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 865,996,766	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal Customer Access	$ 454,792,861	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Distribution Capacity Cost - Primary	$ 439,382,040	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Distribution Capacity Cost - New Business	$ 476,043,853	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Distribution Capacity Cost - Secondary	$ 29,945,145	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,833,578,625	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission	$ 1,447,654,612	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 58,854,252	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Fund Charge	$ 63,120,120	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Hardening Charge	$ 68,921,008	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Recovery Bond Charge	$ 215,256,658	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Recovery Bond Credit	$ (215,256,658)	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 230,732,710	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Nuclear Decommissioning	$ 37,938,712	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	New System Generation Charge	$ 96,956,158	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Competition Transition Charge	$ 8,518,646	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Energy Cost Recovery Account	$ (19,846,861)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	0.00%	0.00%	100.00%
	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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 606,708,166	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 584,831,167	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 1,378,829,544	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 427,567,610	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal - Grid	$ 888,543,196	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal - Peak	$ 503,372,326	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,845,967,040	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Base Transmission	$ 599,320,433	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (1,839,212)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 23,619,309	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Fund Charge	$ 103,390,404	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Hardening Charge	$ 17,556,861	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Recovery Bond Charge	$ -	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Recovery Bond Credit	$ (40,575,857)	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 313,291,510	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Nuclear Decommissioning	$ 2,364,701	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	New System Generation Charge	$ 148,976,188	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	0.00%	0.00%	100.00%
	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	0.00%	0.00%	100.00%
Generation	Marginal Energy Cost	$ 100,915,850	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 57,547,258	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 163,094,812	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 183,005,936	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Demand - Non-Coincident Peak	$ 198,205,378	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Demand - Coincident Peak	$ 26,974,391	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 490,650,411	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Base Transmission	$ 537,401,722	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (111,012,377)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 8,781,000	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Fund Charge	$ 29,143,070	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 61,433,000	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Nuclear Decommissioning	$ 526,530	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Local Generation Charge/New System Generation Cha	$ 81,949,029	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Competition Transition Charge	$ 11,052,908	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Total Rate Adjustment Component - Baseline adjustme	$ 1,000,000	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Reliability Services	$ 177,809	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	0.00%	0.00%	100.00%
	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		Uniform Weights	Uniform Weights	Uniform Weights
Customer Charge Weighting is used when Customer Charge Option is set to "Uniform Weights"				
Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.0000	1.0000	1.0000
	[100,150]	1.0000	1.0000	1.0000
	[150,200]	1.0000	1.0000	1.0000
	200+	1.0000	1.0000	1.0000
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	5.0000	5.0000	5.0000
	[25,50]	5.0000	5.0000	5.0000
	[50,75]	5.0000	5.0000	5.0000
	[75,100]	5.0000	5.0000	5.0000
	[100,150]	5.0000	5.0000	5.0000
	[150,200]	5.0000	5.0000	5.0000
	200+	5.0000	5.0000	5.0000
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	2.0000	2.0000	2.0000
	[100,150]	2.0000	2.0000	2.0000
	[150,200]	2.0000	2.0000	2.0000
	200+	2.0000	2.0000	2.0000
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ 5.0000	$ 5.0000	$ 5.0000
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	$ 3.0000	$ 3.0000	$ 3.0000
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

Based on CARE program size from E-TOU-C

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
$ -	$ -	$ 456,691,194

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	$ 387,770,187
Non-Dist	$ 68,921,008

SDG&E

Based on CARE program size from TOU-DR1

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
$ -	$ -	$ 104,759,721

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	$ 104,759,721
Non-Dist	$ -

SCE

Based on CARE program size from TOU-D-4-9

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
$ -	$ -	$ 295,490,197

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	$ 318,509,193
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]	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335
[25,50]	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335
[50,75]	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335
[75,100]	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335
[100,150]	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335
[150,200]	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335
200+	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335	$ 7.5900	$ 4.9335
Tier Credits/Charges ($/kWh)						
Baseline Credit	$ 0.0687	$ 0.0446	$ 0.0687	$ 0.0446	$ -	$ -
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	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
Demand Charge ($/kW-mo)	$ -	$ -	$ -	$ -	$ -	$ -
Energy Charges ($/kWh)						
Summer - Peak	$ 0.3732	$ 0.2283	$ 0.4646	$ 0.2877	$ 0.5263	$ 0.3279
Summer - Part-Peak	$ 0.3732	$ 0.2283	$ -	$ -	$ 0.4208	$ 0.2593
Summer - Off-Peak	$ 0.3732	$ 0.2283	$ 0.4014	$ 0.2466	$ 0.2309	$ 0.1359
Winter - Peak	$ 0.3732	$ 0.2283	$ 0.3684	$ 0.2252	$ 0.4045	$ 0.2487
Winter - Part-Peak	$ 0.3732	$ 0.2283	$ -	$ -	$ 0.3881	$ 0.2380
Winter - Off-Peak	$ 0.3732	$ 0.2283	$ 0.3511	$ 0.2140	$ 0.2304	$ 0.1355
Total CARE Program Funding - Modeled						
Customer		$ (43,973,135)		$ (43,973,135)		$ (43,973,135)
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		$ (988,701,583)		$ (980,343,778)		$ (975,556,430)
Residential CARE Funding		$ 268,061,825		$ 265,795,814		$ 264,497,844
Non-Res CARE Funding		$ 720,639,758		$ 714,547,964		$ 711,058,586
Total IOU forecast CARE program size						
2023 Forecast (Existing Rates)		$ (891,914,356)		$ (891,914,356)		$ (891,914,356)
Modeled Credits as % of Forecast		11%		10%		9%

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
$ 7.5900	$ 4.9335	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216
$ 7.5900	$ 4.9335	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216
$ 7.5900	$ 4.9335	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216
$ 7.5900	$ 4.9335	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216
$ 7.5900	$ 4.9335	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216
$ 7.5900	$ 4.9335	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216
$ 7.5900	$ 4.9335	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216	$ 7.8838	$ 5.3216
$ -	$ -	$ 0.0573	$ 0.0387	$ 0.0627	$ 0.0423	$ -	$ -
$ -	$ -	$ 0.0645	$ 0.0435	$ -	$ -	$ -	$ -
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
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.5467	$ 0.3413	$ 0.3677	$ 0.2381	$ 0.5213	$ 0.3416	$ 0.6368	$ 0.4196
$ 0.3736	$ 0.2287	$ 0.2445	$ 0.1549	$ 0.4129	$ 0.2685	$ 0.3791	$ 0.2456
$ 0.3148	$ 0.1905	$ 0.2445	$ 0.1549	$ 0.3124	$ 0.2006	$ 0.2518	$ 0.1597
$ 0.3027	$ 0.1827	$ 0.3677	$ 0.2381	$ 0.4534	$ 0.2958	$ 0.5798	$ 0.3811
$ 0.2803	$ 0.1681	$ 0.2445	$ 0.1549	$ 0.3371	$ 0.2173	$ 0.2306	$ 0.1454
$ 0.2663	$ 0.1590	$ 0.2445	$ 0.1549	$ 0.3041	$ 0.1950	$ 0.2306	$ 0.1454
	$ (43,973,135)		$ (36,030,659)		$ (36,030,659)		$ (36,030,659)
	$ -		$ -		$ -		$ -
	$ (512,834,336)		$ (361,429,971)		$ (361,429,971)		$ (361,429,971)
	$ (405,034,979)		$ (339,559,859)		$ (347,681,851)		$ (354,957,511)
	$ (961,842,449)		$ (737,020,489)		$ (745,142,480)		$ (752,418,140)
	$ 260,779,640		$ 189,412,151		$ 191,499,480		$ 193,369,304
	$ 701,062,810		$ 547,608,337		$ 553,643,000		$ 559,048,837
	$ (891,914,356)		$ (660,034,291)		$ (660,034,291)		$ (660,034,291)
	8%		12%		13%		14%

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
$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290
$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290
$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290
$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290
$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290
$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290
$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290	$ 11.2560	$ 7.4290
$ 0.0902	$ 0.0596	$ 0.0902	$ 0.0596	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 0.5202	$ 0.3311	$ 0.8208	$ 0.5296	$ 0.8485	$ 0.5478	$ 0.7812	$ 0.5035
$ 0.5202	$ 0.3311	$ 0.5073	$ 0.3227	$ 0.5135	$ 0.3267	$ 0.4120	$ 0.2598
$ 0.5623	$ 0.3588	$ 0.3427	$ 0.2140	$ 0.2528	$ 0.1547	$ 0.3634	$ 0.2278
$ 0.3397	$ 0.2119	$ 0.5815	$ 0.3716	$ 0.5437	$ 0.3467	$ 0.5401	$ 0.3444
$ 0.3397	$ 0.2119	$ 0.4970	$ 0.3158	$ 0.4800	$ 0.3046	$ 0.3988	$ 0.2511
$ 0.5212	$ 0.3317	$ 0.4724	$ 0.2996	$ 0.2445	$ 0.1492	$ 0.3546	$ 0.2220
	$ (15,485,781)		$ (15,485,781)		$ (15,485,781)		$ (15,485,781)
	$ -		$ -		$ -		$ -
	$ (121,075,241)		$ (121,075,241)		$ (121,075,241)		$ (121,075,241)
	$ (100,157,376)		$ (96,179,165)		$ (96,851,978)		$ (93,461,884)
	$ (236,718,398)		$ (232,740,187)		$ (233,413,000)		$ (230,022,906)
	$ 67,978,068		$ 66,835,651		$ 67,028,862		$ 66,055,334
	$ 168,740,330		$ 165,904,536		$ 166,384,138		$ 163,967,573
	$ (178,549,476)		$ (178,549,476)		$ (178,549,476)		$ (178,549,476)
	33%		30%		31%		29%

Docket No: R.22-07-005

Sierra Club
Direct Testimony of John D. Wilson

Attachment 6
Data Request Responses

PACIFIC GAS AND ELECTRIC COMPANY
Electric Rates Demand Flexibility OIR
Rulemaking 22-07-005
Data Response

PG&E Data Request No.:	TURN_004-Q005		
PG&E File Name:	ElectricRatesDemandFlexibility_DR_TURN_004-Q005		
Request Date:	February 24, 2023	Requester DR No.:	004
Date Sent:	March 10, 2023	Requesting Party:	The Utility Reform Network
PG&E Witness:	Benjamin Kolnowski	Requester:	Matthew Freedman

QUESTION 005

Regarding "transmission": please provide a list of primary cost subcategories that comprise this, and the dollar amount of each cost subcategory, such that the total equals what is provided in the E3 tool. Please provide as granularly as available and define cost subcategories if not clear from the name.

ANSWER 005

The "transmission" category in the tab titled "Cost Allocation – PG&E" is equal to $1,447,654,612. This is comprised of five main categories, as defined below:

1. Transmission Owner 20 (TO20) Revenue Year 2023 (RY 2023) Retail Revenue Requirement: $1,470,441,642
2. Transmission Access Charge Balancing Account: $114,463,027
3. Transmission Revenue Balancing Account: ($156,442,132)
4. Reliability Services Balancing Account: $19,192,075
5. End-Use Customer Refund Balancing Account: $0

These revenue requirements and revenue allocation are regulated by the Federal Energy Regulatory Commission (FERC) in its Transmission Operator (TO) proceedings. Detailed information supporting the total TO20 RY2023 retail revenue requirement of $3.179 billion (of which $1.470 billion is allocated to residential customers) can be found in PG&E's TO20 RY2023 Formula Rate model. In particular, a break-out of various cost categories that comprise the total TO20 RY2023 retail revenue requirement can be found on Tab 1 titled "1-BaseTRR".

PACIFIC GAS AND ELECTRIC COMPANY
Electric Rates Demand Flexibility OIR
Rulemaking 22-07-005
Data Response

PG&E Data Request No.:	TURN_004-Q006		
PG&E File Name:	ElectricRatesDemandFlexibility_DR_TURN_004-Q006		
Request Date:	February 24, 2023	Requester DR No.:	004
Date Sent:	March 10, 2023	Requesting Party:	The Utility Reform Network
PG&E Witness:	Benjamin Kolnowski	Requester:	Matthew Freedman

QUESTION 006

Regarding the non-marginal distribution cost category: please provide a list of primary cost subcategories that comprise this category, and the dollar amount of each cost subcategory, such that the total equals what is provided in the E3 tool. Please provide as granularly as available and define cost subcategories if not clear from the name.

ANSWER 006

The non-marginal distribution cost component is determined as a residual calculation by taking the total distribution revenue requirement and subtracting the separately-identified distribution cost components (MCAC, MDCC – Primary, MDCC – Primary New Business, MDCC – Secondary). As a result, PG&E does not have a list of cost subcategories and associated dollar amounts that comprise the non-marginal distribution cost component. However, a full list of programs and associated decisions or advice letters which contribute to the total distribution revenue requirement can be found in Table 2 of PG&E's 2023 Annual Electric True-Up advice letter (Advice 6805-E). Many of these programs would likely contribute, in some capacity, to the non-marginal distribution cost component.

Southern California Edison
R.22-07-005 – Advance Demand Flexibility OIR

DATA REQUEST SET T U R N - S C E - 2 0 2 3 - 0 4

To: TURN
Prepared by: Reuben Behlihomji
Job Title: Prin Mgr
Received Date: 2/24/2023

Response Date: 3/9/2023

Question 05:
Regarding “base transmission”: please provide a list of primary cost subcategories that comprise this, and the dollar amount of each cost subcategory, such that the total equals what is provided in the E3 tool. Please provide as granularly as available and define cost subcategories if not clear from the name.

Response to Question 05:
A breakdown of SCE’s base transmission revenue requirements can be found in SCE’s current Federal Energy Regulatory Commission (FERC) Formula Annual Update (TO2023) Formula Rate Schedule 1 Base TRR, FERC Docket No. ER19-1553 and can also be accessed using the link below. However, SCE notes that base transmission revenues and resulting rates fall under the exclusive jurisdiction of the FERC.

https://www.sce.com/sites/default/files/inline-files/TO2023_Attachment1_AnnualUpdateFormulaSpreadsheet.xlsx

Southern California Edison
R.22-07-005 – Advance Demand Flexibility OIR

DATA REQUEST SET T U R N - S C E - 2 0 2 3 - 0 4

To: TURN
Prepared by: Ruben Pardo
Job Title: Senior Advisor
Received Date: 2/24/2023

Response Date: 3/9/2023

Question 06:

Regarding the non-marginal distribution cost category: please provide a list of primary cost subcategories that comprise this category, and the dollar amount of each cost subcategory, such that the total equals what is provided in the E3 tool. Please provide as granularly as available and define cost subcategories if not clear from the name.

Response to Question 06:

SCE does not have a complete list of the cost subcategories of the non-marginal distribution costs. The non-marginal distribution costs in the E3 tool, are calculated as the difference between authorized distribution revenue requirements, and distribution marginal cost revenues as adopted in Phase 2 of SCE's 2021 General Rate Case, adjusted for January 2023 sales.

Demand Flexibility OIR (R.22-07-005)
SDGE Response to TURN Data Request #5
Received: February 24, 2023
Submitted: March 10, 2023

<u>Question 1</u>:
In the E3 Tool, "Glossary tab," there are several categories of costs that are the result of calculations performed by the utility (rather than being transparently adopted revenue requirements). Please provide a description of how costs were calculated for each category, including descriptions of calculations and assumptions, and a cite to any Commission decision/proceeding in which such costs were adopted. This includes, but may not be limited to the following:

Utility	Cost Category
SDG&E	Marginal Energy Cost
SDG&E	Marginal Generation Capacity Cost
SDG&E	Marginal - Customer
SDG&E	Marginal Demand - Non-Coincident Peak
SDG&E	Marginal Demand - Coincident Peak

<u>SDG&E Response to Question 1</u>:

This response contains "Protected Information" (i.e., trade secret, market sensitive, or other confidential and/or proprietary information) as determined by SDG&E in accordance with the provisions of D. 06-06-066 and subsequent decisions and subject to a Nondisclosure Agreement. The Protected Materials have been highlighted in yellow. The confidentiality declaration of Gwendolyn Morien is also provided.

- **Marginal Energy Cost Revenue**: SDG&E calculated marginal energy cost revenue by taking SDG&E's proposed residential marginal energy costs from its last GRC Phase 2 Application proceeding with a final decision (A.19-03-002, SDG&E's 2019 GRC Phase 2 Application) and multiplying that $/kWh cost by SDG&E's current effective sales forecast residential customer class bundled billing determinants implemented on 1/1/23 per AL 4129-E. The residential marginal energy costs reflect the final customer class rate structure adopted by the Commission in D.21-07-010.
    - Marginal energy cost = summer average marginal energy rate of $[redacted]/kWh x [redacted] residential bundled summer volumetric energy billing determinants + winter average marginal energy rate of $[redacted]/kWh x [redacted] residential bundled volumetric energy winter billing determinants = $100,915,850
- **Marginal Generation Capacity Cost Revenue**: SDG&E calculated marginal generation capacity cost revenue by taking SDG&E's proposed residential marginal generation capacity costs from its 2019 GRC Phase 2 Application and multiplying that $/kW and $/kWh cost by SDG&E's current effective sales forecast residential customer class bundled billing determinants implemented on 1/1/23 per AL 4129-E. The residential marginal generation capacity costs reflect the final customer class rate structure adopted by the Commission in D.21-07-010. SDG&E discovered an error in the calculation in the current version of the E3 Public Tool; this corrected amount has been provided to Energy Division and will be reflected in the final version of the Public Tool.
    - Marginal generation capacity cost = $[redacted]/kW x [redacted] coincident peak demand residential bundled billing determinants + $[redacted]/kWh x [redacted] summer off-peak volumetric energy determinants = $57,547,258
- **Marginal Distribution Customer Cost Revenue**: SDG&E calculated marginal distribution customer cost revenue by taking SDG&E's proposed residential marginal distribution customer costs from its last GRC Phase 2 Application proceeding with a final decision (A.19-03-002, SDG&E's 2019 GRC Phase 2 Application) and multiplying that $/month cost by SDG&E's current effective sales forecast residential customer class system net billing determinants implemented on 1/1/23 per AL 4129-E. The residential marginal customer costs reflect the final customer class rate structure adopted by the Commission in D.21-07-010.

  - Marginal distribution customer cost = $11.26/month x 16,258,458 basic service fee billing determinants = $183,005,936.
- **Marginal Distribution Demand Cost Revenue**: Similar to the marginal customer cost revenue, SDG&E calculated marginal distribution demand costs by taking SDG&E's proposed residential marginal distribution demand costs from its 2019 GRC Phase 2 Application and multiplying that $/kW cost by SDG&E's current effective system net sales forecast residential customer class billing determinants implemented on 1/1/23 per AL 4129-E.
  - Marginal distribution demand cost (coincident peak) = $1.32/kW x 20,432,465 on-peak summer demand residential billing determinants = $26,974,391
  - Marginal distribution demand cost (non-coincident peak) = $3.74/kW x 53,008,977 non-coincident demand residential billing determinants = $198,205,378
- **PCIA:** PCIA revenues in the E3 model represent both the amounts paid by departing load customers and the PCIA embedded in the bundled commodity rate that is recovered from bundled customers. The departing load customer PCIA revenues are calculated as SDG&E's 2023 vintage PCIA residential rates implemented in AL 4129-E, multiplied by the 2023 residential departing load vintage forecast adopted in SDG&E's 2023 ERRA Forecast Application decision (D.22-12-042). The bundled PCIA revenues are calculated as the residential 2023 PCIA vintage rate per AL 4129-E multiplied by the residential 2023 forecasted bundled volumetric energy billing determinants adopted in SDG&E's 2023 ERRA Forecast Application decision (D.22-12-042).
- **Non-Marginal Generation Revenues**: Non-marginal generation revenues are calculated as the difference between the 1/1/2023 residential bundled revenue requirement (per AL 4129-E) less: marginal energy revenues, marginal generation capacity revenues, and bundled PCIA revenues.
- **Non-Marginal Distribution Revenues**: Non-marginal distribution revenues are calculated as the difference between the 1/1/2023 residential distribution revenue requirement (per AL 4129-E) less: marginal distribution customer access costs, marginal distribution coincident peak costs, and marginal distribution non-coincident peak costs.

<u>Question 2</u>:
Please explain whether the marginal energy cost accounts for cap and trade costs paid for by ratepayers. If not, please provide these costs, consistent with the methodology in the E3 tool (e.g., same year, etc.).

<u>SDG&E Response to Question 2</u>:
SDG&E's marginal energy cost is a forecast of the CAISO market price, which includes Greenhouse Gas costs. Although SDG&E's marginal energy cost does not explicitly break out GHG cap and trade components, it does account for cap and trade costs by the nature of the forecast.

<u>Question 3</u>:
Identify the methodology used to calculate marginal customer costs including the marginal cost methodology applied to this calculation (e.g. New Customer Only (NCO), rental, other).

<u>SDG&E Response to Question 3</u>:
As stated in the SDG&E 2024 GRC Phase 2 (A.23-01-008) Chapter 4 Prepared Direct Testimony of William G. Saxe, consistent with previous GRC Phase 2 proceeding SDG&E is using the Rental Method to calculate the marginal distribution customer costs.[1] However, because other parties in previous GRC Phase 2 proceedings have proposed the New Customer Only (NCO) Method to calculate marginal distribution customer costs, SDG&E also calculated the marginal distribution customer costs based on the NCO Method for comparison purposes.[2] But again, SDG&E's calculated marginal distribution customer costs in this proceeding are based on the Rental Method.

[1] SDG&E 2024 Chapter 4 Prepared Direct Testimony of William G. Saxe at WGS-7.

[2] SDG&E 2024 Chapter 4 Prepared Direct Testimony of William G. Saxe at WGS-11.

Demand Flexibility OIR (R.22-07-005)
SDGE Response to TURN Data Request #5
Received: February 24, 2023
Submitted: March 10, 2023

<u>Question 4</u>:
Regarding the non-marginal generation cost category: please provide a list of primary cost subcategories that comprise this category, and the dollar amount of each cost subcategory, such that the total equals what is provided in the E3 tool. Please provide as granularly as available and define cost subcategories if not clear from the name.

<u>SDG&E Response to Question 4</u>:
See attached file titled "TURN DR 05 - SDGE Response to Q4.xlsx" for a breakout of SDG&E's generation-related revenue requirements by subcategory. The marginal commodity cost categories are theoretical, and therefore SDG&E cannot directly attribute any of the marginal commodity costs to these revenue requirements.

<u>Question 5</u>:
Regarding "base transmission": please provide a list of primary cost subcategories that comprise this, and the dollar amount of each cost subcategory, such that the total equals what is provided in the E3 tool. Please provide as granularly as available and define cost subcategories if not clear from the name.

<u>SDG&E Response to Question 5</u>:
SDG&E objects to this request on grounds that it seeks information regarding transmission revenues that fall under the exclusive jurisdiction of the Federal Energy Regulatory Commission. Subject to and without waiving the foregoing objection, SDG&E responds as follows:

The attached file ("TURN DR-05 – SDG&E Response to Q5") provides the breakdown of SDG&E's current January 1, 2023, adopted transmission revenues for SDG&E system and residential.

<u>Question 6</u>:
Regarding the non-marginal distribution cost category: please provide a list of primary cost subcategories that comprise this category, and the dollar amount of each cost subcategory, such that the total equals what is provided in the E3 tool. Please provide as granularly as available and define cost subcategories if not clear from the name.

<u>SDG&E Response to Question 6</u>:
The attached file ("TURN DR-05 – SDG&E Response to Q6") provides the breakdown of SDG&E's current January 1, 2023, adopted distribution revenues for SDG&E system and residential.

BREAKDOWN OF 2023 RESIDENTIAL DISTRIBUTION REVENUE REQUIREMENT
2024 GENERAL RATE CASE (GRC) PHASE 2 APPLICATION (A.23-01-008) - TURN DR-05, QUSTION 6

	System Distribution Revenues ($000)	Residential Distribution Revenues ($000)
Marginal Distribution Customer Costs	$267,402	$183,006
Marginal Distribution Demand Costs		
Marginal Feeder & Local Distribution (MFLD) Demand Costs		
Non-Coincident MFLD Demand Costs	$290,809	$138,144
On-Peak MFLD Demand Costs	$40,851	$18,800
Marginal Substation Costs		
Non-Coincident Substation Demand Costs	$126,437	$60,062
On-Peak Substation Demand Costs	$17,761	$8,174
Subtotal Marginal Distribution Demand Costs	$475,859	$225,180
Total Marginal Distribution Costs	$743,261	$408,186
Non-Marginal Distribution Costs		
Non-Marginal Base Distribution Costs	$930,050	$360,758
Distribution Balancing Accounts	$253,592	$110,924
Programs collected in Distribution Rates		
Vehicle Grid Integration (VGI)	$6,783	$3,097
Medium Duty/Heavy Duty Electric Vehicle (MD/HD)	$14,749	$4,971
Assembly Bill 1082	$3,521	$1,608
Assembly Bill 1054	-$10,098	-$4,611
VG2 Pilot	$225	$103
Power Your Drive Extension Program (PYD)	$19,553	$8,929
Demand Response	$11,369	$4,872
Schedule DG-R Under-Collection	$17,468	NA
Subtotal Distribution Program Costs	$63,571	$18,968
Total Non-Marginal Distribution Costs	$1,247,213	$490,650
Total Resident	$1,990,473	$898,836

Note: Total Non-Marginal Distribution Costs consist of Non-Marginal Base Distribution, Distribution Balancing Accounts, and Distribution Program costs. The Non-Marginal Base Distribution Costs consist of distribution costs that are not directly tied to hooking up a customer for electric service (Marginal Distribution Customer Costs) or meeting the peak demand needs of the customer (Marginal Distribution Demand Costs). Non-Marginal Distribution Costs consist of costs such as the costs to meet distribution system reliability need, wildfire mitigation and vegetation management needs, safety and risk management needs, etc.

Southern California Edison
R.22-07-005 – Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates

DATA REQUEST SET Sierra Club-SCE-2023-03

To: Sierra Club
Prepared by: Ruben Pardo
Job Title: Senior Advisor
Received Date: 2/28/2023

Response Date: 3/14/2023

Question 02:
For each of the following categories, please provide the number of residential customers served and the total marginal customer access cost (revenue requirement corresponding to the data used in the E3 Public Tool). If the customer counts can be differentiated by CARE, FERA and non-CARE/FERA, or other crosscuts, please do so. If there is any overlap among the categories, please explain the overlap and why it cannot be eliminated.

a. Multi-family housing (shared transformer and service line)
b. Single-phase service line, non-dedicated transformer
c. Three-phase service line, non-dedicated transformer
d. Dedicated transformer and service line
e. Service at primary voltage (understanding that this number is small or zero)

Response to Question 02:

For categories a and b, please see the tables below. For categories c through e, SCE does not have that data readily available.

	Residential Customers		
	Non-CARE	CARE	Total
Single	2,300,914	637,001	2,937,916
Multi	1,046,691	534,842	1,581,533
Total	3,347,606	1,171,843	4,519,449

	Marginal Customer Cost Revenues ($M)		
	Non-CARE	CARE	Total
Single	$ 217.7	$ 60.3	$ 277.9
Multi	$ 99.0	$ 50.6	$ 149.6
Total	$ 316.7	$ 110.9	$ 427.6

Southern California Edison
R.22-07-005 – Advance Demand Flexibility OIR

DATA REQUEST SET Sierra Club-SCE-2023-03

To: Sierra Club
Prepared by: Ruben Pardo
Job Title: Senior Advisor
Received Date: 2/28/2023

Response Date: 3/27/2023

Question Q.02.a Follow up:
requested customer count and marginal cost revenues for multi-family housing using a shared transformer and service line. Question 2(b) requested customer count and marginal cost revenues for customers with single-phase service line and a non-dedicated transformer. According to the response, SCE is in possession of these data, but does not possess similar data for the other three categories of exclusive residential service types (c-e). The response for questions (a) and (b) was provided as a single table, which does not permit the analysis of categories (a) and (b) separately. Please provide the data in a disaggregated format.

Response to Question Q.02.a Follow up:

SCE does not have the disaggregated single and multi-family marginal customer cost revenues as requested.

In SCE's 2021 GRC, the marginal customer costs used to determine marginal customer cost revenue requirement were a settled value, adopted in D.22-10-022. The settled residential customer marginal costs value was based on 50/50 average of SCE's residential Real Economic Carrying Charge customer cost, and TURN's New Customer Only marginal class cost, resulting in a weighted class average of $7.88/Month.

SCE does produce single-phase ($12.13/Mo.), and multi-family ($8.82/Mo.) disaggregated marginal costs but does not produce TURN's equivalent disaggregated marginal costs. Because SCE did not have the disaggregated amount for TURN's single and multi-family marginal costs, SCE used the weighted average class cost ($7.88/Mo.) to determine the revenues, which was the basis of determining the allocated residential class marginal cost revenues.