BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

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

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

June 2, 2023

EXECUTIVE SUMMARY OF REBUTTAL

This testimony presents the rebuttal testimony of the Solar Energy Industries Association (SEIA) responding to the proposals of the other parties in Track A of Phase 1 of this rulemaking. This track is considering how to implement income-graduated fixed charges (IGFCs) for the residential customers of the state's investor-owned utilities (IOUs). Assembly Bill 205 (AB 205) directed the Commission to add IGFCs to the IOUs' default residential rates, authorized the Commission to add IGFCs to other residential schedules, and removed the prior statutory limitation on the magnitude of fixed charges in default residential rates.

SEIA opposes the proposals of other parties – in particular the three investor-owned utilities (Joint IOUs) and the Utility Reform Network / Natural Resources Defense Council (TURN/NRDC) – who have advocated IGFCs far higher than the average residential fixed charge for U.S. electric utilities, which is about $11 per month. SEIA also does not support the IGFC proposals of the Sierra Club and the California Public Advocates (Cal Advocates), which are not has high as the Joint IOU/TURN/NRDC proposals but raise similar concerns.

This rebuttal shows that the proposals for high IGFCs will run contrary to many of the rate design principles that the Commission recently adopted in D. 23-04-040.

- **Rate Design Principle 5: Rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner.** The IGFC proposals will reduce volumetric rates by an equal cents per kWh amount across all TOU periods, including the on-peak period. As a result, the proposals for high IGFCs will result in much lower on-peak volumetric rates. These lower on-peak rates will increase the summer peak demands that California has struggled to meet in recent years, endangering reliability. Adding to this increase in demand will be accelerated adoption of EVs, which is a welcome outcome but one which must be managed carefully to avoid reliability problems and to mitigate the future expense of upgrading grid capacity to accommodate EVs.
- **Rate Design Principle 4: Rates should encourage economically efficient (i) use of energy, (ii) reduction of greenhouse gas emissions, and (iii) electrification.** High fixed charges discourage conservation, which remains critically important during summer on-peak periods of high demand. Higher demand in peak periods will also increase emissions of greenhouse gases and criteria air pollution.

The proponents of high IGFCs claim that lower volumetric rates are necessary to support electrification. However, there are better ways to support electrification that avoid these adverse impacts. The lower volumetric rates needed to encourage electrification are already available in the low off-peak rates of the existing residential electrification and EV charging schedules. The time-of-use (TOU) rate differences in the current "TOU-lite" residential default rates need to be increased so that all residential rates offer low off-peak rates.

SEIA supports the use of modest fixed charges to reduce volumetric rates, but further rate design changes to support electrification should focus on lower rates in off-peak periods when clean energy is abundant and less expensive. Adding electrification load in off-peak hours will reduce rates going forward, because this new load can be served with existing infrastructure. The moderate fixed charges that SEIA has proposed should be just one of a balanced set of rate design tools used to support electrification, along with lower off-peak rates and more dynamic rates. Further, the availability of lower volumetric rates does not mean that customers will use them to adopt electrification measures; there is also a need for targeted incentives that actually will result in the adoption of clean energy and electrification measures by customers across the income spectrum.

- **Rate Design Principle 1: All residential customers (including low-income customers and those who receive a medical baseline or discount) should have access to enough electricity to ensure that their essential needs are met at an affordable cost.** The proponents of high IGFCs tout the bill reductions that their proposals would achieve for low-income ratepayers. SEIA supports providing further bill relief to low-income customers, beyond the small reductions that would result from SEIA's moderate IGFCs. Such relief can be provided without the problems of the proposals for high IGFCs. For example, the Commission should pursue the proposal of Cal Advocates to re-allocate the biannual California Climate Credit, so that a higher share of these funds is rebated to low-income customers. If the SEIA proposal were enhanced by using just 50% of the Climate Credit to fund additional CARE discounts – by reducing the CARE fixed charge to zero and raising the CARE discount percentage for volumetric rates – this would achieve the same reductions in CARE customers' monthly bills as the Joint IOU proposal.
- **Rate Design Principle 10: Transitions to new rate structures should … (ii) minimize or appropriately consider the bill impacts associated with such transitions.** The proposals for high IGFCs will have major adverse bill impacts on customers who have or will invest in distributed solar and storage. This will upset the delicate balance that the Commission forged in its recent order (D. 22-12-056) adopting a new Net Billing Tariff

(NBT) for future solar and storage customers. The impacts of high IGFCs on the existing 1.5 million solar customers under the NEM 1.0 and 2.0 programs will be even more devastating, as these customers generally do not take service on a residential rate that includes a fixed charge. California is depending on the sustainable growth of these customer-sited resources as an integral part of its resource plan and as an important alternative to utility-scale resources that face challenges – in terms of land use and adequate transmission – in meeting the accelerated pace of deployment needed to reach the state's clean energy goals.

If IGFCs higher than those that SEIA has proposed are adopted, this rebuttal recommends that the Commission should adopt changes to the NBT and must provide legacy treatment for NEM 1.0 and 2.0 customers. These mitigations are necessary to avoid adverse impacts on the millions of customers who have made or want to make significant investments in the state's clean energy infrastructure. Specifically, the Commission should (1) raise the ACC Plus Adders in the NBT to compensate for any increases to the fixed charges in the residential electrification rates and (2) allow NEM 2.0 customers to retain their current rate design for legacy periods of 5 years for solar-only customers and 8 years for solar-plus-storage customers.

- **Rate Design Principle 6: Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs.** High IGFCs will cause large rate increases for higher-income customers. This will increase the potential for significant grid defection by the customers who can best afford to leave the system. SEIA presents a new model of grid defection in the IOU service territories which shows that the combination of high rates, high fixed charges, and new vehicle-to-home technology that enables a customer's EV to support their home electric use could make it more economic for middle- and high-income customers to leave the grid than to remain connected.
- **Rate Design Principle 2: Rates should be based on marginal cost.** A central justification for the high IGFC proposals is the idea that the current electric rates of the IOUs are far above social marginal costs, and that this difference is best collected in fixed charges. This conclusion is based on an outdated calculation of social marginal costs. This rebuttal updates that calculation for (1) today's higher marginal generation costs, (2) the latest estimates of the damages from climate change, and (3) a full accounting for the costs of methane leakage from the natural gas system and the health impacts of criteria air pollution. This update shows that current residential rates actually are close to updated social marginal costs, such that there is no need for high fixed charges. This

comparison also shows clearly the need to reduce the relatively high off-peak rates in default residential rates.

- **Rate Design Principle 3: Rates should be based on cost causation.** This rebuttal analyzes the rate components that other parties propose to include in their IGFCs. These proposals would include in their fixed charges several types of costs that are not fixed, and that are caused by customers' usage of kWh of energy and kW of demand. This includes (1) certain generation-related costs caused by customer usage, (2) energy efficiency and demand response programs that are substitutes for generation, (3) transportation electrification programs designed to serve higher demand for EV charging, and (4) non-bypassable charges such as Public Purpose Program costs that, by law, must be recovered in volumetric, usage-based rates.
- **Rate Design Principle 10: Transitions to new rate structures should (i) include customer education and outreach that enhances customer understanding and acceptance of new rates….** The Commission recently noted that "[t]he risk of a negative customer reaction to residential fixed charges is demonstrated by history, granted by the IOUs, and of great concern to the Commission."[1] The potential for customer backlash is particularly great from the proposals for high IGFCs, which are five to ten times higher than the fixed charge proposals that have caused customer acceptance issues in the past. These proposals also would require – in the Joint IOU proposal – a new state bureaucracy to verify the incomes of 10.8 million residential customers, and would adversely impact the solar investments of 1.5 million California families. The results of focus groups asked about the IOUs' proposals, which the Joint IOUs candidly report in their testimony, indicate the very negative initial reaction that customers will have to a high IGFC. The IOUs' marketing, education, and outreach (ME&O) plans outlined in their testimony show that the messages that the IOUs plan to convey are likely to cause further customer confusion and opposition to what customers are likely to perceive as a new tax on income that falls the heaviest on middle-income customers.

Finally, implementing high IGFCs would be expensive and time-consuming. The IOUs estimate that the costs for income verification and implementation of their proposal would be at least $200 million, with further significant ongoing costs. Based on the timeline in their testimony, the Joint IOU proposal would not be implemented until 2028, five years from now, and would require further legislation to allow a new state bureaucracy to access customers' tax returns. SEIA's proposal would be far less expensive and much quicker to implement, because it would not go beyond the existing CARE/FERA program structure, would represent more gradual

[1] See D. 20-03-003, at pp. 20-21.

change with far lower bill impacts, and would not require legacy treatment for existing net metering customers. To advance both the state's electrification and equity goals, the scarce resources in time and money saved from not implementing a high IGFC would be better spent to augment programs that provide direct incentives to encourage customers of all means to adopt electrification measures.

TABLE OF CONTENTS

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I. INTRODUCTION

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

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

Q: Have you previously served testimony in this proceeding?

A: Yes, I served direct testimony on behalf of the Solar Energy Industries Association (SEIA) on April 7, 2023. My experience and qualifications are described in my *curriculum vitae* (CV), which is **Attachment RTB-1** to my direct testimony.

Q: What is the purpose of your rebuttal testimony?

A: This rebuttal responds to the opening testimony of other parties who proposed income-graduated fixed charges (IGFCs) for the residential customers of the investor-owned utilities (IOUs), pursuant to Assembly Bill 205 (AB 205), enacted in 2022.

II. THE PROPOSALS

A. Summary of Parties' IGFC Proposals

Q: Please summarize the essential elements of the major proposals for IGFCs.

A: I summarize the major elements of the parties' IGFC proposals in **Table 1**, focusing on the impact of each proposal on the volumetric rates in each utility's default residential time-of-use (TOU) rate.

Table 1: *Summary of Parties' IGFC Proposals*

Party	Utility	New Income-graduated Fixed Charges *($/month)*				Costs included in Fixed Charge	Volumetric Rate Reductions (Non-CARE)	
		Average	Number of Tiers	Top Income Tier			*Tier 2 (S/kWh)*	Tier 2 %
				Income	Charge			
Joint IOUs	PG&E	$53	4	> $150k (> 650% FPL)	$92	MCAC, D-EPMC, NBCs, MDC-NB (PG&E), EIA (SDG&E)	-0.143	-36%
	SCE	$49			$85		-0.125	-30%
	SDG&E	$74			$125		-0.248	-43%
	Average	**$54**			**$94**		**-0.146**	**-34%**
TURN/NRDC	PG&E	$37	3	> $150k	$62	MCAC, MDC-NB, EPMC, NBCs	-0.094	-24%
	SCE	$36			$62		-0.088	-21%
	SDG&E	$37			$62		-0.117	-20%
	Average	**$36**			**$62**		**-0.094**	**-22%**
Cal Public Advocates	PG&E	$27	3 CARE, 3 Non-CARE	> $100k	$37	MCAC, EPMC, NBCs	-0.074	-18%
	SCE	$26			$35		-0.068	-17%
	SDG&E	$33			$43		-0.107	-18%
	Average	**$28**			**$37**		**-0.075**	**-18%**
Sierra Club	PG&E	$24	5	> $200k	$94	MCAC, 10% MDC, EPMC, NBCs	-0.065	-16%
	SCE	$32			$189		-0.101	-25%
	SDG&E	$32			$136		-0.116	-20%
	Average	**$28**			**$131**		**-0.086**	**-20%**
SEIA	PG&E	$8	3	Above CARE or FERA	$9	MCAC	-0.019	-5%
	SCE	$8			$9		-0.043	-10%
	SDG&E	$11			$13		-0.055	-9%
	Average	**$8**			**$10**		**-0.034**	**-8%**

Acronyms and Abbreviations for Table 1:
MCAC – marginal customer access costs
MDC – marginal distribution costs
MDC-NB – marginal distribution costs for new business (PG&E proposal)
EPMC – EPMC scalar for specified marginal costs
D-EPMC – all non-marginal distribution costs (IOU proposal)
NBCs – non-bypassable charges (exactly which NBCs are included varies between proposals)
FPL – federal poverty limits/guidelines
EIA – new Electrification Incentive Adjustment (SDG&E proposal)

The implementation of new residential fixed charges will result in a reduction in volumetric rates. The last two columns of Table 1 show the typical volumetric rate reductions from each proposal, based on the reductions in the default residential rate reported in each parties' output from the E3 Fixed Charge Tool (E3 Tool). Importantly, the new fixed charges generally reduce volumetric rates by an equal cents per kWh across all TOU periods, including in the 4 p.m. to 9 p.m. on-peak period.

Q: In general, what will be the bill impacts of these proposals?

A: Residential customers in the lowest income tiers will see bill reductions. There will be significant bill increases for ratepayers in the top income tiers, particularly for middle- and upper-income customers in cooler coastal climate zones where electric use is lower. In addition, as discussed further in Section VI, bills will increase substantially for all customers who have reduced their use of electricity through investments in clean distributed energy resources (DERs) such as energy efficiency measures and distributed solar and storage systems. All residential customers will see reductions in the volumetric rates applied to their electricity usage.

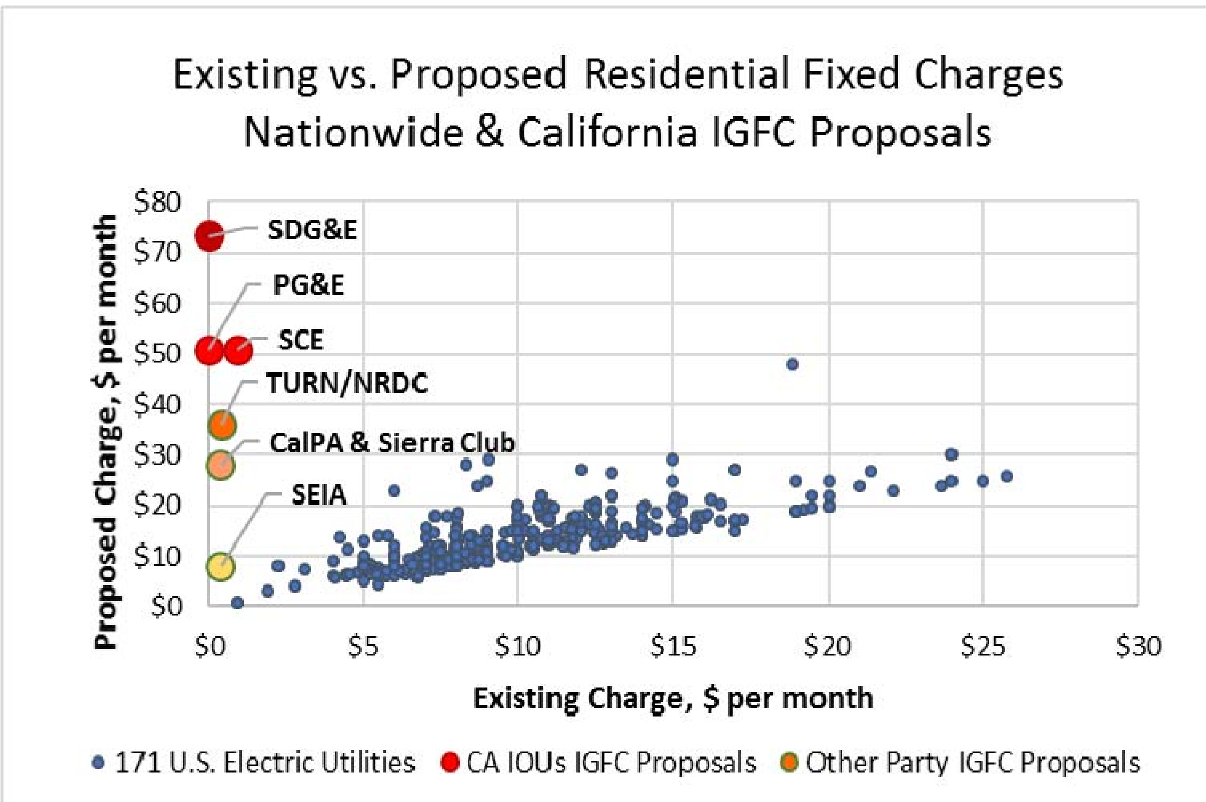
Q: What is the central issue that emerges from these proposals?

A: The central issue is clearly the magnitude of the residential IGFC. This rebuttal testimony will focus on that key issue.

Q: Would the proposals of the parties other than SEIA result in monthly residential fixed charges in California that are far larger than those typical in the U.S. electric utility industry?

A: Yes. **Figure 1** below shows the major IGFC proposals in this case, compared to a survey from EQ Research of the current monthly residential fixed charges for 171 other U.S. electric utilities, as well as the fixed charges that these 171 utilities proposed in their last rate cases.

Figure 1: *Residential Fixed Charges in the U.S. Electric Industry*



The average approved residential fixed charge of these 171 electric utilities is $11 per month.

As shown in Figure 1, EQ Research's survey data also includes the most recent utility rate case proposals to increase residential fixed charges. In the four years 2019-

2022, the average increase proposed by the utility was about $2 per month, with the state commission adopting an average increase of less than $1 per month.

Q: Given that the proposals for high IGFCs would result in a major structural change in residential rates that is far beyond industry experience or norms, have the proponents of these high fixed charges considered the possibly significant consequences of such a change?

A: No, they have not. For example, in discovery we asked the three IOUs (Joint IOUs) and the Utility Reform Network / Natural Resources Defense Council (TURN/NRDC) if they had considered any of these likely impacts of their proposals for high IGFCs:

- Much lower on-peak volumetric rates will increase the summer net peak demands that California has struggled to meet in recent years, jeopardizing reliability.
- The high IGFCs will slow customer adoption of load-reducing DERs such as energy efficiency and distributed renewable generation and storage.
- The large rate increases for higher-income customers will increase the potential for significant grid defection by the customers who can most afford to leave.

In response, the Joint IOUs and TURN/NRDC stated that they have not considered any of these possible consequences of their proposals.[2] Exploring those consequences will be the major theme of this rebuttal, in Sections III to VII.

In addition, Section VIII of this rebuttal shows that the economic rationale for high fixed charges disappears if one updates the social marginal cost of electricity in California. Section IX discusses why the high IGFC proposals violate several of the Commission's longstanding rate design principles. Finally, Section X addresses the implementation issues associated with these proposals, including the high cost of implementation.

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2 See the responses of the Joint IOUs to SEIA DR 1, Q3, Q5, Q6, and Q7 and of TURN/NRDC to SEIA DR 1, Q3, Q5, Q6, and Q7. These responses are provided in **Attachment RTB-4**.

B. Interpreting AB 205

Q: Has your review of parties' IGFC proposals identified any possible issues with compliance with AB 205?

A: Possibly, depending on how the Commission interprets AB 205. AB 205 provides as follows: "[t]he fixed charge shall be established on an income-graduated basis with no fewer than three income thresholds so that a low-income ratepayer in each baseline territory would realize a lower average monthly bill without making any changes in usage."[3] This sentence is ambiguous in terms of the "lower average monthly bill" standard, because it does not state exactly what the average bill has to be lower than. This language can be interpreted simply as specifying what is meant by "income-graduated" – in other words, defining "income-graduated" as meaning that, in every baseline territory, a customer whose income falls in a lower level will see a lower electric bill than if the customer were in a higher income level, assuming no change in usage.[4] However, another reasonable interpretation of this section of AB 205 is that "a lower average monthly bill" means that, in each baseline territory, a low-income customer's bill after implementation of the IGFC must be lower than their bill before the fixed charge was implemented, again assuming the same usage.

Q: If the Commission adopts this second interpretation, are there potential issues with parties' proposals?

A: Yes. I believe this issue impacts the following IGFC proposals of other parties:

- Cal Advocates for CARE customers in SCE's Baseline Territory
- TURN/NRDC for FERA customers in coastal baseline territories

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[3] P.U. Code Section 739.1(c)(1).

[4] This is the interpretation used in SEIA's direct testimony, at p. 22, where I note: "The first-tier (CARE) and second-tier (FERA+) discounts to the fixed charge will ensure that low-income customers in these tiers will realize a lower average monthly bill compared to a third-tier (non-low-income) residential customer with the same usage."

SEIA's proposal is also impacted slightly by this second interpretation. In SEIA's proposal, there are a few coastal climate zones where CARE and FERA bills would increase very slightly (typically by 1% or less), compared to bills before the fixed charge is implemented.[5]

C. Possible Modification to SEIA's Proposal

Q: If the Commission adopts the interpretation that AB 205 requires that a typical low-income customer's bill after implementation of the IGFC to be lower than their bill before the fixed charge was implemented, in each baseline territory, is there a simple modification to SEIA's proposal to resolve this issue?

A: Yes. If this interpretation of AB 205 is adopted, then SEIA proposes to reduce our proposed CARE fixed charges as necessary to produce lower bills for the average low-income (CARE and FERA) customer in all baseline territories for each IOU. The Tier 3 fixed charge for non-low-income customers would be increased as necessary to recover the additional fixed charge discounts. **Table 2** shows SEIA's proposed fixed charges, both the unmodified fixed charges from my direct testimony and, in the shaded middle lines of the table, the modified fixed charges necessary to resolve this issue using the second interpretation of AB 205. **Attachment RTB-3** to this rebuttal is the requested output from the E3 Fixed Charge Tool for the Modified SEIA proposal shown in the middle section of Table 2.

[5] SEIA's direct testimony acknowledged these very small bill increases in coastal baseline territories, on page 23, lines 22-24.

Table 2: *Modifications to the SEIA Proposal ($ per Month)*

Version	Customer	PG&E	SCE	SDG&E
Direct Testimony (Errata)	CARE	4.93	5.32	7.43
	FERA+	7.45	7.71	10.77
	All other	9.09	9.41	13.14
Modified	CARE	3.37	3.44	6.21
	FERA+	7.96	8.29	11.12
	All other	9.72	10.11	13.57
Change: Direct to Modified	CARE	(1.56)	(1.88)	(1.22)
	FERA+	0.51	0.58	0.35
	All other	0.63	0.70	0.43

III. HIGH RESIDENTIAL FIXED CHARGES WILL RESULT IN RECKLESS INCREASES IN SUMMER NET PEAK DEMAND, HIGHER LONG-TERM RATES, AND ENVIRONMENTAL HARM

Q: What is the first stated goal of this OIR?

A; The first goal of the OIR is to "enhance the reliability of California's electric system." This goal aligns with the Commission's Rate Design Principle No. 5: "[r]ates should encourage customer behaviors that improve electric system reliability in an economically efficient manner."

Q: You have observed that the IGFC proposals will reduce volumetric rates by an equal cents per kWh amount across all TOU periods, including the on-peak period. Should these on-peak rate reductions be a significant concern for the Commission?

A: Yes. Large reductions in on-peak electric rates will increase on-peak electric demand. California can barely meet today's summer demand in the net load peak hours. As the Commission is well aware, the California Independent System Operator (CAISO) had to implement rolling blackouts in 2020 and just barely avoided them on September 6, 2022.

The Joint IOUs propose to reduce summer on-peak volumetric residential default rates by an average of -26%. This will increase the summer peak residential demand of the IOUs by +3.4% in the short-run and by +13% to +26% in the long-run, assuming a short-run price elasticity of electric demand of -0.13 and a long-run elasticity of -0.5 to -1.0.[6] Today's residential peak demand for the three IOUs in the net load peak hours is about 17,000 MW, based on the residential load profile data in the E3 Tool. Thus, if the Joint IOU proposal is adopted, demand in the net load peak could be expected to increase by 575 MW immediately and by 2,200 to 4,400 MW over time. This contrasts to the SEIA proposal, which would increase short-run demand by just 130 MW and long-run demand by 500 to 1,000 MW.

Q: Are there reasons to believe that the increases in peak demand resulting from high residential fixed charges could be even larger than what you have just cited?

A: Yes. Electrifying transportation is a central goal of the state's clean energy efforts. EVs represent a major new end use of electricity that has only become widely available in recent years. EV adoption is unlikely to be reflected in estimates of long-term price elasticities derived from data on historical electric demand. An EV can add significantly to a residential customer's annual electric use and the customer's maximum demand. A typical EV driven 12,000 miles per year will use over 3,400 kWh per year; a Level 2 home charger will draw 7 kW when in use. As a result, the additional uptake of EVs resulting from lower residential rates will increase electric demand for EV charging more quickly than expected, above the forecasts for light-duty EV charging now used for the state's Integrated Resource Plan (IRP). The Joint IOU testimony cites a study that demand for EVs increases by 2% for each $0.01 per kWh reduction in electric rates.[7]

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6 The Sierra Club testimony, at p. 56, footnote 80, cites an Energy Information Administration (EIA) study of price elasticities of electric demand based on energy use in buildings, with a short-run price elasticity of -0.13 and a long-run elasticity of -0.5. Other estimates of the long-run elasticity in the U.S. have centered on -1.0; see Paul J. Burke and Ashani Abayasekara, *The price elasticity of electricity demand in the United States: A three-dimensional analysis* (Centre for Applied Macroeconomic Analysis, August 2017), at p. 17. Available at https://cama.crawford.anu.edu.au/sites/default/files/publication/cama_crawford_anu_edu_au/2017-08/50_2017_burke_abayasekara_0.pdf.

7 See Joint IOU testimony, at p. 13.

This suggests that the Joint IOUs' proposal to reduce residential rates by an average of $0.146 per kWh (see Table 1) will increase uptake of light-duty EVs by 29%. In discovery, the IOUs provided their current forecasts of the demand for light-duty EV charging as well as the hourly profile of EV charging loads. A 29% increase in these forecasts will raise net peak demand by an additional 270 MW over the next 10 years, assuming the current load profiles for EV charging. An acceleration of the trajectory of EV adoption would be welcome for achieving the state's carbon reduction and clean air goals, but only if it does not come at the expense of electric reliability. As discussed fully in Section IV, the same acceleration of EV adoption can be achieved without endangering reliability, by encouraging customers to move to TOU rates with lower off-peak rates and to charge their EVs only in off-peak hours.

Q: What are current projections for increases in peak demand, and the associated need for additional transmission and distribution infrastructure, to meet California's existing electrification goals?

A: The Commission contracted with the consultancy Kevala to perform a bottom-up load forecast of the impact on electrification on the IOUs' distribution systems. The Kevala report was issued on May 9, 2023.[8] Here are some highlights, with references to the report:

- Needed distribution upgrades could total $50 billion by 2035 if not mitigated (Figure ES-1).
- Both of the High Transportation Electrification scenarios that Kevala examined would result in almost doubling the current rate of spend reported by the IOUs in their Grid Needs Assessment reports for capacity requirements related to feeders, transformer banks, and substations (page ES-6).
- The system-level peak load increase from 2025 to 2035 is 56%, or 4.5% per year, on average across the three IOUs and the High Transportation Electrification

[8] The Kevala report is available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF.

scenarios (see Figure ES-2); this dramatic increase in peak load growth for the scenarios considered in Part 1 is primarily due to transportation electrification impacts, with over 60% of this demand coming from light-duty EVs. Kevala's estimates for additional peak demand growth from light-duty EVs are significantly higher than those reflected in the Joint IOU light-duty EV forecasts provided to SEIA in discovery.

- Kevala's unmitigated load forecast assumes today's TOU rate structures. Kevala did not examine mitigation strategies such as alternative TOU or dynamic rate designs and flexible load management strategies; nor did they consider changes such as high IGFCs and the associated lower on-peak rates that would make future peak demands even higher than estimated by Kevala (pp. ES-1 to ES-2).

Q: Does California face significant challenges in procuring adequate clean energy resources, and transmitting and distributing that new generation to load, even without the large increases in residential demand that would result from the high fixed charge proposals of the Joint IOUs and TURN/NRDC?

A: Yes. On May 4, 2023, the California Energy Commission held a workshop on the increasing difficulties of interconnecting utility-scale clean generation to the CAISO grid, including the growing need for new transmission capacity.[9] The CAISO's presentation at this workshop emphasized that "California's climate change goals are driving escalating load forecasts," especially as a result of increasing load forecasts for transportation electrification (i.e. EVs), resulting in "unprecedented resource needs" to meet the escalating future demand for electricity.[10] The pace of deployment of solar and other renewables must grow to several times the recent historical growth,[11] and there is a clear

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[9] CEC IEPR Commissioner Workshop on Clean Energy Interconnection: Bulk Grid (CEC Interconnection Workshop), held May 4, 2023. The presentations at this workshop are available at https://www.energy.ca.gov/event/workshop/2023-05/commissioner-workshop-clean-energy-interconnection-bulk-grid.

[10] See CEC Interconnection Workshop, CAISO presentation of Jeff Billinton, at Slides 3 and 4.

[11] See CEC Interconnection Workshop, Environmental Defense Fund (EDF) presentation of Michael B. Colvin, at Slide 5; also CAISO presentation of Neil Millar, at Slide 3.

need for new transmission, which has increasingly long lead times to develop, permit, and build.[12]

Given the tight supply/demand balance in California today, and the increasing challenges of meeting escalating future demand, the proposals for high IGFCs are reckless. They threaten significant and unanticipated increases in summer peak demand of a magnitude that could threaten the reliability of the state's electric system at a time when the growth in demand must be carefully but aggressively managed if clean energy goals are to be met. Despite these parlous circumstances, both the Joint IOUs and TURN/NRDC admitted in discovery that they have not considered the impacts of their proposals on electric demand.[13] The Sierra Club admits that "electricity demand could increase by about 2-3%" in the short-run, but does not recognize the consequences of such an increase except to hope that the increased usage is for electrification (which it recognizes is not guaranteed).[14] As noted above, both the first stated goal of this OIR and Rate Design Principle No. 5 emphasize that rates should encourage customer behaviors that improve electric system reliability. The proposals for high IGFCs would do exactly the opposite.

Q: There is no debate among the parties that electric rates on California are high.[15] Will the proposals for high residential IGFCs result in higher or lower rates over time, in comparison to the SEIA proposal?

A: The proposals for high IGFCs will result in higher rates over time. As discussed above, these proposals will result in significantly higher peak demands. Peak demand is the key

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[12] See CEC Interconnection Workshop, SEIA presentation of Rick Umoff, at Slide 8; EDF (Colvin), at Slides 6 and 10; Center for Energy Efficiency and Renewable Technology and GridLab presentation of Ed Smeloff, at Slides 2 and 3.

[13] See the responses of the Joint IOUs to SEIA DR 1, Q3 and of TURN/NRDC to SEIA DR 1, Q3, which are included in **Attachment RTB-4**.

[14] Sierra Club testimony, at p. 56.

[15] See SEIA testimony, at pp. 3 and 9; California Public Advocates testimony, at pp. 3-5; Joint IOU testimony, at p. 1.

driver of the costs for generation, transmission, and distribution infrastructure, as the Kevala report highlights. This is shown clearly by the hourly profile of long-run marginal costs, discussed in Section VIII and illustrated clearly in **Figure 4** in that discussion. For example, based on the long-run marginal costs for generation, transmission, and distribution capacity used in the ACC and shown in Figure 4, the Joint IOU proposal will result significantly higher annual revenue requirements compared to the SEIA proposal, with the difference growing from $195 million per year (initially) to $1.1 billion per year (in the long run).[16] Over time, this will reduce the difference between the average volumetric rates under the SEIA and Joint IOU proposals.

The Commission's sixth Rate Design Principle is that "[r]ates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs." This goal is reflected in one of the stated objectives of this OIR: to "reduce long-term system costs through more efficient pricing of electricity." Implementing high IGFCs that raise on-peak demand will <u>increase</u> long-term system costs. As discussed further in Section IV below, a more efficient and effective pricing strategy will be to focus on reducing off-peak electric rates, in order to serve electrification needs using off-peak electricity that is cleaner and lower in cost, and that does not cause unnecessary infrastructure investments that, in the long-term, would raise system costs and customers' rates. Adding electrification load in off-peak hours will reduce rates going forward, because this new load can be served with existing infrastructure, and will spread the costs for the existing system over greater volumes.

Q: Did any of the parties who are proposing high IGFCs assess the impact of their proposals on future IOU revenue requirements and rates?

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16 This assumes that, in the long run, demand would be 450 MW to 2,500 MW higher under the IOU IGFC proposal than the SEIA proposal. The average of the marginal costs for generation, transmission, and distribution capacity used in the 2022 ACC for the three IOUs is $431 per kW-yr. 0.45 to 2.5 million kW x $431 per kW-yr = $195 to $1,080 million.

A: Only the Sierra Club acknowledged that lower rates will result in higher usage, but they did not consider the impact on peak demand or on future revenue requirements or rates.[17] The other proponents of high IGFCs are silent on the impacts of their proposals on future revenue requirements and rates. Given the potential for these proposals to increase peak demand and future grid infrastructure costs, they are inconsistent with Rate Design Principle No. 6.

Q: Will the higher on-peak demand stimulated by high IGFCs degrade California's environment?

A: Yes. California still burns significant amounts of natural gas for electric generation, particularly during summer peak demand periods. When electric demand is high, the least-efficient gas plants are on the margin, producing higher amounts of greenhouse gases and criteria air pollution. **Figure 4** in Section VIII quantifies the societal costs of the additional environmental harm from these higher on-peak air emissions, using the social cost of carbon to quantify the additional damages from climate change and recent Commission-sponsored research to value the health impacts of greater emissions of criteria air pollution.

IV. LOWER OFF-PEAK RATES ARE A BETTER WAY TO INCENTIVIZE ELECTRIFICATION

Q: The proponents of high IGFCs argue that significant across-the-board reductions in volumetric rates are needed to encourage customers to use more electricity in electrification technologies.[18] Are there better ways to encourage electrification than high IGFCs?

[17] See Sierra Club testimony, at pp. 55-56.

[18] See Joint IOU testimony, at p. 13: "The Joint IOUs' proposals make electrification more attractive than the status quo by helping incentivize adoption through lower volumetric rates...."

A: Yes. A better way to incentivize electrification is (1) to offer low off-peak rates, (2) to market the benefits of these rates to customers adopting electrification measures, and (3) to provide direct incentives for adoption of these measures. As I discussed in my opening testimony, using PG&E as an example, the existing PG&E residential electrification rate (E-ELEC) and PG&E's EV charging rate (EV2A) offer off-peak rates that are $0.09 to $0.17 per kWh (22% to 43%) lower than the current off-peak E-TOU-C default rate. PG&E's IGFC proposal would reduce E-TOU-C volumetric rates by about $0.14 per kWh. In other words, the E-ELEC and EV2A schedules already offer off-peak rates that are similar to, or lower than, the default E-TOU-C rates that would result from PG&E's IGFC proposal. More important, the existing E-ELEC and EV2A rates have markedly higher (by $0.20 per kWh!) summer on-peak rates than would result from PG&E's IGFC proposal, so they continue to encourage vital conservation and demand reduction during summer peak periods. This comparison between the existing E-ELEC rate (which SEIA would not change) and SEIA's proposed EV2A rates, versus PG&E's IGFC proposal for its default E-TOU-C rate, is shown in **Table 3**.

Table 3: *Existing E-ELEC and EV2A Rates versus PG&E's IGFC Proposal*

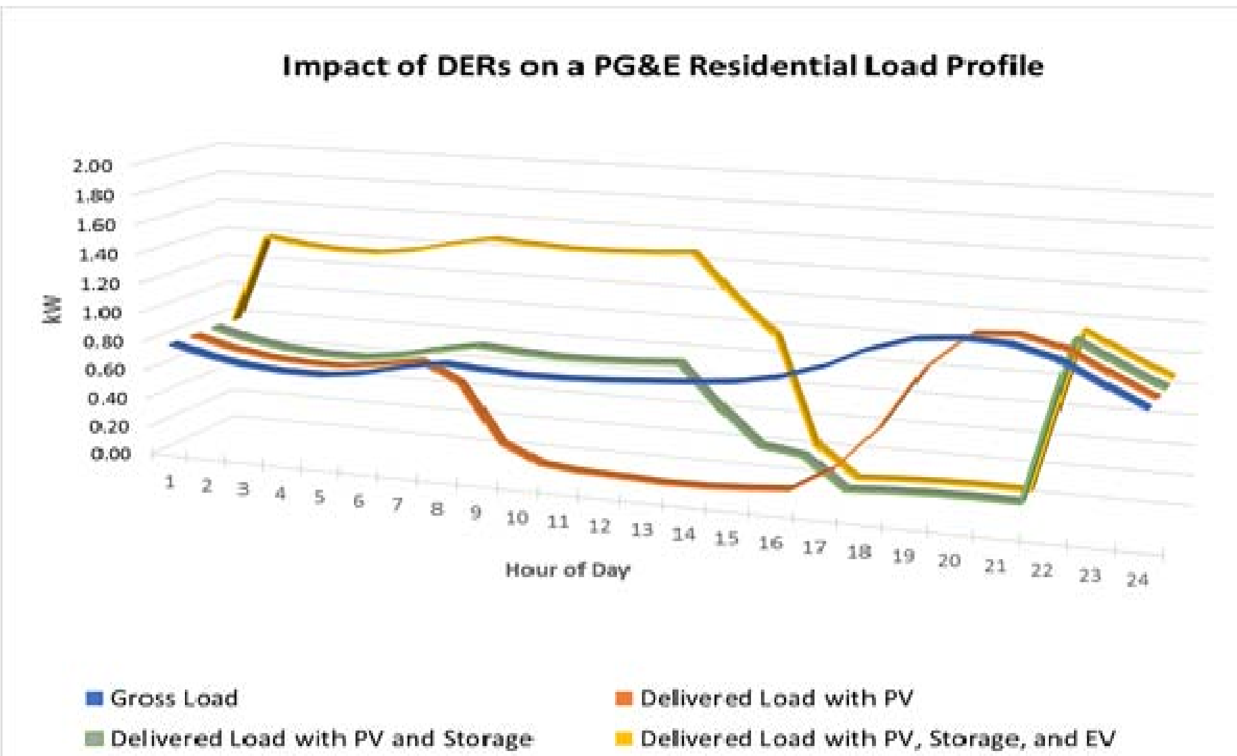
Rate	Fixed Charge *($/month)*	Summer			Winter		
		Peak	Part	Off-peak	Peak	Part	Off-peak
PG&E Proposed E-TOU-C (Tier 2)	53.00	0.341	0.278		0.244	0.227	
SEIA Proposed EV2	9.09	0.528	0.420	0.230	0.404	0.388	0.230
Existing / SEIA E-ELEC	15.00	0.546	0.373	0.314	0.302	0.280	0.266

Q: Can you provide an example of a customer who takes multiple steps to electrify their home and transportation? Please compare the customer's costs after completing this process under (1) the Joint IOU IGFC proposal and (2) the SEIA proposal.

A: In my opening testimony, I discussed the likelihood that customers will adopt multiple DER technologies in the electrification process. I provided the example of a PG&E residential customer who adopts three different DER technologies in succession. **Figure 2** shows this customer's changing load profile through their electrification journey:

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

Figure 2



This multiple-DER customer makes three important contributions to California's reliability, clean energy, and environmental goals:

- A significant reduction in peak capacity, from the storage unit;
- Reduced carbon emissions and criteria air pollution, from the EV; and

- From the solar, local renewable energy equal to more than half of the customer's usage. This new renewable generation is sited on the customer's own premises, without requiring the use of other lands or new transmission or distribution capacity.

Notably, at the end of this process, the customer has reduced their on-peak demand by 80%. The customer's annual usage of delivered energy from the PG&E system actually has increased to 8,450 kWh, compared to their pre-DER usage of 7,500 kWh per year, but this is significantly less than their total electric end use of 11,000 kWh per year. Finally, the customer exports 2,500 kWh per year of excess solar output, which is used by neighboring customers.

I have calculated the change in this customer's electric bill from the beginning to the end of this electrification journey, under both the SEIA and Joint IOU proposals. I assume that the exports from the customer's solar-plus-storage facilities are compensated at the rates used in the new net billing tariff (NBT) adopted in D. 22-12-056. The customer saves money on its electric bill, despite the increased usage from the EV (and also saves additional money from reduced purchases of gasoline). I evaluated the annual bill savings under three difference PG&E residential rates – the default E-TOU-C rate, and the two PG&E electrification rates – E-ELEC and EV2A. The results are shown in **Table 4**. The bill savings are significantly greater if the customer elects one of the two electrification rates, which have larger and more cost-based TOU rate differentials. SEIA's proposal, despite its modest fixed charge, produces similar bill savings as the PG&E IGFC under the E-ELEC rate, and superior bill savings under EV2A – by almost $300 per year – because EV2A has the largest TOU differentials and the lowest off-peak rates of any PG&E residential schedule. These results show that cost-based TOU rates, with low off-peak rates and larger TOU differentials, are more effective than large fixed charges in promoting beneficial electrification scenarios in which customers adopt multiple types of DERs that produce a comprehensive set of system benefits. It is important to design rates that support customer adoption of multiple electrification measures that produce a range of important system benefits, as I have modeled here.

Table 4: *Bill Savings from Electrification: SEIA vs. Joint IOU Proposals ($ per year)*

Proposal	Average IGFC *($/month)*	Bill Savings by Rate Schedule *($/year)*		
		E-TOU-C	**E-ELEC**	**EV2A**
SEIA	8	105	520	745
Joint IOU (PG&E)	53	239	560	450

Q: Are there circumstances under which it might be necessary to lower volumetric rates to make electrification economic?

A: Possibly. Lower volumetric rates might be needed, for example, if electric rates for EV charging were not competitive in price with liquid fossil fuels such as gasoline and diesel, or if the electric heat pumps were more expensive than burning natural gas for space or water heating. However, this is not the case today. Current gasoline prices of $5 per gallon in California are equivalent to electricity at about $0.50 per kWh,[19] which is above even SDG&E's average residential rates. Thus, there is no pressing need for a major reduction in residential volumetric rates to provide fuel cost savings for EV owners. It is illuminating that, a few days before PG&E served its testimony arguing that it needs to implement a high IGFC to encourage EV adoption, the utility filed a report on its commercial EV rates warning that the utility expects to <u>increase</u> these rates, from their current levels of $0.19 - $0.24/kWh.[20] I reproduce below Figure 3.31 from the PG&E report in AL 6906-E, in which PG&E shows that its current commercial EV charging rates of $0.19 - $0.24/kWh (green bars) are very competitive with liquid fuels (yellow diamonds) at costs equivalent to about $0.50 per kWh. PG&E's message in this report is that liquid fuel costs present no barrier to <u>increasing</u> these commercial EV rates. Yet a

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[19] For example, assuming gasoline at $5.00 per gallon, a comparable gasoline vehicle with a fuel efficiency of 35 miles per gallon, and an EV that can go 3.5 miles per kWh of electricity used (the average mileage per kWh for today's EVs), the EV needs to be supplied with electricity priced at less than $0.50 per kWh to realize fuel cost savings over the gasoline vehicle (i.e. [$5.00/gallon / 35 mpg] x 3.5 mpkWh = $0.50 per kWh).

[20] See PG&E Advice Letter 6906-E (April 3, 2023), conveying PG&E's second *Business Electric Vehicle (BEV) Rate Annual Performance Report*. At page 5, PG&E states that "PG&E will likely recommend in its 2023 GRC Phase II proceeding that BEV distribution rates should be increased…."

few days later PG&E served its fixed charge proposal saying that it is necessary to reduce residential volumetric rates to these same or lower levels to encourage EV adoption. Both of these cannot be true.

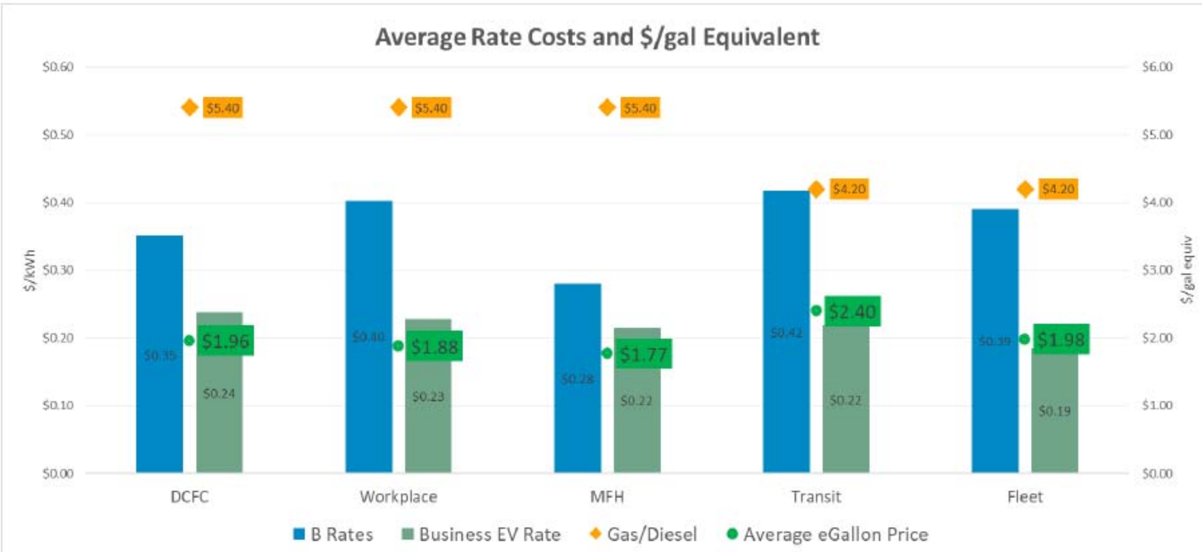

Figure 3.3-1 BEV Rate Savings per Use Case

Natural gas prices have moved to higher levels since the war in Ukraine began, resulting in additional savings for building electrification. The results from the E3 Tool show that all of the proposals in this case produce significant savings from the use of heat pumps for space and water heating. Examples of these savings under the SEIA and Joint IOU proposals for inland climate zones are shown in **Table 5**. These results show that taking service under a rate with lower off-peak rates (such as the PG&E EV2A and SCE TOU-D-PRIME rates) provides just as significant a boost to electrification as the lower volumetric rates from the high fixed charges in the Joint IOU proposal. Thus, as shown in Table 5, the SEIA proposal under the EV2A and TOU-D-PRIME rates produces similar savings to the default residential rates under the Joint IOU proposal.

Table 5: *Monthly Bills When Mixed Fuel Customers Electrify*

Utility	Zone	Rate	Bill	SEIA			Joint IOU		
				Mixed fuel	**Electrify**	**Savings**	**Mixed fuel**	**Electrify**	**Savings**
PG&E	Inland Zone X	E-TOU-C	Electric	305	340	36	293	316	22
			Gas	76	13	(64)	76	13	(64)
			Total	381	353	(28)	370	328	(41)
		EV2A	Electric	294	318	24	287	299	11
			Gas	76	13	(64)	76	13	(64)
			Total	370	331	(40)	364	312	(52)
SCE	Inland Zone 6	TOU-D 4p-9p	Electric	312	348	35	313	339	26
			Gas	84	16	(67)	84	16	(67)
			Total	396	364	(32)	397	355	(41)
		TOU-D PRIME	Electric	321	344	23	313	326	13
			Gas	84	16	(67)	84	16	(67)
			Total	404	360	(44)	397	343	(54)

Q: But aren't lower rates important to encourage customers to invest in electrification measures such as EVs and heat pumps, by increasing their savings from these investments?

A: Sure, I agree that lower rates are helpful to promote electrification, but my point is that it is not necessary to reduce rates by significant amounts across the board, in every TOU period – as high IGFCs would do. Given current prices for fossil fuels in California, it is not necessary to sacrifice other important rate design goals – such as continuing to promote conservation during peak demand periods when reliability is threatened and when high demands drive infrastructure costs that raise long-term rates even further.

Q: Should the Commission take a broader approach to using rate design to encourage electrification, rather than focusing just on using fixed charges?

A: Yes. Commendably, the Commission has adopted a broad perspective for this OIR. Subsequent phases of this case will examine the use of more dynamic and more time-sensitive rates to encourage demand flexibility. It is unfortunate that this initial phase is focusing only on fixed charges, which are just one of many rate design tools that the

Commission should use to promote electrification. The theme of this rebuttal is that an overreliance on high fixed charges will have adverse, and foreseeable, consequences for the state's electric system. It would be far more prudent for the Commission to implement modest, cost-based fixed charges that are coordinated with other important rate design changes in subsequent phases of this OIR, such as:

- **Increased TOU differentials**, particularly in default residential rates, which continue to be "TOU-lite," with TOU rate differences that are far below marginal cost levels. When the Commission adopts new fixed charges that result in reductions in the overall level of default residential TOU rates, this change should be coordinated with increases in TOU rate differentials, so that there are minimal changes to on-peak rates, which should remain at levels that strongly encourage conservation during peak demand periods.
- **Phase-out the outdated increasing block rates.** I agree with the Joint IOUs that these rates are not cost-based and send the wrong message that any increase in electricity use will cost more.[21]
- The Commission should approve the **expanded use of more dynamic rates** that provide consumers with better information – beyond the basic TOU periods – about exactly when demands and costs are high and when it is cheaper and cleaner to use more electricity.

As discussed in the later sections of this testimony, implementing high IGFCs would be difficult, contentious, costly, and time-consuming. It makes little sense for the Commission and the state to spend significant time and resources in such an effort, when that time and money would be better spent on more direct, more effective, less risky, and less costly ways to advance electrification.

[21] See Joint IOU testimony, at p. 12, footnote 11: "Inclining-block tiered rates are especially problematic in this regard, charging artificially inflated rates for usage in the upper tiers – precisely the tiers that customers who substitute electric appliances for those powered by fossil fuels are likely to end up in."

V. OTHER OPTIONS ARE AVAILABLE FOR LOW-INCOME RATE REDUCTIONS

Q: Based on the outputs from the E3 Tool, other parties' proposals would result in larger rate reductions for low-income customers than the SEIA proposal. Please provide the context for SEIA's proposal with respect to rate reductions for low-income customers.

A: SEIA supports expanding assistance for low-income ratepayers who are most burdened by California's high electric rates. The passage of AB 205 clearly indicated the Legislature's intent that this assistance should increase – for example, although AB 205 did not increase the CARE rate discounts in percentage terms, it did increase the overall rate discounts for CARE customers by directing that the CARE discount be applied after exempting CARE customers from certain costs.[22] Significantly, this exclusion includes "discounts to fixed charges." Other parties appear to interpret this as allowing significantly larger low-income discounts for fixed charges than the 30% to 35% CARE discount and the 18% FERA discount, although AB 205 provided no specific guidance on how large the new fixed charges, or the associated low-income discounts, should be. As is obvious from other parties' proposals, a major expansion of low-income customer assistance through IGFCs will come at the expense of large rate increases for other ratepayers.

In SEIA's view, income-graduated fixed charges are neither the only nor the best way to expand assistance to low-income customers. SEIA's proposals for the low-income discounts for new fixed charges for CARE and FERA+ customers follow the guidance in existing law and in AB 205. Our fixed charge discounts are based the existing 30% to 35% CARE discount and the 18% FERA discount, and include the new condition from AB 205 that the fixed charge discounts are not included in the calculation of the effective CARE discount. SEIA also supports further expansion of support for low-income ratepayers beyond its fixed charge proposal, but recommends that other

[22] See P.U. Code Section 739.1(c)(1).

mechanisms be used instead of rate reductions that must be funded directly from electric rates or that are not offset by other benefits that will reduce rates.

Q: What other such mechanisms are available?

A: There are several. First, SEIA supports exploring the proposal from Cal Advocates to re-allocate the biannual California Climate Credit,[23] which is funded from revenues from the GHG cap & trade program, so that a higher share of these funds is rebated to low-income customers. For example, if the SEIA proposal were enhanced by using just 50% of the Climate Credit for additional CARE discounts – by reducing the CARE fixed charge to zero and raising the CARE discount percentage for volumetric rates – this would achieve the same reductions in CARE customers' monthly bills as the Joint IOU proposal.[24]

Second, SEIA supports expanding low-income programs that result in direct participation of low-income customers in adopting DERs, including electrification measures. Providing low-income customers with support to actually invest in DERs is preferable to simply providing lower bills. For example, the Commission should adopt the robust new community solar program recommended in A. 22-05-022 by the Coalition for Community Solar Access (CCSA), pursuant to AB 2316. The CCSA proposal would provide low-income customers who are unable to install solar on their own premises with access to the power from specific community solar-plus-storage projects and with significant guaranteed bill savings for the low-income participants. AB 2316 mandates that at least 51% of the power from such projects must serve low-income ratepayers.

Finally, SEIA recommends that the state should devote increased support to targeted EV and heat pump incentives for low- and moderate-income customers. Such

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[23] Cal Advocates testimony (Chau/Nichols), at pp. 1-23 to 1-24.

[24] This use of 50% of the Climate Credit for targeted bill savings for CARE customers is an average across all three IOUs. For individual IOUs, based on the IOU-specific Climate Credit amounts shown in Cal Advocates' Table 13 on page 24, after providing the additional support for CARE customers, PG&E still have 30% of its original credit funds ($24 per year) available to distribute to all residential customers. SCE would be able to distribute 64% of its original credit ($76 per year), and SDG&E 54% of its original credit ($69 per year).

direct incentives are better than relying on lower rates (which customers may just pocket), because they ensure that the purchase of the electrification technology is made and that citizens of all means are participating in advancing the state's electrification goals. As the Sierra Club also recognized, simply lowering rates may not result in the uptake of electrification measures:

> 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.[25]

As discussed in Section X, rather than spend more than $200 million per year to implement a high IGFC and create a new bureaucracy to administer a possibly intrusive income verification scheme, this money would be better spent on incentives to help low-income customers actually acquire electrification technologies and become participants in the energy transition.

VI. HIGH FIXED CHARGES WILL DISCOURAGE LOAD-REDUCING DERS

Q: What impact will the lower volumetric rates resulting from high IGFCs have on DERs that reduce electric loads, such as distributed solar, storage, energy efficiency (EE), and demand response (DR) resources?

A: Obviously, lower volumetric rates will reduce the bill savings for customers who adopt these DERs. The proposals for high IGFCs will have particularly large impacts, disrupting the Commission's carefully crafted programs that support these important clean energy resources, which remain at the top of the state's longstanding "loading order" for new electric resources.[26] Load-reducing DERs are particularly important in

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[25] See Sierra Club testimony, at pp. 55-56.

[26] The state's adopted "loading order" for new resources is part of the Energy Action Plan II adopted by this Commission and the California Energy Commission in October 2005, at page 2. The state's first priority is to encourage energy efficiency; the second priority is to develop renewable

reducing peak demand and supplying the off-peak clean energy that must be the source for incremental electric use in battery storage, EVs, and heat pumps.

Q: Did the parties who are proposing high IGFCs – the Joint IOUs and TURN/NRDC in particular – assess the impact of their proposals on customers who adopt load-reducing DERs?

A: No, they did not.[27] Given the very significant bill impacts on DER customers, discussed below, this failure violates Rate Design Principle No. 10 that "[t]ransitions to new rate structures should… minimize or appropriately consider the bill impacts associated with such transitions."

A. High Fixed Charges Will Upset the Balance Achieved with the NBT Tariff

1. Impact on Solar and Solar + Storage Customers

Q: What is the current status of California's programs for residential customers who install solar and solar-plus-storage systems?

A: The Commission just completed a difficult, multi-year proceeding (R. 20-08-020) to re-set its policies and compensation for DER customers who install solar and solar-paired-storage. This proceeding involved the complex and contentious task of balancing the conflicting statutory objectives of (1) reducing the compensation to new solar and storage customers to better align the benefits and costs of these resources and (2) ensuring that these resources continue to grow in a sustainable fashion.[28] The implementation of the new net billing tariff (NBT) for prospective solar and solar-paired-storage customers is now underway.

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generation, including on-site DG such as solar PV that typically is located behind the retail meter. The Energy Action Plan II can be found at https://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf.

[27] See the response of the Joint IOUs to SEIA DR 1, Q7 and the response of TURN/NGC to SEIA DR 1, Q7, which are included in **Attachment RTB-4**.

[28] See AB 327, cited in D. 22-12-056, at pp. 7-8. D. 22-12-056 established the new NBT.

Distributed solar resources are an important component of California's Integrated Resource Plan (IRP), with expected growth in distributed solar of 1 GW per year.[29] The new NBT, plus increasing customer concerns with the resilience of their electric supply, will strongly encourage the pairing of distributed storage with new rooftop solar. The storage associated with these new solar units will be an important source of the incremental capacity needed to meet escalating peak demands.

There are also 1.5 million residential net energy metering (NEM) customers in the NEM 1.0 and 2.0 programs that operate existing solar and solar-paired-storage systems. The current and future economics of this existing renewable generation depend critically on the retail rates that these customers pay. These NEM customers represent about 14% of IOU customers, and are the ratepayers who have made the most significant personal, long-term investments in clean energy infrastructure for California.

Q: What would be the impact of other parties' proposals on solar and solar-plus-storage customers?

A: **Table 6** summarizes the impacts of the Joint IOU and TURN/NRDC proposals on customers using the new NBT, calculated with the E3 NBT model used in R. 20-08-020. The Joint IOU proposals would result in -27% to -48% reductions in bill savings for future NBT solar-plus-storage customers, with corresponding increases of 37% to 94% in the payback periods for these important customer-owned resources.[30]

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[29] D. 22-02-004 adopted the current Preferred System Portfolio (PSP) in the IRP. The RESOLVE model runs in the adopted PSP scenario show 14 GW of customer solar in 2023 and 37 GW in 2045, for growth of about 1 GW per year over this period.

[30] Tables 5a and 5b show paybacks using two solar costs: the $3.30 per watt-DC used in D. 22-12-056 and the $4.00 per watt-DC that is the current cost of solar in California, as reported in the DG Stats website that is the most comprehensive source of data on installed distributed solar in the state. See https://www.californiadgstats.ca.gov/charts/. Note that DG Stats reports prices in $ per watt-AC.

Table 6: *Impacts of IGFCs on NBT Solar and Solar-plus-Storage Customers*

IGFC Proposal	Utility	Solar-only				Solar-plus-Storage			
		Bill Savings	Paybacks (years)			Bill Savings	Paybacks (years)		
			$3.3/w	$4.0/w	Change		$3.3/w	$4.0/w	Change
D.22-12-056	PG&E	--	9.0	10.9	--	--	6.6	7.6	--
	SCE	--	9.0	10.9	--	--	6.6	7.6	--
	SDG&E	--	6.0	7.2	--	--	4.7	5.4	--
Joint IOU	PG&E	-28%	12.5	15.1	+39%	-27%	9.0	10.3	+37%
	SCE	-27%	12.3	14.9	+37%	-29%	9.2	10.6	+40%
	SDG&E	-39%	9.7	11.7	+63%	-48%	9.1	10.4	+94%
TURN NRDC	PG&E	-22%	11.6	14.0	+29%	-20%	8.2	9.4	+25%
	SCE	-25%	12.0	14.5	+33%	-26%	8.9	10.2	+35%
	SDG&E	-21%	7.5	9.1	+26%	-25%	6.3	7.2	+34%

Table 7 shows that the impacts of high IGFCs on NEM 1.0 and 2.0 solar customers would be even larger: reductions in bill savings of -34% for PG&E, -38% for SCE, and -52% for SDG&E. The impacts on NEM 1.0 and NEM 2.0 customers are larger because these customers, unlike NBT customers, are not likely to take service on an electrification rate that already includes a significant fixed charge.

Table 7: *Impacts of IGFCs on NEM 1.0 / 2.0 Solar and Solar-plus-Storage Customers*

IGFC Proposal	Utility	Solar-only				Solar-plus-Storage			
		Bill Savings	Paybacks (years)			Bill Savings	Paybacks (years)		
			$3.3/w	$4.0/w	Change		$3.3/w	$4.0/w	Change
Joint IOU	PG&E	-34%	7.2	8.7	+51%	-32%	9.7	11.1	+46%
	SCE	-38%	9.1	11.0	+61%	-31%	10.2	11.7	+45%
	SDG&E	-52%	7.6	9.2	+108%	-49%	9.8	11.2	+96%
TURN NRDC	PG&E	-27%	6.5	7.8	+37%	-26%	8.9	10.2	+34%
	SCE	-35%	8.6	10.4	+53%	-29%	9.8	11.3	+41%
	SDG&E	-27%	5.0	6.1	+38%	-26%	6.7	7.7	+35%

In terms of the percentage reductions in bill savings, the impacts shown in Tables 6 and 7 are independent of the fixed charge a customer would pay, because all residential customers would see the same percentage volumetric rate reductions. Thus, the same percentage reductions in bill savings would also apply to low-income CARE/FERA customers who install solar and storage. Tables 6 and 7 do not show the impacts of the somewhat smaller proposed IGFCs in the Cal Advocates and Sierra Club proposals; the impacts of these proposals on solar and solar-plus-storage customers are roughly half as large as the impacts shown in Tables 6 and 7.

Q: What is your conclusion about the bill impacts on prospective NBT customers?

A: High IGFCs would upset the delicate balance achieved in the difficult decision reached in December 2022 (D. 22-12-056) to establish the NBT. In that decision, the Commission adopted a target of a nine-year simple payback for a stand-alone solar system, finding that such a payback was a balanced approach to ensuring that customer-sited renewable distributed generation continues to grow sustainably, as required by P.U. Code 2827.1.[31] A fixed charge which results in a payback in excess of nine years undoes this balance and negates the Commission's determination that the newly adopted NBT will ensure sustained growth of the industry.

Q: What are the consequences of a slowdown in customer adoption of solar and solar-plus-storage systems, if a high IGFC undermines the economics of new customer-owned distributed generation and storage?

A: Distributed, customer-sited solar contributes significantly to the needed solar generation in the state's current Preferred System Portfolio (PSP). As noted above, California already faces challenging problems with bringing on-line the amounts of utility-scale solar and storage in the PSP, which assumes that all of the forecasted 1 GW per year of customer solar continues to materialize. The storage that increasingly will be paired with

[31] See D. 22-12-056, at p. 77: "As this decision determined that monthly bill savings is a major factor in customers deciding to install a solar system, this decision finds that a target of a nine-year simple payback for a stand-alone solar system — equivalent to nearly $100 in monthly bill savings — presents a balanced approach to ensuring customer-sited renewable distributed generation continues to grow sustainably."

new customer solar is also important to meeting the state's escalating peak demands. Sustaining this much-needed growth in distributed solar and storage will be threatened if the customer economics of this resource are undermined.

2. Legacy treatment to mitigate high fixed charges

Q: Has the Commission dealt in the past with changes in rates or policies that would have a significant adverse impact on the investments of NEM customers?

A: Yes, several times. This issue has emerged each time the Commission has changed its NEM policies – i.e. from NEM 1.0 to NEM 2.0 and from NEM 2.0 to the NBT – as well as when the Commission made the major structural change in TOU rates to move the on-peak period from noon to 6 p.m. to 4 p.m. to 9 p.m. In these circumstances, the Commission has adopted legacy treatment for existing NEM customers who would have been impacted adversely by the change. Thus, NEM 1.0 and 2.0 customers have been allowed to operate under the rules of those programs for 20 years from the initial operating date for their facilities.[32] The Commission also adopted limited periods – five years for residential customers and ten years for C&I customers – in which existing NEM

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[32] See D. 14-03-041, at p. 3: "The timing and rules established in this decision for transitioning to the new tariff should ensure that customers who interconnect renewable distributed generation systems under the currently applicable net energy metering program have a reasonable opportunity to recoup the costs of their investment in those systems. In addition, a 20-year transition period is consistent with some estimates of the expected useful life of such systems, reflected in many existing power purchase agreements and financing arrangements for renewable distributed generation."

Also see D. 16-01-044, at p. 100: "The Commission recently decided, in D.14-03-041 (implementing the requirements of Section 2827.1(b)(6)), that 20 years from the customer's interconnection under the existing NEM tariff was a reasonable period over which a customer taking service under the existing NEM tariff should be eligible to continue taking service under that tariff. This decision should be applied to customers under the NEM successor tariff as well, to allow customers to have a uniform and reliable expectation of stability of the NEM structure under which they decided to invest in their customer-sited renewable DG systems."

customers could continue to use the legacy TOU structure with an earlier on-peak period.[33]

Q: Do you recommend legacy treatment for NBT customers?

A: That depends on the level of the fixed charges that the Commission adopts. According to the balance struck in D. 22-12-056, NBT customers must use one of the residential electrification rates that have a fixed charge in the vicinity of $15 per month. As a result, no legacy treatment is needed under SEIA's proposal, which recommends new residential fixed charges lower than those in the existing electrification rates and no change to the fixed charges in the electrification rates. If the Commission decides to raise the fixed charges and lower the volumetric rates in the existing electrification rates – for example, as proposed in the other IGFC proposals – then changes to the NBT should be made to restore the balance just adopted in D. 22-12-056. For example, the ACC Plus Adders adopted in D. 22-12-056 can be re-calculated using the new design of the electrification rates, if the fixed charges in these rates are raised and the volumetric rates reduced. SEIA has done these calculations with the E3 net billing model used to design the NBT. These revised ACC+ Adders are summarized in **Table 8**.

[33] See, for certain residential NEM customers, D.16-01-044 at 93–94. For all types of NEM customers, see D. 17-01-006, at pp. 57-66 and footnote 48.

Table 8: *Revised ACC Plus Adders for Other Parties' IGFC Proposals*

Party	ACC Plus Adders *($/kWh)*		
	PG&E	**SCE**	**SDG&E**
Non-CARE			
D.22-12-056	0.022	0.040	--
Revised for IGFC Proposals			
Joint IOU	0.093	0.105	0.018
TURN/NRDC	0.078	0.100	--
Cal Public Advocates	0.057	0.076	--
Sierra Club	0.054	0.085	--
CARE			
D.22-12-056	0.090	0.093	--
Revised for IGFC Proposals			
Joint IOU	0.125	0.125	0.080
TURN/NRDC	0.117	0.124	0.038
Cal Public Advocates	0.099	0.104	0.029
Sierra Club	0.098	0.116	0.032

Q: Do any of the other parties support similar changes to the NBT if significant fixed charges are adopted?

A: In discovery, TURN/NRDC support revisions to the ACC+ Adders that include consideration of new fixed charges, provided there is a comprehensive update to all of the assumptions used to calculate those adders.[34] Although this update might result in a reasonable re-set of the NBT for prospective NBT customers, it does not address the NBT customers who may invest in solar and solar + storage in reliance on today's rate structure, before the IGFC is approved or implemented and before the prospective update that TURN/NRDC suggest can be performed. These pre-IGFC-implementation NBT customers should have their ACC Plus Adders revised to those shown in Table 8, because the revised adders in Table 8 are based on the assumptions used for the NBT being implemented today, with the sole change of the rate design revision of the IGFC.

[34] See response of TURN/NGC to SEIA DR 1, Q8(a), which is included in **Attachment RTB-4**.

Q: What about the significant impacts of high IGFCs on existing NEM 1.0 and 2.0 customers – reductions in bill savings from 34% to 52% for the Joint IOU proposal -- as shown in Table 7?

A: These customers also deserve legacy treatment if such proposals are adopted. According to the DG Stats data base, there are 423,000 residential NEM 2.0 systems that came on-line in just the last two years (2021 and 2022) – representing almost 30% of the total NEM 1.0 and 2.0 fleet and 4% of all IOU residential customers. The economic expectations of these customers who recently invested in solar systems will be impacted substantially if a high IGFC is adopted. Recognizing that these customers have benefitted from relatively shorter paybacks of 4 to 5 years for NEM 2.0 solar systems and 6 to 8 years for NEM 2.0 solar-paired-storage, these customers should be accorded legacy treatment under their current rate structure for 5 years from the on-line date for solar-only systems, and 8 years from the on-line date for solar-plus-storage systems. These legacy periods are in line with NEM 2.0 customers' payback expectations when they made these investments. Thus, a NEM 2.0 solar system that has been on-line for more than 5 years when IGFCs are implemented would not qualify for legacy treatment. SEIA also does not propose legacy treatment if its proposal is adopted, because fixed charges in the range of SEIA's proposal (i.e. $10 per month) were allowed and were a possibility before the enactment of AB 205.

SEIA's reading of the implementation sections of the Joint IOU proposal is that the Joint IOUs do not expect their IGFC proposal to be implemented until sometime in 2028.[35] If this is the timeline for IGFC implementation, then the number of NEM 2.0 systems requiring legacy treatment, and the effective length of such treatment, will be reduced, given the April 15, 2023 end date for systems to qualify for the NEM 2.0

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[35] See Joint IOU testimony, at pp. 94-95 for the timeline for the income verification apparatus; at pp. 100-102 (esp. Table IV-15) for the timeline to implement the Joint IOU IGFC, which is 32 months after the "end of 2025" when the contracting and cybersecurity review would be completed with Third Party state agency that will verify incomes.

program and the requirement that systems with NEM 2.0 status have three years after that date to come on-line.

B. Impact on Energy Efficiency and Demand Response

Q: In the past, has the Commission considered the potential for residential fixed charges to impede the state's energy efficiency (EE) and demand response (DR) efforts?

A: Yes. In D. 15-07-001, the Commission concluded, with respect to the capped residential fixed charges allowed by AB 327 (a maximum of $10 per month) that "the impact [on conservation] is likely to be small." Only the SEIA proposal in this case is recommending fixed charges at this level. The other parties are proposing average fixed charges that range from three to seven times higher than $10 per month, at levels that the Commission has firmly rejected in the past even for optional residential rates.[36] The other parties argue that the IOUs' residential rates will be high enough to encourage conservation even after significant volumetric rate reductions.[37] However, if you reduce the price for a good, the demand for it will increase, even if the good is high-priced initially. Indeed, a central purpose of the proposals for high IGFCs is to increase the demand for electricity in electrification measures. What is concerning is that the increase in demand from significant reductions in volumetric rates in <u>all</u> TOU periods would include higher summer peak demands that may threaten reliability and that will produce higher rates in the long run.

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[36] In D. 20-03-003, at pp. 42-44, the Commission rejected an SDG&E proposal for an optional residential rate with a high monthly fixed charge of approximately $72 per month, and instead ordered SDG&E to propose a residential electrification rate. In response, SDG&E submitted an optional electrification rate with a demand-differentiated fixed charge as high as $85 per month. D. 22-11-022, at pp. 24-27 rejected this proposal in favor of a flat $16 per month fixed charge.

[37] See Joint IOU testimony, at pp. 32-33; TURN/NRDC testimony, at pp. 3-4; Sierra Club testimony, at p. 57.

VII. THE IOU PROPOSALS WILL INCREASE THE POTENTIAL FOR SIGNIFICANT GRID DEFECTION

Q: The high IGFCs would result in large rate increases for higher-income customers. Would these rate increases raise the potential for such customers to install off-the-grid systems to supply their electric needs without using the utility grid?

A: Yes. As I discussed in my direct testimony, the only way that customers can respond to high fixed charges is to leave the grid. There is a broad range of possible types of grid defection, from individual customers with solar-plus-storage systems (plus a backup source of generation in low-solar months), to groups of customers who form a local micro-grid, to communities that pursue the creation or expansion of a municipal utility.

The recent National Academies report on net energy metering summarized why it is important for policymakers to consider the potential for grid defection when they adopt any change in rate design that has a significant impact on the bill savings of customers who want to install a solar-plus-storage system that is the foundation for off-the-grid service:

> While the circumstances that may drive customers to disconnect, and the instances of actual disconnection are currently few, understanding this dynamic is important for policymakers and regulators so that they design net metering variants that discourage uneconomic disconnection and leverage the BTM DG for the benefit of the electricity system (i.e., where customers that disconnect from the grid pay more for their electricity needs than it would cost the utility to serve them). A customer has the incentive to disconnect from the grid when they can receive comparable or better service from a DG system (PV, storage, and perhaps fossil backup) at less than the total cost of their pre-DG utility bill over the useful life of the DG system. Net metering compensation levels can be a factor in a customer's decision to disconnect. For example, traditional net metering of BTM DG provides a much more convenient and less capital-intensive method for customers to reduce their electricity bills using rooftop solar and can avoid uneconomic outcomes (for all customers) when retail rates are aligned with costs to serve. To the extent that utility cost recovery occurs more through fixed

charges, variable charges will decrease along with the resulting net metering compensation for the customer.[38]

Q: Did any of the parties who are proposing high IGFCs assess the impact of their proposals on the potential for grid defection?

A: No, they did not.[39] The study from Next 10 and the Energy Institute at Haas that appears to be a key source for the high IGFC proposals discusses grid defection briefly at the end of the study.[40] The Next 10 Study cites a study from U.C. Berkeley published in 2020,[41] which it asserts concludes that "it remains expensive to install sufficient battery storage to reach reliability levels comparable with the grid" and that the "vast majority of [relatively wealthy] households would need to invest in over 100 kWh of storage to reach a level of reliability comparable to the grid." A more serious near-term grid defection threat, the Next 10 Study observes, is the use of a backup natural gas generator to supplement a solar-plus-storage system and thus reduce the need for storage capacity.[42] The study concludes that there is little evidence of significant grid defection today, but "that could change as technology improves and the financial incentives for defection increase, making income-based fixed charges relatively less viable compared to covering residual costs through the state budget."[43]

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38 National Academies of Sciences, Engineering, and Medicine, *The Role of Net Metering in the Evolving Electricity System* (2023, The National Academies Press), at p. 65. See https://doi.org/10.17226/26704.

39 See the response of the Joint IOUs to SEIA DR 1, Q5; response of TURN/NGC to SEIA DR 1, Q5, which are included in **Attachment RTB-4**.

40 Next 10 and Energy Institute at Haas, University of California, *Paying for Electricity in California: How Residential Rate Design Impacts Equity and Electrification* (September 2022), at pp. 32-33, hereinafter "Next 10 Study."

41 Will Gorman, Stephen Jarvis, Duncan Callaway, Energy and Resources Group, University of California Berkeley, *Should I Stay or Should I Go? The importance of electricity rate design for household defection from the power grid* (Applied Energy 262 [January 2020], 114494, hereafter "UCB Grid Defection Study."

42 Next 10 Study, at pp. 32-33.

43 *Id*.

Q: Please discuss your views on the Next 10 Study's conclusions on grid defection.

A: First, the Next 10 Study mischaracterizes the results of the UCB Grid Defection Study. The latter study found that the scenario with the greatest potential for grid defection is one with the following characteristics:

- Customers with relatively low electric demand
- Rate design with high fixed charges
- Low costs for solar and storage
- Customer willingness to accept a lower level of reliability from the solar-plus-storage system – for example, if the customer also has access to an alternative supply of electricity in the low-solar winter months.[44]

The median size of the storage system in the UCB study's scenario that results in significant grid defection is 34 kWh,[45] not the 100 kWh that the Next 10 Study misstates. The UCB study concludes that, in this scenario, 2.6 million out of 6.9 million single-family homes in California (i.e. 38%) could defect from the grid.[46]

Q: What are the limitations of the UCB Grid Defection Study, for the purposes of this case?

A: The UCB study used 2016 retail electric rates. Rates in California have increased significantly since then, which of course increases the potential for grid defection. On the other side of the coin, the assumptions used in the study for the future costs of solar and storage are much lower than today's costs – for example, storage is assumed to cost $100 per kWh.[47] However, the availability of low-cost storage is not far-fetched when one

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44 See UCB Grid Defection Study, at Table 4 and p. 9: "If customers were willing to accept the "flexible" reliability conditions we outlined above in our optimization framework, a significant portion of the low demand customers would decide to defect and install a solar/storage system."

45 *Id.*, at Table 3, showing a median storage size of 34 kW, with 10%/90% range of 21 to 56 kWh.

46 *Id.*, at Table 4. This case limited grid defection to single-family homes, but estimated that defection would be three times higher if multi-family dwellings were included. See p. 9.

47 *Id.*, at p. 7 and Table 1.

recognizes that millions of customers may soon purchase a large amount of battery storage in the EVs that will sit parked – mostly in the customer's home driveway or garage – for the 95% of hours when they are not in use for transportation. EVs have large batteries – for example, Tesla EVs have battery packs ranging from 60 to 100 kWh; the Ford F-150 Lightning and Rivian pickups have batteries with more than 130 kWh.[48] EVs are purchased to provide transportation, but emerging vehicle-to-home (V2H) technologies are making this storage available to power the home when the EV is connected.[49] Since the EV is purchased to provide transportation, this additional storage for the home is essentially free so long as its use for the home is coordinated with the customer's transportation needs. EVs also will have access to nearby public fast-charging stations where they can be re-filled while the owner is shopping or recreating, and to workplace charging while the owner is at work. The UCB Grid Defection Study did not consider the use of EVs as a backup source of kWhs for an off-the-grid home, nor did it consider the available option to include a fossil generator to provide supplemental power during winter months when there may be extended low-solar periods.

Q: Have you developed an updated model of grid defection in California?

A: Yes. Our model calculates the extent to which a solar-plus-storage system of a certain size will be able to supply the hourly electric needs of a typical residential customer. The model includes the current electric rates used in the E3 Tool, plus the parties' IGFC proposals for the highest income tier. Our grid defection model has three cases for the costs of distributed solar and storage, shown in **Table 9**.

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[48] See https://electricvehicles.energysage.com/?.

[49] See, for example, https://media.ford.com/content/fordmedia/fna/us/en/news/2022/02/02/f-150-lightning-power-play.html. Also https://www.youtube.com/watch?v=P7gCIT5FoAw. And https://www.greencarreports.com/news/1135793_california-utility-expands-bidirectional-ev-charging-pilots.

Table 9: *Costs of Solar, Storage, and Natural Gas Backup in the Grid Defection Model*

Component	Cost Cases			Sources
	Current	Low	2025 ATB	
Solar ($/W-DC)	4.05	3.30	1.90	Current: DGStats,[50] LBNL 2022 TTS[51] Low: E3 model from D. 22-12-056[52] 2025: NREL 2022 ATB for 2025[53]
Storage ($/kWh)	1,001	880	740	
Natural gas generator	$5,900 capital, $0.55/kWh operating			10 kW Generac home generator[54]

Q: Past grid defection studies have sized the solar-plus-storage system to meet the customer's load in all hours, or in almost all hours (for example, see the "flexible reliability" case in the UCB Study). How does your study assume that the customer who "cuts the cord" with the utility obtains reliable electric service in all hours?

A: Our study oversizes the solar system to produce 175% of the customer's annual usage and adds a four-hour battery that can store 125% of the customer's average daily electric use. This system reliability serves about 96% of the customer's annual kWh needs (higher [98%-99%] in southern California; lower [93%-94%] in northern California). To the extent that the specified solar-plus-storage system is unable to serve the customer's load in an hour, the model assumes either (1) the additional power is supplied by a backup natural gas-fired generator or (2) the customer supplements the home storage with

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50 See https://www.californiadgstats.ca.gov/charts/, cost data for IOU residential solar systems smaller than 10 kW, with a 1.2 inverter loading ratio.

51 Lawrence Berkeley National Lab, *Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States – 2022 Edition* (September 2022), at Slide 30. $1,001 per kWh is the reported storage cost in California in 2021 for residential storage systems sized 15 to 30 kWh. See https://emp.lbl.gov/publications/tracking-sun-pricing-and-design-1. We have also adjusted the costs for the solar array for the economies of scale available from the larger solar arrays (175% of annual usage) that would be used in an off-the-grid installation. This adjustment uses the data on pages 12 and 36 of the *2022 Tracking the Sun* report.

52 See D. 22-12-056, Appendix B, p. B2, #14.

53 National Renewable Energy Lab, 2022 Annual Technology Baseline (2022 ATB), available at https://atb.nrel.gov/electricity/2022/index, for a residential PV system and 4-hour battery in 2025.

54 See the cost for a 10 kW Generac Guardian natural gas generator with transfer switch, plus $2,000 for installation, at https://www.generac.com/all-products/generators/home-backup-generators#?cat=6&cat=214&cat=217&cat=249.

additional stored kWh from the customer's EV, which is assumed to have 80 kWh of available storage that can be re-filled as necessary at a local public EV or workplace charging station, at current rates for public EV charging. The model shows that a home generally will use power from the backup generator or EV in 100 to 220 hours per year in northern California and 35 to 85 hours per year in southern California (with the variation depending on the customer's annual usage), with almost all of these hours in the months of November - February. The model includes a simplified pattern of a customer's EV usage that accounts for [1] electric consumption in the EV while driving, [2] the times when the EV is at the customer's premises (and able to supply the home or be charged with excess solar), [3] when the EV has access to workplace charging, and [4] the number of annual trips when the EV must be driven to a public charging station to obtain kWh needed for the home. Generally, the model shows that there are 0 to 5 such trips annually – more in northern California, fewer in southern California – when the off-the-grid customer must "go to the store" (i.e. a public EV charging facility) to bring home additional kWh to use in the home.

Q: What are the results of your grid defection model?

A: **Tables 10abc** summarize the results for each of the utilities, for three different customer sizes and the three cost scenarios in Table 9. Tables 10abc show the paybacks, in years, for the specified off-the-grid system that can meet the customer's electric demand in every hour. The numerator of the payback is the cost of the system; the denominator is what the customer would have spent annually if connected to the grid under the specified IGFC proposal, minus the annual operating costs for the off-the-grid system (such as the fuel costs for the gas generator or the public/workplace charging costs for the EV V2H backup power).

Table 10a: *Grid Defection Model Results – Paybacks (years) – PG&E*

Off-the-grid System	Cost Case	PG&E IGFC Proposal Annual Usage *(kWh / yr)*			Sierra Club IGFC Proposal Annual Usage *(kWh / yr)*		
		6,000	7,500	9,000	6,000	7,500	9,000
Solar + Storage Natural gas backup	Current	18	18	17	15	15	14
	Low	16	15	15	13	13	12
	2025 ATB	12	11	11	10	9	9
Solar + Storage EV V2H backup	Current	17	17	16	13	13	12
	Low	15	14	14	11	11	10
	2025 ATB	10	10	9	8	7	7

Table 10b: *Grid Defection Model Results – Paybacks (years) – SCE*

Off-the-grid System	Cost Case	SCE IGFC Proposal Annual Usage *(kWh / yr)*			Sierra Club IGFC Proposal Annual Usage *(kWh / yr)*		
		6,000	7,500	9,000	6,000	7,500	9,000
Solar + Storage Natural gas backup	Current	17	16	15	11	11	10
	Low	15	14	13	9	9	9
	2025 ATB	11	10	10	7	7	7
Solar + Storage EV V2H backup	Current	16	15	14	10	9	9
	Low	14	13	12	8	8	8
	2025 ATB	10	9	8	6	6	5

Table 10c: *Grid Defection Model Results – Paybacks (years) – SDG&E*

Off-the-grid System	Cost Case	SDG&E IGFC Proposal Annual Usage *(kWh / yr)*			Sierra Club IGFC Proposal Annual Usage *(kWh / yr)*		
		6,000	7,500	9,000	6,000	7,500	9,000
Solar + Storage Natural gas backup	Current	13	12	12	14	12	11
	Low	11	10	10	12	11	10
	2025 ATB	8	8	7	9	8	7
Solar + Storage EV V2H backup	Current	11	11	10	11	10	9
	Low	10	9	9	9	8	8
	2025 ATB	7	6	6	6	6	5

At current solar and storage costs, the economics of grid defection using a natural gas generator as backup are marginal, and are not better than remaining on the grid with a smaller solar-plus-storage system under the NBT. This can be seen by comparing the paybacks in the first line of Tables 10abc to the paybacks in Table 6 for solar + storage systems under the Joint IOU proposal. However, if solar and storage costs fall (see the Low and 2025 ATB cost cases), and as V2H technologies emerge that provide convenient and clean backup power, moving off the grid may become the more economic way to add solar and storage. This will be particularly true if high IGFCs significantly increase the paybacks from solar and solar-plus-storage systems that remain on the grid (see Tables 6 and 7), and if there are very high top tier fixed charges – such as those proposed by the Sierra Club[55] – that higher-income customers can only avoid by leaving. The higher-income customers who are being given the strongest incentive to defect are, of course, exactly the ones with the most means to do so. According to the data in the E3 Tool, there are 2.4 million residential customers in the Joint IOUs' highest income tier.

Q: Do you have any final observations on grid defection?

A: Yes. The grid defection that we modeled – an individual residential customer installing and managing adequate generation and storage resources to serve their single-family home reliably – is one of the more difficult and expensive ways to leave the grid. Other arrangements where groups of residential customers move their electric service off the IOU grid may take advantage of economies of scale and thus be less expensive than the single-family grid defection that we modeled. This could be a micro-grid for a new greenfield neighborhood, or an upscale community joining the neighboring community's existing municipal utility.[56] As another example, the grid defection models discussed in this section show that a solar-plus-storage system can provide very close to 100% service

[55] The Sierra Club proposal provides the largest incentive for grid defection because the fixed charges in the Sierra Club's highest income tier are the largest relative to the volumetric rate reductions.

[56] As an obvious example, PG&E is proposing that many if not most of its customers in the upscale communities on the San Francisco Peninsula and in the Silicon Valley should pay $1,100 per year in fixed charges. In contrast, these customers' neighbors in Palo Alto and Santa Clara are served by municipal utilities that offer rates lower than what PG&E's rates would be even after its full IGFC was implemented. The IGFC would exacerbate and highlight the economic incentive for these communities to explore leaving the PG&E system to join their neighbors as expansions of the existing municipal utilities.

except in the low-solar winter months of November to February. This suggests the option of discontinuing service from the utility for eight months of the year – avoiding the high fixed charge for those months – while resuming service only in the winter months when a backup supply from the grid is at times needed. The key point is that it is dangerous to establish a strong economic incentive to leave IOU service, as that will incentivize customers to find creative ways to balkanize the California grid. Increasing grid defection would come at the long-term expense of the remaining captive customers who do not have that opportunity.

VIII. THE PROPOSALS FOR HIGH FIXED CHARGES ARE NOT BASED ON REASONABLE SOCIAL MARGINAL COSTS

Q: What appears to be the economic foundation for the proposals for high IGFCs?

A: The proponents of high IGFCs base their proposals on the idea that current retail electric rates in California are far above the "social marginal cost" to produce electricity, including the costs of mitigating the environmental impacts of that production.[57] For example, several parties cite the Next 10 Study's comparison of retail rates to short-run social marginal costs (SRSMC).[58] These parties also use the long-run marginal avoided costs from the Commission's Avoided Cost Calculator (ACC), which includes long-run marginal costs for transmission and distribution, as well as certain avoided environmental costs that directly impact utility rates.[59] They assert that fixed charges could be set at the difference between retail rates and social marginal costs, so that electricity consumption

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[57] See Joint IOU testimony, at p. 34: "The top priority and guiding principle of the fixed charge is to bring volumetric rates closer to cost basis. As seen in Table II-4 below, today's default utility rates are far higher than marginal costs as measured by both: (1) recent PG&E GRC Phase II marginal costs, and (2) the CPUC's 2022 version of the avoided cost calculator (ACC)."

[58] See Joint IOU testimony, at p. 35; TURN/NRDC testimony, at pp. 6-11.

[59] See Joint IOU testimony, at p. 35 (Table II-4); TURN/NRDC testimony, at pp. 7-10 and 13: "Avoided costs in the Avoided Cost Calculator are an intuitive adaptation of the LRMC concept."

is priced at its full marginal costs to society, avoiding what economists call the "deadweight loss" if it is priced above this level.

Q: Please respond to these assertions about the social marginal cost of electricity in California.

A: The problem is that these estimates significantly understate the present social marginal cost of electricity in California. First, these comparisons should use marginal costs for all functional parts of the electric system's infrastructure – generation, transmission, distribution, and customer access. Marginal costs for all of these functions have been the foundation of electric rates in California for almost 40 years,[60] and this continues to be reflected in Rate Design Principle No. 2. This policy has recognized correctly that the short-run marginal costs of electric production – basically just fuel, line losses, and a short-run capacity value – are a relatively small (and at times volatile) portion of the costs of electricity, and of electric rates. Short-run marginal costs are declining as the resource mix comes to be dominated by renewable resources such as solar and wind that have no fuel costs. Most of the costs of delivered electricity consist of long-run infrastructure costs for power plants and for the transmission and distribution (T&D) grid that delivers the power.[61] Customer usage drives these long-run costs – in particular, it is customer usage during the peak periods which causes capacity-related infrastructure costs to be incurred. In addition, short-run marginal costs will always be below long-run marginal costs in the electric industry, where regulation – in the form of reserve margins and resource adequacy requirements – mandates a constant over-supply of the product to ensure that it is always available. For this reason, any comparison of social marginal costs to electric rates should use long-run social marginal costs (LRSMC).

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[60] See D. 15-07-001, at p. 198: Historically, in setting electric rates, we have sought to design and set rate structures that are based on marginal cost and that allow each utility to recover its costs of service in a manner that ensures that costs specific to each class of customer are recovered from that same customer class."

[61] See D. 92-12-058, at p. 1: "LRMC [long-run marginal cost] is a valuable tool for rate design as well as making efficient capital investment decisions."

Q: TURN and NRDC assert that "the economic ideal is to set prices at SRSMC," and cite the famed economist Alfred E. Kahn.[62] Please respond.

A: First, TURN/NRDC misquote Kahn. Footnote 4 on page 7 of their testimony says: "See, for example, A.E. Kahn, The Economics of Regulation (Vol. I), at 75. 'The economic ideal is to set all public utility rates at short run marginal costs….'" (emphasis added). What page 75 of Kahn's seminal book actually says is:

> *In sum: the economic ideal would be to set all public utility rates at short run marginal costs with appropriate adjustments for the problems of second-best); and these must cover all sacrifices, present or future and external as well as internal to the company, for which production is at the margin causally responsible. The ideal is worth emphasizing, because in certain circumstances it can and should be embodied in rates. But, in the real world, it is not usually feasible or even desirable to do so, for a variety of reasons that will become clear as we consider two other related aspects of the problem of defining marginal costs.* (emphasis added).

In the rest of the chapter, Kahn recognizes that a public utility's constraint that its product must be continually available and stable in price means that long-run social marginal costs are the "practically achievable benchmark" for public utility rates:

> *As J.M. Clark has often pointed out, excess capacity is the typical condition of modern industry; and we would probably want this to be the case in public utilities, which we intend to insist be perpetually in a position to supply whatever demand are placed upon them. In these circumstances, firms could far more often be operating at the point where SRMC [short-run marginal cost] is less than ATC [average total cost] than the reverse, and if they based their prices exclusively on the former, they would have to find some other means of making up the difference. Partly for this reason, and partly because of the infeasibility of permitting prices to fluctuate widely along the SRMC function, depending on the immediate relation of demand to capacity, the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC, estimated for a*

62 See TURN/NRDC testimony, at p. 7.

single additional sale. <u>This long-run incremental cost (which we shall loosely refer to as long-run marginal cost as well)</u> would be based on (1) the average incremental variable costs of those added sales and (2) estimated additional capital costs per unit, for the additional capacity that will have to be constructed if sales at that price are expected to continue over time or to grow.[63]

Q: Do you agree with TURN / NRDC that the Commission's ACC is a reasonable metric for LRSMC?

A: I agree that the ACC is the place to start to calculate LRSMC. However, four changes need to be made to the 2022 ACC values to derive reasonable, up-to-date long-run social marginal costs in California, for comparison to today's retail rates. I discuss these changes in detail below. In addition, I observe that the social marginal costs used in the Next 10 Study, on which the proponents of high IGFCs rely, is based on an earlier Next 10 report that used values from the <u>2019</u> ACC.[64] Since the 2019 ACC, the Commission has completed two major updates and a minor update to the ACC, including a major update in 2020 that completely restructured the ACC to align it more closely with the state's IRP process.[65] Thus, the social marginal cost values used in the Next 10 Study are out of date.[66]

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63 See Kahn, Alfred E., *The Principles of Regulation: Principles and Institutions, Part I* (1989 Edition), at pp. 84-85, (emphasis added).

64 The Next 10 Study (see page 4) uses social marginal cost calculations from Severin Borenstein, Meredith Fowlie, and James Sallee, *Designing Electricity Rates for An Equitable Energy Transition* (Next 10 and the U.C. Berkeley Energy Institute, February 23, 2021), hereafter, "Next 10 Rates Paper." See https://www.next10.org/publications/electricity-rates.

65 See D. 20-04-010, D. 22-05-002, and Resolutions E-5077, E-5150, and E-5228, all adopting updates to the ACC since the 2019 ACC.

66 As one example of how the marginal costs used in the Next 10 Rates Paper are out of date, the paper uses a short-run marginal cost of generation capacity of just $30 per kW-year, from the resource adequacy market, on the grounds that "peak load has been declining over time" (page 21). Obviously, since this report was written, conditions have changed dramatically in California's now-tight market for generation capacity. The 2022 ACC uses a marginal cost of generation capacity of $232 per kW-year in 2022, based on the costs of the new battery storage that the state is now adding as rapidly as possible. See *2022 ACC Documentation v1b updated*, pages 38-46, available at https://www.cpuc.ca.gov/-/media/cpuc-

Q: Please describe the changes and updates to the 2022 ACC needed for it to be a reasonable measure of today's LRSMC in California?

A: The first necessary update recognizes that the 2022 ACC uses a natural gas forecast produced in early 2020, before the Covid pandemic and the war in Ukraine. As a result, the avoided energy costs in the 2022 ACC are too low, because marginal fuel costs in California have moved to a new, higher level that has not yet been incorporated into the ACC. This is easily remedied by replacing the avoided energy costs (and the avoided greenhouse gas [GHG] cap & trade [C&T] costs) in the ACC with actual 2022 CAISO energy market prices (which include actual C&T costs).

The second change is to replace the ACC's avoided cost of compliance with GHG regulations with a social cost of carbon (SCC) that estimates the marginal damages to society from carbon emissions. This change is necessary to capture the full societal benefits of mitigating climate change.[67] The Next 10 Study appears to rely on an SCC value of $50 per metric tonne used in an earlier Next 10 paper; this is an SCC value dating from the Obama administration's Interagency Working Group (IWG) on the SCC.[68] Recent developments indicate an emerging consensus in the scientific community and among federal regulators that such older estimates of the SCC need to be revised upwards, substantially. In September 2022, the U.S. Environmental Protection Agency (EPA) released for comment new calculations of the SCC that "reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering,

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website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf.

[67] The ACC's Avoided GHG component is the amount by which the cost of mitigating GHG emissions exceeds the established GHG emission allowance prices in the California C&T market. As noted above, the C&T costs are a separate component in the ACC. In this way, total avoided GHG costs are not double counted in the ACC.

[68] The Next 10 Study (see page 4) uses social marginal cost calculations from the Next 10 Rates Paper. Page 20 of the Next 10 Rates Paper indicates the use of an SCC value of $50 per tonne from a 2016 IWG update of the Obama Administration's SCC.

and Medicine."[69] The EPA is a member of the IWG, which is in the process of formally revising the Obama-era SCC. The EPA's new median 2% discount rate value for the SCC for CO_2 is $190 per tonne of CO_2, in 2020. Other recent academic studies of the SCC also support the use of this new, higher SCC. In September 2022 researchers from Resources for the Future and the University of California Berkeley published new calculations of the SCC in the journal *Nature.*[70] This work finds the current SCC value to be $185 per metric tonne, almost four times the Obama-era estimate of $51 per ton adopted on an interim basis by the Biden Administration, and close to the EPA's $190 per metric tonne.[71] Another academic estimate of the SCC for the U.S. is even higher – a median estimate of $417 per metric tonne from an academic review of a range of SCC values published in October 2018 in *Nature Climate Change*.[72] Finally, in February 2022 the IPCC released the second part of its Sixth Assessment Report, *Climate Change 2022: Impacts, Adaptation and Vulnerability* (IPCC Sixth Report).[73] In the summary of this report for policymakers, the IPCC presented the "high confidence" finding that "the extent and magnitude of climate change impacts are larger than estimated in previous assessments."[74] All of these recent developments support the conclusion that the estimates of the SCC performed a decade ago in the Obama administration, and used in the Next 10 study, are too low. I have used the EPA value of $190 per tonne as an updated SCC.

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[69] See U.S. EPA, *EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, at p. 1, available at https://www.epa.gov/environmental-economics/scghg. See also https://www.eenews.net/articles/epa-floats-sharply-increased-social-cost-of-carbon/.

[70] See https://www.nature.com/articles/s41586-022-05224-9.

[71] See https://www.rff.org/news/press-releases/social-cost-of-carbon-more-than-triple-the-current-federal-estimate-new-study-finds/.

[72] See Ricke et al., "Country-level social cost of carbon," *Nature Climate Change* (October 2018). Available at: https://www.nature.com/articles/s41558-018-0282-y.epdf.

[73] Available at https://www.ipcc.ch/report/sixth-assessment-report-working-group-ii/.

[74] IPCC Sixth Report, *Summary for Policymakers*, at p. 9.

The third change modifies the ACC component for avoided methane leakage.[75] The ACC considers only methane leaked from the production and transportation of natural gas within the state of California, due to the arbitrary boundaries of the CARB's GHG inventory. CARB's GHG inventory for methane emissions is limited to the small portion – less than 10% – of the state's gas supply produced in-state and to the gas pipeline and distribution infrastructure within California's borders. However, the full societal cost of the methane leakage associated with natural gas burned in California must consider the leakage associated with all of the state's natural gas supplies. This must include the 90+% of the state's natural gas supplies that are produced out-of-state and imported via interstate pipelines to the state's border and into California. The out-of-state methane leakage associated with these imported gas supplies is not included in the ACC today; however, in R. 22-11-013 the Commission is reviewing a staff proposal for a societal cost-effectiveness test (SCT) that includes expanding the methane leakage component of the ACC to cover all natural gas burned in the state, including the gas imported into California.[76] Modifying the ACC to include all methane leakage associated with natural gas burned for electric generation in California is necessary to cover the full societal impacts of California's continuing use of natural gas.[77]

Finally, I include the results of the recent research that the Commission sponsored that quantifies the health benefits of reductions in criteria air pollution when emissions from gas-fired power plants are displaced with clean energy. These benefits average $14

[75] The Next 10 social marginal cost values do not include the impacts of methane leakage from the natural gas system that supplies the gas-fired power plants that are often the marginal source of electric generation in California. See Next 10 Rates Study, at p. 19, footnote 10.

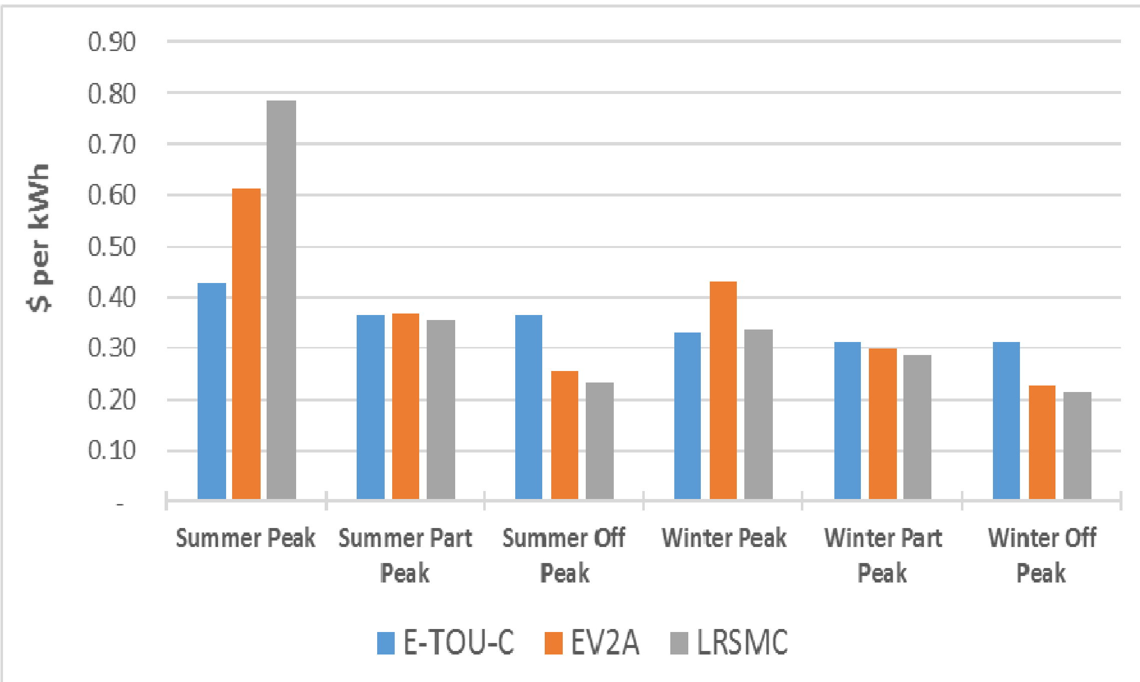
[76] See R. 22-11-013, Administrative Law Judge's Ruling dated February 13, 2023 (SCT Ruling) seeking comments on a Staff Report, the *Societal Cost Test Impact Evaluation* (Staff SCT Report). This report, at pages 15-16, proposes to use the leakage associated with all natural gas burned for electric generation or direct use in California, including imported gas supplies produced outside of the state.

[77] In addition, I chose the setting in the ACC that uses the 25-year global warming potential for methane, as the next 25 years is the period when methane has the largest impacts on the climate, and is the time frame which California has set to achieve its goal to substantially decarbonize the state's economy.

per MWh across all hours. The expanded SCT that the Commission is considering in R. 22-11-013 would incorporate this important externality, using the results of this new research.[78]

These changes and updates to the 2022 ACC result in long-run social marginal costs (LRSMCs) that are significantly higher than presented in other parties' testimony or in the Next 10 reports. **Figure 3** shows the on-, mid-, and off-peak components of the LRSMC, in comparison to the on-, mid-, and off-peak rates in PG&E's E-TOU-C and EV2A rates.

Figure 3: *PG&E LRSMC vs. E-TOU-C and EV2A, by TOU Period*



The figure demonstrates that current PG&E residential rates are close to long-run social marginal costs; on average over all hours, LRSMC is within 5% of PG&E's average residential retail rate. Contrary to the Next 10 Study, there is not a substantial difference

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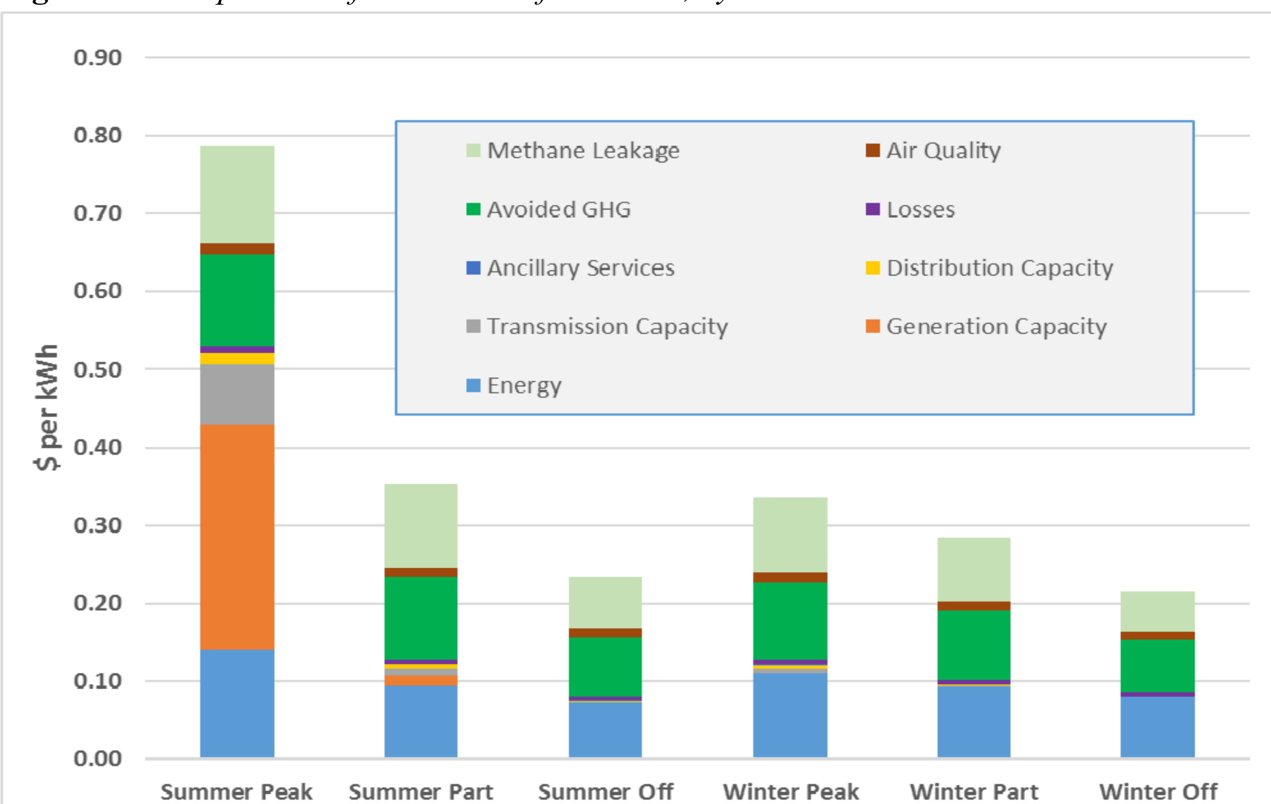
[78] See SCT Ruling, requesting comments on the attached report *Quantifying the Air Quality Impacts of Decarbonization and Distributed Energy Programs in California.* Page 7 of this report cites the $14 per MWh health costs of gas-fired electric generation.

that justifies the need for a large fixed charge. The PG&E EV2A rate with its low off-peak rate and high on-peak rate best approximates the time profile of PG&E's LRSMC. In comparison, the default E-TOU-C rate is clearly too "flat," with on-peak rates that are too low and off-peak rates that are too high; the default rate needs to have larger TOU differentials to come closer to social marginal costs. Figure 3 also shows the high social marginal costs in the peak period, which is due to (1) the higher environmental costs for GHG emissions in these hours when less-efficient gas-fired generation is on the margin and (2) the high marginal capacity-related costs for generation and transmission in the peak hours. To show this more clearly, **Figure 4** breaks down the components of the LRSMC shown in Figure 3, again by time period.

Figure 4: *Components of the LRSMC for PG&E, by TOU Period*



Q: What do you conclude from this updated analysis of LRSMC?

A: I conclude that the foundational economic rationale for high IGFCs – that retail rates in California are far above the social marginal costs to produce and distribute electricity – does not stand up to scrutiny when the analysis is updated for the most recent data on fossil energy costs, the extent of the damages from climate change, and a more complete quantification of the environmental impacts of electricity production in California. An updated calculation shows that current residential electric rates are close to LRSMC on average, so there is no economic justification for high IGFCs. My updated analysis also strongly supports the need to increase the differentials in residential TOU rates (particularly for the default rates such as E-TOU-C). At a minimum, the Commission should maintain high on-peak rates and reduce off-peak rates. As explained earlier, this is also the best means to incentivize the additional off-peak electric use for electrification that will inflict the least damage to the environment in California or globally, and that will have the most beneficial impacts in moderating future electric rates.

IX. THE DESIGN OF THE HIGH FIXED CHARGES VIOLATES THE COMMISSION'S RATE DESIGN PRINCIPLES

A. Many of the Costs Included in the High IGFC Proposals Are Usage-based

Q: Table 1 shows the general categories of costs that each party proposes to include in their IGFC. Have you evaluated the reasonableness of these proposals?

A: Yes. My opening testimony discussed why only marginal customer access costs should be included in a monthly fixed charge, and why certain other categories of costs should not be included.[79] That discussion bears directly on the proposals of other parties for high IGFCs. I also observe that the other parties largely "back into" what categories of costs to include in the fixed charge, based on the size of the fixed charge that they want to propose and their overly broad assumption that any non-marginal costs must be "fixed"

[79] See SEIA testimony, at pp. 18-19.

and therefore do not vary with usage.[80] This results-oriented approach gives short shrift to an in-depth examination of whether the costs included in the fixed charge are really independent of customers' usage.

The Commission's third Rate Design Principle is that "rates should be based on cost causation." Consistent with this principle, to the extent that costs are caused by customers' usage of kWh or kW, those costs should not be included in the fixed charge.

Q: All of the proponents of higher IGFCs propose that the residential fixed charge include at least a portion of the equal percentage of marginal cost (EPMC) scalar for marginal distribution costs (MDC).[81] What is the EPMC scalar for MDC?

A: A utility's revenue requirement is based on its operating costs plus a return on its investments in plant at their embedded (historical), depreciated cost (i.e. a return on rate base). Typically, the revenue requirement for delivery services (customer access plus distribution) exceeds the marginal costs for these services. As a result, to set rates that cover the revenue requirement, rates based on marginal costs for customer access and distribution are scaled up by an equal percentage of marginal costs (EPMC) until they collect the full revenue requirement for delivery. The difference between the revenue requirement and marginal costs, divided by marginal costs, is the "EPMC scalar."[82]

Q: Why is the EPMC scalar typically much greater than 1.0?

A: There are multiple reasons for this. First, a utility's recovery of a rate-based capital asset in the revenue requirement is front-loaded in time, and declines over time as the rate base depreciates. In contrast, marginal costs tend to be calculated on a levelized basis. This

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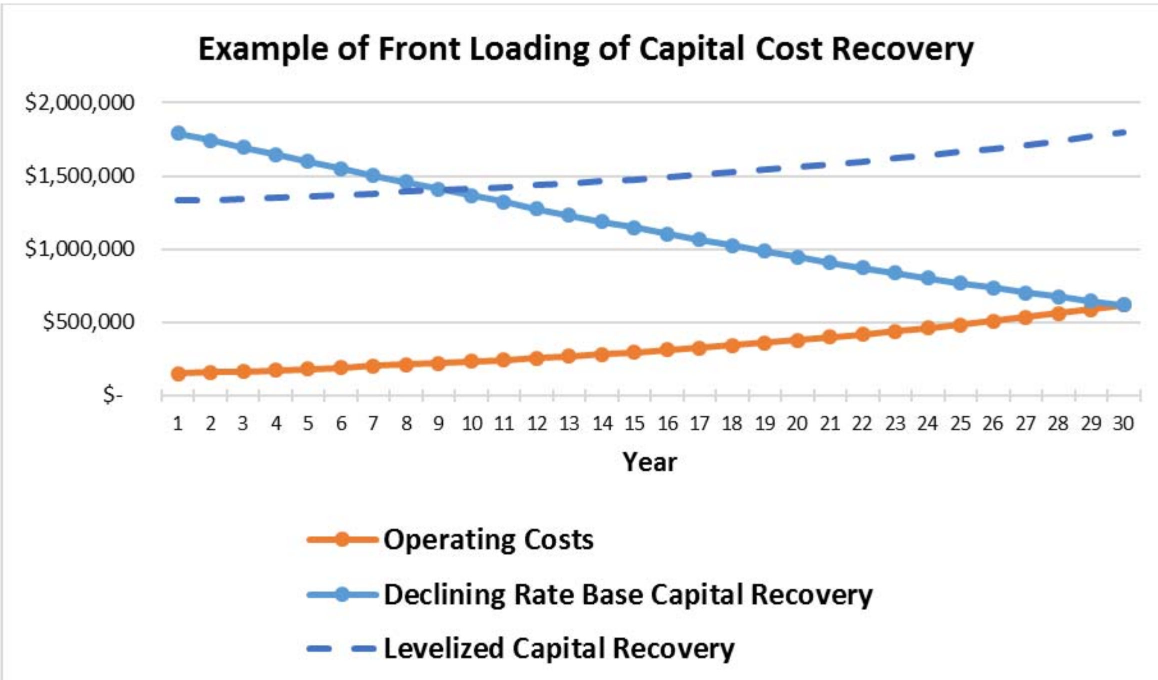
80 See, for example, TURN/NRDC testimony, at pp. 19-20: "To develop our fixed charge recommendation, we start with including all feasible cost categories and then add a portion of non-marginal distribution costs for each utility until achieving our desired fixed charge amount."

81 See Cal Advocates testimony, at pp. 8-9; TURN/NRDC testimony, at pp. 3-4; Sierra Club testimony, at pp. 11-13; Joint IOU testimony, at p. 39.

82 See D. 17-09-035, at p. 25, for a basic description of the EPMC scalar.

difference is shown in **Figure 5** for the exemplary cost recovery of a $10 million distribution capital asset.

Figure 5



Due to this difference in the accounting for rate-base versus marginal costs, as well as the inevitable differences in the timing of rate base additions and marginal cost calculations, it is probably coincidence if marginal cost revenues ever equal the embedded cost revenue requirement. For example, if the utility has made significant rate base additions in the recent past, this will increase the revenue requirement but reduce marginal costs (because the system may be temporarily overbuilt), leading to an EPMC scalar greater than 1.0. Moreover, there are structural reasons why the revenue requirement for delivery services is likely always to exceed marginal costs. First, the delivery revenue requirement includes the costs for programs that are not categorized as delivery services – for example, in California the delivery revenue requirement includes costs for demand response, emergency capacity, and transportation electrification programs. Second, marginal distribution cost calculations focus only on the cost to supply another kW; this understates the marginal cost of distribution because it does not consider the changing standards for the safety and reliability with which that kW is supplied. As a result, a growing portion of the EPMC scalar for delivery includes costs for wildfire hardening and to improve the reliability of the distribution grid – costs which should be included in marginal distribution costs in order to reflect these changing standards for safety and reliability. For example, if the distribution line serving a community is nearing capacity and must be upgraded, the cost to do that in California today is not just the cost of upgrading the line to a higher voltage or larger conductors – the new line also must meet new requirements for fire safety and reliability – possibly even installing the new line underground. In addition, in the past marginal costs have excluded replacement costs, but from a long-run perspective the cost of supplying an additional kW of capacity must include the cost to replace aging facilities to prevent the system's capacity from declining or becoming unsafe or unreliable. For these reasons, the major new costs to replace aging infrastructure, to upgrade the safety of the IOUs' distribution systems (including wildfire hardening), and to improve reliability – all of which are likely to be included in the EPMC scalar – should be included in marginal distribution costs and thus should not be assumed to be "fixed" costs. When an IOU adds distribution infrastructure in response to a change in customer demand, it is adding new infrastructure that must comply with the higher level of safety and reliability that is now expected of the IOUs.

Q: The IOUs would allocate 100% of their non-marginal distribution costs to the IGFC. This is a major portion of their IGFC. Can you evaluate whether their non-marginal distribution costs include costs that are driven by customer usage?

A: Not readily, because the IOUs themselves cannot specify exactly what costs are included in their non-marginal distribution costs, as they admitted in discovery:

> … 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.[83]

The Joint IOUs simply assert that "[t]hese costs are not driven by a customer's usage, and therefore should be collected through the IGFC," without a detailed justification.[84]

An inspection of Table 2 of PG&E Advice 6805-E shows that there are significant categories of costs in the distribution revenue requirement that are driven by customer usage of kWh of energy or kW of capacity. For example, the distribution revenue requirement includes substantial costs for demand response and emergency capacity programs whose costs clearly are driven by customers' usage in peak demand periods. There are costs for programs like transportation electrification, which include utility "make ready" costs to expand their facilities to meet higher customer usage of kWh and kW for EV charging. And, as just discussed, the non-marginal distribution costs also include significant costs to meet the higher standards for safety, wildfire hardening, and reliability that must be met by the incremental kWh and kW that the utilities deliver in the future.

Q: The Joint IOUs and TURN/NRDC propose that PG&E's marginal primary distribution costs for new business should be included in the IGFC.[85] Do you agree?

A: No. Contrary to TURN/NRDC's testimony, these marginal costs are not marketing or customer access costs for "acquiring new customers." These are the distribution circuits and associated equipment at primary voltages that PG&E installs to extend service to new customers. The primary distribution facilities that are installed are

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83 See PG&E response to TURN DR 4, Q6, included in **Attachment RTB-4**.

84 Joint IOU testimony, at p. 39.

85 See TURN/NRDC testimony, at pp. 20-21; Joint IOU testimony, at p. 39.

dependent to a significant extent on the size of the loads that are served, as shown by the fact that these marginal costs are calculated per kW of load served.[86] These are not metering and customer access facilities that are similar for all the customers in a class, and these marginal costs are not calculated on per customer basis. For this reason, they should not be included in a fixed charge.

Q: The other parties propose to collect certain non-bypassable charges (NBCs) through their IGFCs. Please respond to these proposals.

A: I will respond by showing why including certain NBCs in the IGFC would be contrary to cost causation.

Public Purpose Program (PPP) costs. PPP costs include program costs for energy efficiency and the Self Generation Incentive Program (SGIP – now largely incentives for customer storage), plus the residential portion of the discounts used to fund the volumetric rate discounts for CARE customers. The Joint IOUs would include all of these costs in their IGFC, arguing that these costs should be collected through the "intentionally progressive" IGFC.[87] However, the entire purpose of energy efficiency programs and the SGIP is to manage customer demand for energy and capacity. There is no set amount allocated to these programs irrespective of the IOUs' resource needs. The Commission periodically reviews the need for and cost-effectiveness of these programs, and adjusts the budgets for these programs accordingly. These demand-side programs are substitutes for utility procurement of incremental supply-side generation resources, and are counted in the IRP as resources

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[86] See A. 19-11-019 (PG&E GRC Phase 2), PG&E Testimony, Exhibit PG&E-2, at Table 1-2, showing that marginal primary distribution costs for new business is calculated a $ per kW-year amount, where the cost driver is customers' non-coincident peak demand (in kW) at the final line transformer (FLT). Also see p. 8-11 of this testimony: "Non-coincident demand at the FLT is the cost driver for the new business primary and secondary MDCCs [marginal distribution capacity costs]."

[87] Joint IOU testimony, at p. 39.

to meet the forecasted demand. Thus, like generation costs, this portion of PPP costs clearly are driven by customer demand for kWh and kW.[88]

With respect to the rate discounts for CARE customers that are collected through the PPP, this is the CARE discount for costs that are collected volumetrically because they are caused by consumption of kWh.[89] As a result, it is most consistent with cost causation to recover these CARE discounts volumetrically. In effect, for non-CARE customers, each kWh of usage carries with it the responsibility for the volumetric CARE discount associated with that kWh. It makes no sense to recover these volumetric CARE discounts through a fixed charge, because that will result in low-usage non-CARE customers funding a greater portion of the volumetric CARE discounts than is equitable based on their usage.

Finally, the plain language of Public Utilities Code Section 381(a) states clearly that the PPP "shall be a non-bypassable element of the local distribution service and collected on the basis of usage" (emphasis added).

Generation NBCs - PCIA. Several parties propose that the IGFC include NBCs that recover certain generation-related costs. In general, generation costs are driven by a customer's use of energy and capacity. The argument for including certain generation costs in a fixed charge is that a portion of generation costs were incurred in the past (i.e. are "sunk" today) and may exceed today's market prices for generation energy and capacity. There are significant problems with this argument, however. Generation market prices will fluctuate from year to year, so costs that are above-market today may not be above-market next year. In addition, customers have more than one option for obtaining generation, as well as the ability to switch their

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88 This was the Commission's conclusion in D. 17-09-035, at p. 32: "We also find the argument that some of the non-bypassable costs [in the PPP] are incurred to provide alternatives to conventional generation, such as energy efficiency, and therefore should be equivalent to generation costs in their treatment, convincing."

89 For the fixed charge discounts for CARE customers, SEIA proposes that these be collected through higher fixed charges on non-CARE customers. This recovery of the CARE fixed charge discounts is included in SEIA's IGFC proposal.

load-serving entity (LSE), which makes it difficult to track which set of customers is responsible for the above-market costs of a particular utility or other LSE in a specific year. If the generation costs included in a fixed charge are incurred only to serve the IOU's bundled customers, then there will be the complexity of two sets of fixed charges, one for bundled customers and another for unbundled. These problems can be summarized by the Commission's finding in D. 17-09-035 that "inclusion of generation costs in a fixed charge would conflict with State energy policies encouraging alternatives to utility-owned generation."[90]

Finally, there are difficult intergenerational equities. For example, the costs for a portion of California's portfolio of renewable generation are above-market today. These are largely higher-priced long-term power purchase contracts from the earlier years of the state's Renewable Portfolio Standard (RPS) program. Yet California's willingness to sign those early RPS contracts helped to bring down the cost of renewables. From this perspective, it is not fair for a portion of today's ratepayers – who benefit from today's low costs for renewables – to escape a share of the past costs that enabled those benefits. From a cost causation perspective, it is equitable for today's customers to pay for those past above-market generation costs – from which they continue to benefit – on the basis of the kWh that they use today.

TURN/NRDC appear to be the only parties who propose to include the Power Charge Indifference Adjustment (PCIA) in their IGFC.[91] The PCIA was established to allow an IOU to recover the above-market costs of generation resources purchased on behalf of a bundled customer who leaves the IOU's generation service to purchase generation from another provider such as a Community Choice Aggregator (CCA). The PCIA is calculated based on the difference between the total portfolio costs of the utility's generation resources and a market price benchmark re-determined every year; thus, the PCIA represents a short-run above-market generation cost. The PCIA is

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90 See D. 17-09-035, at p. 29.

91 TURN/NRDC testimony, at pp. 20-21.

also vintaged, so it varies significantly based on when a customer left bundled service. As the Sierra Club recognizes,[92] the problem with including the PCIA in a fixed charge is that it is hardly fixed, and can vary significantly from year to year as market prices fluctuate. TURN/NRDC also do not undertake the difficult task of calculating vintaged IGFCs that correspond to all of the vintages of the PCIA for each IOU, and simply assert that the IOUs have the data to do these complex calculations.[93] TURN/NRDC also do not address the central intergenerational equity issue that I discussed above. For these reasons of volatility, complexity, and intergenerational equity, the PCIA should not be included in the IGFC.

Other Generation NBCs. The Joint IOUs propose to recover certain other generation-related NBCs through the IGFC – specifically, the Nuclear Decommissioning Charge (ND) and the New System Generation Charge (NSGC) / Local Generation Charge (LGC). ND charges should be recovered on the same basis that the IOUs have recovered from residential ratepayers all of the other costs for nuclear generation – including the ongoing costs for PG&E's still-operating Diablo Canyon plant – that is, through volumetric charges covering the costs for the energy and capacity from this resource. The NSGC/LGC charge covers certain existing generation resources that the IOUs procured for the benefit of all customers, to enhance overall system reliability. Every grid includes a certain amount of such "common" costs necessary for the operation of the overall system, and such common costs increase as the load that the system must serve grows. Thus, it is equitable and consistent with cost causation for customers to pay for those common resources based on their use of energy from the system.[94]

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[92] Sierra Club testimony, at pp. 8 and 10.

[93] TURN/NRDC testimony, at p. 21.

[94] This was also the Commission's conclusion in D. 17-09-035, at p. 32: "Some of the other charges such as Nuclear Decommissioning charge or new system generation charge are ultimately generation-related and should not be included in a fixed charge."

B. The Levels of the High Fixed Charges May Be Volatile and Uncertain

Q: The high IGFCs proposed by other parties are supposed to be fixed charges that change only in periodic rate cases, but are they likely to change more frequently and in less certain ways?

A: Yes. There is the potential for significant volatility in the levels of the high fixed charges proposed by other parties. The Joint IOUs propose that, between their respective GRC Phase II proceedings, each of their IGFC rate components should be updated to follow changes in the underlying revenue requirements.[95] Moreover, the IOUs admit that they are unsure of how many customers will be in each fixed charge tier, due to the uncertainties in the yet-to-be-established income verification process. As a result, they propose a balancing account for fixed charge revenues that will cause the fixed charges to vary over time depending on whether or not they collect the expected amount of revenue.[96] In addition, some of the major categories of costs that other parties propose to be included in the fixed charges, such as non-marginal distribution costs, will fluctuate as the difference between marginal distribution costs and the embedded cost revenue requirement changes over time in ways that are difficult to predict. For example, if an IOU undertakes a major effort to upgrade its distribution system to serve higher electrification loads, one would expect the distribution revenue requirement to rise while marginal distribution costs fall. This would spike the amount of non-marginal distribution costs in rates and increase the size of any IGFCs that include them, particularly for middle- and high-income customers – perhaps precipitating a wave of grid defections by such customers precisely when you want them all on the system to pay for the recent improvements. Finally, there are always significant differences of opinion in general rate cases (GRCs) on how to calculate marginal costs, including marginal distribution costs.

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[95] Joint IOU Testimony, at p. 45.

[96] *Id.*, at pp. 136-138.

Table 11 shows the range of marginal distribution costs proposed in the most recent GRC Phase 2 cases for the three IOUs, illustrating this range. Changes in marginal distribution costs will impact the level of non-marginal distribution costs, and thus the levels of the fixed charges of the parties who propose IGFCs that include such costs.

Table 11: *GRC Phase 2 Proposals for Marginal Distribution Costs ($/kW-yr)*

Party	**Utility**		
	PG&E	**SCE**	**SDG&E**
Proceeding:	*A. 19-11-019*	*A. 20-10-012*	*A. 19-03-002*
Utility	48	181	78
Cal Advocates	46	285	129
CLECA	31	189	n/a

C. Customer Confusion and Resistance to High Fixed Charges Is Certain

Q: Which Commission Rate Design Principle addresses customer understanding and acceptance of changes in rate design?

A: Rate Design Principle 10 provides that "[t]ransitions to new rate structures should (i) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (ii) minimize or appropriately consider the bill impacts associated with such transitions."

Q: What have been the customer acceptance issues when California utilities have tried to implement residential fixed charges in the past?

A: It is useful to quote from D. 88-07-023 from 1988, when the Commission rescinded an SDG&E residential fixed charge due to customer protests less than seven months after the charge was adopted:

> The message [residential customers] have conveyed is that [they] do not:
>
> 1. Understand the need for a customer charge to unbundle rates. Although there was a rate reduction in January 1988, residential customers

uniformly stated that the establishment of a customer charge resulted in an increase in their bills.

2. Accept the explanation that certain fixed costs which are recovered through a customer charge would not otherwise be recovered in commodity rates.
3. Believe customer charges are fair and reasonable.

> This customer reaction caused us to question whether the goals of residential rate design were being furthered through SDG&E's residential customer charge….
>
> From San Diego we have learned that many residential customers believe they cannot respond to customer charges by adjusting their consumption patterns. This is particularly true of those who use very small quantities of electricity and have little ability to use even less. This group is also the most sensitive to perceived increases in their monthly bills. As a result, they believe the charge is unfair. Under these circumstances, the public's attention has focused on the customer charge, making it impossible for the pricing policy to have any desired effect. The utility's costs of providing service will be recovered with or without the customer charge, and so we conclude that here, at least, the theoretical efficacy of the charge is simply not worth the confusion it has caused.[97]

More recently, in 2020, the Commission rejected IOU requests to implement residential fixed charges in the $10 per month range, out of a concern that the marketing, education, and outreach (ME&O) plans of the IOUs were insufficient to ensure customer understanding and acceptance. The order noted that "[t]he risk of a negative customer reaction to residential fixed charges is demonstrated by history, granted by the IOUs, and of great concern to the Commission."[98] With respect the submitted ME&O plans, three years ago the Commission found:

> The ME&O plans offered by the IOUs in this proceeding do not adequately describe how residential customers will be prepared to accept and understand a charge that they cannot avoid. SCE's plan, while being the most specific, acknowledges that most of its residential customers will not receive targeted messaging about the fixed charge at all. Additionally, SCE's planned messaging

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[97] See D. 88-07-023, 28 CPUC 2d 503 (1988), at pp. 2-3.
[98] See D. 20-03-003, at pp. 20-21.

> to mitigate negative reaction to the fixed charge is to promote energy efficiency and conservation – two actions that will not actually reduce the impact of the fixed charge on a customer's bill.[99]

Q: Are the customer acceptance issues with the high IGFCs proposed in this case more challenging than with past fixed charge proposals?

A: Yes. There are proposals for IGFCs in this case that are five to ten times higher than the fixed charge proposals that caused customer acceptance issues in the past. The initial reactions in focus groups to the IOUs' proposals, candidly reported in the Joint IOU testimony, indicate the very negative initial reactions that customers are likely to have to a high IGFC:

- "Initial reactions to the IGFC involve confusion and distrust. Customers had a lot of questions about how the charge would work and the impact it would have on their bills."
- "Customers from all income groups expected their bills to increase with the implementation of the IGFC."
- "Customers presumed the IGFC amount may go up to $20 or $25 dollars at most and reacted negatively to any amount above this range."
- "There is a general concern that the IGFC would not incentivize conservation. Many, especially CARE customers in the study, felt the IGFC would be unfair to those who intentionally try to minimize their energy usage."
- "The charge evoked negative feelings of worry, helplessness, anger and/or confusion, with 66% feeling that it was not acceptable for SCE to have access to their income data and that they believed it was effectively a tax, and another way for SCE to make higher profits."

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99 *Id*.

- "Customers would be more likely to support a fixed charge based mainly on their usage instead of solely on their income level (54% support vs. 25% oppose this option)."
- "Overall, customers believed it was not fair that the fixed charge be based on their income, but instead, it should be based on usage. For example, energy conscious lower users felt they were being penalized through fixed charges. Also, they stated they already pay high property taxes, and believed that the IGFC would increase their financial burden."[100]

Q: Do the ME&O plans submitted in this case remedy the concerns that the Commission stated in D. 20-03-003?

A: No, they do not. While the IOUs clearly plan to do targeted marketing around the IGFC, they have not shown how they will assuage customers' significant concerns with an IGFC. For example, in the sample communications shown in Table V-18 on page 120 of the Joint IOU testimony, PG&E would tell a Tier 4, low usage solar customer in the Bay Area (San Mateo) that "their bills will stay about the same or be a bit more every month." In reality, the Joint IOUs' own bill impact results using the E3 Tool show that such a solar customer will see their bills almost doubling (+98% or +$65 per month). Being told by PG&E that this sizeable increase is "about the same" or just "a bit more" is unlikely to lead to a happy customer. Other of the sample communications around the fixed charge in Table V-18 are directed at "messaging about saving energy," "EE and program energy saving information," and "seasonal ad about lowering usage in winter." These conservation messages, as the Commission observed in D, 20-03-003, are "actions that will not actually reduce the impact of the fixed charge on a customer's bill." As the focus groups show, customers realize immediately that fixed charges do not promote conservation. Finally, customers who are receiving notice of significant bill increases are not likely to respond well to the

[100] Joint IOU testimony, at pp. 111-112, 114.

message that they should spend even more money on an EV or heat pumps, or to understand and find compelling that this added spending is beneficial because it "reduces their price per energy units."[101]

Q: What is dangerous about customer confusion around the message that high fixed charges would send?

A: High fixed charges and lower volumetric rates send a message that the customer should consume more electricity. But at the same time the state still needs consumers to conserve during peak demand periods, and I assume that the past strong messaging about the need to "flex your power" in the summer will continue. This will lead to confused customers unless a clear message – and stronger price signals in TOU rates – are conveyed that customers should increase their usage in electrification measures <u>only in off-peak hours</u>, and should continue to conserve in peak hours.

Q: Could customers perceive a high IGFC as a tax?

Yes. Assume Customers A and B live in the same apartment building in identical units, and have exactly the same electric usage. Customer A's income falls into the third tier of the Joint IOUs' proposed IGFC (non-CARE/FERA, >250% to 650% of the FPL), while Customer B's income falls into the fourth tier (non-CARE/FERA, > 650% of FPL). The utility's costs to serve Customer A and B clearly are identical, yet Customer B will pay a much higher electric bill (by $408 to $660 per year, depending on the IOU) than Customer A. The resulting difference in the bills for Customers A and B is, without question, solely a result of the income difference between the customers.[102] This is likely to be perceived as a new income tax on middle- and high-income residents, even if the Joint IOU IGFCs survive a possible

[101] *Id.*, at p. 116.

[102] The Joint IOUs essentially conceded this point when presented with this example in discovery. See Joint IOU response to SEIA DR 2, Q16, included in **Attachment RTB-4**.

legal challenge on this point and IGFCs are found to be a legitimate utility fee for services and not a tax. The focus group reactions to IGFCs, cited above, show that customers associate IGFCs with other types of taxes.

X. THE SIGNIFICANT RESOURCES REQUIRED TO IMPLEMENT AND ADMINISTER HIGH IGFCS WOUD BE BETTER SPENT ON DIRECT INCENTIVES FOR LOW-INCOME CUSTOMERS TO ADOPT ELECTRIFICATION MEASURES

Q: Are there significant unanswered questions about how the utilities would implement the high IGFCs that they and TURN/NRDC propose, and about the role of the state agency that the Joint IOUs propose to verify customers' incomes?

A: Yes. In discovery, the IOUs deferred the following questions about implementation to either further proceedings at the Commission or to the state agency that they suggest should handle income verification.

- How will incomes be verified for residential customers who receive service through a master metered rate schedule, where the utility has limited information about the end-use customers served by each such account? The three IOUs report that there are 27,500 such master-metered accounts.[103]
- How will incomes be verified for customers who are served from residential accounts that are held in the name of a corporate or business entity, or a legal entity such as a trust or estate, rather than in the name of an individual person? The three IOUs estimate that there are 375,000 residential accounts held by non-person entities.[104]
- If data from the Franchise Tax Board is not available, how will incomes be verified for self-employed customers who only report their income once a year on federal Schedule C?[105]

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[103] See Joint IOU response to SEIA DR 2, Q2 and Q3, included in **Attachment RTB-4**.

[104] See Joint IOU response to SEIA DR 2, Q4, included in **Attachment RTB-4**.

[105] See Joint IOU response to SEIA DR 2, Q5, included in **Attachment RTB-4**.

- How will the determination be made of the number of residents in a household, in order to apply income tiers based on the federal poverty guidelines that include household size?[106]
- Will the IOUs allow customers to take utility service only in the winter months?

Q: Would the costs to implement the high IGFC proposals be significantly larger than the costs to implement the SEIA proposal?

A: Yes. Based on the costs discussed in Sections III.I, III.J, IV.F, and V.I of the Joint IOU testimony, I have assembled **Table 12** to consolidate the costs to implement the Joint IOUs' IGFC proposal. For income verification, I use the Joint IOUs' reported $11.77 per customer income verification costs for CARE, extended to all 10.8 million residential accounts. As noted in the IOU testimony, this does not include start-up costs for the state agency that would administer income verification.[107]

Table 12: *Joint IOUs' IGFC Implementation Costs ($ millions)*

Cost Category	PG&E	SCE	SDG&E	Total
Residential accounts (millions)	*4.9*	*4.7*	*1.3*	*10.8*
Income verification[108]	$58	$55	$15	$128
Implementation[109]	$24	$16	$14	$55
Marketing, education & outreach[110]	$11	$8	$4	$23
Total				$206

Q: Do you think that the costs to implement the SEIA proposal would be far lower?

---

[106] See Joint IOU response to SEIA DR 2, Q10, included in **Attachment RTB-4**.

[107] Joint IOU testimony, at p. 90: "The initial costs to start-up this new income verification process and apply it to 10.8 million residential electric customers of the Joint IOUs cannot be reliably estimated, however, until more information is known."

[108] *Id.*, at p. 92.

[109] *Id.*, at p. 106 (Table IV-16).

[110] *Id.*, at p. 127 (Table V-19).

A: Yes. SEIA's IGFC proposal is based on the existing CARE and FERA eligibility guidelines, and thus would require no expansion of the existing administrative structure for these programs, including for income verification. SCE already administers a small fixed charge in its residential bills, and all three IOUs have existing residential rate schedules that include fixed charges. Given the much smaller impacts of the SEIA proposal, the ME&O budgets could be substantially smaller. Finally, if the Commission adopts our proposal, there would be no need for legacy treatment for the 1.5 million solar and solar-plus-storage customers.

Q: Could SEIA's proposed fixed charges be implemented far more quickly than the proposals for high IGFCs?

A: Yes. Based on the timeline in their testimony, the Joint IOU proposal would not be implemented until sometime in 2028, five years from now, and would require further legislation to allow a new state bureaucracy to access customers' tax returns. SEIA's proposal would be far less expensive and could be in place much sooner, because it would not go beyond the existing CARE/FERA program structure, would represent more gradual change with far lower bill impacts, and would not require legacy treatment for existing net metering customers.

Q: What would be a better use of the $200 million that the IOUs would spend to implement and administer their IGFC proposal?

A: To advance both the state's electrification and equity goals, this money would be better spent to augment programs that provide direct incentives to customers to adopt electrification measures. To provide context on what these funds could accomplish, I note that D. 22-04-036 allocated $85 million in SGIP and GHG allowance funds toward incentives in 2023 for heat pump water heaters (HPWH), with 50% of these incentives allocated to the equity HPWH program for low-income ratepayers.[111]

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[111] See D. 22-04-036, at p. 1.

Although these are not the only funds available to support incentives for heat pump water heaters, it will be a significant source of funds to encourage customer adoption of this important electrification measure.[112] This program could be extended for several more years with the savings from not having to administer the Joint IOU or TURN/NRDC proposals for high IGFCs.

XI. CONCLUSION: A BALANCED APPROACH TO ELECTRIFICATION

Q: Please summarize your rebuttal.

A: Fixed charges are not the only, and not the best, way to encourage electrification. High fixed charges will cause significant problems that their proponents have not adequately considered:

- Much lower on-peak volumetric rates will increase summer net peak demands that the state has been barely able to meet.
- Higher peak summer demands will increase carbon emissions and air pollution, and will require more infrastructure and higher long-term rates, than if the increased electrification loads are served with cleaner, more abundant off-peak energy.
- High fixed charges will undermine the Commission's recent efforts to adopt a net billing tariff that balances the interests of participating solar and storage customers and non-participating ratepayers.
- Significant rate increases for middle- and high-income customers, combined with new vehicle-to-home technology, has the potential to encourage uneconomic grid defection by the residential customers with the most means to pursue off-the-grid options. High fixed charges will also encourage defection to micro-grids or municipal utilities.

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112 D. 22-04-036, at pp. 48-50.

The Commission should take a balanced, measured approach to supporting electrification by residential customers. SEIA has proposed moderate income-graduated fixed charges that are consistent with AB 205, avoid the problems with high IGFCs, and are much more likely to be accepted by customers than the high IGFC proposals. They also can be adopted far more quickly, with lower administrative costs, than the high IGFC proposals that may require new legislation and a new state bureaucracy to verify customer incomes. The Commission should focus in subsequent phases of this rulemaking on reducing off-peak rates in all residential rate schedules, on adopting more dynamic rates, and on phasing out the outdated increasing block rates. Recognizing that the Commission is likely to be concerned with affordability, SEIA recommends pursuing Cal Advocates' innovative idea to allocate a portion of the California Climate Credit to additional bill reductions for CARE customers. Finally, the money and resources that will be saved from not having to verify the incomes of 11 million residential customers can be better spent on targeted incentives that will help customers of all means actually to adopt electrification measures.

Q: Does this conclude your rebuttal testimony in this case?

A: Yes, it does.

Attachment RTB-3

Fixed Charge Tool Printable Results for

SEIA's Modified Income-Graduated Fixed Charges

1. Tiered Rates – Printable Results

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

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						

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		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]	2.0000	2.0000	2.0000
	[75,100]	2.0000	2.0000	2.0000
	[100,150]	3.0000	3.0000	3.0000
	[150,200]	3.0000	3.0000	3.0000
	200+	3.0000	3.0000	3.0000
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	3.3700	3.4400	6.2100
	[25,50]	3.3700	3.4400	6.2100
	[50,75]	3.3700	3.4400	6.2100
	[75,100]	3.3700	3.4400	6.2100
	[100,150]	3.3700	3.4400	6.2100
	[150,200]	3.3700	3.4400	6.2100
	200+	3.3700	3.4400	6.2100
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.2200	1.2200	1.2200
	[100,150]	1.2200	1.2200	1.2200
	[150,200]	1.2200	1.2200	1.2200
	200+	1.2200	1.2200	1.2200
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ -	$ -	$ -
Demand Charge Options	Billing determinant to use	X Highest Demand Months	X Highest Demand Months	X Highest Demand Months
	No. of highest demand months to include	$ 3.0000	$ 3.0000	$ 3.0000
Adjustments to distribution rate		Equal Cents	Equal Cents	Equal Cents
Include baseline credit from existing rate	(if applicable)	TRUE	TRUE	TRUE

Revenue Requirement Components

PG&E

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

Based on CARE program size from E-TOU-C

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

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

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

SDG&E

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

Based on CARE program size from TOU-DR1

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ -	$ -	$ 100,312,693

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	$ 100,312,693
Non-Dist	$ -

SCE

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

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

Delivery - CARE-exempt		
Rev Req - Customer	Rev Req - Demand	Rev Req - Volumetric
$ -	$ -	$ 286,230,421

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 3,237,882,561

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -

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]	$ 7.9632	$ 3.3700	~~$ 7.9632~~	~~$ 3.3700~~	~~$ 7.9632~~	~~$ 3.3700~~
[25,50]	$ 7.9632	$ 3.3700	~~$ 7.9632~~	~~$ 3.3700~~	~~$ 7.9632~~	~~$ 3.3700~~
[50,75]	$ 7.9632	$ 3.3700	~~$ 7.9632~~	~~$ 3.3700~~	~~$ 7.9632~~	~~$ 3.3700~~
[75,100]	$ 9.7152	$ 3.3700	~~$ 9.7152~~	~~$ 3.3700~~	~~$ 9.7152~~	~~$ 3.3700~~
[100,150]	$ 9.7152	$ 3.3700	~~$ 9.7152~~	~~$ 3.3700~~	~~$ 9.7152~~	~~$ 3.3700~~
[150,200]	$ 9.7152	$ 3.3700	~~$ 9.7152~~	~~$ 3.3700~~	~~$ 9.7152~~	~~$ 3.3700~~
200+	$ 9.7152	$ 3.3700	~~$ 9.7152~~	~~$ 3.3700~~	~~$ 9.7152~~	~~$ 3.3700~~
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	X Highest Demand	~~X Highest Demand~~	~~X Highest Demand~~	~~X Highest Demand~~	~~X Highest Demand~~
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	$ 0.3727	$ 0.2283	~~$ 0.4647~~	~~$ 0.2881~~	~~$ 0.5363~~	~~$ 0.3347~~
Summer - Part-Peak	$ 0.3727	$ 0.2283	~~$ -~~	~~$ -~~	~~$ 0.4258~~	~~$ 0.2629~~
Summer - Off-Peak	$ 0.3727	$ 0.2283	~~$ 0.4012~~	~~$ 0.2469~~	~~$ 0.2237~~	~~$ 0.1316~~
Winter - Peak	$ 0.3727	$ 0.2283	~~$ 0.3676~~	~~$ 0.2250~~	~~$ 0.4091~~	~~$ 0.2521~~
Winter - Part-Peak	$ 0.3727	$ 0.2283	~~$ -~~	~~$ -~~	~~$ 0.3924~~	~~$ 0.2412~~
Winter - Off-Peak	$ 0.3727	$ 0.2283	~~$ 0.3502~~	~~$ 0.2138~~	~~$ 0.2237~~	~~$ 0.1316~~
Total CARE Program Funding - Modeled						
Customer		$ -		~~$ -~~		~~$ -~~
Demand		$ -		~~$ -~~		~~$ -~~
Volumetric - Delivery		$ (512,834,336)		~~$ (512,834,336)~~		~~$ (512,834,336)~~
Volumetric - Generation		$ (431,894,113)		~~$ (423,536,307)~~		~~$ (418,748,960)~~
Total CARE Credits		$ (944,728,448)		~~$ (936,370,643)~~		~~$ (931,583,295)~~
Residential CARE Funding		$ 256,139,604		~~$ 253,873,593~~		~~$ 252,575,623~~
Non-Res CARE Funding		$ 688,588,844		~~$ 682,497,050~~		~~$ 679,007,672~~
Total IOU forecast CARE program size						
2023 Forecast (Existing Rates)		$ (891,914,356)		~~$ (891,914,356)~~		~~$ (891,914,356)~~
Modeled Credits as % of Forecast		6%		~~5%~~		~~4%~~

Not Included in SEIA Proposal						**Not Included in SEIA Proposal**	
~~PG&E~~	~~PG&E~~	SCE	SCE	SCE	SCE	~~SCE~~	~~SCE~~
~~E-ELEC~~	~~E-ELEC~~	D	D	TOU-D-4-9	TOU-D-4-9	~~TOU-D-PRIME~~	~~TOU-D-PRIME~~
~~Non-CARE~~	~~CARE~~	Non-CARE	CARE	Non-CARE	CARE	~~Non-CARE~~	~~CARE~~
~~$ 7.9632~~	~~$ 3.3700~~	$ 8.2886	$ 3.4400	~~$ 8.2886~~	~~$ 3.4400~~	~~$ 8.2886~~	~~$ 3.4400~~
~~$ 7.9632~~	~~$ 3.3700~~	$ 8.2886	$ 3.4400	~~$ 8.2886~~	~~$ 3.4400~~	~~$ 8.2886~~	~~$ 3.4400~~
~~$ 7.9632~~	~~$ 3.3700~~	$ 8.2886	$ 3.4400	~~$ 8.2886~~	~~$ 3.4400~~	~~$ 8.2886~~	~~$ 3.4400~~
~~$ 9.7152~~	~~$ 3.3700~~	$ 10.1121	$ 3.4400	~~$ 10.1121~~	~~$ 3.4400~~	~~$ 10.1121~~	~~$ 3.4400~~
~~$ 9.7152~~	~~$ 3.3700~~	$ 10.1121	$ 3.4400	~~$ 10.1121~~	~~$ 3.4400~~	~~$ 10.1121~~	~~$ 3.4400~~
~~$ 9.7152~~	~~$ 3.3700~~	$ 10.1121	$ 3.4400	~~$ 10.1121~~	~~$ 3.4400~~	~~$ 10.1121~~	~~$ 3.4400~~
~~$ 9.7152~~	~~$ 3.3700~~	$ 10.1121	$ 3.4400	~~$ 10.1121~~	~~$ 3.4400~~	~~$ 10.1121~~	~~$ 3.4400~~
~~$ -~~	~~$ -~~	$ 0.0783	$ 0.0529	~~$ 0.0858~~	~~$ 0.0579~~	~~$ -~~	~~$ -~~
~~$ -~~	~~$ -~~	$ 0.0882	$ 0.0595	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
~~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~~
~~$ -~~	~~$ -~~	$ -	$ -	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
~~$ 0.5349~~	~~$ 0.3339~~	$ 0.3797	$ 0.2465	~~$ 0.5484~~	~~$ 0.3603~~	~~$ 0.6328~~	~~$ 0.4172~~
~~$ 0.3730~~	~~$ 0.2287~~	$ 0.3797	$ 0.2465	~~$ 0.4400~~	~~$ 0.2871~~	~~$ 0.3751~~	~~$ 0.2432~~
~~$ 0.3164~~	~~$ 0.1919~~	$ 0.3797	$ 0.2465	~~$ 0.3333~~	~~$ 0.2151~~	~~$ 0.2528~~	~~$ 0.1607~~
~~$ 0.3034~~	~~$ 0.1835~~	$ 0.3797	$ 0.2465	~~$ 0.4805~~	~~$ 0.3144~~	~~$ 0.5754~~	~~$ 0.3784~~
~~$ 0.2813~~	~~$ 0.1691~~	$ 0.3797	$ 0.2465	~~$ 0.3580~~	~~$ 0.2317~~	~~$ 0.2320~~	~~$ 0.1466~~
~~$ 0.2675~~	~~$ 0.1601~~	$ 0.3797	$ 0.2465	~~$ 0.3228~~	~~$ 0.2080~~	~~$ 0.2320~~	~~$ 0.1466~~
	~~$ -~~		$ -		~~$ -~~		~~$ -~~
	~~$ -~~		$ -		~~$ -~~		~~$ -~~
	~~$ (512,834,336)~~		$ (361,429,971)		~~$ (361,429,971)~~		~~$ (361,429,971)~~
	~~$ (405,034,979)~~		$ (339,559,859)		~~$ (347,681,851)~~		~~$ (354,957,511)~~
	~~$ (917,869,314)~~		$ (700,989,830)		~~$ (709,111,821)~~		~~$ (716,387,482)~~
	~~$ 248,857,419~~		$ 180,152,375		~~$ 182,239,704~~		~~$ 184,109,528~~
	~~$ 669,011,896~~		$ 520,837,455		~~$ 526,872,117~~		~~$ 532,277,954~~
	~~$ (891,914,356)~~		$ (660,034,291)		~~$ (660,034,291)~~		~~$ (660,034,291)~~
	~~3%~~		6%		~~7%~~		~~9%~~

Not Included in SEIA Proposal

SDG&E	SDG&E	SDG&E	SDG&E	SDG&E	SDG&E	~~SDG&E~~	~~SDG&E~~
DR	DR	TOU-DR1	TOU-DR1	~~EV-TOU-5~~	~~EV-TOU-5~~	~~TOU-ELEC~~	~~TOU-ELEC~~
Non-CARE	CARE	Non-CARE	CARE	~~Non-CARE~~	~~CARE~~	~~Non-CARE~~	~~CARE~~
$ 11.1197	$ 6.2100	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~
$ 11.1197	$ 6.2100	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~
$ 11.1197	$ 6.2100	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~
$ 13.5660	$ 6.2100	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~
$ 13.5660	$ 6.2100	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~
$ 13.5660	$ 6.2100	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~
$ 13.5660	$ 6.2100	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~
$ 0.1078	$ 0.0711	~~$ 0.1078~~	~~$ 0.0711~~	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
$ -	$ -	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
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~~
$ -	$ -	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
$ 0.5516	$ 0.3523	~~$ 0.8138~~	~~$ 0.5255~~	~~$ 0.8457~~	~~$ 0.5465~~	~~$ 0.7804~~	~~$ 0.5035~~
$ 0.5516	$ 0.3523	~~$ 0.5004~~	~~$ 0.3186~~	~~$ 0.5107~~	~~$ 0.3254~~	~~$ 0.4112~~	~~$ 0.2598~~
$ 0.5516	$ 0.3523	~~$ 0.3357~~	~~$ 0.2099~~	~~$ 0.2563~~	~~$ 0.1575~~	~~$ 0.3626~~	~~$ 0.2278~~
$ 0.5516	$ 0.3523	~~$ 0.6171~~	~~$ 0.3956~~	~~$ 0.5409~~	~~$ 0.3453~~	~~$ 0.5394~~	~~$ 0.3444~~
$ 0.5516	$ 0.3523	~~$ 0.5325~~	~~$ 0.3398~~	~~$ 0.4771~~	~~$ 0.3032~~	~~$ 0.3980~~	~~$ 0.2511~~
$ 0.5516	$ 0.3523	~~$ 0.5080~~	~~$ 0.3236~~	~~$ 0.2480~~	~~$ 0.1520~~	~~$ 0.3538~~	~~$ 0.2220~~
	$ -		~~$ -~~		~~$ -~~		~~$ -~~
	$ -		~~$ -~~		~~$ -~~		~~$ -~~
	$ (121,075,241)		~~$ (121,075,241)~~		~~$ (121,075,241)~~		~~$ (121,075,241)~~
	$ (100,157,376)		~~$ (96,179,165)~~		~~$ (96,851,978)~~		~~$ (93,461,884)~~
	$ (221,232,617)		~~$ (217,254,406)~~		~~$ (217,927,218)~~		~~$ (214,537,125)~~
	$ 63,531,039		~~$ 62,388,623~~		~~$ 62,581,833~~		~~$ 61,608,305~~
	$ 157,701,577		~~$ 154,865,783~~		~~$ 155,345,385~~		~~$ 152,928,820~~
	$ (178,549,476)		~~$ (178,549,476)~~		~~$ (178,549,476)~~		~~$ (178,549,476)~~
	24%		~~22%~~		~~22%~~		~~20%~~

Bill Impacts

PG&E

			Customer Average Bill Impact ($/mo)										
Income Bracket	Discount		PG&E	P	Q	R	S	T	V	W	X	Y	Z
$0 - $25,000	None	1	$ 0.97	$ (2.45)	$ (1.81)	$ (2.34)	$ (1.62)	$ 2.47	$ (0.36)	$ (1.70)	$ 0.41	$ 0.33	$ 3.48
$25,000 - $50,000	None	2	$ 0.13	$ (2.36)	$ (1.80)	$ (2.37)	$ (1.56)	$ 2.50	$ (0.40)	$ (1.78)	$ 0.40	$ 0.33	$ 3.48
$50,000 - $75,000	None	3	$ 0.07	$ (2.27)	$ (1.77)	$ (2.08)	$ (1.36)	$ 2.52	$ (0.40)	$ (1.43)	$ 0.45	$ 0.34	$ 3.48
$75,000 - $100,000	None	4	$ 2.03	$ (0.36)	$ (0.02)	$ 0.05	$ 0.68	$ 4.30	$ 1.39	$ 0.83	$ 2.23	$ 2.11	$ 5.23
$100,00 - $150,000	None	5	$ 2.28	$ (0.18)	$ 0.08	$ 0.49	$ 1.00	$ 4.32	$ 1.43	$ 1.43	$ 2.30	$ 2.11	$ 5.24
$150,000 - $200,000	None	6	$ 2.59	$ 0.17	$ 0.16	$ 0.99	$ 1.41	$ 4.34	$ 1.48	$ 2.11	$ 2.38	$ 2.14	$ 5.22
$200,000+	None	7	$ 3.00	$ 0.62	$ 0.41	$ 1.76	$ 2.00	$ 4.37	$ 1.49	$ 2.90	$ 2.63	$ 2.19	$ 5.22
	None	Avg	**$ 1.83**	**$ (1.03)**	**$ (0.36)**	**$ (0.46)**	**$ 0.35**	**$ 3.78**	**$ 0.43**	**$ 0.48**	**$ 1.96**	**$ 1.27**	**$ 4.43**
$0 - $25,000	CARE	1	$ (2.29)	$ (4.76)	$ (3.53)	$ (3.71)	$ (3.13)	$ (0.31)	$ (1.45)	$ (3.50)	$ (1.45)	$ (3.88)	$ (2.09)
$25,000 - $50,000	CARE	2	$ (2.39)	$ (4.73)	$ (3.53)	$ (3.58)	$ (3.04)	$ (0.29)	$ (1.46)	$ (3.31)	$ (1.42)	$ (3.88)	$ (2.13)
$50,000 - $75,000	CARE	3	$ (2.21)	$ (4.67)	$ (3.41)	$ (3.44)	$ (2.98)	$ (0.29)	$ (1.42)	$ (3.09)	$ (1.41)	$ (3.87)	$ (2.16)
$75,000 - $100,000	CARE	4	$ (2.14)	$ (4.66)	$ (3.18)	$ (3.39)	$ (2.88)	$ (0.27)	$ (1.39)	$ (2.89)	$ (1.41)	$ (3.87)	$ (2.17)
$100,00 - $150,000	CARE	5	$ (2.03)	$ (4.62)	$ (3.49)	$ (3.23)	$ (2.79)	$ (0.27)	$ (1.44)	$ (2.77)	$ (1.38)	$ (3.87)	$ (2.19)
$150,000 - $200,000	CARE	6	$ (1.86)	$ (4.55)	$ (3.59)	$ (3.13)	$ (2.71)	$ (0.27)	$ (1.45)	$ (2.48)	$ (1.37)	$ (3.87)	$ (2.11)
$200,000+	CARE	7	$ (1.60)	$ (4.33)	$ (3.59)	$ (2.94)	$ (2.57)	$ (0.27)	$ (1.39)	$ (2.35)	$ (1.33)	$ (3.86)	$ (3.37)
	CARE	Avg	**$ (2.27)**	**$ (4.73)**	**$ (3.52)**	**$ (3.59)**	**$ (3.04)**	**$ (0.30)**	**$ (1.45)**	**$ (3.30)**	**$ (1.43)**	**$ (3.88)**	**$ (2.10)**
$0 - $25,000	FERA	1	$ (0.64)	$ (4.18)	$ (2.62)	$ (2.43)	$ (1.81)	$ 1.69	$ 0.17	$ (2.09)	$ 0.21	$ (3.05)	$ (0.44)
$25,000 - $50,000	FERA	2	$ (0.68)	$ (4.13)	$ (2.61)	$ (2.11)	$ (1.63)	$ 1.71	$ 0.16	$ (1.67)	$ 0.26	$ (3.04)	$ (0.62)
$50,000 - $75,000	FERA	3	$ (0.45)	$ (4.05)	$ (2.37)	$ (1.81)	$ (1.49)	$ 1.72	$ 0.21	$ (1.24)	$ 0.29	$ (3.01)	$ (0.69)
$75,000 - $100,000	FERA	4	$ 1.08	$ (2.59)	$ (0.48)	$ (0.26)	$ 0.13	$ 3.18	$ 1.69	$ 0.57	$ 1.72	$ (1.58)	$ 0.71
$100,00 - $150,000	FERA	5	$ 1.21	$ (2.54)	$ (1.09)	$ 0.05	$ 0.30	$ 3.19	$ 1.62	$ 0.77	$ 1.78	$ (1.56)	$ 0.65
$150,000 - $200,000	FERA	6	$ 1.38	$ (2.43)	$ (1.29)	$ 0.24	$ 0.44	$ 3.18	$ 1.61	$ 1.23	$ 1.80	$ (1.56)	$ 0.90
$200,000+	FERA	7	$ 1.64	$ (2.11)	$ (1.29)	$ 0.56	$ 0.68	$ 3.19	$ 1.69	$ 1.41	$ 1.86	$ (1.55)	$ (0.11)
	FERA	Avg	**$ (0.38)**	**$ (4.04)**	**$ (2.45)**	**$ (1.99)**	**$ (1.43)**	**$ 1.86**	**$ 0.24**	**$ (1.49)**	**$ 0.48**	**$ (2.93)**	**$ (0.41)**
	CARE & FERA	Avg	**$ (2.22)**	**$ (4.72)**	**$ (3.48)**	**$ (3.56)**	**$ (2.99)**	**$ (0.25)**	**$ (1.41)**	**$ (3.27)**	**$ (1.36)**	**$ (3.85)**	**$ (2.01)**

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)	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	$ (0.57)	$ (0.79)	$ (0.31)	$ (0.97)	$ (6.72)
$25,000 - $50,000	None	2	$ (0.61)	$ (1.12)	$ (0.31)	$ (1.29)	$ (5.77)
$50,000 - $75,000	None	3	$ (0.69)	$ (1.16)	$ (0.27)	$ (0.36)	$ (5.48)
$75,000 - $100,000	None	4	$ 1.84	$ 1.45	$ 2.24	$ 3.32	$ (2.62)
$100,00 - $150,000	None	5	$ 2.19	$ 1.98	$ 2.45	$ 2.53	$ (1.55)
$150,000 - $200,000	None	6	$ 2.70	$ 2.76	$ 2.71	$ 8.95	$ (0.07)
$200,000+	None	7	$ 3.55	$ 3.85	$ 3.41	$ 2.21	$ 1.78
	None	Avg	**$ 1.71**	**$ 1.57**	**$ 1.89**	**$ (0.20)**	**$ (2.46)**
$0 - $25,000	CARE	1	$ (1.33)	$ (2.22)	$ (0.30)	$ (9.77)	$ (11.15)
$25,000 - $50,000	CARE	2	$ (1.36)	$ (2.20)	$ (0.30)	$ (10.26)	$ (10.97)
$50,000 - $75,000	CARE	3	$ (1.31)	$ (2.16)	$ (0.29)	N/A	$ (11.00)
$75,000 - $100,000	CARE	4	$ (1.12)	$ (2.13)	$ (0.23)	N/A	$ (11.22)
$100,00 - $150,000	CARE	5	$ (1.01)	$ (2.17)	$ (0.26)	N/A	N/A
$150,000 - $200,000	CARE	6	$ 0.00	N/A	$ 0.00	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
	CARE	Avg	**$ (1.34)**	**$ (2.20)**	**$ (0.30)**	**$ (9.85)**	**$ (11.08)**
$0 - $25,000	FERA	1	$ (0.44)	$ (1.41)	$ 0.90	$ (10.28)	$ (13.30)
$25,000 - $50,000	FERA	2	$ (0.45)	$ (1.34)	$ 0.90	$ (11.44)	$ (12.94)
$50,000 - $75,000	FERA	3	$ (0.34)	$ (1.25)	$ 0.93	N/A	$ (13.00)
$75,000 - $100,000	FERA	4	$ 1.92	$ 0.81	$ 3.06	N/A	$ (11.41)
$100,00 - $150,000	FERA	5	$ 2.04	$ 0.72	$ 3.01	N/A	N/A
$150,000 - $200,000	FERA	6	$ 3.52	N/A	$ 3.52	N/A	N/A
$200,000+	FERA	7	N/A	N/A	N/A	N/A	N/A
	FERA	Avg	**$ (0.39)**	**$ (1.32)**	**$ 0.94**	**$ (10.46)**	**$ (13.15)**
	CARE & FERA	Avg	**$ (1.30)**	**$ (2.17)**	**$ (0.25)**	**$ (9.86)**	**$ (11.18)**

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		SCE	5	6	8	9	10	13	14	15	16
			Customer Average Bill Impact ($/mo)									
$0 - $25,000	None	1	$ (0.14)	$ (0.62)	$ 1.35	$ 0.87	$ (0.92)	$ (1.05)	$ (2.99)	$ (2.36)	$ (3.63)	$ 0.47
$25,000 - $50,000	None	2	$ (0.47)	$ (0.62)	$ 1.36	$ 0.83	$ (1.06)	$ (1.41)	$ (2.80)	$ (2.23)	$ (3.98)	$ 0.51
$50,000 - $75,000	None	3	$ (0.40)	$ (0.62)	$ 1.38	$ 0.83	$ (1.07)	$ (1.36)	$ (2.46)	$ (2.08)	$ (3.74)	$ 0.54
$75,000 - $100,000	None	4	$ 1.53	$ 1.20	$ 3.22	$ 2.68	$ 0.80	$ 0.61	$ (0.38)	$ (0.03)	$ (1.71)	$ 2.47
$100,00 - $150,000	None	5	$ 1.71	$ 1.20	$ 3.25	$ 2.74	$ 0.88	$ 0.89	$ (0.05)	$ 0.20	$ (1.52)	$ 2.58
$150,000 - $200,000	None	6	$ 1.92	$ 1.20	$ 3.29	$ 2.81	$ 1.01	$ 1.15	$ 0.18	$ 0.46	$ (1.29)	$ 2.70
$200,000+	None	7	$ 2.26	$ 1.20	$ 3.37	$ 2.98	$ 1.21	$ 1.47	$ 0.68	$ 0.79	$ (0.91)	$ 2.78
	None	Avg	**$ 1.02**	**$ 0.48**	**$ 2.62**	**$ 2.11**	**$ 0.31**	**$ 0.15**	**$ (1.16)**	**$ (0.87)**	**$ (2.66)**	**$ 1.35**
$0 - $25,000	CARE	1	$ (2.12)	N/A	$ (0.31)	$ (0.85)	$ (1.70)	$ (3.10)	$ (3.68)	$ (3.79)	$ (4.41)	$ (2.47)
$25,000 - $50,000	CARE	2	$ (2.05)	N/A	$ (0.31)	$ (0.85)	$ (1.70)	$ (3.06)	$ (3.59)	$ (3.69)	$ (4.27)	$ (2.43)
$50,000 - $75,000	CARE	3	$ (2.01)	N/A	$ (0.30)	$ (0.84)	$ (1.69)	$ (3.00)	$ (3.52)	$ (3.63)	$ (4.20)	$ (2.44)
$75,000 - $100,000	CARE	4	$ (2.00)	N/A	$ (0.30)	$ (0.84)	$ (1.68)	$ (2.96)	$ (3.44)	$ (3.62)	$ (4.13)	$ (2.44)
$100,00 - $150,000	CARE	5	$ (1.93)	N/A	$ (0.29)	$ (0.83)	$ (1.68)	$ (2.89)	$ (3.43)	$ (3.51)	$ (4.09)	$ (2.38)
$150,000 - $200,000	CARE	6	$ (1.81)	N/A	$ (0.28)	$ (0.81)	$ (1.66)	$ (2.78)	$ (3.35)	$ (3.39)	$ (3.98)	$ (2.30)
$200,000+	CARE	7	$ (1.65)	N/A	$ (0.28)	$ (0.80)	$ (1.63)	$ (2.69)	$ (3.22)	$ (3.31)	$ (3.78)	$ (2.21)
	CARE	Avg	**$ (2.05)**	**#DIV/0!**	**$ (0.31)**	**$ (0.84)**	**$ (1.69)**	**$ (3.03)**	**$ (3.60)**	**$ (3.70)**	**$ (4.33)**	**$ (2.45)**
$0 - $25,000	FERA	1	$ (0.06)	N/A	$ 2.08	$ 1.42	$ 0.36	$ (1.26)	$ (1.91)	$ (2.13)	$ (2.85)	$ (0.69)
$25,000 - $50,000	FERA	2	$ 0.01	N/A	$ 2.10	$ 1.44	$ 0.38	$ (1.18)	$ (1.71)	$ (1.94)	$ (2.59)	$ (0.62)
$50,000 - $75,000	FERA	3	$ 0.06	N/A	$ 2.10	$ 1.45	$ 0.40	$ (1.07)	$ (1.57)	$ (1.84)	$ (2.46)	$ (0.63)
$75,000 - $100,000	FERA	4	$ 1.57	N/A	$ 3.60	$ 2.95	$ 1.90	$ 0.49	$ 0.07	$ (0.33)	$ (0.85)	$ 0.87
$100,00 - $150,000	FERA	5	$ 1.66	N/A	$ 3.62	$ 2.96	$ 1.91	$ 0.61	$ 0.08	$ (0.14)	$ (0.77)	$ 0.97
$150,000 - $200,000	FERA	6	$ 1.81	N/A	$ 3.63	$ 2.99	$ 1.95	$ 0.80	$ 0.23	$ 0.05	$ (0.58)	$ 1.09
$200,000+	FERA	7	$ 2.01	N/A	$ 3.63	$ 3.03	$ 1.99	$ 0.94	$ 0.45	$ 0.18	$ (0.26)	$ 1.23
	FERA	Avg	**$ 0.29**	**#DIV/0!**	**$ 2.35**	**$ 1.70**	**$ 0.66**	**$ (0.84)**	**$ (1.52)**	**$ (1.76)**	**$ (2.55)**	**$ (0.48)**
	CARE & FERA	Avg	**$ (2.00)**	**#DIV/0!**	**$ (0.25)**	**$ (0.79)**	**$ (1.64)**	**$ (2.98)**	**$ (3.56)**	**$ (3.67)**	**$ (4.31)**	**$ (2.41)**

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

2. TOU Rates – Printable Results

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

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						

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		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]	2.0000	2.0000	2.0000
	[75,100]	2.0000	2.0000	2.0000
	[100,150]	3.0000	3.0000	3.0000
	[150,200]	3.0000	3.0000	3.0000
	200+	3.0000	3.0000	3.0000
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	3.3700	3.4400	6.2100
	[25,50]	3.3700	3.4400	6.2100
	[50,75]	3.3700	3.4400	6.2100
	[75,100]	3.3700	3.4400	6.2100
	[100,150]	3.3700	3.4400	6.2100
	[150,200]	3.3700	3.4400	6.2100
	200+	3.3700	3.4400	6.2100
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.2200	1.2200	1.2200
	[100,150]	1.2200	1.2200	1.2200
	[150,200]	1.2200	1.2200	1.2200
	200+	1.2200	1.2200	1.2200
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ -	$ -	$ -
Demand Charge Options	Billing determinant to use	X Highest Demand Months	X Highest Demand Months	X Highest Demand Months
	No. of highest demand months to include	$ 3.0000	$ 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
$ -	$ -	$ 444,768,973

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

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

SDG&E

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
$ -	$ -	$ 100,312,693

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	$ 100,312,693
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
$ -	$ -	$ 286,230,421

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 3,237,882,561

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -

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$):						
[0,25]	~~$ 7.9632~~	~~$ 3.3700~~	$ 7.9632	$ 3.3700	$ 7.9632	$ 3.3700
[25,50]	~~$ 7.9632~~	~~$ 3.3700~~	$ 7.9632	$ 3.3700	$ 7.9632	$ 3.3700
[50,75]	~~$ 7.9632~~	~~$ 3.3700~~	$ 7.9632	$ 3.3700	$ 7.9632	$ 3.3700
[75,100]	~~$ 9.7152~~	~~$ 3.3700~~	$ 9.7152	$ 3.3700	$ 9.7152	$ 3.3700
[100,150]	~~$ 9.7152~~	~~$ 3.3700~~	$ 9.7152	$ 3.3700	$ 9.7152	$ 3.3700
[150,200]	~~$ 9.7152~~	~~$ 3.3700~~	$ 9.7152	$ 3.3700	$ 9.7152	$ 3.3700
200+	~~$ 9.7152~~	~~$ 3.3700~~	$ 9.7152	$ 3.3700	$ 9.7152	$ 3.3700
Tier Credits/Charges ($/kWh)						
Baseline Credit	~~$ 0.0687~~	~~$ 0.0446~~	$ 0.0687	$ 0.0446	$ -	$ -
High Usage Charge	~~$ -~~	~~$ -~~	$ -	$ -	$ -	$ -
Demand Charges ($/kW)						
Billing Determinant	~~X Highest Demand~~	~~X Highest Demand~~	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand
No. of Highest Demand Months	~~$ 3.0000~~	~~$ 3.0000~~	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
Demand Charge ($/kW-mo)	~~$ -~~	~~$ -~~	$ -	$ -	$ -	$ -
Energy Charges ($/kWh)						
Summer - Peak	~~$ 0.3727~~	~~$ 0.2283~~	$ 0.4641	$ 0.2877	$ 0.5257	$ 0.3279
Summer - Part-Peak	~~$ 0.3727~~	~~$ 0.2283~~	$ -	$ -	$ 0.4202	$ 0.2593
Summer - Off-Peak	~~$ 0.3727~~	~~$ 0.2283~~	$ 0.4008	$ 0.2466	$ 0.2304	$ 0.1359
Winter - Peak	~~$ 0.3727~~	~~$ 0.2283~~	$ 0.3679	$ 0.2252	$ 0.4039	$ 0.2487
Winter - Part-Peak	~~$ 0.3727~~	~~$ 0.2283~~	$ -	$ -	$ 0.3876	$ 0.2380
Winter - Off-Peak	~~$ 0.3727~~	~~$ 0.2283~~	$ 0.3506	$ 0.2140	$ 0.2298	$ 0.1355
Total CARE Program Funding - Modeled						
Customer		~~$ -~~		$ -		$ -
Demand		~~$ -~~		$ -		$ -
Volumetric - Delivery		~~$ (512,834,336)~~		$ (512,834,336)		$ (512,834,336)
Volumetric - Generation		~~$ (431,894,113)~~		$ (423,536,307)		$ (418,748,960)
Total CARE Credits		~~$ (944,728,448)~~		$ (936,370,643)		$ (931,583,295)
Residential CARE Funding		~~$ 256,139,604~~		$ 253,873,593		$ 252,575,623
Non-Res CARE Funding		~~$ 688,588,844~~		$ 682,497,050		$ 679,007,672
Total IOU forecast CARE program size						
2023 Forecast (Existing Rates)		~~$ (891,914,356)~~		$ (891,914,356)		$ (891,914,356)
Modeled Credits as % of Forecast		~~6%~~		5%		4%

Not Included in SEIA Proposal | Not Included in SEIA Proposal

~~PG&E~~	~~PG&E~~	SCE	SCE	SCE	SCE	~~SCE~~	~~SCE~~
~~E-ELEC~~	~~E-ELEC~~	D	D	TOU-D-4-9	TOU-D-4-9	~~TOU-D-PRIME~~	~~TOU-D-PRIME~~
~~Non-CARE~~	~~CARE~~	Non-CARE	CARE	Non-CARE	CARE	~~Non-CARE~~	~~CARE~~
~~$ 7.9632~~	~~$ 3.3700~~	~~$ 8.2886~~	~~$ 3.4400~~	$ 8.2886	$ 3.4400	~~$ 8.2886~~	~~$ 3.4400~~
~~$ 7.9632~~	~~$ 3.3700~~	~~$ 8.2886~~	~~$ 3.4400~~	$ 8.2886	$ 3.4400	~~$ 8.2886~~	~~$ 3.4400~~
~~$ 7.9632~~	~~$ 3.3700~~	~~$ 8.2886~~	~~$ 3.4400~~	$ 8.2886	$ 3.4400	~~$ 8.2886~~	~~$ 3.4400~~
~~$ 9.7152~~	~~$ 3.3700~~	~~$ 10.1121~~	~~$ 3.4400~~	$ 10.1121	$ 3.4400	~~$ 10.1121~~	~~$ 3.4400~~
~~$ 9.7152~~	~~$ 3.3700~~	~~$ 10.1121~~	~~$ 3.4400~~	$ 10.1121	$ 3.4400	~~$ 10.1121~~	~~$ 3.4400~~
~~$ 9.7152~~	~~$ 3.3700~~	~~$ 10.1121~~	~~$ 3.4400~~	$ 10.1121	$ 3.4400	~~$ 10.1121~~	~~$ 3.4400~~
~~$ 9.7152~~	~~$ 3.3700~~	~~$ 10.1121~~	~~$ 3.4400~~	$ 10.1121	$ 3.4400	~~$ 10.1121~~	~~$ 3.4400~~
~~$ -~~	~~$ -~~	~~$ 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	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~~
~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~	$ -	$ -	~~$ -~~	~~$ -~~
~~$ 0.5462~~	~~$ 0.3413~~	~~$ 0.3673~~	~~$ 0.2381~~	$ 0.5208	$ 0.3416	~~$ 0.6364~~	~~$ 0.4196~~
~~$ 0.3730~~	~~$ 0.2287~~	~~$ 0.2440~~	~~$ 0.1549~~	$ 0.4124	$ 0.2685	~~$ 0.3786~~	~~$ 0.2456~~
~~$ 0.3142~~	~~$ 0.1905~~	~~$ 0.2440~~	~~$ 0.1549~~	$ 0.3119	$ 0.2006	~~$ 0.2514~~	~~$ 0.1597~~
~~$ 0.3022~~	~~$ 0.1827~~	~~$ 0.3673~~	~~$ 0.2381~~	$ 0.4529	$ 0.2958	~~$ 0.5793~~	~~$ 0.3811~~
~~$ 0.2797~~	~~$ 0.1681~~	~~$ 0.2440~~	~~$ 0.1549~~	$ 0.3366	$ 0.2173	~~$ 0.2302~~	~~$ 0.1454~~
~~$ 0.2657~~	~~$ 0.1590~~	~~$ 0.2440~~	~~$ 0.1549~~	$ 0.3036	$ 0.1950	~~$ 0.2302~~	~~$ 0.1454~~
	~~$ -~~		~~$ -~~		$ -		~~$ -~~
	~~$ -~~		~~$ -~~		$ -		~~$ -~~
	~~$ (512,834,336)~~		~~$ (361,429,971)~~		$ (361,429,971)		~~$ (361,429,971)~~
	~~$ (405,034,979)~~		~~$ (339,559,859)~~		$ (347,681,851)		~~$ (354,957,511)~~
	~~$ (917,869,314)~~		~~$ (700,989,830)~~		$ (709,111,821)		~~$ (716,387,482)~~
	~~$ 248,857,419~~		~~$ 180,152,375~~		$ 182,239,704		~~$ 184,109,528~~
	~~$ 669,011,896~~		~~$ 520,837,455~~		$ 526,872,117		~~$ 532,277,954~~
	~~$ (891,914,356)~~		~~$ (660,034,291)~~		$ (660,034,291)		~~$ (660,034,291)~~
	~~3%~~		~~6%~~		7%		~~9%~~

Not Included in SEIA Proposal

SDG&E	SDG&E	SDG&E	SDG&E	SDG&E	SDG&E	~~SDG&E~~	~~SDG&E~~
DR	DR	TOU-DR1	TOU-DR1	~~EV-TOU-5~~	~~EV-TOU-5~~	~~TOU-ELEC~~	~~TOU-ELEC~~
Non-CARE	CARE	Non-CARE	CARE	~~Non-CARE~~	~~CARE~~	~~Non-CARE~~	~~CARE~~
~~$ 11.1197~~	~~$ 6.2100~~	$ 11.1197	$ 6.2100	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~
~~$ 11.1197~~	~~$ 6.2100~~	$ 11.1197	$ 6.2100	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~
~~$ 11.1197~~	~~$ 6.2100~~	$ 11.1197	$ 6.2100	~~$ 11.1197~~	~~$ 6.2100~~	~~$ 11.1197~~	~~$ 6.2100~~
~~$ 13.5660~~	~~$ 6.2100~~	$ 13.5660	$ 6.2100	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~
~~$ 13.5660~~	~~$ 6.2100~~	$ 13.5660	$ 6.2100	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~
~~$ 13.5660~~	~~$ 6.2100~~	$ 13.5660	$ 6.2100	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~
~~$ 13.5660~~	~~$ 6.2100~~	$ 13.5660	$ 6.2100	~~$ 13.5660~~	~~$ 6.2100~~	~~$ 13.5660~~	~~$ 6.2100~~
~~$ 0.0902~~	~~$ 0.0596~~	$ 0.0902	$ 0.0596	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
~~$ -~~	~~$ -~~	$ -	$ -	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
~~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~~
~~$ -~~	~~$ -~~	$ -	$ -	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
~~$ 0.5194~~	~~$ 0.3311~~	$ 0.8200	$ 0.5296	~~$ 0.8477~~	~~$ 0.5478~~	~~$ 0.7804~~	~~$ 0.5035~~
~~$ 0.5194~~	~~$ 0.3311~~	$ 0.5065	$ 0.3227	~~$ 0.5127~~	~~$ 0.3267~~	~~$ 0.4112~~	~~$ 0.2598~~
~~$ 0.5615~~	~~$ 0.3588~~	$ 0.3419	$ 0.2140	~~$ 0.2521~~	~~$ 0.1547~~	~~$ 0.3626~~	~~$ 0.2278~~
~~$ 0.3389~~	~~$ 0.2119~~	$ 0.5807	$ 0.3716	~~$ 0.5429~~	~~$ 0.3467~~	~~$ 0.5394~~	~~$ 0.3444~~
~~$ 0.3389~~	~~$ 0.2119~~	$ 0.4962	$ 0.3158	~~$ 0.4792~~	~~$ 0.3046~~	~~$ 0.3980~~	~~$ 0.2511~~
~~$ 0.5204~~	~~$ 0.3317~~	$ 0.4716	$ 0.2996	~~$ 0.2438~~	~~$ 0.1492~~	~~$ 0.3538~~	~~$ 0.2220~~
	~~$ -~~		$ -		~~$ -~~		~~$ -~~
	~~$ -~~		$ -		~~$ -~~		~~$ -~~
	~~$ (121,075,241)~~		$ (121,075,241)		~~$ (121,075,241)~~		~~$ (121,075,241)~~
	~~$ (100,157,376)~~		$ (96,179,165)		~~$ (96,851,978)~~		~~$ (93,461,884)~~
	~~$ (221,232,617)~~		$ (217,254,406)		~~$ (217,927,218)~~		~~$ (214,537,125)~~
	~~$ 63,531,039~~		$ 62,388,623		~~$ 62,581,833~~		~~$ 61,608,305~~
	~~$ 157,701,577~~		$ 154,865,783		~~$ 155,345,385~~		~~$ 152,928,820~~
	~~$ (178,549,476)~~		$ (178,549,476)		~~$ (178,549,476)~~		~~$ (178,549,476)~~
	~~24%~~		22%		~~22%~~		~~20%~~

Bill Impacts

PG&E

Income Bracket	Discount		PG&E	P	Q	R	S	T	V	W	X	Y	Z
			Customer Average Bill Impact ($/mo)										
$0 - $25,000	None	1	$ 0.73	$ (2.81)	$ (2.10)	$ (2.75)	$ (1.99)	$ 2.30	$ (0.60)	$ (2.11)	$ 0.15	$ 0.07	$ 3.33
$25,000 - $50,000	None	2	$ (0.15)	$ (2.72)	$ (2.09)	$ (2.78)	$ (1.93)	$ 2.33	$ (0.64)	$ (2.20)	$ 0.15	$ 0.08	$ 3.33
$50,000 - $75,000	None	3	$ (0.21)	$ (2.62)	$ (2.05)	$ (2.48)	$ (1.72)	$ 2.36	$ (0.64)	$ (1.83)	$ 0.20	$ 0.09	$ 3.33
$75,000 - $100,000	None	4	$ 1.76	$ (0.71)	$ (0.31)	$ (0.34)	$ 0.34	$ 4.13	$ 1.15	$ 0.44	$ 1.99	$ 1.85	$ 5.08
$100,00 - $150,000	None	5	$ 2.02	$ (0.52)	$ (0.20)	$ 0.12	$ 0.67	$ 4.15	$ 1.19	$ 1.06	$ 2.05	$ 1.86	$ 5.09
$150,000 - $200,000	None	6	$ 2.34	$ (0.15)	$ (0.12)	$ 0.63	$ 1.10	$ 4.17	$ 1.24	$ 1.76	$ 2.14	$ 1.89	$ 5.07
$200,000+	None	7	$ 2.77	$ 0.31	$ 0.14	$ 1.42	$ 1.71	$ 4.21	$ 1.25	$ 2.57	$ 2.40	$ 1.94	$ 5.07
	None	Avg	**$ 1.57**	**$ (1.38)**	**$ (0.64)**	**$ (0.84)**	**$ 0.02**	**$ 3.61**	**$ 0.18**	**$ 0.10**	**$ 1.72**	**$ 1.02**	**$ 4.28**
$0 - $25,000	CARE	1	$ (2.50)	$ (5.04)	$ (3.74)	$ (4.00)	$ (3.39)	$ (0.43)	$ (1.60)	$ (3.80)	$ (1.62)	$ (4.11)	$ (2.26)
$25,000 - $50,000	CARE	2	$ (2.62)	$ (5.00)	$ (3.73)	$ (3.87)	$ (3.30)	$ (0.41)	$ (1.61)	$ (3.61)	$ (1.59)	$ (4.11)	$ (2.30)
$50,000 - $75,000	CARE	3	$ (2.43)	$ (4.94)	$ (3.61)	$ (3.73)	$ (3.23)	$ (0.40)	$ (1.57)	$ (3.38)	$ (1.58)	$ (4.10)	$ (2.32)
$75,000 - $100,000	CARE	4	$ (2.35)	$ (4.93)	$ (3.37)	$ (3.68)	$ (3.13)	$ (0.39)	$ (1.53)	$ (3.18)	$ (1.58)	$ (4.10)	$ (2.33)
$100,00 - $150,000	CARE	5	$ (2.24)	$ (4.89)	$ (3.69)	$ (3.51)	$ (3.04)	$ (0.38)	$ (1.59)	$ (3.05)	$ (1.54)	$ (4.10)	$ (2.35)
$150,000 - $200,000	CARE	6	$ (2.06)	$ (4.82)	$ (3.79)	$ (3.41)	$ (2.96)	$ (0.39)	$ (1.60)	$ (2.75)	$ (1.53)	$ (4.10)	$ (2.28)
$200,000+	CARE	7	$ (1.78)	$ (4.59)	$ (3.79)	$ (3.21)	$ (2.81)	$ (0.39)	$ (1.53)	$ (2.62)	$ (1.50)	$ (4.09)	$ (3.52)
	CARE	Avg	**$ (2.49)**	**$ (5.01)**	**$ (3.72)**	**$ (3.89)**	**$ (3.30)**	**$ (0.42)**	**$ (1.60)**	**$ (3.60)**	**$ (1.59)**	**$ (4.11)**	**$ (2.27)**
$0 - $25,000	FERA	1	$ (0.90)	$ (4.53)	$ (2.87)	$ (2.79)	$ (2.13)	$ 1.54	$ (0.02)	$ (2.47)	$ 0.00	$ (3.34)	$ (0.65)
$25,000 - $50,000	FERA	2	$ (0.94)	$ (4.48)	$ (2.86)	$ (2.46)	$ (1.94)	$ 1.56	$ (0.03)	$ (2.04)	$ 0.06	$ (3.33)	$ (0.83)
$50,000 - $75,000	FERA	3	$ (0.71)	$ (4.39)	$ (2.61)	$ (2.15)	$ (1.80)	$ 1.58	$ 0.02	$ (1.58)	$ 0.08	$ (3.30)	$ (0.90)
$75,000 - $100,000	FERA	4	$ 0.83	$ (2.94)	$ (0.71)	$ (0.60)	$ (0.17)	$ 3.03	$ 1.51	$ 0.23	$ 1.52	$ (1.87)	$ 0.50
$100,00 - $150,000	FERA	5	$ 0.96	$ (2.88)	$ (1.34)	$ (0.27)	$ 0.00	$ 3.05	$ 1.43	$ 0.44	$ 1.58	$ (1.85)	$ 0.45
$150,000 - $200,000	FERA	6	$ 1.15	$ (2.77)	$ (1.55)	$ (0.09)	$ 0.15	$ 3.04	$ 1.42	$ 0.92	$ 1.60	$ (1.85)	$ 0.70
$200,000+	FERA	7	$ 1.42	$ (2.43)	$ (1.55)	$ 0.25	$ 0.40	$ 3.04	$ 1.51	$ 1.10	$ 1.66	$ (1.83)	$ (0.29)
	FERA	Avg	**$ (0.64)**	**$ (4.39)**	**$ (2.70)**	**$ (2.35)**	**$ (1.75)**	**$ 1.71**	**$ 0.05**	**$ (1.85)**	**$ 0.27**	**$ (3.22)**	**$ (0.62)**
	CARE & FERA	Avg	**$ (2.44)**	**$ (4.99)**	**$ (3.69)**	**$ (3.85)**	**$ (3.25)**	**$ (0.36)**	**$ (1.56)**	**$ (3.57)**	**$ (1.53)**	**$ (4.09)**	**$ (2.18)**

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

Bill Impacts

PG&E

Income Bracket	Discount		PG&E	P	Q	R	S	T	V	W	X	Y	Z
			Customer Average Bill Impact ($/mo)										
$0 - $25,000	None	1	$ 0.89	$ (2.72)	$ (1.70)	$ (2.97)	$ (2.15)	$ 2.52	$ 0.16	$ (2.64)	$ 0.33	$ 0.17	$ 3.45
$25,000 - $50,000	None	2	$ (0.07)	$ (2.66)	$ (1.70)	$ (2.99)	$ (2.12)	$ 2.54	$ 0.13	$ (2.68)	$ 0.33	$ 0.17	$ 3.45
$50,000 - $75,000	None	3	$ (0.22)	$ (2.59)	$ (1.67)	$ (2.84)	$ (1.99)	$ 2.56	$ 0.13	$ (2.50)	$ 0.36	$ 0.17	$ 3.44
$75,000 - $100,000	None	4	$ 1.70	$ (0.73)	$ 0.07	$ (0.89)	$ (0.05)	$ 4.32	$ 1.92	$ (0.49)	$ 2.13	$ 1.92	$ 5.20
$100,00 - $150,000	None	5	$ 1.92	$ (0.61)	$ 0.14	$ (0.66)	$ 0.16	$ 4.34	$ 1.94	$ (0.17)	$ 2.18	$ 1.92	$ 5.20
$150,000 - $200,000	None	6	$ 2.22	$ (0.36)	$ 0.20	$ (0.40)	$ 0.42	$ 4.35	$ 1.98	$ 0.18	$ 2.23	$ 1.93	$ 5.18
$200,000+	None	7	$ 2.65	$ (0.04)	$ 0.38	$ 0.00	$ 0.80	$ 4.37	$ 1.99	$ 0.58	$ 2.40	$ 1.94	$ 5.18
	None	Avg	**$ 1.51**	**$ (1.43)**	**$ (0.31)**	**$ (1.47)**	**$ (0.46)**	**$ 3.80**	**$ 0.95**	**$ (0.97)**	**$ 1.82**	**$ 1.09**	**$ 4.39**
$0 - $25,000	CARE	1	$ (2.48)	$ (4.80)	$ (3.41)	$ (4.09)	$ (3.48)	$ (0.30)	$ (1.31)	$ (3.93)	$ (1.53)	$ (3.80)	$ (1.88)
$25,000 - $50,000	CARE	2	$ (2.65)	$ (4.78)	$ (3.41)	$ (4.02)	$ (3.43)	$ (0.29)	$ (1.32)	$ (3.82)	$ (1.51)	$ (3.80)	$ (1.95)
$50,000 - $75,000	CARE	3	$ (2.49)	$ (4.75)	$ (3.32)	$ (3.94)	$ (3.39)	$ (0.28)	$ (1.29)	$ (3.71)	$ (1.50)	$ (3.81)	$ (1.98)
$75,000 - $100,000	CARE	4	$ (2.44)	$ (4.74)	$ (3.14)	$ (3.92)	$ (3.33)	$ (0.28)	$ (1.27)	$ (3.59)	$ (1.51)	$ (3.81)	$ (2.00)
$100,00 - $150,000	CARE	5	$ (2.35)	$ (4.72)	$ (3.38)	$ (3.83)	$ (3.27)	$ (0.27)	$ (1.31)	$ (3.53)	$ (1.48)	$ (3.81)	$ (2.03)
$150,000 - $200,000	CARE	6	$ (2.16)	$ (4.68)	$ (3.45)	$ (3.77)	$ (3.22)	$ (0.28)	$ (1.31)	$ (3.37)	$ (1.48)	$ (3.81)	$ (1.91)
$200,000+	CARE	7	$ (1.87)	$ (4.55)	$ (3.45)	$ (3.67)	$ (3.13)	$ (0.27)	$ (1.27)	$ (3.30)	$ (1.45)	$ (3.81)	$ (3.87)
	CARE	Avg	**$ (2.51)**	**$ (4.79)**	**$ (3.40)**	**$ (4.03)**	**$ (3.43)**	**$ (0.29)**	**$ (1.31)**	**$ (3.82)**	**$ (1.52)**	**$ (3.80)**	**$ (1.89)**
$0 - $25,000	FERA	1	$ (0.88)	$ (4.15)	$ (2.32)	$ (3.05)	$ (2.29)	$ 1.74	$ 0.40	$ (2.82)	$ 0.14	$ (2.88)	$ (0.51)
$25,000 - $50,000	FERA	2	$ (1.02)	$ (4.12)	$ (2.31)	$ (2.87)	$ (2.18)	$ 1.75	$ 0.39	$ (2.59)	$ 0.18	$ (2.88)	$ (0.96)
$50,000 - $75,000	FERA	3	$ (0.84)	$ (4.07)	$ (2.14)	$ (2.71)	$ (2.09)	$ 1.76	$ 0.43	$ (2.34)	$ 0.19	$ (2.90)	$ (1.14)
$75,000 - $100,000	FERA	4	$ 0.66	$ (2.63)	$ (0.39)	$ (1.21)	$ (0.54)	$ 3.21	$ 1.90	$ (0.70)	$ 1.63	$ (1.46)	$ 0.20
$100,00 - $150,000	FERA	5	$ 0.75	$ (2.59)	$ (0.81)	$ (1.03)	$ (0.44)	$ 3.21	$ 1.85	$ (0.59)	$ 1.67	$ (1.47)	$ 0.08
$150,000 - $200,000	FERA	6	$ 0.95	$ (2.53)	$ (0.96)	$ (0.94)	$ (0.35)	$ 3.21	$ 1.84	$ (0.33)	$ 1.68	$ (1.47)	$ 0.69
$200,000+	FERA	7	$ 1.26	$ (2.35)	$ (0.96)	$ (0.76)	$ (0.20)	$ 3.21	$ 1.90	$ (0.23)	$ 1.71	$ (1.47)	$ (1.80)
	FERA	Avg	**$ (0.69)**	**$ (4.03)**	**$ (2.15)**	**$ (2.74)**	**$ (1.99)**	**$ 1.90**	**$ 0.47**	**$ (2.40)**	**$ 0.40**	**$ (2.77)**	**$ (0.55)**
	CARE & FERA	Avg	**$ (2.46)**	**$ (4.77)**	**$ (3.35)**	**$ (4.00)**	**$ (3.38)**	**$ (0.24)**	**$ (1.27)**	**$ (3.80)**	**$ (1.45)**	**$ (3.78)**	**$ (1.82)**

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		Customer Average Bill Impact ($/mo) SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ (1.01)	$ (1.01)	$ (0.79)	$ (0.41)	$ (7.69)
$25,000 - $50,000	None	2	$ (1.02)	$ (1.33)	$ (0.79)	$ (0.80)	$ (6.86)
$50,000 - $75,000	None	3	$ (1.06)	$ (1.36)	$ (0.75)	$ 0.33	$ (6.61)
$75,000 - $100,000	None	4	$ 1.47	$ 1.24	$ 1.75	$ 4.27	$ (3.80)
$100,00 - $150,000	None	5	$ 1.80	$ 1.75	$ 1.95	$ 3.31	$ (2.86)
$150,000 - $200,000	None	6	$ 2.27	$ 2.48	$ 2.20	$ 11.05	$ (1.58)
$200,000+	None	7	$ 3.07	$ 3.52	$ 2.86	$ 2.92	$ 0.05
	None	Avg	**$ 1.30**	**$ 1.33**	**$ 1.38**	**$ 0.45**	**$ (3.75)**
$0 - $25,000	CARE	1	$ (1.55)	$ (2.37)	$ (0.49)	$ (10.43)	$ (15.19)
$25,000 - $50,000	CARE	2	$ (1.56)	$ (2.35)	$ (0.49)	$ (10.98)	$ (14.11)
$50,000 - $75,000	CARE	3	$ (1.49)	$ (2.32)	$ (0.48)	N/A	$ (14.29)
$75,000 - $100,000	CARE	4	$ (1.32)	$ (2.30)	$ (0.44)	N/A	$ (15.59)
$100,00 - $150,000	CARE	5	$ (1.19)	$ (2.33)	$ (0.46)	N/A	N/A
$150,000 - $200,000	CARE	6	$ (0.27)	N/A	$ (0.27)	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
	CARE	Avg	**$ (1.54)**	**$ (2.35)**	**$ (0.49)**	**$ (10.52)**	**$ (14.76)**
$0 - $25,000	FERA	1	$ (0.79)	$ (1.66)	$ 0.62	$ (10.55)	$ (19.68)
$25,000 - $50,000	FERA	2	$ (0.77)	$ (1.60)	$ 0.62	$ (11.86)	$ (17.58)
$50,000 - $75,000	FERA	3	$ (0.64)	$ (1.53)	$ 0.65	N/A	$ (17.94)
$75,000 - $100,000	FERA	4	$ 1.59	$ 0.52	$ 2.75	N/A	$ (18.38)
$100,00 - $150,000	FERA	5	$ 1.75	$ 0.45	$ 2.71	N/A	N/A
$150,000 - $200,000	FERA	6	$ 3.09	N/A	$ 3.09	N/A	N/A
$200,000+	FERA	7	N/A	N/A	N/A	N/A	N/A
	FERA	Avg	**$ (0.72)**	**$ (1.59)**	**$ 0.66**	**$ (10.75)**	**$ (18.86)**
	CARE & FERA	Avg	**$ (1.51)**	**$ (2.32)**	**$ (0.45)**	**$ (10.52)**	**$ (14.95)**

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

SDG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ (0.17)	$ (0.14)	$ (0.27)	$ 0.01	$ 2.41
$25,000 - $50,000	None	2	$ (0.16)	$ 0.02	$ (0.27)	$ 0.17	$ 1.95
$50,000 - $75,000	None	3	$ (0.13)	$ 0.03	$ (0.29)	$ (0.30)	$ 1.81
$75,000 - $100,000	None	4	$ 2.27	$ 2.40	$ 2.13	$ 1.52	$ 4.06
$100,00 - $150,000	None	5	$ 2.10	$ 2.15	$ 2.02	$ 1.92	$ 3.54
$150,000 - $200,000	None	6	$ 1.86	$ 1.78	$ 1.89	$ (1.32)	$ 2.83
$200,000+	None	7	$ 1.45	$ 1.26	$ 1.55	$ 2.09	$ 1.94
	None	Avg	**$ 1.39**	**$ 1.51**	**$ 1.29**	**$ 0.14**	**$ 2.91**
$0 - $25,000	CARE	1	$ (0.96)	$ (0.57)	$ (1.40)	$ 2.51	$ 3.07
$25,000 - $50,000	CARE	2	$ (0.94)	$ (0.58)	$ (1.40)	$ 2.78	$ 3.07
$50,000 - $75,000	CARE	3	$ (0.97)	$ (0.60)	$ (1.41)	N/A	$ 3.07
$75,000 - $100,000	CARE	4	$ (1.05)	$ (0.61)	$ (1.44)	N/A	$ 3.07
$100,00 - $150,000	CARE	5	$ (1.10)	$ (0.59)	$ (1.42)	N/A	N/A
$150,000 - $200,000	CARE	6	$ (1.55)	N/A	$ (1.55)	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
	CARE	Avg	**$ (0.95)**	**$ (0.58)**	**$ (1.40)**	**$ 2.56**	**$ 3.07**
$0 - $25,000	FERA	1	$ (0.09)	$ 0.29	$ (0.61)	$ 3.66	$ 4.72
$25,000 - $50,000	FERA	2	$ (0.09)	$ 0.26	$ (0.61)	$ 4.30	$ 4.72
$50,000 - $75,000	FERA	3	$ (0.14)	$ 0.21	$ (0.63)	N/A	$ 4.72
$75,000 - $100,000	FERA	4	$ 1.76	$ 2.19	$ 1.31	N/A	$ 6.72
$100,00 - $150,000	FERA	5	$ 1.72	$ 2.23	$ 1.34	N/A	N/A
$150,000 - $200,000	FERA	6	$ 1.07	N/A	$ 1.07	N/A	N/A
$200,000+	FERA	7	N/A	N/A	N/A	N/A	N/A
	FERA	Avg	**$ (0.07)**	**$ 0.29**	**$ (0.58)**	**$ 3.76**	**$ 4.73**
	CARE & FERA	Avg	**$ (0.92)**	**$ (0.54)**	**$ (1.37)**	**$ 2.57**	**$ 3.15**

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

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	$ (2.95)	$ (0.61)	$ (0.59)	$ (1.71)	$ (4.38)	$ (4.71)	$ (7.57)	$ (7.46)	$ (7.41)	$ (0.80)
$25,000 - $50,000	None	2	$ (3.60)	$ (0.61)	$ (0.58)	$ (1.75)	$ (4.57)	$ (5.18)	$ (7.34)	$ (7.34)	$ (7.67)	$ (0.79)
$50,000 - $75,000	None	3	$ (3.56)	$ (0.61)	$ (0.56)	$ (1.76)	$ (4.58)	$ (5.12)	$ (6.92)	$ (7.20)	$ (7.49)	$ (0.78)
$75,000 - $100,000	None	4	$ (1.62)	$ 1.22	$ 1.28	$ 0.10	$ (2.69)	$ (3.10)	$ (4.77)	$ (5.16)	$ (5.51)	$ 1.07
$100,00 - $150,000	None	5	$ (1.37)	$ 1.22	$ 1.31	$ 0.16	$ (2.60)	$ (2.74)	$ (4.37)	$ (4.94)	$ (5.37)	$ 1.11
$150,000 - $200,000	None	6	$ (1.08)	$ 1.22	$ 1.35	$ 0.25	$ (2.43)	$ (2.40)	$ (4.08)	$ (4.69)	$ (5.20)	$ 1.14
$200,000+	None	7	$ (0.56)	$ 1.22	$ 1.43	$ 0.45	$ (2.18)	$ (1.97)	$ (3.46)	$ (4.38)	$ (4.91)	$ 1.17
	None	Avg	**$ (2.04)**	**$ 0.50**	**$ 0.68**	**$ (0.46)**	**$ (3.16)**	**$ (3.51)**	**$ (5.55)**	**$ (6.00)**	**$ (6.47)**	**$ (0.03)**
$0 - $25,000	CARE	1	$ (3.70)	N/A	$ (0.66)	$ (1.73)	$ (2.77)	$ (5.41)	$ (6.33)	$ (6.97)	$ (6.12)	$ (4.07)
$25,000 - $50,000	CARE	2	$ (3.62)	N/A	$ (0.66)	$ (1.73)	$ (2.77)	$ (5.36)	$ (6.21)	$ (6.87)	$ (5.99)	$ (4.04)
$50,000 - $75,000	CARE	3	$ (3.57)	N/A	$ (0.66)	$ (1.72)	$ (2.78)	$ (5.29)	$ (6.12)	$ (6.81)	$ (5.93)	$ (4.04)
$75,000 - $100,000	CARE	4	$ (3.58)	N/A	$ (0.66)	$ (1.72)	$ (2.78)	$ (5.24)	$ (6.03)	$ (6.80)	$ (5.86)	$ (4.04)
$100,00 - $150,000	CARE	5	$ (3.48)	N/A	$ (0.65)	$ (1.72)	$ (2.78)	$ (5.16)	$ (6.02)	$ (6.69)	$ (5.82)	$ (4.00)
$150,000 - $200,000	CARE	6	$ (3.31)	N/A	$ (0.65)	$ (1.71)	$ (2.78)	$ (5.03)	$ (5.91)	$ (6.58)	$ (5.72)	$ (3.94)
$200,000+	CARE	7	$ (3.05)	N/A	$ (0.65)	$ (1.71)	$ (2.78)	$ (4.92)	$ (5.75)	$ (6.49)	$ (5.53)	$ (3.87)
	CARE	Avg	**$ (3.62)**	**#DIV/0!**	**$ (0.66)**	**$ (1.73)**	**$ (2.77)**	**$ (5.33)**	**$ (6.22)**	**$ (6.89)**	**$ (6.04)**	**$ (4.05)**
$0 - $25,000	FERA	1	$ (2.10)	N/A	$ 1.60	$ 0.26	$ (0.99)	$ (4.15)	$ (5.40)	$ (6.34)	$ (5.25)	$ (3.21)
$25,000 - $50,000	FERA	2	$ (2.03)	N/A	$ 1.60	$ 0.27	$ (1.00)	$ (4.06)	$ (5.15)	$ (6.16)	$ (4.98)	$ (3.15)
$50,000 - $75,000	FERA	3	$ (1.98)	N/A	$ 1.60	$ 0.27	$ (1.01)	$ (3.92)	$ (4.97)	$ (6.06)	$ (4.84)	$ (3.16)
$75,000 - $100,000	FERA	4	$ (0.49)	N/A	$ 3.09	$ 1.77	$ 0.49	$ (2.35)	$ (3.29)	$ (4.55)	$ (3.22)	$ (1.66)
$100,00 - $150,000	FERA	5	$ (0.37)	N/A	$ 3.09	$ 1.77	$ 0.48	$ (2.21)	$ (3.27)	$ (4.36)	$ (3.14)	$ (1.58)
$150,000 - $200,000	FERA	6	$ (0.17)	N/A	$ 3.09	$ 1.78	$ 0.47	$ (1.98)	$ (3.08)	$ (4.18)	$ (2.94)	$ (1.48)
$200,000+	FERA	7	$ 0.14	N/A	$ 3.09	$ 1.79	$ 0.45	$ (1.81)	$ (2.81)	$ (4.06)	$ (2.61)	$ (1.37)
	FERA	Avg	**$ (1.74)**	**#DIV/0!**	**$ 1.85**	**$ 0.53**	**$ (0.72)**	**$ (3.70)**	**$ (4.96)**	**$ (5.98)**	**$ (4.94)**	**$ (3.01)**
	CARE & FERA	Avg	**$ (3.58)**	**#DIV/0!**	**$ (0.60)**	**$ (1.68)**	**$ (2.73)**	**$ (5.29)**	**$ (6.20)**	**$ (6.87)**	**$ (6.03)**	**$ (4.03)**

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

Attachment RTB-4

Selected Data Responses

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

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Andre Ramirez
Job Title: Senior Advisor
Received Date: 4/20/2023

Response Date: 5/2/2023

Question 03:
Did any of the Joint IOUs consider, study, or analyze the impact of their fixed charge proposals on residential electric demand for energy (kWh) or capacity (peak kW, at either the gross or net load peaks)? If so, please provide any such analysis or study.

Response to Question 03:
No. The Joint IOUs only conducted analysis required by the guidance in the ALJ's rulings, consistent with the statute.

Southern California Edison

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

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Andre Ramirez
Job Title: Senior Advisor
Received Date: 4/20/2023

Response Date: 5/2/2023

Question 05:
Please provide any study or analysis that any of the Joint IOUs have conducted or reviewed of the potential for higher residential fixed charges, such as the Joint IOU fixed charge proposals, to result in the significant defection of customers from the California grid, to off-the-grid service from solar-plus-storage systems, on-site fossil-fueled generation, or combinations of such technologies.

Response to Question 05:
The Joint IOUs have no material that is responsive to this request.

Southern California Edison

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

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Andre Ramirez
Job Title: Senior Advisor
Received Date: 4/20/2023

Response Date: 5/2/2023

Question 06:
Have any of the Joint IOUs studied or estimated the additional uptake of specific DERs (or the reduction in adoption for other DERs) that will result from their fixed charge proposals? Please provide any such study or estimate, for any and all types of DERs (electric vehicles [EVs], heat pumps, behind-the-meter solar, behind-the-meter storage, energy efficiency, and demand response) that an IOU has studied.

Response to Question 06:

The Joint IOUs did not conduct any studies or develop such estimates.

Southern California Edison

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

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Andre Ramirez
Job Title: Senior Advisor
Received Date: 4/20/2023

Response Date: 5/2/2023

Question 07:
Have any of the Joint IOUs studied or estimated the impact of their fixed charge proposals on net energy metering (NEM, either NEM 1 or NEM 2) customers or Net Billing Tariff (NBT, per D. 22-12-056) customers? Please provide any such study or estimate.

Response to Question 07:
The Joint IOUs did not conduct any analysis beyond what was embedded in the Public Tool.

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

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Andre Ramirez
Job Title: Senior Advisor
Received Date: 4/20/2023

Response Date: 5/2/2023

Question 08:
"If the Joint IOUs' fixed charge proposals will have a significant adverse impact on NEM or NBT customers, would the Joint IOUs support either of the following:
a. A change to the compensation structure for NBT customers that would maintain the same paybacks for solar and solar-paired-storage systems that results from the NBT structure adopted in D. 22-12-056, based on the results of the E3 model used to set the ACC Plus Adders adopted in R. 20-08-020?
b. Legacy treatment for NEM 1 and 2 customers, such as the legacy treatments provided to NEM customers when the Commission changed from NEM 1 to NEM 2 or from NEM 2 to the NBT, or when the Commission changed the on peak TOU periods for customers from (roughly) noon to 6 p.m. to the current on peak period of 4 p.m. to 9 p.m.?

Please explain, in particular and in detail, why any of the Joint IOUs would not support either [a] or [b]. "

Response to Question 08:

The Joint IOUs have not examined the impacts of their proposals on technology-specific customer groups.

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

DATA REQUEST SET S E I A - S C E - 0 0 2

To: SEIA
Prepared by: Monica Shors
Job Title: Senior Advisor
Received Date: 5/12/2023

Response Date: 5/26/2023

Question 01:
1. Please provide, for each IOU:
a. The total number of residential accounts in 2021 and 2022.
b. The IOU's best estimate of the number of residential accounts in 2021 and 2022 that were single-family homes.
c. The IOU's best estimate of the number of residential accounts in 2021 and 2022 that were customers living in multi-family dwellings, e.g. apartments.

2. Please provide, for each IOU:
a. The number in 2021 and 2022 of master-metered multi-family residential-class customers, where the individual customers are not sub-metered – for example but not limited to, customers served under schedules such as PG&E Schedule EM, SCE Schedule DM, or SDG&E Schedule DM.
b. The annual kWh usage in 2021 and 2022 under each such rate schedule.
c. Do the Joint IOUs have information identifying the individuals served in the multi-family dwellings or mobile home parks that take service under these rates? If the IOUs have this information, please describe generally what information the IOUs possess.
d. How do the IOUs propose to verify (or have verified by a third-party administrator) the household income for such residential end-use customers, for the purposes of the Joint IOU income-graduated fixed charge (IGFC) proposal?

3. Please provide, for each IOU:
a. The number in 2021 and 2022 of master-metered multi-family residential-class customers, where the individual customers are sub-metered – for example but not limited to, customers served under schedules such as PG&E Schedule ES, SCE Schedules DMS-1/2/3, or SDG&E Schedules DS/DT/DT-RV.
b. The annual kWh usage in 2021 and 2022 under each such rate schedule.
c. Do the Joint IOUs have information identifying the individuals served in the multi-family dwellings or mobile home parks that take service under these rates? If the IOUs have this information, please describe generally what information the IOUs possess.
d. How do the IOUs propose to verify (or have verified by a third-party administrator) the household income for such residential end-use customers, for the purposes of the Joint IOU IGFC proposal?

4. Please provide, for each IOU:
a. the number of residential accounts for each IOU that are in the name of a corporate or business entity, or a legal entity such as a trust or estate, rather than in the name of an individual person. If a precise number is not readily available, please estimate.

b. If the IOU does not have or cannot produce the data requested in a., please explain why not.
c. How do the Joint IOUs propose to verify (or have verified by a third-party administrator) the income of the customers who are served from residential accounts that are held in the name of a corporate or business entity, or a legal entity such as a trust or estate, rather than in the name of an individual person.

5. Please explain how each IOU proposes to verify (or have verified by a third-party administrator) the incomes of self-employed persons who only report their annual income once a year on federal Internal Revenue Service Schedule C?

6. Assume that a residential customer has a home office, at which they work full-time, and where they also reside. Assume that the customer asks that his electric utility account at that premises be moved to a small commercial rate schedule paid by the business entity for which the customer works, on the grounds that their premises is a business. Please explain whether utility would grant this request, and the information that the customer would need to provide to justify such a change (please answer for each IOU individually). Please explain the grounds on which the utility might refuse this request.

7. Assume that a residential customer has an accessory dwelling unit (ADU) on their property that is presently separately metered. Assume that the customer in the primary residence asks that the utility service to their home and the ADU be consolidated into a single meter and service, replacing the two meters.
a. Please explain whether utility would grant this request, and the information that the customer would need to provide to justify such a change (please answer for each IOU individually).
b. Please explain the grounds on which the utility might refuse this request.
c. Assume the owner of the primary dwelling re-wires the property to serve the ADU from the service for the primary dwelling, and closes the account for the ADU, without notifying the utility of the wiring change. How would the utility respond to such situations, and what monitoring would the utility conduct to detect such changes?

8. When a utility customer constructs an ADU on their property:
a. What are the requirements for the ADU to be separately metered with a separate utility account distinct from the primary dwelling? Please answer for each IOU individually.
b. How does each utility ascertain that an ADU has been built, and how does the utility notify the customer of the requirements for a separate service? Please answer for each IOU individually
c. Please provide each IOU's rules and policies on the treatment of ADUs in their service territory.

9. Assume that a rural customer with a large property takes residential service from the utility in several locations on their property, with a separate account for each location. For example, assume one service is for the dwelling on the property, while a second service is for the pump for the water well located a distance from the dwelling.
a. Would the utility charge a separate IGFC for each account?
b. Does such a customer receive a baseline allowance for each account?
c. If the customer decided to install wiring to link the dwelling to the pump house, and to remove the second service from the utility at the pump house, would the utility grant this request?
d. More generally, under what circumstances would each utility charge multiple IGFCs to a single parcel, or to a single customer who has multiple residential accounts with the utility for a single property?

10. For purposes of verifying compliance with CARE and FERA eligibility, please explain:
a. how each IOU defines and verifies the size of the household (i.e. the number of persons who reside in the home); and
b. how the utility treats college students or other part-time residents in a household.
c. Please explain whether each IOU proposes to use a similar definition and verification process for household size in their IGFC proposal, including for the division between IGFC tiers 3 and 4 at 650% of the Federal Poverty Limits. If not, please explain the process that each IOU proposes to use.

11. One of the principles underlying the Joint IOUs' IGFC proposal is to stimulate uptake of electrification measures on their systems. However, the Joint IOU response to SEIA DR 1, Q6 is that the Joint IOUs have not estimated the impact of their proposed IGFCs on the uptake of such measures. This response raises questions about the visibility that the IOUs have into the pace of customer adoption of EVs or other beneficial electrification measures.
a. What technologies does each IOU consider to be beneficial electrification measures?
b. Do each of the IOUs track the number of beneficial electrification measures taken by their residential customers? If so, please provide that data for 2021 and 2022.
c. What methods does each of the IOUs utilize to estimate or track these trends (i.e., customer surveys, load analytics, etc.?)
12. These questions concern the service upgrades (i.e., on the utility's side of the meter) that are required in whole or in part as a result of customer adoption of beneficial electrification measures. (Monica-SCE)
a. Do the IOUs track the number of such service upgrades?
b. If so, how many such upgrades were completed in 2021 and 2022?
c. What was the average cost for such upgrades?
d. What portion of these service upgrade costs were borne by all ratepayers?

13. Please respond to the following:
a. Do the Joint IOUs agree that customer adoption of many electrification measures, especially combinations of such measures, will require the customer to undertake a main electric panel upgrade to their premises? What percentage of homes does each IOU estimate might need a main panel upgrade to facilitate adoption of one or more electrification measures?
b. Do the IOUs track the number of residential customer main panel upgrades that are sought as a result of the customer undertaking one or more beneficial electrification measures? Please provide that data for 2021 and 2022, if available.
c. If so, do the IOUs track the different technologies that are requiring these upgrades? Please provide that data for 2021 and 2022, if available.
d. What was the average number of days it took in 2021 and 2022 to complete the residential main panel upgrade process where no IOU service upgrade was required?
e. What was the average number of days it took in 2021 and 2022 to complete the residential main panel upgrade process where an IOU service upgrade was required?
f. What was the average total cost billed to residential customers in 2021 and 2022 for accomplishing a main panel upgrade?

14. Do the IOUs currently provide any information to customers regarding the availability of state or federal incentives for beneficial electrification measures on their websites? Please specify what is provided.

15. Given that the Joint IOUs' IGFC proposal will impact solar customers very differently than EV owners, it is important to understand the overlap and correlation between the two. Please provide, for each IOU, the following data for 2021 and 2022:

a. The total number of residential solar customer-generators interconnected as of the end of 2021 and 2022.

b. Total number of residential solar (NEM) customer-generators who are known to have at least one EV that charges behind-the-meter at the residence. This should include all NEM customers who take service on a residential EV charging rate, plus an estimate (if available) of the NEM customers on other residential rate schedules who have at least one EV that charges behind-the-meter at the residence.

c. Total number of all residential customers who are known to have at least one EV that charges behind-the-meter at the residence.

d. Please provide any data that the IOU possesses of the 8760 hourly load shapes for: (Effie—SCE)

i. Residential customers with at least one known EV that charges behind-the-meter at the residence.

ii. Residential NEM customers with at least one known EV that charges behind-the-meter at the residence.

iii. All residential NEM customers.

iv. All residential customers.

16. Assume Customers A and B live in the same apartment building in identical units, and have exactly the same electric usage. Customer A's income falls into the third tier of the Joint IOUs' proposed IGFC (non-CARE/FERA, >250% to 650% of the FPL), while Customer B's income falls into the fourth tier (non-CARE/FERA, > 650%of FPL).

a. Would you agree that the utility's cost to serve Customer A and B are the same?

b. Would you agree that Customer B will pay a much higher electric bill (by $408 to $660 per year, depending on the IOU) than Customer A?

c. Do you agree that the resulting difference in the bills for Customers A and Bisa tax on income? If not, then please explain why not.

17. Please provide, for the year before IGFC implementation, the year of implementation, and the two years after implementation:

a. any estimate that the IOUs have prepared of the average rate increase (in cents per kWh) for each IOU due to the expected costs of implementing the Joint IOUIGFC proposal (including implementation and ME&O costs but not including state funds for income verification),and

b. how this rate increase would be allocated to each IOU's customer classes.

18. Pages1-6 to 1-8 of the PG&E Supplemental Testimony (Exh. PG&E-01-E) discuss PG&E's different treatment of the volumetric rate adjustments for Schedule EV2.

a. Please provide the workpapers used for this adjustment, as shown in Tables 1-3 and 1-4, or confirm that these results are taken exclusively from the Public Tool, with an "Constant Ratio" reduction used for EV2insteadof an "Equal Cents per kWh" reduction.

b. Please provide any workpapers showing that the use of an "Equal Cents per kWh" reduction for EV2 "would make the EV2 off-peak distribution rates negative by a significant margin."

19. SDG&E's response to SEIADR 1 Q1states that all data for SDG&E-specific tables in testimony" can be found in the public tool." We have received the Public Tool spreadsheet files for PG&E and SCE that show results that match the printable results for these IOUs that are attached to Exh. Joint IOUs-2. However, we cannot find a Public Tool spreadsheet with rates for SDG&E that match the printable results for SDG&E in Appendix B of Exh. Joint IOUs-2. For example, the Joint IOUs' printable results errata for SDG&E shows a TOU-DR1 Non-CARE summer peak rate of $0.603 per kWh (see page 9 of 33). We cannot find this rate in either of the versions of the Public Tool that the

Joint IOUs have provided:
- Fixed Charge Design Model 2023-04-13 - Unaltered - Join IOU Proposals.xlsb
- Fixed Charge Design Model 2023-04-13 - Updated FERA - Join IOU Proposals.xlsb

So please provide the Public Tool spreadsheet model that SDG&E used to develop its rate proposal in this case.

Response to Question 01:

1. SCE responds as follows:

1.a. SCE's response to this question is provided in the Table below, specifically the column labeled "Total."

Residential Customers			
Year	Single	Multi	Total
2021	2,796,316	1,694,948	4,491,264
2022	2,816,883	1,707,415	4,524,299

1.b. SCE's response is provided in question 1.a, specifically the column labeled "Single."

1.c. SCE's response is provided in question 1.a, specifically the column labeled "Multi."

2.a. SCE's response is provided in the table below, specifically in the column labeled "Customers."

DM		
Year	Customers	Net kWh
2021	4,883	83,079,737
2022	4,609	77,753,806

2.b. SCE's response is provided in question 2.a, specifically in the column labeled "Net kWh."

2.c. By email dated May 23, 2023, SEIA counsel further clarified: "SEIA is not seeking personally identifiable information or other information that is protected by privacy laws or regulations. SEIA is seeking the **type** of information which the IOUs collect regarding customers under master-meter rate schedules. By way of example, such information could entail the number of customers served by a master meter account, or information to determine the CARE status of customers served by the account. Again, we are not looking for the specific information collected, but only the type of information the IOUs collect."

SCE response: SCE responds that it has the following information with respect to individuals served as part of master-metered multi-family residential groupings in which individual customers ***are not*** sub-metered:

On a master metered bill, SCE provides the number of units enrolled in CARE, FERA, and/or those receiving a medical baseline allocation. Master meter customers in turn, provide theses discounted rates or additional baseline allocations to their respective tenants.

2.d. By email dated May 23, 2023, SEIA counsel further clarified: "SEIA is not requesting that the Joint IOUs generate any new material or supplement testimony. If the Joint IOUs have not considered the scenario in question or have considered the scenario but do not know the answer, then they can so state."

The Joint IOUs refer the questioning party to the Joint IOUs' Opening Testimony (Exhibit Joint IOUs-01 at pp. 76-78), which provides the Joint IOUs' recommendation as to the general approach that should be taken on income verification, namely that "the optimal approach would be for the CPUC to contract with a Third Party that would use actual income data on a consistent statewide basis" to perform income verification. In addition, that same Joint IOU Opening Testimony, at pp. 82-84 also discussed how the TPA could address cases where data is missing or incomplete. The Joint IOUs do not have any additional documentation regarding the specific mechanics of determining income tiers for master-metered multi-family residential-class customers.

3. SCE responds as follows:

3.a. SCE's response is provided in table below, specifically in the column labeled "Customers."

DMS-1 & DMS-2		
Year	Customers	Net kWh
2021	1,477	469,885,649
2022	1,481	483,362,075

3.b. SCE's response is provided in question 3.a, specifically in the column labeled "Net kWh."

3.c. By email dated May 23, 2023, SEIA counsel further clarified: "SEIA is not seeking personally identifiable information or other information that is protected by privacy laws or regulations. SEIA is seeking the **type** of information which the IOUs collect regarding customers under master-meter rate schedules. By way of example, such information could entail the number of customers served by a master meter account, or information to determine the CARE status of customers served by the account. Again, we are not looking for the specific information collected, but only the type of information the IOUs collect."

SCE response: SCE has the following information with respect to individuals served as part of master-metered multi-family residential groupings in which individual customers ***are*** sub-metered:

If the multi-family accommodation or mobile home park is master metered, SCE provides the number of units enrolled in CARE, FERA, and/or those receiving a medical baseline allocation. Master meter customers in turn, provide these discounted rates or additional baseline allocations to their respective tenants.

If the individual dwellings are individually metered by SCE, then we would capture CARE, FERA, and/or those receiving a medical baseline as well.

3.d. By email dated May 23, 2023, SEIA counsel further clarified: “SEIA is not requesting that the Joint IOUs generate any new material or supplement testimony. If the Joint IOUs have not considered the scenario in question or have considered the scenario but do not know the answer, then they can so state.”

Please see response to SEIA-002 Question 2.d. above.

4. SCE responds as follows:

4.a. SCE response: SCE has identified 108,515 accounts on residential tariffs which have no data in the “first name” and “last name” fields used for “person” account holders but do have an “organization” listed in the field used for business name. SCE has not done an extensive analysis of this population but upon a brief analysis it appears that the vast majority of these accounts are held by “non-persons” though some could be “person” account holders which do not have the data for “first name” and “last name” filled out for an unknown reason, or have the first/last name saved in the business name field.

4.b. SCE response: Please see response to question 4.a.

4.c. By email dated May 23, 2023, SEIA counsel further clarified: “SEIA is not requesting that the Joint IOUs generate any new material or supplement testimony. If the Joint IOUs have not considered the scenario in question or have considered the scenario but do not know the answer, then they can so state.”

SCE responds on behalf of the Joint IOUs as follows: These accounts would be included in the handling of other customers who are not able to be matched with whatever income data source is selected. (See Joint IOU Opening Testimony pp. 77-78, 84, and 88.) As noted, the Joint IOUs have stated that the CPUC should direct income verification be conducted by a Third Party that would use actual income data on a consistent statewide basis to perform income verification. The specific mechanics of determining income tiers for customers who are served from residential accounts that are held in the name of a corporate or business entity, or a legal entity such as a trust or estate, rather than in the name of an individual person, would be for the CPUC and its chosen Third Party to resolve.

5. By email dated May 23, 2023, SEIA counsel further clarified: “SEIA is not requesting that the Joint IOUs generate any new material or supplement testimony. If the Joint IOUs have not considered the scenario in question or have considered the scenario but do not know the answer, then they can so state.”

The Joint IOUs' proposal is to use tax information from the California Franchise Tax Board to determine customer household income. This would be sufficient to determine the incomes of self-employed persons who file taxes. Here again, the Joint IOUs have stated that the CPUC should take charge of income verification by contracting with a Third Party that would use actual income data on a consistent statewide basis to perform income verification. The specific mechanics of determining income brackets for self-employed persons would be for the CPUC and its chosen Third Party to resolve.

6. The Joint IOUs object to this question on grounds that in asking the Joint IOUs to "assume" a particular situation it poses an incomplete hypothetical and calls for speculation as to the facts of a specific situation and the laws, regulations, and/or utility tariffs that would apply to that particular situation.

Subject to and without waiving the above objection, the Joint IOUs respond that our existing rules define how this situation would be handled.

7. Joint Response: The Joint IOUs object to this question on grounds that in asking the Joint IOUs to "assume" a particular situation it poses an incomplete hypothetical and calls for speculation as to the facts of a specific situation and the laws, regulations, and/or utility tariffs that would apply to that particular situation.

7.a. Subject to and without waiving the above objection, the Joint IOUs respond that our existing rules require each individual residential dwelling unit to have a separate account, save for limited exceptions outlined in those rules.

7.b. Please see response to 7.a.

7.c. Subject to and without waiving the above objection, the Joint IOUs respond that they will follow applicable procedures with respect to any situation in which a customer re-wires a property or set of properties without appropriate approvals or otherwise in contravention of applicable law, regulation, or tariffs. The Joint IOUs expect that specific implementation and customer compliance issues relating to the Income-Graduated Fixed Charge ordered by AB 205 such as the scenario raised by this question will be further addressed in the course of this proceeding and that the Commission will issue appropriate orders in that regard.

8. SCE responds as follows:

8.a. SCE response: The ADU is defined as a single-family dwelling (as defined in SCE Tariff Rule 1). The customer must provide to SCE a new address (separate from the primary dwelling unit address) which has been both permitted by the governmental authority having jurisdiction and approved by the Post Office.

8.b. SCE response: The customer must contact SCE (either through our Customer Call Center or through the Local Planning Office) and request service. Upon notification, an SCE representative will contact the customer to discuss the project (new ADU service request). The SCE representative will inform the customer what documents/information (application, plans, CAD file, etc.) are required to be provided by the customer to SCE to move forward with the customer request for service to the ADU. The SCE representative will provide the customer with an overview of the energization process, customer and SCE responsibilities, and the anticipated timeline that the new ADU service will be installed and energized. The SCE representative will perform a site visit so that a new approved meter panel location can be communicated to the customer.

8.c. SCE response: SCE provides service to ADUs per tariff Rules 1, 2, 11, and 16.

9. The Joint IOUs object to this question on grounds that in asking the Joint IOUs to "assume" a particular situation it poses an incomplete hypothetical and calls for speculation as to the facts of a specific situation and the laws, regulations, and/or utility tariffs that would apply to that particular situation.

Subject to and without waiving the above objection, the Joint IOUs respond as follows:

9.a. Joint Response: The IGFC only applies to customers served on Residential rate schedules.

9.b. The Joint IOUs respond as follows:

SCE Response: Baseline allowances are only applicable to Schedule TOU-D 4to9, TOU-D 5to8, and Tiered Schedule D. To the extent the account is served on one of these rate options, then baseline would apply.

SDG&E Response: Baseline allowances are applicable to Schedules TOU-DR1, TOU-DR2, TOU-DR, and tiered Schedule DR. To the extent the account is served on one of these rate options, then baseline would apply.

PG&E Response: Baseline allowances are applicable to Schedules E-1 and E-TOU-C. To the extent the account is served on one of these rate options, then baseline would apply.

9.c. Joint Response: Yes, as long as the change complied with Rule 18 and Rule 21 (Interconnection Rule). However, if the voltage of the pump and the residence are not the same then the customer will not be able to combine the meters. Also, if there were no added load all the cost would be at the applicant's expense.

9.d. Joint Response: Other than the exception for EV submetering described in testimony, all residential accounts would be assessed a separate IGFC.

10.a. Joint Response: As stated in our Joint Opening Brief on statutory construction, the Joint IOUs use the definition of household found in PUC § 878(d)(3) and additionally as defined by the US Census Bureau. See Joint IOU Opening Brief, response to question 2.

The Joint IOUs rely on information regarding the number of adults and children in a household provided by the customer at the time of enrollment, which the customer must attest is true and correct.

10.b. Joint response: The Joint IOUs do not have rules regarding the amount of time a person must live in the household in order to be counted on CARE and FERA applications and does not collect that type of information.

10.c. Joint response: The Joint IOUs' proposal is to have a Third Party Administrator (TPA), under the supervision of the CPUC, use data from the Franchise Tax Board (FTB) and Department of Social Services (DSS) to determine the number of individuals in a household. See Joint IOU Opening Testimony pp. 76-77.

11.a. Joint response: As noted in Section I.B.1.c of the Joint IOUs-01, "widespread electrification of customer homes and vehicles will be critical in accelerating decarbonization." Technologies that can enable residential building electrification and transportation electrification include heat pump water heaters, heat pump space heating and cooling, electric appliances, and electric vehicles.

11.b. SCE response: SCE tracks the volume of several of its electrification technologies for residential customers in its billing system. Due to SCE's billing replacement in April 2021, only limited data for TOU-Prime customers was available for that year. In 2022, more thorough reporting was available. The data below is based on self-reported attestations and may not represent the full population. The following electrification technologies were reported:

	Total on TOU Prime with Electric Vehicle	Total Residential with Electric Vehicle	Total on TOU Prime with Heat Pump (Water or Space Heating)	Total Residential with Heat Pump (Water or Space Heating)
March 2021	25,856	Not available	2,339	Not Available
2022	92,956	96,623	11,309	14,572 (as of 1/31/23)

11.c. SCE response: SCE tracks the electrification technologies listed in 1b. via customer attestation. Pursuant to Ordering Paragraph 5 and Appendix D of Decision (D.) 21-11-002, SCE also started tracking water heating heat pumps separately in 2022, again via customer attestation. Water heater heat pumps are included in the overarching heat pump category in question 15b.

SCE also tracks customer participation through incentives and rebates for various programs, such as low-income Building Electrification, Energy Efficiency, SGIP, etc.), via information submitted through third-party implementers or through customer applications. This information is not housed in our billing system.

12. SCE responds as follows:

12.a. SCE response: SCE does not track service upgrade projects in this manner (e.g., beneficial electrification measures).

12.b. SCE response: see response to question a.

12.c. SCE response: see response to question a.

12.d. SCE response: see response to question a.

13. SCE responds as follows:

13.a. SCE response: SCE does not govern whether or not an existing panel is required to be upgraded. Generally speaking, this requirement is managed by the governmental authority having jurisdiction (e.g., City, County, School District, etc.).

13.b. SCE response: SCE does not track upgrades in this manner.

13.c. SCE response: SCE: See response to question 13.b.

13.d. SCE response: SCE: See response to question 13.b.

13.e. SCE response: SCE: See response to question 13.b.

13.f. SCE response: SCE: See response to question 13.b.

14. SCE response: For building electrification, SCE currently provides multiple areas on their website regarding the availability of state and federal incentives, with most of it focused on its Residential Rebates and Incentives website page (https://www.sce.com/rebates). This landing page provides information and incorporates links to programs such as The Switch is On, Golden State Rebates, and other available programs that offer incentives for space and water heat pumps, and other related technologies. SCE Marketplace (https://marketplace.sce.com) is also another resource that provides information about smart energy products, programs, and tools.

15. SCE responds as follows:

15.a. SCE response: This data is publicly available at https://www.californiadgstats.ca.gov/charts/

15.b. SCE response: In December 2022, across all residential rates, SCE had 26,378 NEM customers who had attested to having an EV at their residence. This is customer reported data and likely does not reflect the true full population of customers with EVs. Due to SCE's 2021 billing system change, SCE does not have these numbers readily available for 2021.

15.c. SCE response: In December 2022, across all residential rates, SCE had 96,623 customers who had attested to having an EV at their residence. Due to SCE's 2021 billing system change, SCE does not have these numbers readily available for 2021. This is customer reported data and likely does not reflect the true full population of customers with EVs – for example, in Q15.d., we provide additional data for customers with EVs, including both customers who have self-identified as EV owners and/or who have taken advantage of EV rebates.

15.d. SCE response:

i. Residential customers with at least one known EV that charges behind-the-meter at the residence.

Please see attached file titled, "SEIA-d-i-APRX1_RES_EV_2022.xlxs."

ii. Residential NEM customers with at least one known EV that charges behind-the-meter at the residence.

Please see attached file titled, "SEIA-d-i-iAPRX1_RES_EV_NEM_2022.xlxs."

iii. All residential NEM customers.

Please refer to the Joint IOUs' Public Tool results.

iv. All residential customers.

Please refer to the Joint IOUs' Public Tool results.

16. Joint response: The Joint IOUs object to this question on grounds that in asking the Joint IOUs to "assume" a particular situation it poses an incomplete hypothetical and calls for speculation as to the facts of a specific situation and the laws, regulations, and/or utility tariffs that would apply to that particular situation.

16.a. Subject to and without waiving the above objection, the Joint IOUs agree that the cost-to-serve both customers with regards to usage are the same, as would certain other costs. The hypothetical is insufficiently specified to agree that all possible drivers of cost-to-serve are the same for both customers.

16.b. Subject to and without waiving the above objection, the Joint IOUs respond that yes, Customer B's bill is greater than Customer C's bill as defined in SEIA's hypothetical.

16.c. Subject to and without waiving the above objection, the Joint IOUs respond that any difference in bills between customers in different tiers of the IGFC will result from the rate structures ordered by the CPUC pursuant to its mandate under AB 205. The Joint IOUs object to and will not attempt to answer this question to the extent it asks the Joint IOUs to provide legal conclusions or explanations relating to what constitutes a "tax."

17.a. Joint response: The Joint IOUs have not prepared a forecast for an average rate increase in cents per kWh.

17.b. Joint response: Unless otherwise ordered, it would be allocated consistent with each IOUs most recent GRC Ph 2 decision.

18. Please refer to PG&E's response to this question, which PG&E will submit separately.

19. Please refer to SDG&E's response to this question, which SGD&E will submit separately.

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

PG&E Data Request No.:	SEIA_002-Q002		
PG&E File Name:	ElectricRatesDemandFlexibility_DR_SEIA_002-Q002		
Request Date:	May 12, 2023	Requester DR No.:	002
Date Sent:	May 26, 2023	Requesting Party:	Solar Energy Industries Association
PG&E Witness:	Colin Kerrigan Claire Coughlan	Requester:	Jeanne Armstrong/ R. Thomas Beach

QUESTION 002

Please provide, for each IOU:

a. The number in 2021 and 2022 of master-metered multi-family residential-class customers, where the individual customers are not sub-metered – for example but not limited to, customers served under schedules such as PG&E Schedule EM, SCE Schedule DM, or SDG&E Schedule DM.

b. The annual kWh usage in 2021 and 2022 under each such rate schedule.

c. Do the Joint IOUs have information identifying the individuals served in the multi-family dwellings or mobile home parks that take service under these rates? If the IOUs have this information, please describe generally what information the IOUs possess.

d. How do the IOUs propose to verify (or have verified by a third-party administrator) the household income for such residential end-use customers, for the purposes of the Joint IOU income-graduated fixed charge (IGFC) proposal?

ANSWER 002

On May 22, 2023, SCE provided the following objection to part c of this data request:

> *Objection (i) on grounds that question is vague and ambiguous as to what "information identifying the individuals" is sought, and (ii) to the extent it potentially encompasses personally identifiable information, personal information, or other customer data that is protected by privacy laws and/or regulations.*

On May 23, 2023, SEIA provided the following clarification:

> *SEIA is not seeking personally identifiable information or other information that is protected by privacy laws or regulations. SEIA is seeking the type of information which the IOUs collect regarding customers under master-meter rate schedules. By way of example, such information could entail the number of customers served by a master meter account, or information to determine the CARE status of customers served by the account. Again, we are not looking for the specific information collected, but only the type of information the IOUs collect.*

On May 22, 2023, SCE provided the following objection to part d of this data request:

> *Objection to the extent question purports to require the Joint IOUs to generate any new material or supplement to testimony served in this proceeding.*

On May 23, 2023, SEIA provided the following clarification:

> *SEIA is not requesting that the Joint IOUs generate any new material or supplement testimony. If the Joint IOUs have not considered the scenario in question or have considered the scenario but do not know the answer, then they can so state.*

Based on this clarification, PG&E reasserts the originally-stated objections. Notwithstanding and without waiving those objections, PG&E responds as follows:

a. See table below.

Rate	2021 Count	2022 Count	2021 kWh	2022 kWh
EM	15227	14903	229,223,000	222,514,000
EM-TOU	795	983	7,422,000	8,952,000

b. See response to a.
c. For master-metered multi-family residential-class customers, where the individual customers are not sub-metered, PG&E can identify a count of total dwelling units.
d. See Joint IOU Response to this request, which is being separately submitted by SCE.

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

PG&E Data Request No.:	SEIA_002-Q003		
PG&E File Name:	ElectricRatesDemandFlexibility_DR_SEIA_002-Q003		
Request Date:	May 12, 2023	Requester DR No.:	002
Date Sent:	May 26, 2023	Requesting Party:	Solar Energy Industries Association
PG&E Witness:	Colin Kerrigan Claire Coughlan	Requester:	Jeanne Armstrong/ R. Thomas Beach

QUESTION 003

Please provide, for each IOU:

a. The number in 2021 and 2022 of master-metered multi-family residential-class customers, where the individual customers are sub-metered – for example but not limited to, customers served under schedules such as PG&E Schedule ES, SCE Schedules DMS-1/2/3, or SDG&E Schedules DS/DT/DT-RV.

b. The annual kWh usage in 2021 and 2022 under each such rate schedule.

c. Do the Joint IOUs have information identifying the individuals served in the multi-family dwellings or mobile home parks that take service under these rates? If the IOUs have this information, please describe generally what information the IOUs possess.

d. How do the IOUs propose to verify (or have verified by a third-party administrator) the household income for such residential end-use customers, for the purposes of the Joint IOU IGFC proposal?

ANSWER 003

On May 22, 2023, SCE provided the following objection to part c of this data request:

> *Objection (i) on grounds that question is vague and ambiguous as to what "information identifying the individuals" is sought, and (ii) to the extent it potentially encompasses personally identifiable information, personal information, or other customer data that is protected by privacy laws and/or regulations.*

On May 23, 2023, SEIA provided the following clarification:

> *SEIA is not seeking personally identifiable information or other information that is protected by privacy laws or regulations. SEIA is seeking the type of information which the IOUs collect regarding customers under master-meter rate schedules. By way of example, such information could entail the number of customers served by a master meter account, or information to determine the CARE status of customers served by the account. Again, we are not looking for the specific information collected, but only the type of information the IOUs collect.*

On May 22, 2023, SCE provided the following objection to part d of this data request:

> *Objection to the extent question purports to require the Joint IOUs to generate any new material or supplement to testimony served in this proceeding.*

On May 23, 2023, SEIA provided the following clarification:

> *SEIA is not requesting that the Joint IOUs generate any new material or supplement testimony. If the Joint IOUs have not considered the scenario in question or have considered the scenario but do not know the answer, then they can so state.*

Based on this clarification, PG&E reasserts the originally-stated objections. Notwithstanding and without waiving these objections, PG&E responds as follows:

a. See table below. Because there are fewer than 100 customers on ESR, PG&E has consolidated the data for Schedules ES and ESR, to maintain compliance with customer privacy rules.

Rate	2021 Count	2022 Count	2021 kWh	2022 kWh
ET	1223	1219	351,237,000	341,516,000
ES and ESR	479	479	58,083,000	53,861,000

b. See response to a.
c. For master-metered multi-family residential-class customers, where the individual customers are sub-metered, PG&E can identify a count of total dwelling units, as well as the tenant names and addresses for customers that are enrolled in CARE, FERA or Medical Baseline.
d. See Joint IOU Response being separately submitted by SCE.

SEIA DATA REQUEST 02
CPUC DEMAND FLEXIBILITY OIR – R.22-07-005
SDG&E RESPONSE
DATE RECEIVED: May 12, 2023
DATE RESPONDED: May 30, 2023

1. Please provide, for each IOU:

a. The total number of residential accounts in 2021 and 2022.
SDG&E Response:

YEAR	RES_ACCOUNTS
2021	1,332,386
2022	1,341,397

b. The IOU's best estimate of the number of residential accounts in 2021 and 2022 that were single-family homes.
SDG&E Response:

YEAR	DWELL_TYPE	RES_ACCOUNTS
2021	S	833,019
2022	S	836,674

c. The IOU's best estimate of the number of residential accounts in 2021 and 2022 that were customers living in multi-family dwellings, e.g. apartments.
SDG&E Response:

YEAR	DWELL_TYPE	RES_ACCOUNTS
2021	M	499,367
2022	M	504,724

2. Please provide, for each IOU:

a. The number in 2021 and 2022 of master-metered multi-family residential-class customers, where the individual customers are not sub-metered – for example but not limited to, customers served under schedules such as PG&E Schedule EM, SCE Schedule DM, or SDG&E Schedule DM.
SDG&E Response:

YEAR	RATE	RES_ACCOUNTS
2021	DM	2,781
2021	DMDA	2
2021	DMNM	488
2022	DM	2,731
2022	DMDA	2
2022	DMNM	544

b. The annual kWh usage in 2021 and 2022 under each such rate schedule.

SDG&E Response:

YEAR	RATE	NET_KWH
2021	DM	32,665,902
2021	DMDA	14,905
2021	DMNM	3,348,306
2022	DM	31,837,180
2022	DMDA	9,067
2022	DMNM	3,769,710

c. Do the Joint IOUs have information identifying the individuals served in the multi-family dwellings or mobile home parks that take service under these rates? If the IOUs have this information, please describe generally what information the IOUs possess.

SDG&E Response: SDG&E does not have information identifying the individuals served in the multi-family dwellings or mobile home parks that take service under these rates.

d. How do the IOUs propose to verify (or have verified by a third-party administrator) the household income for such residential end-use customers, for the purposes of the Joint IOU income-graduated fixed charge (IGFC) proposal?

SDG&E Response: See Joint IOU response.

3. Please provide, for each IOU:

a. The number in 2021 and 2022 of master-metered multi-family residential-class customers, where the individual customers are sub-metered – for example but not limited to, customers served under schedules such as PG&E Schedule ES, SCE Schedules DMS-1/2/3, or SDG&E Schedules DS/DT/DT-RV.

SDG&E Response:

YEAR	RATE	RES_ACCOUNTS
2021	DS	220
2021	DSNM	4
2021	DT	282
2021	DTNM	50
2021	DTRV	43
2021	DTRVNM	2
2022	DS	217
2022	DSNM	5
2022	DT	271

2022	DTNM	47
2022	DTRV	44
2022	DTRVNM	3

b. The annual kWh usage in 2021 and 2022 under each such rate schedule.
SDG&E Response:

YEAR	RATE	NET_KWH
2021	DS	16,590,207
2021	DSNM	3,301
2021	DT	88,789,686
2021	DTNM	16,002,513
2021	DTRV	7,526,917
2021	DTRVNM	19,246
2022	DS	16,703,312
2022	DSNM	19,137
2022	DT	83,388,196
2022	DTNM	19,138,264
2022	DTRV	8,209,998
2022	DTRVNM	(2,768)

c. Do the Joint IOUs have information identifying the individuals served in the multi-family dwellings or mobile home parks that take service under these rates? If the IOUs have this information, please describe generally what information the IOUs possess.
SDG&E Response: SDG&E does not have information identifying the individuals served in the multi-family dwellings or mobile home parks that take service under these rates.

d. How do the IOUs propose to verify (or have verified by a third-party administrator) the household income for such residential end-use customers, for the purposes of the Joint IOU IGFC proposal?
SDG&E Response: See Joint IOU response.

4. Please provide, for each IOU:

a. the number of residential accounts for each IOU that are in the name of a corporate or business entity, or a legal entity such as a trust or estate, rather than in the name of an individual person. If a precise number is not readily available, please estimate.
SDG&E Response: There are approximately 88k residential customer accounts where the category of the account is listed as something other than an individual person.

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.