California Public Utilities Commission

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Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020

A Comparative Analysis

Energy+Environmental Economics

VERDANT

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Executive Summary

This study compares NEM successor proposals as submitted by the parties in CPUC Rulemaking 20-08-020 to replace the existing NEM tariff ("NEM 2.0"). Only the proposals that contained sufficient detail were modeled. Eleven residential proposals and six small commercial proposals were modeled in addition to NEM 2.0, the existing tariff, which was modeled for comparison. This comparative analysis is intended to serve as a guide for the CPUC and parties to understand how the various party proposals approach reducing the cost misalignment under NEM 2.0. The analysis was done with two key principles in mind:

- **Consistency**. While the party proposals differ significantly from each other, E3 used a single evaluation method, five standardized output metrics, and the same set of model inputs and assumptions to provide a consistent evaluation across proposals. E3 developed an Excel-based model to calculate annual customer bills for representative customers assuming standalone solar and solar paired with storage. For each party proposal, bill savings were calculated relative to a counterfactual customer with no solar or solar+storage system.

- **Transparency**. In cases where the exact specification of a proposal could not be modeled or an assumption had to be made, it is noted in this document. In addition to this report, the Excel-based analysis tool itself will be made publicly available to provide transparency in this process.

Dimensions of the Analysis

The dimensions of the analysis are designed to illustrate differences between the party proposals for a range of customer types, technology, and installation years. They are the following:

- 3 investor-owned utilities: PG&E, SCE, and SDG&E;
- 3 customer categories: non-CARE residential[1], CARE residential, and small commercial;
- 2 system types: solar only and solar+battery systems;
- 2 installation years: 2023 installation year and 2030 installation year.

Output Metrics

For each of these customers, 5 metrics were evaluated:

1. Simple payback period
2. First-year cost-shift
3. Participant Cost Test (PCT) benefit-cost ratio
4. Ratepayer Impact Measure (RIM) benefit-cost ratio
5. Total Resource Cost (TRC) benefit-cost ratio

Results Summary

To illustrate the results, this executive summary compares party proposals for a residential customer in PG&E's service territory who adopts customer solar in 2023. This customer has an annual consumption of 7,500 kWh/year and their solar system generates an equivalent 7,500 kWh/year. In the report, different dimensions are varied one by one to illustrate differences. For example, a customer with solar+storage, a

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[1] California Alternate Rates for Energy is a low-income program that provides energy bill discounts. https://www.cpuc.ca.gov/lowincomerates/

customer on CARE rates, and installation in 2030 are all considered. Complete results are provided in Appendix D and the Excel model.

Simple Payback Period and First-year Cost Shift

These two metrics are used to illustrate each proposal's impact on participants and nonparticipants in customer-sited renewable generation.

The ***simple payback period*** is an estimate of how many years of bill savings would be required to recover the upfront costs of a new solar or solar+storage system.[2] A shorter payback period reflects a proposal that is more favorable for participants.

The ***first-year cost shift*** reflects the dollar value of utility costs shifted from participants to nonparticipants in the first year after interconnection. A smaller cost shift reflects a proposal that is more favorable for nonparticipants.

Figure 1 shows the simple payback period and first-year cost shift for a 2023 residential non-CARE solar adopter in PG&E's service territory. There is a wide range in these metrics across the party proposals. Compared to NEM 2.0, all proposals would result in a longer payback period and a smaller first-year cost shift. However, while some proposals would retain a similar payback period to NEM 2.0 in the near-term, other proposals would result in a somewhat or substantially longer payback period and a lower cost shift.

Across the board, the proposals that have a shorter payback period also have a larger cost shift. This reflects the fundamental tension that exists between the solar adopter and the nonparticipant. Absent non-rate funds, utility cost recovery is essentially a "zero sum game" and a tariff that provides a shorter payback period for a solar adopter will result in a larger cost shift to the nonparticipant.

[2] A variety of purchase, lease, and financing options exist for customer solar and storage systems. In this model, an upfront purchase was assumed to facilitate calculation of the Simple Payback Period metric.

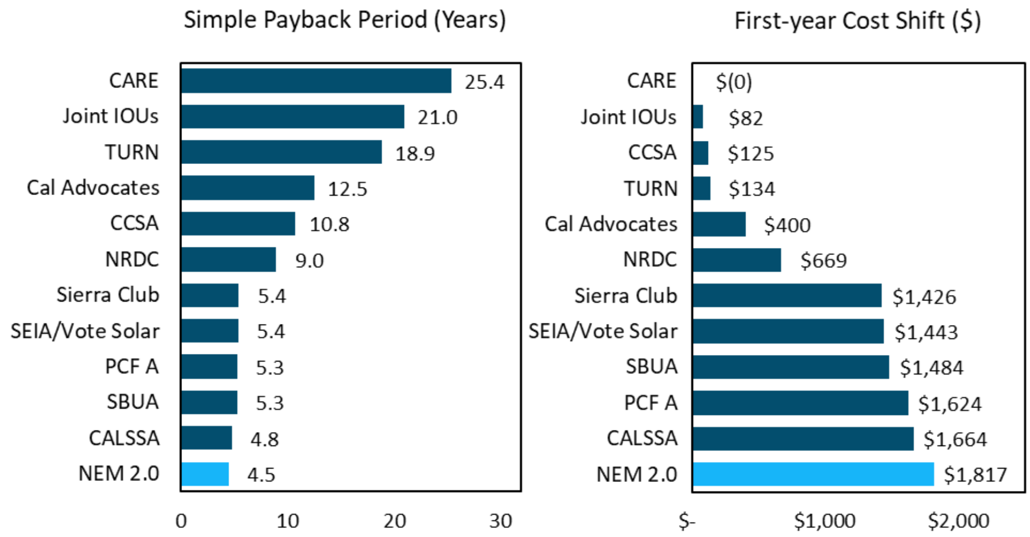

Figure 1: Simple payback period and first-year cost shift for a 2023 residential non-CARE solar adopter in PG&E's service territory.

Standard Practice Manual Cost Tests

The California Standard Practice Manual[3] defines cost tests that are used to explore cost-effectiveness from different stakeholder perspectives. These cost tests reflect the net present value ratio of benefits to costs over the lifetime of the solar system.[4] The exact definition of the cost tests is provided later in this document and results are provided here as an overview for this PG&E customer.

Participant Cost Test

Figure 2 shows the Participant Cost Test (PCT), which reflects the benefit-cost ratio from the participant perspective over the assumed life of the system. A benefit-cost ratio above 1.0 means that customers would find lifecycle benefits exceed lifecycle costs, which we find in 7 of the 12 cases. Compared to NEM 2.0, all proposals would reduce the PCT benefit-cost ratio.

[3] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

[4] In this modeling, both solar and storage systems were assumed to have a 20-year lifetime. More details on this assumption are provided in the body of the report.

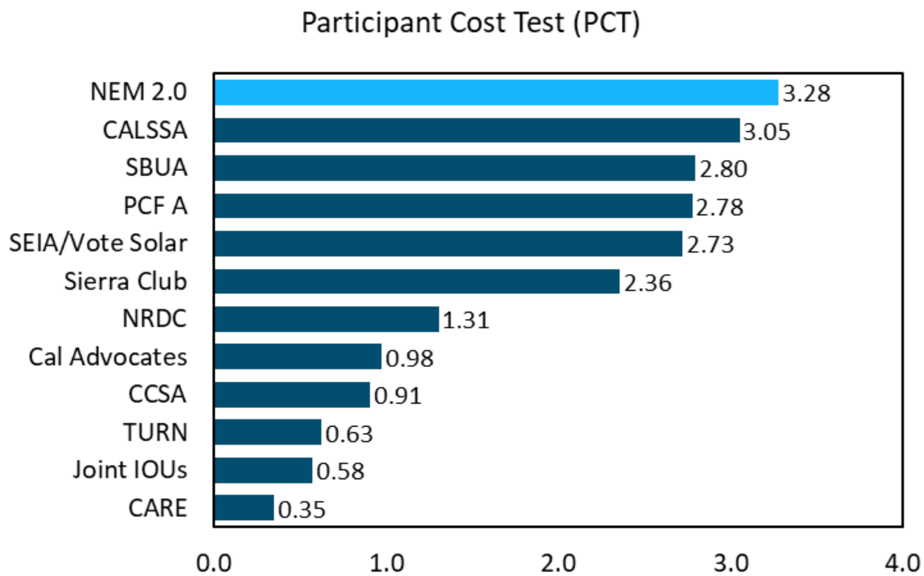

Figure 2: PCT for a 2023 residential non-CARE solar adopter in PG&E's service territory.

Ratepayer Impact Measure

Figure 3 shows the Ratepayer Impact Measure (RIM), which reflects the benefit-cost-ratio from the nonparticipant perspective. The results show that for PG&E's service territory, only one proposal (CARE) is not unfavorable to nonparticipant customers, as it provides a ratio of 1 (equal lifecycle benefits and costs). Compared to NEM 2.0, all proposals increase the RIM benefit-cost ratio.

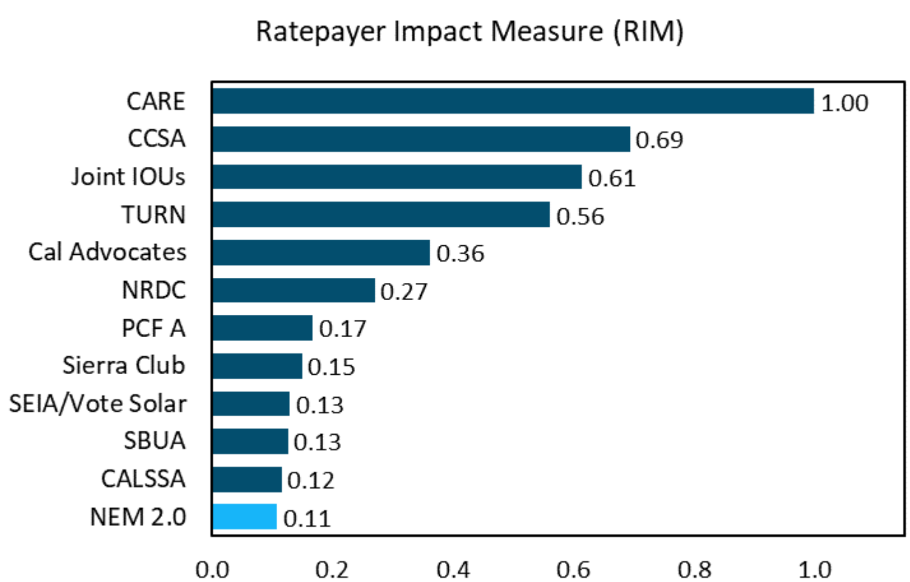

Figure 3: RIM for a 2023 residential non-CARE solar adopter in PG&E's service territory.

Total Resource Cost

Figure 4 shows the Total Resource Cost (TRC), which reflects the benefit-cost ratio from the combined participant and nonparticipant perspective. When looking at the TRC for solar customers, only one factor leads to a distinction in TRC score. Community solar projects have a lower upfront cost than residential projects, leading to a higher TRC score. The CCSA proposal is based on community solar projects, whereas the other proposals are evaluated assuming customer-sited solar.

All of the TRC results are less than a benefit-cost ratio of 1.0. This indicates that the costs of rooftop and community solar exceed the benefits to the grid based on the draft 2021 Avoided Cost Calculator (ACC).

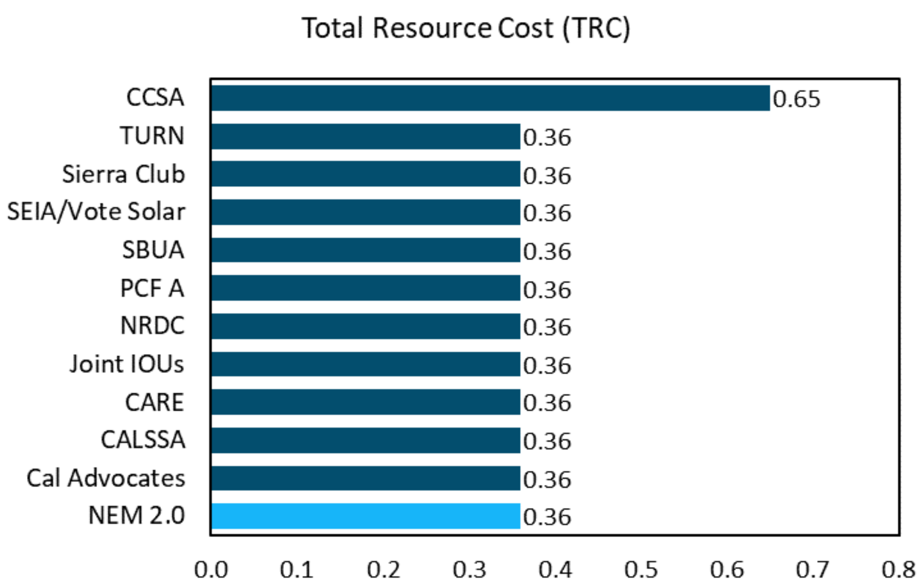

Figure 4: TRC for a 2023 residential non-CARE solar adopter in PG&E's service territory.

1. Introduction

The California Public Utilities Commission (CPUC) launched Rulemaking 20-08-020 to facilitate the development of proposals for a NEM successor tariff that will be compliant with California legislation. The Rulemaking seeks to reform the existing NEM program to comply with Assembly Bill (AB) 327 of 2013[5]. AB 327 requires that the NEM Successor "Ensure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs," and that it "ensures that customer-sited renewable distributed generation continues to grow sustainably."

CPUC staff provided a whitepaper in January 2021 that illustrated how a reform of retail rates for solar customer-sited generation along with transition mechanisms would enable a reasonable payback period for customers investing in onsite renewable generation. Other parties subsequently submitted NEM successor tariff proposals for customer-sited renewable generation as well as solar plus storage.

To support a consistent and transparent comparison of party proposals, E3 prepared an Excel-based template for each party to complete with key details of their proposal in order for E3 to perform a comparative cost-effectiveness analysis. An Excel-based model was developed to use these inputs and evaluate annual customer bills for representative customers assuming standalone solar and solar paired with storage. In order to calculate annual bill savings, a counterfactual customer with no solar system was also modeled.

2. Proposals Modeled

For residential customers, NEM 2.0 was modeled in addition to the following party proposals based on their submission of templates that represent a complete proposal for a tariff.

1. **Cal Advocates** (Public Advocates Office)
2. **CALSSA** (California Solar and Storage Association)
3. **CARE** (CAlifornians for Renewable Energy)
4. **CCSA** (Coalition for Community Solar Access)
5. **Joint IOUs**[6] (PG&E, SCE, SDG&E)
6. **NRDC** (National Resources Defense Council)
7. **PCF "A"** (Protect Our Communities Foundation)
8. **SBUA** (Small Business Utility Advocates)
9. **SEIA/Vote Solar** (Solar Energy Industries Association and Vote Solar)
10. **Sierra Club**
11. **TURN** (The Utility Reform Network)

For small commercial customers, NEM 2.0 was modeled in addition to the following party proposals based on their submission of templates that represent a complete proposal for a tariff.

1. **Cal Advocates** (Public Advocates Office)

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[5] Legislative language of AB327 is available online; see SEC. 11. Section 2827.1

[6] Joint submission of three Investor-Owned Utilities: Pacific Gas & Electric Company, Southern California Edison, and San Diego Gas and Electric Company

2. **CARE** (CAlifornians for Renewable Energy)
3. **CCSA** (Coalition for Community Solar Access)
4. **Clean Coalition**
5. **Joint IOUs** (PG&E, SCE, SDG&E)
6. **SBUA** (Small Business Utility Advocates)

3. Model Output Metrics

The model outputs five metrics including three Standard Practice Manual cost tests. The metrics evaluated for each proposal and customer type include:

- Simple payback period
- First-year cost-shift
- Standard Practice Manual (SPM) Cost Tests:
    - Participant Cost Test (PCT)
    - Ratepayer Impact Measure (RIM)
    - Total Resource Cost (TRC)

Each metric is described below.

First-year Metrics

Two metrics are included using first-year values: the Simple Payback Period and the First-year Cost Shift. These are illustrative metrics meant to facilitate comparison among proposals.

Simple Payback Period

Simple payback period is a common metric used to describe the customer cost-effectiveness of solar or solar+storage. The definition used here is:

$$Simple\ payback\ period = \frac{Upfront\ cost - Upfront\ incentives + Interconnection\ fee}{Year\ 1\ bill\ savings}$$

Note that this definition of simple payback period is based on first-year bill savings rather than average or cumulative bill savings over multiple years.

A shorter simple payback period reflects a better investment for the customer.

First-year Cost Shift

The first-year cost shift reflects the difference between nonparticipant costs and benefits in the first year of system operation. The interconnection fee is assumed to directly offset interconnection costs and is only included in this metric for proposals that collect additional funds through this fee. In this metric, any upfront fees or incentive are levelized over 20 years. Note that for solar+storage customers, the SGIP incentive is included in upfront incentives.

$$\begin{aligned} First - year\ cost\ shift &= [Nonparticipant\ costs] - [Nonparticipant\ benefits] \\ &= [Y1\ bill\ savings + Incentives] - [Y1\ avoided\ costs + Fees] \end{aligned}$$

A larger first-year cost shift reflects a larger cost burden for nonparticipants.

Standard Practice Manual (SPM) Cost Tests

The California Standard Practice Manual[7] defines cost tests that are widely used to explore cost-effectiveness from different stakeholder perspectives. Three SPM cost tests are included as metrics. All three metrics are reported as ratios of lifecycle benefits divided by lifecycle costs. Net Present Values (NPV) are calculated from the installation year through the assumed system life. The assumed discount rate is the average utility WACC of 7.68%, as described in more detail below. Incentives that are paid out over time are included in the bill savings.

The three SPM cost tests used in this modeling are defined here. Figure 5 below illustrates the components included in each cost test for a solar+storage customer under NEM 2.0.

Participant Cost Test (PCT)

The PCT reflects the benefit-cost ratio from a participant perspective. The PCT is defined as:

$$PCT = \frac{NPV[Bill\ savings + Upfront\ incentives]}{NPV[Upfront\ cost + Interconnection\ fee]}$$

Ratepayer Impact Measure (RIM)

The RIM reflects the benefit-cost ratio from a nonparticipant perspective. The interconnection fee is assumed to directly offset interconnection costs and is only included in this metric for proposals that collect additional funds through this fee. The RIM is defined as:

$$RIM = \frac{NPV[Avoided\ costs + Fees]}{NPV[Bill\ savings + Upfront\ incentives]}$$

Total Resource Cost (TRC)

The TRC reflects the benefit-cost ratio from a utility system perspective, including both participant and utility costs and benefits. The TRC is defined as:

$$TRC = \frac{NPV[Avoided\ costs]}{NPV[Upfront\ cost]}$$

[7] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

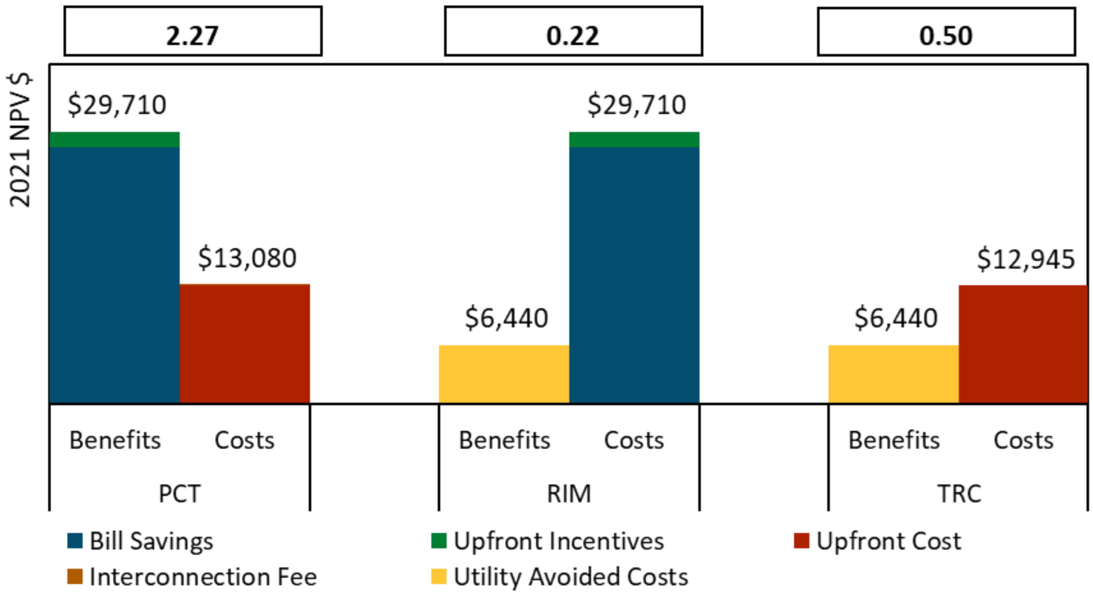

Figure 5: SPM cost tests under NEM 2.0 for a 2023 Non-CARE Solar+Storage adopter in PG&E's service territory. The benefit-cost-ratio scores are included along with a chart illustrating which components are included in each test. Values reflect the 20-year net present value (NPV) over the system lifetime.

4. Methodology: Fixed Assumptions

An Excel-based model was developed to model annual customer bills for the representative customers under each party proposal. In order to calculate annual bill savings, a counterfactual customer is also modeled with no solar or battery system.

Residential Customers Modeled

The residential proposals specified different tariffs that would apply to different customers. Three customer attributes were identified that reflect the variation within a single proposal.

1. **Adoption year**. Many proposals have a transitional structure for some rate components (*e.g.*, "step-downs" or "phase-ins") that depends on the year of interconnection. The year 2030 was found to reflect the last phase for most proposals. To account for the transitional structure, customers were modeled adopting new systems in **2023 and 2030.**

2. **CARE status**. Many proposals include a separate tariff for low-income customers. The criteria for low-income qualification vary by proposal. In this analysis, the distinction has been modeled based on a customer's qualification for California Alternate Rates for Energy (CARE). Both **Non-CARE and CARE** customers were modeled.

3. **System Type**. Many proposals include separate tariffs for customers adopting **solar vs. solar+storage** systems. Both kinds of customers were modeled.

In their different combinations, these three discrete attributes reflect eight representative customers, as shown below in Table 1.

Adoption Year	CARE Status	System Type
2023	Non-CARE	Solar
2023	Non-CARE	Solar+Storage
2023	CARE	Solar
2023	CARE	Solar+Storage
2030	Non-CARE	Solar
2030	Non-CARE	Solar+Storage
2030	CARE	Solar
2030	CARE	Solar+Storage

Table 1: 8 representative residential customers in the residential model

All eight representative customers were modeled for the three IOUs: PG&E, SCE, and SDG&E. This results in 24 overall customers modeled per proposal. For each IOU, a single load profile was used for the eight representative residential customers. The three customer profiles had annual electricity consumption between 7,000 and 8,000 kWh per year. The profiles were scaled to exactly 7,500 kWh/year annual load to facilitate comparison across IOUs.

These three IOU load profiles reflect aggregates of pre-interconnection load profiles from the customer database used in the NEM 2.0 Lookback Study[8]. In particular, these profiles reflect medium-sized single-family customers in inland climate zones for each IOU. The representative PG&E customer reflects CA Climate Zone 12 and the SCE and SDG&E customers reflect CA Climate Zone 10. Inland climate zones were chosen for this modeling because the strong solar resource and high electricity demands for air conditioning make the inland region particularly well-suited for customer solar.

Small Commercial Customers Modeled

Taking a similar approach, four representative commercial customers were modeled for each IOU. These vary by adoption year and system type, but no CARE or other low-income discounts were evaluated.

A single load profile was used for small commercial customers for each IOU. The load profiles were produced in the same manner as for residential customers. The three customer load profiles were between 16,000 and 17,500 kWh per year. The profiles were scaled to exactly 17,000 kWh/year annual load to facilitate comparison across IOUs.

There is substantial diversity in the commercial customer class. These load profiles are not meant to be reflective of the entire class. Rather, they provide an example and are used to explore differences among the party proposals. In addition, these are relatively small commercial customers and are likely to be on simple time-of-use tariffs that do not include critical peak pricing, peak day pricing, or demand charges. Thus, this modeling will not be reflective of the impact of the party proposals on customers whose tariffs include these more sophisticated charges.

[8] https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442467448

Solar System Size

The size of a customer's solar system relative to the customer load varies widely among installations. Some party proposals suggest that the NEM Successor Tariff should encourage the sizing of larger systems. In contrast, other party proposals include elements that may encourage customers to size smaller systems. For any proposal, the assumed solar system size may have an impact on simple payback period and other metrics.

In this analysis, solar systems were sized to 100% of annual customer load, *i.e.*, 7,500 kWh/year of solar production for residential customers and 17,000 kWh/year of solar production for commercial customers. The capacity factor is slightly higher for the SCE/SDG&E solar profile. Thus, the corresponding solar capacity differs for PG&E (4.7 kW-DC for residential, 10.7 kW-DC for commercial) vs. SCE/SDG&E (4.4 kW-DC for residential, 9.9 kW-DC for commercial).

This sizing criteria was chosen based on historical solar sizing under NEM 2.0. Currently, customer solar exports are eligible for NEM 2.0 compensation if they do not exceed annual customer imports from the grid. Sizing a solar system at 100% of annual load thus enables a customer to receive the maximum amount of NEM 2.0 export compensation that is allowed. As described in the NEM 2.0 Lookback Study, the average residential PV system size under NEM 2.0 represents 89% of post-interconnection consumption for PG&E and 96% of post-interconnection consumption for SDG&E[9]. Thus, sizing at 100% of customer load is approximately reflective of sizing decisions under NEM 2.0.

Solar Load Profiles

For each IOU, Verdant Associates generated a normalized (1 kW) solar profile for the corresponding climate zone. Solar PV production was estimated using the same model assumptions as the NEM 2.0 Lookback Study[10]. Verdant used the PV_LIB Toolbox developed by the PV Performance Modeling Collaborative. The solar shapes were developed using irradiance, temperature, and wind speed data from the CTZ22 weather year as described in the NEM 2.0 Lookback Study Report. Verdant modeled a 1 kW_{DC} system using 20-degree tilt and 180-degree azimuth for climate zones 10 and 12. All other model assumptions were set to mirror the PV Watts default assumptions as closely as possible. For model simplicity, the same solar profile was used for community solar in the CCSA proposal, which does not reflect that community solar systems may use single-axis tracking.

Customer Battery Storage

For solar paired with storage, a 2-hour battery was modeled with AC power capacity equal to the solar system's AC capacity (for residential: 3.8 kW for PG&E, 3.5 kW for SCE/SDG&E; for commercial: 8.6 kW for PG&E, 7.9 kW for SCE/SDG&E). The battery was assumed to have 85% round-trip efficiency.

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[9] https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442467448

[10] https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442467448

Storage charge/discharge profiles were generated for each IOU to approximately optimize the battery following a heuristic. The proposals were broken into two categories based on whether the export rate varies hourly or varies by time of use (TOU) period.

Proposals with export rates that vary hourly

For proposals with export rates that vary hourly, battery charging was calculated in two steps:

1. In off-peak hours only, the battery is charged from excess solar (solar generation greater than load), favoring the lowest-priced hours.
2. If the battery is not fully charged after step 1, it is then charged from remaining solar generation in off-peak hours, again favoring the lowest-price hours. (This results in increased imports). If there is insufficient solar to charge the battery during the off-peak period, it will not fully charge.

Similarly, battery discharging was calculated in two steps:

1. In peak hours only, the battery is discharged to reduce customer load, favoring the highest-priced hours.
2. If the battery has charge remaining after step 1, it is discharged fully (through grid exports) in on-peak hours, again favoring the highest-priced hours.

Proposals with export rates that vary by TOU period

For proposals with TOU-period export rates, a similar two-step logic is used for charging and for discharging. However, a single price is assumed within each TOU period. Therefore, in each step, charging and discharging is assumed to occur as soon as possible within a period.

Other notes on battery storage dispatch profiles

25-year levelized total avoided costs from the 2021 ACC were used. Note that in all cases, the battery is charged from on-site solar generation. While charging the battery may increase imports in some hours (by reducing self-consumption of solar power), the battery is never charged from the grid.

The TOU periods used to generate the storage shapes are based on the existing EV-rate TOU periods for each IOU. Here, the terms 'peak' and 'off-peak' are used to refer to the highest-priced and lowest-priced TOU periods respectively; individual IOUs use different terminology.

Avoided Costs

Avoided costs used in the modeling are from the Draft 2021 Avoided Cost Calculator (ACC)[11] and reflect PG&E Climate Zone 12, SCE Climate Zone 10, and SDG&E Climate Zone 10 (the same climate zones used for load and solar profiles). These avoided costs are used in calculating export rates for some proposals as well as in calculating some of the model output metrics.

Avoided costs in solar hours are lower than in the 2020 ACC. Thus, for proposals with export compensation tied to avoided costs, modeled bill savings may be smaller, and the modeled payback period may be longer, than parties may have expected based on calculations using the 2020 ACC.

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[11] https://www.cpuc.ca.gov/general.aspx?id=5267

Additionally, CAISO market prices were required for calculating net surplus compensation as well as some components of certain proposals. As a proxy for CAISO market prices, the model uses the sum of two components from the hourly ACC values: Energy and Cap-and-Trade.

Inflation, Discount Rate, and Electric Rate Escalation

Based on the 2021 Draft Avoided Cost Calculator, an inflation rate of 2.2% and a discount rate of 7.68% were used[12]. The discount rate reflects the IOU weighted average cost of capital (WACC) and is a simple average across the three IOUs. The discount rate was used for net present value calculations in the cost tests.

Electric rates for all three IOUs were assumed to escalate at 4%/year (nominal). A single escalation rate was used for all three IOUs and across all proposals, ensuring consistency in analysis.[13]

In some proposals, certain rate components were explicitly linked to avoided costs. Other rate components, including fixed fees and interconnection charges, were assumed to escalate at 4%/year.

Customer Solar and Storage System Lifetime

A timeframe of 20 years was chosen as a reasonable lifetime that can be applied uniformly in this modeling across all proposals for both solar and solar+storage systems. The 20-year lifetime for solar is supported by the August 6, 2020 Decision Adopting Standardized Inputs and Assumptions for Calculation of Estimated Electric Utility Bill Savings from Residential Photovoltaic Solar Energy Systems[14]. In addition, the same lifetime is used for solar and solar+storage systems in the model, and lifetimes longer than 20 years may not be realistic for battery storage as customer battery systems are often warrantied for 10 years[15].

No solar or battery degradation was assumed over the lifetime. However, battery degradation over a 20-year term may be significant. To account for this, battery storage costs assume that the battery energy is oversized by 30% to approximate full output over the 20-year period.

Note that the choice of system lifetime will not impact the Simple Payback Period or First-year Cost Shift metrics, as these metrics are based on first-year bill savings. However, the system lifetime is used to calculate the SPM cost tests, which are calculated as a lifecycle benefit-cost-ratio over the assumed lifetime of the system. For the PCT and TRC tests, assuming a longer lifetime would increase the score. For the RIM test, the impact of assuming a longer lifetime would depend on the interplay between bill savings and avoided costs.

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[12] https://www.cpuc.ca.gov/general.aspx?id=5267

[13] The assumption of 4% reflects the upper bound permitted in the August 6, 2020 *Decision Adopting Standardized Inputs and Assumptions for Calculation Estimated Electric Utility Bill Savings from Residential Photovoltaic Solar Energy Systems*. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M344/K976/344976563.PDF

[14] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M344/K976/344976563.PDF

[15] https://www.tesla.com/sites/default/files/pdfs/powerwall/powerwall_2_ac_warranty_us_1-4.pdf

Customer Solar and Storage Costs

A variety of purchase, lease, and financing options exist for customer solar and storage systems. In this model, an upfront purchase was assumed to facilitate calculation of the Simple Payback Period metric.

Solar system capital and operating costs ($/kW) and cost forecasts are based on the National Renewable Energy Laboratory 2020 Advanced Technology Baseline (NREL ATB)[16]. The forecast of capital expenditures (CAPEX) includes the cost of the modules, installation, and any other costs "required to achieve commercial operation in a given year."[17]

For this modeling, the residential solar costs are based on the Los Angeles "Moderate" residential costs in ATB.

Small commercial solar costs are also based on the ATB residential costs, as the C&I (commercial and industrial) system in ATB is much larger than the small commercial system used in this modeling. For small commercial solar costs, the residential solar costs were used and were reduced by 4.9% based on cost benchmarks by system size provided in the Lawrence Berkeley National Lab report "Tracking the Sun – Distributed Solar 2020 Data Update."[18]

Community solar costs were calculated using NREL ATB C&I (commercial and industrial) solar costs and E3's pro forma financial model that captures the tax benefits of accelerated depreciation. A 10% margin was assumed for management of the community solar system.

2021 residential and small commercial battery storage costs were obtained from Lazard Levelized Cost of Storage 6.0[19]. No cost reduction was assumed for small commercial vs. residential. Community storage costs are based on the Commercial and Industrial customer survey data. Forecasted battery storage costs are based on the NREL ATB forecast of utility solar cost declines and adjusted based on the share of each project type that is driven by DC system costs.

Two important incentives were included. The federal Investment Tax Credit (ITC) applies to both solar and solar+storage systems. In 2023, the ITC provides a credit of 22% of system CAPEX for all customers. In 2030, the ITC provides 10% of system CAPEX for commercial and community projects and 0% for residential systems. Because the ITC reflects federal funds, it is treated as a reduction to the upfront cost but is not otherwise represented in the cost test metrics.

The Self-Generation Incentive Program (SGIP) was also included[20]. The additional rebate available through the SGIP Equity program was not included, as the requirements for this program are strict and there is limited budget remaining for the program. SGIP is assumed to provide a $200/kWh rebate for residential battery storage projects and a $220/kWh rebate for commercial projects (on top of ITC)[21]. Unlike the ITC,

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[16] https://atb.nrel.gov/electricity/2020/data.php

[17] https://atb.nrel.gov/electricity/2020/index.php?t=sr

[18] https://emp.lbl.gov/sites/default/files/distributed_solar_2020_data_update.pdf

[19] https://www.lazard.com/media/451566/lazards-levelized-cost-of-storage-version-60-vf2.pdf

[20] https://www.cpuc.ca.gov/sgip/

[21] https://www.selfgenca.com/home/program_metrics/

SGIP is a ratepayer-funded incentive. Thus, the value of the SGIP rebate is included as a cost to nonparticipants in the First-year Cost Shift and Ratepayer Impact Measure (RIM) metrics.

5. Methodology: Bill Calculation

Customer Bills

The party proposals include many different rate components. The model includes the following key components (as applicable to the proposals) of customer bills. Where a rate component is not included in a proposal, it would contribute $0/year to customer bills. The components included are:

1. Import rate
2. Export rate
3. Treatment of net surplus compensation
4. Hourly self-consumption charge
5. Fixed (customer) charge
6. Solar system charge ($/kW)
7. Self-generation incentive ($/kWh)
8. Minimum bill

Although some bill components are calculated monthly, the bill itself is calculated on an annual basis. In addition, the minimum bill is compared to the entire customer bill rather than just the delivery components. This simplification was required to reflect the complex bill components used in some party proposals. However, it does represent a distinction from how the IOUs account for the minimum bill in their monthly billing and annual true-up.

In addition, two other components of party proposals are included that affect the system upfront cost but not the annual customer bill:

1. Upfront incentives ($/kW)
2. Interconnection charge

Import Rates

Imports (consumption from the grid) are modelled at the TOU rates specified in each proposal. Each residential customer was assigned to one of four rate categories based on the proposal's specifications. The following residential rates were used for each category:

Rate Category	PG&E	SCE	SDG&E
Existing TOU Rates	E-TOU-C	TOU-D	TOU-DR1
Existing EV Rates	EV-2A	TOU-D-PRIME	EV-TOU-5
IOU Proposed Rates	E-DER	TOU-D-PRIME	TOU-DER
Sierra Club Rates	E-ELEC	TOU-D-PRIME	TOU-DER

Table 2: Residential TOU rates used for each IOU

Where proposals indicated that any existing TOU rate could be used, the "Existing TOU Rates" were modeled. The counterfactual customer (without solar) was also modeled using Existing TOU Rates. Although the "Existing EV Rates" may not currently be available to customers without an electric vehicle, they were included to reflect rates with a larger spread between peak and off-peak prices that may be available to all customers in the future. The IOU Proposed Rates and Sierra Club Rates were modeled at the request of these parties.

Small commercial customers were modeled using a single set of TOU rates.

Rate Category	PG&E	SCE	SDG&E
Existing TOU Rates	B-1	TOU-GS-1	TOU-A

Table 3: Commercial TOU rates used for each IOU

Export Rates

Among all the bill components modeled, the treatment of export rates had the greatest amount of variation among the different proposals. Many proposals include different export rate treatments for different kinds of customers and different adoption years.

To reflect this, a flexible model of export rates was implemented. Export rates were based on import rates, avoided cost values, and/or other factors. Proposals also varied widely in levelization, averaging, and lock-in of export rates. All of this variation is reflected in the export rate calculation.

Two important nuances are included in the treatment of export rates to account for specific proposals:

1. **Net exports vs. all solar generation.** Most of the proposals use an export rate to compensate net exports on an hourly or subhourly basis. However, the CARE and CCSA proposals have an export rate that is applied to all generation. For CARE and CCSA, the model considers all onsite generation to be exported to the grid.
2. **"Exports above imports."** Most proposals treat all exports within a given month (or day) using the same compensation structure. However, the SBUA and Joint IOU proposal use separate compensation for exports in excess of imports on a monthly (or daily) basis, by TOU period. To capture this, the model accounts for monthly "exports below imports" and "exports above imports" independently. In the SBUA and Joint IOU proposals, these are credited at different rates. In all other proposals, these are compensated at the same export rate.

For more details on modeling the proposed export rates, please see Appendix B. The proposals have been modelled as precisely as possible, with any changes noted in Appendix C: Modifications to Party Proposals.

Treatment of Baseline Credits

The "Default IOU Rates" in Table 2 are two-tier TOU rates. Tiered rates are meant to reduce the cost of electricity corresponding to baseline consumption as well as incentivize conservation. Accordingly, the first tier is set a lower price than the second tier. In practice, on these tiered TOU rates, customers are billed at the higher tier for their usage and then receive a monthly baseline credit for consumption up to their baseline allowance.

The interaction between the baseline credit and self-generation is an important element in the resulting bill savings for some of the party proposals. Customers with on-site generation may be net exporters in some months. There is no conceptual ideal for how to compensate net exports on a tiered rate; however, the IOUs have adopted a method that is consistent with their billing practices.[22] This method works as follows:

- First, all imports are billed at the Tier 2 rates for the corresponding TOU periods and all exports are credited at the Tier 2 rates for the corresponding TOU periods.
- For months where the customer is a net importer, they receive a baseline credit corresponding to their net consumption for the month (imports minus exports), up to the baseline allowance. In effect, this adjusts some or all of net imports to the Tier 1 rate.
- For months where the customer is a net exporter, a baseline adjustment reduces export credits. This corresponds to net exports for the month (exports minus imports), up to the baseline allowance. In effect, this adjusts some or all of net exports to the Tier 1 rate.

This existing methodology has been applied in the modeling for the counterfactual customer (no solar), customers on NEM 2.0, and party proposals that credit exports based on the import rate.

However, some party proposals suggest crediting exports based on avoided costs or some other value that is distinct from the import rate. This creates an issue for modeling customers who remain on a tiered TOU rate for imports. If exports are no longer credited based on the tiered TOU rate, it does not seem appropriate to apply a baseline adjustment to the monthly export compensation in months where the customer is a net exporter. For these proposals, we have removed any baseline adjustments for months where the customer is a net exporter.

Other proposals have suggested compensating exports based on a fixed percentage of import rates; for example, crediting exports at 90% of the import rate. For those proposals, we have scaled baseline adjustments to export compensation by this percentage as well.

Finally, two proposals suggest that solar generation should not be netted against imports. The CARE proposal has all solar generation sold to the utility at avoided costs. The CCSA proposal suggests that customers would receive credits for a community solar subscription. For both proposals, baseline credits are calculated using customer consumption with no consideration of generation or exports.

[22] Based on E3 conversations with PG&E and Verdant conversations with SCE.

6. Model Results

This section includes example results in PG&E's service territory. Appendix D: All Model Results includes model results for all customers, all IOUs, and all proposals.

Residential 2023 Non-CARE Solar

Figure 6 shows the simple payback period and first-year cost shift for a 2023 residential non-CARE solar adopter. This is the same as Figure 1 in the Executive Summary and is provided again here for comparison to other customers.

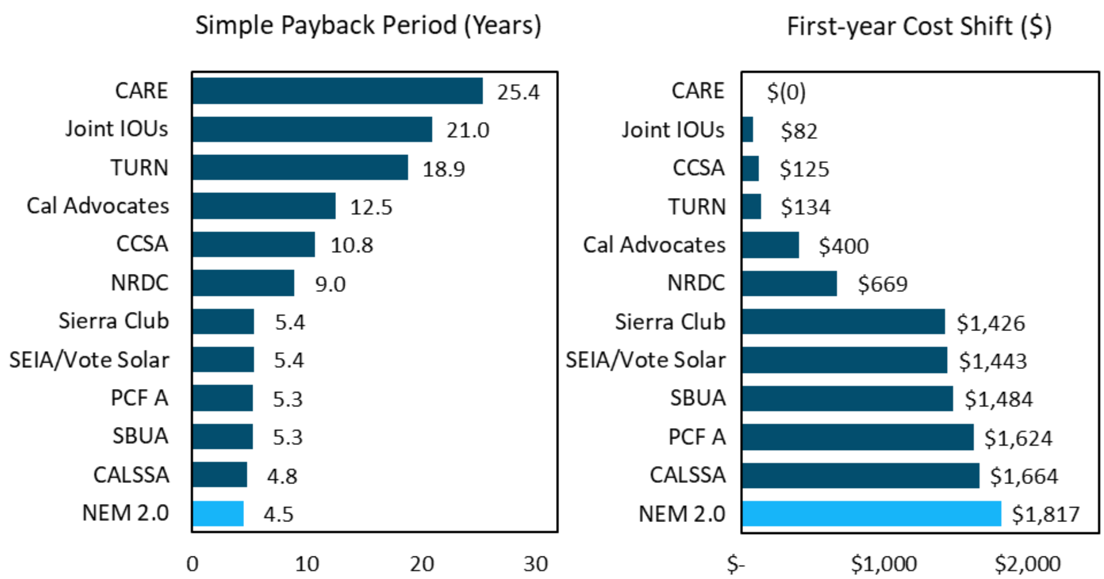

Figure 6: Simple payback period and first-year cost shift for a 2023 residential non-CARE solar adopter in PG&E's service territory.

Figure 7 shows the TRC for this customer. This is the same as Figure 4 in the Executive Summary.

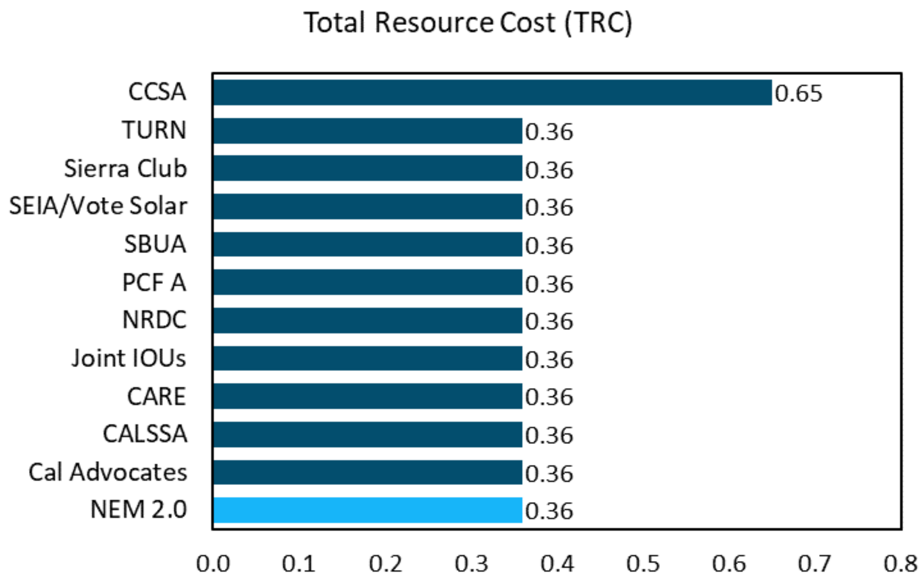

Figure 7: TRC for a 2023 residential non-CARE solar adopter in PG&E's service territory.

Residential 2023 Non-CARE Solar+Storage

Figure 8 shows the simple payback period and first-year cost shift for a 2023 non-CARE solar+storage customer in PG&E's service territory. Overall, payback periods are not considerably longer than for solar-only customers. This is largely due to the SGIP incentive, which reduces the upfront cost of storage. As a ratepayer-funded rebate, the SGIP incentive increases the cost shift for solar+storage adopters.

Two proposals achieve a shorter payback period than NEM 2.0. This is because they suggest modeling the existing EV rates for solar+storage customers, while NEM 2.0 assumes the default TOU rates.

Some proposals have export rates that vary hourly or with substantial variation by TOU period. Under these proposed tariffs, storage can enable the customer to capture greater value with their on-site generation, increasing bill savings and potentially reducing the payback period relative to a solar-only system.

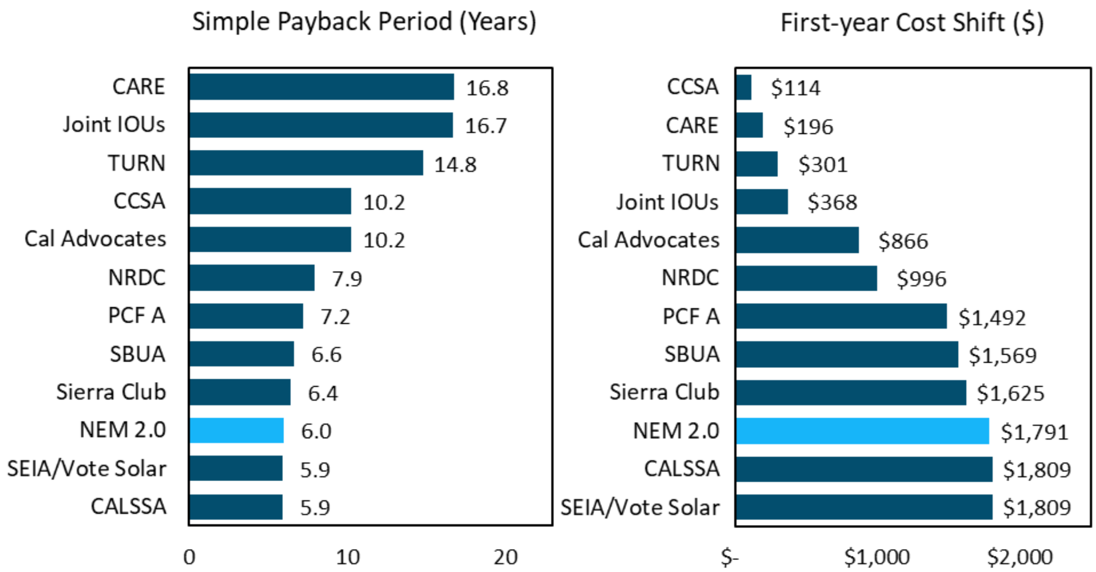

Figure 8: Simple payback period and first-year cost shift for a 2023 residential non-CARE solar+storage adopter in PG&E's service territory

Figure 9 shows the TRC for a 2023 solar+storage customer in PG&E's service territory. For the solar customer, the only distinction in TRC was for community systems. However, for solar+storage, there is an additional distinction among the proposals that factors into the TRC. Two different storage dispatch profiles are used depending whether a proposal's export rate varies hourly or by TOU period. Export rates that vary hourly would encourage storage dispatch that is more aligned with underlying system costs, leading to a higher TRC value for these proposals.

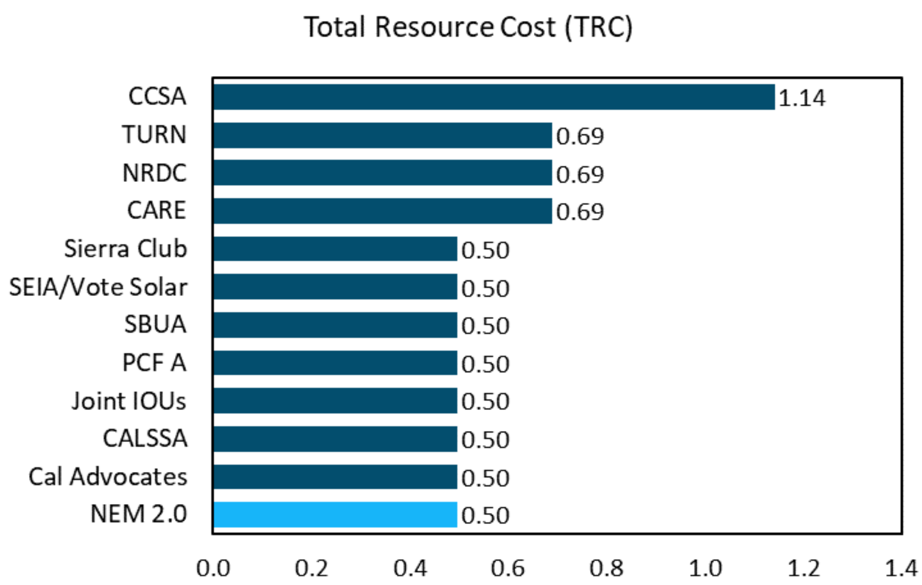

Figure 9: TRC for a 2023 residential solar+storage adopter in PGE's service territory

Residential 2023 CARE Solar

Figure 10 shows the simple payback period and first-year cost shift for a CARE customer. In general, customer bill savings are lower for the CARE customer vs. the Non-CARE customer. For many proposals, this results in a longer payback period and a smaller first-year cost shift relative to the Non-CARE customer.

Under NEM 2.0, there are two reasons why a CARE customer would see smaller bill savings from solar vs. a non-CARE customer. First, exports are credited at a discounted rate; and second, self-consumption of solar generation offsets imports at a discounted rate. Some proposals maintain NEM 2.0 but address the first point by crediting exports at the full non-CARE export rate; however, this does not affect the second point. These proposals achieve a simple payback period that is only slightly shorter than NEM 2.0.

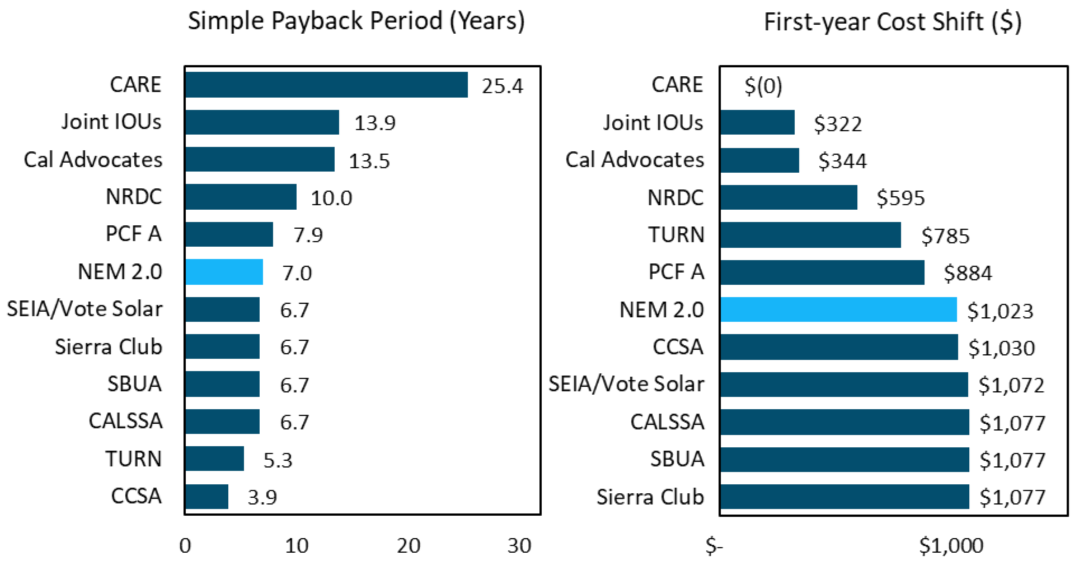

Figure 10: Simple payback period and first-year cost shift for a 2023 residential CARE solar adopter in PG&E's service territory

Residential 2030 Non-CARE Solar

Figure 11 shows the simple payback period and first-year cost shift for a Non-CARE customer adopting solar in 2030. Several key changes occur between 2023 and 2030. First, the upfront cost of solar falls substantially. Second, import rates increase, which increases bill savings in proposals that allow offsetting imports with on-site generation. Third, some proposals transition from a NEM 2.0-like structure to export rates that are based on avoided costs. And fourth, avoided costs during solar hours fall considerably.

Overall, the spread between simple payback period among the proposals increases from 2023 through 2030. NEM 2.0 becomes extremely lucrative for the participant, resulting in a 2.6-year payback period. Some other proposals have similarly short payback periods. On the other hand, proposals with compensation tied to avoided costs may see a similar payback periods for customers in 2023 and 2030.

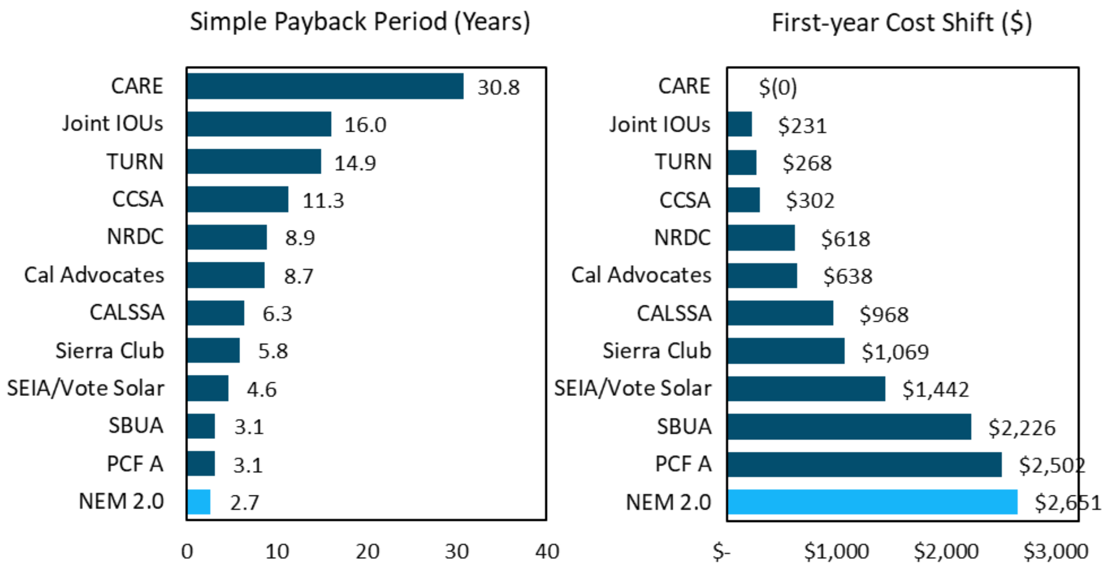

Figure 11: Simple payback period and first-year cost shift for a 2030 residential Non-CARE solar adopter in PG&E's service territory

Residential 2030 Non-CARE Solar+Storage

Figure 12 shows the simple payback period and first-year cost shift for a Non-CARE customer adopting solar+storage in 2030. The trends described above apply to solar+storage as well, with two key differences. First: although upfront costs for battery storage fall from 2023 through 2030, no SGIP incentive is assumed in 2030, which offsets some of the cost decline. Second: although solar avoided costs fall over this period, the solar+storage system can capture higher avoided costs in evening hours. Proposals that vary compensation dramatically based on the timing of imports and exports may see a shorter payback period for solar+storage than for solar alone.

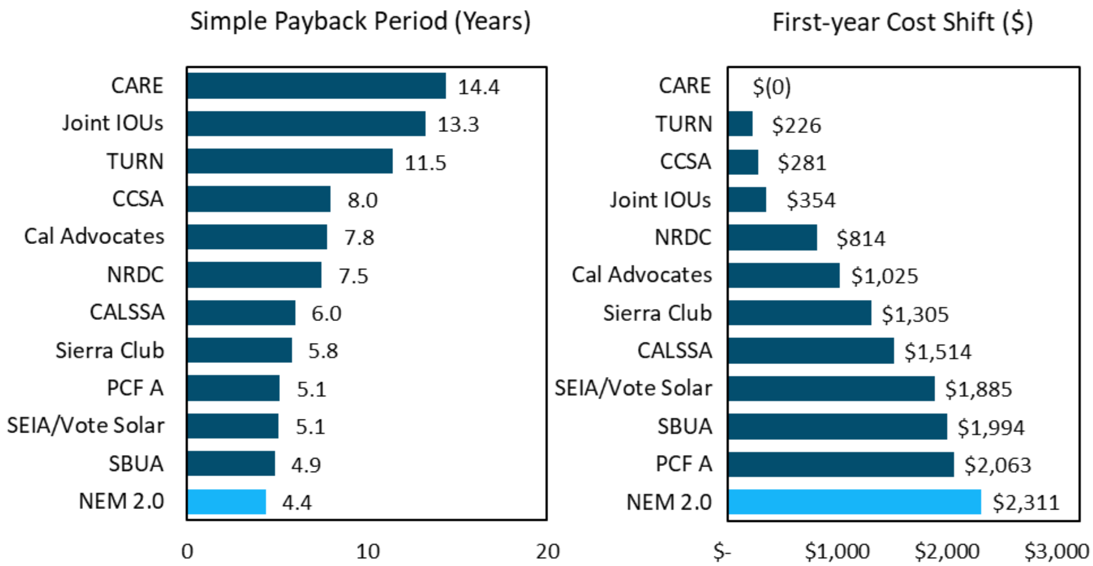

Figure 12: Simple payback period and first-year cost shift for a 2030 residential Non-CARE solar+storage adopter in PG&E's service territory

Additional results

Additional results, including results for SCE and SDG&E and for Small Commercial customers, are available in Appendix D.

Appendix A: Excel Model Documentation

Note: all results are provided in Appendix D: All Model Results. The model itself is provided for documentation purposes only. Instructions for viewing the model results are included here so that parties may investigate how their proposal is being modeled. It is not recommended that parties attempt to change any fixed inputs or make other modifications to the model.

Please note that the model takes a few seconds to calculate, so Automatic Calculations are disabled. **To calculate the model, you must hit F9 or "Calculate Now" (on the ribbon under Formulas).** The model will calculate automatically after running a macro.

The model includes a number of different worksheets. There are three options for calculating and displaying results.

Single Active Customer

The first option is to view the results for one selected IOU, proposal, and customer type. The user can select the IOU, proposal, and customer type on the "Dashboard" worksheet. The user must hit F9 or "Calculate Now" (on the ribbon under Formulas) to calculate the model. After calculating the model, the successor tariff components that correspond to the selected IOU, proposal, and customer type will populate in the "Proposal Successor Tariff Components" section of the Dashboard. The tariff components are filled in based on a pre-programmed mapping of proposals and each tariff components. Costs for the selected system type, including upfront system costs and interconnection charges, are populated in the "System Costs" section of the Dashboard.

After calculating the model, results are generated for the selected customer. Annual, 2021 NPV, first-year, and levelized results are calculated, where applicable, for results including Upfront System Cost, Upfront Incentive, Bill Savings, and System Avoided Costs. These results flow into the Simple Payback Period, First-Year Cost Shift, and SPM Cost Test metrics.

8 Customers

The second option for calculating the model is to generate and view results for all 8 customer types of a specified IOU and proposal. The IOU and proposal must be selected first on the "Dashboard" worksheet. Results for all 8 customer types for the selected IOU and proposal are generated in the "8 Customers" worksheet. (For the commercial model, this is "4 customers"). A macro can be used to generate results for eight customers by clicking the "Run 8 Customers" button. The macro may take around 1 minute to run. Annual results for bill components, such as Upfront Costs, Upfront Incentive, Bill Savings, and System Avoided Costs, are populated after the macro has finished running. Results for the Simple Payback Period, First-Year Cost Shift, and the SPM Cost Tests are generated for the eight customers and appear at the bottom of the worksheet.

All 12 Proposals

The third option for running the model is to calculate results for all 12 proposals (residential) or all 8 proposals (commercial), including NEM 2.0. In this option, results are generated for each of the 3 IOUs and 8 customer types and for each of the proposals. These results can be generated by hitting the "Run 12 Proposals" button on the "Dashboard" worksheet. Note: this macro runs 288 customers and takes approximately 1 hour to run. After running, metrics for all customers are provided in the "metrics" worksheet.

Other key tabs are:

- "Inputs": pre-selected inputs such as project lifetime, inflation, rate escalation, and discount rate are recorded in this tab.
- "Customer Bill Components": calculation of annual customer bill for the active customer and a counterfactual customer.
- "Hourly Data": hourly calculations for the customer bill.
- "Load and Generation Data": load and generation shapes used in the model
- "Upfront Costs": calculation of upfront costs for solar and storage systems
- "Mapping": rate components such as import rates, export rates, and fixed charges are mapped to the structure and numeric values specified in each proposal.

Appendix B: Detail on Export Rate Calculation

Proposals include a wide range of export rates. A summary of the parameters used to capture the party proposals is provided below.

1. Base Rate

   Possible values: Retail rates, Avoided costs, CAISO market prices

   The base rate specifies the basic rates, costs, or prices from which export rates are calculated. All proposals are based on either retail rates, avoided costs, CAISO market prices, or some combination of the three. The remaining parameters are used to modify these base rates.

   When retail rates are specified, the proposed import rates (minus non-bypassable charges) are used. Rates are based on 2021 rates with a 4% yearly escalation rate applied.

   When avoided costs are specified, total avoided costs from the 2021 ACC are used.

   When CAISO market prices are specified, the sum of the energy and cap and trade values from the 2021 ACC are used as a proxy.

2. Hourly Value Types

   Possible values: Single Year, Simple Average, Levelized

   If Base Rates are 'Avoided costs' or 'CAISO market prices', the value in each hour is either taken from a single year or a simple average or levelized value over multiple years.

3. Levelization / Averaging Period

   Possible values: 1 to 25 years

   Number of years to levelize or average over, if applicable.

4. Rate Period

   Possible values: Hourly, TOU Periods

   Specifies whether the export rate varies for each TOU period or is a rate that changes hourly.

5. Lock-in Period

   Possible values: 1 to 25 years

   Duration for which the rate is locked in starting in the customer adoption year.

6. Update Frequency after Lock-in

   Possible values: 1 to 25 years

   When initial lock-in period is finished, frequency with which rates should be updated.

7. TOU Period Weights

   Possible values: Solar, Solar Export Shape, Export Shape, None

If Base Rates are 'Avoided costs' or 'CAISO market prices', the weighted average for each TOU period is taken using the specified weights. 'Solar' is the solar generation profile. 'Solar Export Shape' is the export shape of a representative solar customer. 'Export Shape' is the export shape of the customer, which varies depending on whether it is a solar or solar + storage customer. All shapes are IOU-specific. 'None' means the simple average is used over the TOU period.

8. Percent of Retail Rate

   Possible values: 0 – 100%

   If Base Rates are 'Retail rates', a percentage of the total retail rate can be specified.

9. Adder

   Possible values: CCSA, None

   The specified 8760 array is added to the specified Base Rate. (Only used for the CCSA proposal)

10. Cap TOU Period Rates at Retail

    Possible values: TRUE, FALSE
    If 'TRUE', any calculated TOU period rates are capped at the import rate for that TOU period.

Appendix C: Modifications to Party Proposals

In some cases, party proposals were modified to fit the model framework, to promote consistency in modeling, or due to a lack of available data. The modifications are detailed here.

CALSSA

CALSSA proposed that a 3.1% rate escalation be used. A 4% rate escalation was used for all IOUs for consistency in analysis (see the “Key Inputs and Assumptions” section for more details).

CARE

CARE proposes that customers interconnect as Qualifying Facilities under the Public Utility Regulatory Policies Act (PURPA). CARE did not provide other estimates for interconnection costs, so the existing IOU interconnection fees were assumed.

CCSA

CCSA did not specify an import rate to use for modeling since a customer’s import rate is not relevant to CCSA’s community solar program. However, since the model requires the consideration of customers’ imports in addition to exports, import rates must be included for evaluation of CCSA’s proposal. The Existing TOU rates were selected for CCSA’s import rates.

CCSA proposed that CARE customers receive either a one-time upfront incentive or a self-generation incentive. CCSA specifies that the proposed MTC is intended to be the difference between a customer’s revenue on a NEM 2.0 retail rate export credit and the avoided cost-based export rate for non-CARE customers in CCSA's proposal. E3 modeled this by crediting 2023 CARE customers at the export rate of Retail Rates – NBCs (*i.e.* the export rate under NEM 2.0).

CCSA suggested a methodology for calculating subscriber benefits as a percentage share of export credits. Instead, the export credits were modeled as a bill reduction for the representative customers in the model and the output metrics were calculated as for any other proposal. This treatment appears consistent with CCSA’s proposal.

CCSA did not suggest modeling community solar+storage. However, this was modeled for completeness using the hourly storage dispatch profiles used in the model. The overall effect is to change the upfront cost and generation profile of the community system.

In the modeling, it was assumed that the community solar credits on a customer’s bill would not affect their baseline credits, which would still be based on their meter readings.

Grid Alternatives – Vote Solar – Sierra Club

Grid Alternative – Vote Solar – Sierra Club proposal A is a proposed tariff for low-income customers. This proposal was modeled for the representative CARE customers in both SEIA/Vote Solar and Sierra Club proposals.

Grid Alternative – Vote Solar – Sierra Club proposal B is a proposed tariff for projects owned and controlled by the community. This is outside the scope of the Excel model and was not modeled here.

Joint IOUs

The joint IOUs' proposal for export rates uses avoided costs weighted by "the recorded export profile of existing NEM customers." The export profile of the representative solar customer in each IOU is used as the weights for both 2023 and 2030.

NRDC

As requested by NRDC, E3 calculated the upfront incentives necessary for each customer to reach a 10-year payback period. If a payback period less than 10 years was achieved without an upfront incentive for a customer type, no upfront incentive was added for that customer type.

PCF A

PCF proposal A suggested a methodology for calculating the benefits of community storage. This is outside the scope of the customer bill model. As a simplification, it was assumed that the benefits of community storage are equal to their costs. Thus, the 20% interconnection fee on new systems is treated as a direct nonparticipant benefit.

PCF E

PCF proposal E is a proposal for new import rates for all residential customers, not just NEM customers. PCF did not provide $/kWh rates. Instead, PCF provided relative percentage figures for each TOU period. Substantial modeling and utility data requests would be necessary to estimate the $/kWh rates that fit this template and would recover the full residential revenue requirement. As a result, the proposal was not modeled.

SBUA

SBUA specified that there would be no limitation to charging storage from the grid. The storage charging and discharging shape used in the modeling was developed did not allow for charging from the grid. See the “Representative customers” section for more detail on the storage shapes used in the model.

Sierra Club

Sierra Club proposed that the solar system size be allowed up to the annual load of an all-electric home with two electric vehicles. E3 used the same customer load shape for all proposals and the solar system evaluated was sized to meet 100% of the customer’s annual load (see “Representative customers” section for more detail on the customer load shape and solar system size used).

Cal Advocates

The Public Advocates Office proposes that “the export compensation rates (ECR) are divided into three cost categories—generation, distribution, and transmission, and the monthly export credits should be applied to the same cost component of the customer’s bill.” These cost categories have not been accounted for independently in the model. Instead, the overall value of export credits (at the proposed avoided-cost based rates) are credited against the overall cost of imports (excluding non-bypassable charges).

The Public Advocates Office also proposed incentives for NEM 1.0 and 2.0 customers to switch to the successor tariff. These incentives were not modeled since NEM 1.0 and 2.0 customers were out of the scope of the model.

TURN

TURN's proposal noted that a new residential TOU rate for solar+storage may become appropriate but did not provide specific rates for solar+storage customers. At TURN's request, EV rates were used for both solar and solar+storage customers in TURN's proposal.

TURN included three options for lock-in periods (no lock-in, five year lock in, and ten year lock in) for avoided cost-based export rates. E3 modeled export rates with no lock-in for TURN's proposal.

TURN did not specify 2030 upfront incentive amount for non-CARE customers. Therefore, E3 used the 2023 upfront incentive times the proportional change in solar system costs (*i.e.* 77% of the 2023 incentive).

TURN indicated that non-CARE incentives would come from funding sources external to rates. Therefore, non-CARE incentives were not modeled.

TURN suggested that the funding sources for CARE customers be a combination of NEM 1.0 and NEM 2.0 participants and general rate recovery. The CARE incentives are modeled through general rate recovery.

TURN noted an expectation that the Equity SGIP incentive for storage should be reduced for CARE solar+storage customers that also receive an upfront solar PV incentive. E3 assumed that the Equity SGIP incentive is no longer available due to lack of funds, so the Equity SGIP incentives are not modeled at all.

Appendix D: All Model Results

Table 4: Results for Residential Solar, 2023 Non-CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	4.5	$ 1,817	3.28	0.11	0.36
	SCE	5.4	$ 1,287	2.74	0.21	0.58
	SDG&E	3.2	$ 2,467	4.52	0.09	0.39
Cal Advocates	*PG&E*	12.5	$ 400	0.98	0.36	0.36
	SCE	16.5	$ 144	0.76	0.75	0.58
	SDG&E	9.1	$ 660	1.46	0.26	0.39
CALSSA	*PG&E*	4.8	$ 1,664	3.05	0.12	0.36
	SCE	5.5	$ 1,228	2.64	0.22	0.58
	SDG&E	3.5	$ 2,289	4.23	0.09	0.39
CARE	*PG&E*	25.4	$ 0	0.35	1.00	0.36
	SCE	22.3	$ 0	0.57	1.00	0.58
	SDG&E	26.4	$ 0	0.39	1.00	0.39
CCSA	*PG&E*	10.8	$ 125	0.91	0.69	0.65
	SCE	8.7	$ 172	1.16	0.88	1.04
	SDG&E	9.8	$ 178	1.03	0.67	0.71
Joint IOUs	*PG&E*	21.0	$ 82	0.58	0.61	0.36
	SCE	17.4	$ 115	0.75	0.76	0.58
	SDG&E	9.3	$ 637	1.47	0.26	0.39
NRDC	*PG&E*	9.0	$ 669	1.31	0.27	0.36
	SCE	8.9	$ 550	1.21	0.47	0.58
	SDG&E	8.0	$ 794	1.74	0.22	0.39
PCF A	*PG&E*	5.3	$ 1,624	2.78	0.17	0.36
	SCE	6.4	$ 1,095	2.27	0.29	0.58
	SDG&E	3.9	$ 2,274	3.77	0.13	0.39
SBUA	*PG&E*	5.3	$ 1,484	2.80	0.13	0.36
	SCE	8.4	$ 677	1.73	0.33	0.58
	SDG&E	4.0	$ 1,912	3.64	0.11	0.39
SEIA/Vote Solar	*PG&E*	5.4	$ 1,443	2.73	0.13	0.36
	SCE	6.3	$ 1,039	2.34	0.24	0.58
	SDG&E	3.6	$ 2,183	4.06	0.09	0.39
Sierra Club	*PG&E*	5.4	$ 1,426	2.36	0.15	0.36
	SCE	6.5	$ 983	1.96	0.29	0.58
	SDG&E	3.6	$ 2,160	3.60	0.11	0.39
TURN	*PG&E*	18.9	$ 134	0.63	0.56	0.36
	SCE	21.2	$ 20	0.58	0.98	0.58
	SDG&E	8.6	$ 721	1.59	0.24	0.39

Table 5: Results for Residential Solar+Storage, 2023 Non-CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	6.0	$ 1,791	2.27	0.22	0.50
	SCE	6.3	$ 1,406	2.14	0.38	0.83
	SDG&E	4.2	$ 2,489	3.14	0.20	0.63
Cal Advocates	*PG&E*	10.2	$ 866	1.30	0.38	0.50
	SCE	10.5	$ 648	1.33	0.62	0.83
	SDG&E	6.8	$ 1,391	1.97	0.32	0.63
CALSSA	*PG&E*	5.9	$ 1,809	2.29	0.22	0.50
	SCE	6.7	$ 1,311	2.04	0.40	0.83
	SDG&E	4.4	$ 2,369	3.01	0.21	0.63
CARE	*PG&E*	16.8	$ 196	0.81	0.84	0.69
	SCE	15.2	$ 181	1.15	0.89	1.02
	SDG&E	17.3	$ 181	0.97	0.87	0.85
CCSA	*PG&E*	10.2	$ 114	1.25	0.90	1.14
	SCE	6.1	$ 587	1.98	0.85	1.69
	SDG&E	7.8	$ 385	1.60	0.87	1.41
Joint IOUs	*PG&E*	16.7	$ 368	0.85	0.58	0.50
	SCE	11.5	$ 546	1.20	0.68	0.83
	SDG&E	8.3	$ 1,074	1.62	0.39	0.63
NRDC	*PG&E*	7.9	$ 996	1.51	0.45	0.69
	SCE	8.1	$ 829	1.54	0.66	1.02
	SDG&E	6.6	$ 1,318	2.03	0.42	0.85
PCF A	*PG&E*	7.2	$ 1,492	1.91	0.30	0.50
	SCE	7.9	$ 1,107	1.77	0.48	0.83
	SDG&E	5.2	$ 2,191	2.61	0.27	0.63
SBUA	*PG&E*	6.6	$ 1,569	2.05	0.24	0.50
	SCE	7.4	$ 1,126	1.89	0.43	0.83
	SDG&E	4.7	$ 2,223	2.90	0.21	0.63
SEIA/Vote Solar	*PG&E*	5.9	$ 1,809	2.29	0.22	0.50
	SCE	6.7	$ 1,311	2.04	0.40	0.83
	SDG&E	4.4	$ 2,369	3.01	0.21	0.63
Sierra Club	*PG&E*	6.4	$ 1,625	1.93	0.25	0.50
	SCE	6.7	$ 1,311	2.00	0.41	0.83
	SDG&E	4.4	$ 2,382	2.83	0.22	0.63
TURN	*PG&E*	14.8	$ 301	0.95	0.72	0.69
	SCE	14.6	$ 213	1.03	0.99	1.02
	SDG&E	8.0	$ 1,012	1.77	0.48	0.85

Table 6: Results for Residential Solar, 2023 CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
	PG&E	7.0	$ 1,023	2.10	0.17	0.36
NEM 2.0	*SCE*	7.7	$ 764	1.89	0.30	0.58
	SDG&E	4.7	$ 1,609	3.14	0.12	0.39
	PG&E	13.5	$ 344	0.96	0.37	0.36
Cal Advocates	*SCE*	14.2	$ 229	0.97	0.59	0.58
	SDG&E	9.4	$ 624	1.48	0.26	0.39
	PG&E	6.7	$ 1,077	2.18	0.16	0.36
CALSSA	*SCE*	6.7	$ 947	2.19	0.26	0.58
	SDG&E	4.5	$ 1,702	3.29	0.12	0.39
	PG&E	25.4	$ 0	0.35	1.00	0.36
CARE	*SCE*	22.3	$ 0	0.57	1.00	0.58
	SDG&E	26.4	$ 0	0.39	1.00	0.39
	PG&E	3.9	$ 1,030	3.71	0.17	0.65
CCSA	*SCE*	3.9	$ 894	3.61	0.28	1.04
	SDG&E	2.5	$ 1,688	5.52	0.12	0.71
	PG&E	13.9	$ 322	0.93	0.38	0.36
Joint IOUs	*SCE*	14.9	$ 202	0.89	0.64	0.58
	SDG&E	8.6	$ 717	1.60	0.24	0.39
	PG&E	10.0	$ 595	1.28	0.28	0.36
NRDC	*SCE*	10.5	$ 470	1.23	0.46	0.58
	SDG&E	8.8	$ 694	1.65	0.23	0.39
	PG&E	7.9	$ 884	1.85	0.25	0.36
PCF A	*SCE*	8.1	$ 754	1.82	0.36	0.58
	SDG&E	5.3	$ 1,509	2.75	0.18	0.39
	PG&E	6.7	$ 1,077	2.18	0.16	0.36
SBUA	*SCE*	6.7	$ 947	2.19	0.26	0.58
	SDG&E	4.5	$ 1,702	3.29	0.12	0.39
	PG&E	6.7	$ 1,072	1.82	0.19	0.36
SEIA/Vote Solar	*SCE*	7.8	$ 763	1.60	0.36	0.58
	SDG&E	4.6	$ 1,618	2.86	0.13	0.39
	PG&E	6.7	$ 1,077	2.02	0.18	0.36
Sierra Club	*SCE*	7.0	$ 883	1.79	0.32	0.58
	SDG&E	4.4	$ 1,722	3.07	0.13	0.39
	PG&E	5.3	$ 785	1.24	0.29	0.36
TURN	*SCE*	5.9	$ 635	1.22	0.47	0.58
	SDG&E	2.5	$ 1,192	2.00	0.19	0.39

Table 7: Results for Residential Solar+Storage, 2023 CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	9.3	$ 998	1.51	0.33	0.50
	SCE	8.9	$ 859	1.57	0.52	0.83
	SDG&E	6.0	$ 1,651	2.27	0.28	0.63
Cal Advocates	*PG&E*	12.2	$ 655	1.14	0.43	0.50
	SCE	11.4	$ 557	1.29	0.64	0.83
	SDG&E	8.0	$ 1,129	1.74	0.36	0.63
CALSSA	*PG&E*	9.0	$ 1,048	1.55	0.32	0.50
	SCE	9.6	$ 753	1.46	0.56	0.83
	SDG&E	6.2	$ 1,581	2.19	0.28	0.63
CARE	*PG&E*	16.8	$ 196	0.81	0.84	0.69
	SCE	15.2	$ 181	1.15	0.89	1.02
	SDG&E	17.3	$ 181	0.97	0.87	0.85
CCSA	*PG&E*	6.5	$ 798	2.21	0.37	0.82
	SCE	6.5	$ 608	2.20	0.61	1.37
	SDG&E	4.2	$ 1,455	3.35	0.31	1.04
Joint IOUs	*PG&E*	14.7	$ 471	0.95	0.52	0.50
	SCE	12.7	$ 445	1.10	0.75	0.83
	SDG&E	8.8	$ 989	1.53	0.41	0.63
NRDC	*PG&E*	8.2	$ 922	1.45	0.47	0.69
	SCE	8.6	$ 748	1.48	0.68	1.02
	SDG&E	7.8	$ 1,049	1.80	0.47	0.85
PCF A	*PG&E*	10.9	$ 749	1.31	0.44	0.50
	SCE	11.0	$ 560	1.30	0.66	0.83
	SDG&E	7.4	$ 1,352	1.88	0.37	0.63
SBUA	*PG&E*	9.0	$ 1,048	1.55	0.32	0.50
	SCE	9.9	$ 718	1.45	0.57	0.83
	SDG&E	6.2	$ 1,581	2.19	0.28	0.63
SEIA/Vote Solar	*PG&E*	9.0	$ 1,048	1.54	0.32	0.50
	SCE	9.6	$ 753	1.45	0.56	0.83
	SDG&E	6.2	$ 1,581	2.18	0.29	0.63
Sierra Club	*PG&E*	8.9	$ 1,057	1.53	0.32	0.50
	SCE	8.9	$ 859	1.57	0.52	0.83
	SDG&E	5.9	$ 1,685	2.26	0.28	0.63
TURN	*PG&E*	7.7	$ 883	1.28	0.53	0.69
	SCE	7.8	$ 734	1.34	0.76	1.02
	SDG&E	4.3	$ 1,377	1.93	0.44	0.85

Table 8: Results for Residential Solar, 2030 Non-CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	2.7	$ 2,651	5.52	0.11	0.63
	SCE	3.2	$ 1,788	4.63	0.22	1.05
	SDG&E	1.9	$ 3,432	7.60	0.09	0.73
Cal Advocates	*PG&E*	8.7	$ 638	1.67	0.37	0.63
	SCE	10.7	$ 219	1.34	0.77	1.05
	SDG&E	5.8	$ 962	2.52	0.28	0.73
CALSSA	*PG&E*	6.3	$ 968	2.23	0.27	0.63
	SCE	6.9	$ 588	2.01	0.51	1.05
	SDG&E	4.3	$ 1,394	3.30	0.21	0.73
CARE	*PG&E*	30.8	$ 0	0.61	1.00	0.63
	SCE	16.0	$ 0	1.03	1.00	1.05
	SDG&E	26.5	$ 0	0.71	1.00	0.73
CCSA	*PG&E*	11.3	$ 302	1.12	0.68	0.78
	SCE	8.2	$ 255	1.51	0.85	1.31
	SDG&E	9.3	$ 354	1.35	0.65	0.90
Joint IOUs	*PG&E*	16.0	$ 231	0.97	0.63	0.63
	SCE	11.9	$ 153	1.27	0.81	1.05
	SDG&E	6.0	$ 915	2.49	0.28	0.73
NRDC	*PG&E*	8.9	$ 618	1.58	0.39	0.63
	SCE	8.4	$ 361	1.46	0.71	1.05
	SDG&E	4.9	$ 1,188	2.93	0.24	0.73
PCF A	*PG&E*	3.1	$ 2,502	4.73	0.15	0.63
	SCE	3.8	$ 1,639	3.87	0.27	1.05
	SDG&E	2.3	$ 3,283	6.42	0.12	0.73
SBUA	*PG&E*	3.1	$ 2,226	4.75	0.13	0.63
	SCE	5.1	$ 953	2.96	0.35	1.05
	SDG&E	2.4	$ 2,726	6.19	0.11	0.73
SEIA/Vote Solar	*PG&E*	4.6	$ 1,442	3.22	0.19	0.63
	SCE	4.4	$ 1,180	3.37	0.31	1.05
	SDG&E	2.8	$ 2,294	5.26	0.13	0.73
Sierra Club	*PG&E*	5.8	$ 1,069	2.58	0.24	0.63
	SCE	6.8	$ 601	2.24	0.46	1.05
	SDG&E	3.5	$ 1,788	4.31	0.16	0.73
TURN	*PG&E*	14.9	$ 268	1.06	0.58	0.63
	SCE	15.9	$ 3	1.00	1.03	1.05
	SDG&E	5.6	$ 1,005	2.70	0.26	0.73

Table 9: Results for Residential Solar+Storage, 2030 Non-CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	4.4	$ 2,311	3.37	0.24	0.83
	SCE	4.6	$ 1,474	3.17	0.44	1.40
	SDG&E	3.1	$ 3,026	4.73	0.23	1.09
Cal Advocates	*PG&E*	7.8	$ 1,025	1.87	0.43	0.83
	SCE	7.4	$ 521	1.95	0.71	1.40
	SDG&E	5.0	$ 1,598	2.94	0.36	1.09
CALSSA	*PG&E*	6.0	$ 1,514	2.37	0.34	0.83
	SCE	5.8	$ 968	2.44	0.57	1.40
	SDG&E	3.9	$ 2,245	3.67	0.29	1.09
CARE	*PG&E*	14.4	$ 0	1.16	1.00	1.18
	SCE	8.8	$ 0	1.77	1.00	1.79
	SDG&E	10.8	$ 0	1.49	1.00	1.52
CCSA	*PG&E*	8.0	$ 281	1.64	0.97	1.63
	SCE	4.5	$ 558	2.71	0.90	2.46
	SDG&E	5.7	$ 421	2.22	0.92	2.09
Joint IOUs	*PG&E*	13.3	$ 354	1.12	0.72	0.83
	SCE	8.7	$ 289	1.69	0.82	1.40
	SDG&E	6.3	$ 1,095	2.34	0.46	1.09
NRDC	*PG&E*	7.5	$ 814	1.91	0.61	1.18
	SCE	6.9	$ 352	2.05	0.87	1.79
	SDG&E	4.6	$ 1,453	3.10	0.48	1.52
PCF A	*PG&E*	5.1	$ 2,063	2.85	0.30	0.83
	SCE	5.6	$ 1,225	2.63	0.51	1.40
	SDG&E	3.7	$ 2,778	3.95	0.27	1.09
SBUA	*PG&E*	4.9	$ 1,994	3.04	0.27	0.83
	SCE	5.3	$ 1,162	2.81	0.49	1.40
	SDG&E	3.4	$ 2,731	4.40	0.24	1.09
SEIA/Vote Solar	*PG&E*	5.1	$ 1,885	2.87	0.28	0.83
	SCE	4.9	$ 1,349	3.01	0.46	1.40
	SDG&E	3.6	$ 2,542	4.13	0.26	1.09
Sierra Club	*PG&E*	5.8	$ 1,305	2.60	0.45	1.18
	SCE	5.4	$ 829	2.77	0.64	1.79
	SDG&E	3.7	$ 2,069	4.00	0.37	1.52
TURN	*PG&E*	11.5	$ 226	1.35	0.86	1.18
	SCE	10.2	$ (188)	1.50	1.18	1.79
	SDG&E	5.6	$ 1,008	2.68	0.56	1.52

Table 10: Results for Residential Solar, 2030 CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	4.2	$ 1,606	3.53	0.17	0.63
	SCE	4.6	$ 1,099	3.20	0.32	1.05
	SDG&E	2.8	$ 2,303	5.28	0.13	0.73
Cal Advocates	*PG&E*	9.5	$ 565	1.64	0.37	0.63
	SCE	9.1	$ 331	1.68	0.61	1.05
	SDG&E	6.0	$ 914	2.53	0.28	0.73
CALSSA	*PG&E*	4.0	$ 1,678	3.67	0.17	0.63
	SCE	4.0	$ 1,340	3.70	0.28	1.05
	SDG&E	2.7	$ 2,425	5.53	0.13	0.73
CARE	*PG&E*	30.8	$ 0	0.61	1.00	0.63
	SCE	16.0	$ 0	1.03	1.00	1.05
	SDG&E	26.5	$ 0	0.71	1.00	0.73
CCSA	*PG&E*	11.3	$ 302	1.12	0.68	0.78
	SCE	8.2	$ 255	1.51	0.85	1.31
	SDG&E	9.3	$ 354	1.35	0.65	0.90
Joint IOUs	*PG&E*	14.9	$ 267	1.04	0.59	0.63
	SCE	12.5	$ 124	1.21	0.85	1.05
	SDG&E	7.0	$ 757	2.16	0.33	0.73
NRDC	*PG&E*	9.7	$ 544	1.55	0.39	0.63
	SCE	10.4	$ 240	1.45	0.71	1.05
	SDG&E	5.4	$ 1,057	2.76	0.26	0.73
PCF A	*PG&E*	4.7	$ 1,529	3.14	0.22	0.63
	SCE	4.7	$ 1,191	3.09	0.34	1.05
	SDG&E	3.1	$ 2,276	4.67	0.17	0.73
SBUA	*PG&E*	4.0	$ 1,678	3.67	0.17	0.63
	SCE	6.1	$ 715	2.47	0.42	1.05
	SDG&E	2.8	$ 2,291	5.30	0.13	0.73
SEIA/Vote Solar	*PG&E*	4.7	$ 1,385	2.66	0.23	0.63
	SCE	5.3	$ 879	2.37	0.44	1.05
	SDG&E	3.0	$ 2,118	4.36	0.16	0.73
Sierra Club	*PG&E*	4.2	$ 1,596	3.08	0.20	0.63
	SCE	4.8	$ 1,038	2.70	0.38	1.05
	SDG&E	2.8	$ 2,299	4.73	0.15	0.73
TURN	*PG&E*	2.1	$ 807	1.67	0.37	0.63
	SCE	2.2	$ 523	1.67	0.62	1.05
	SDG&E	0.8	$ 1,335	2.97	0.24	0.73

Table 11: Results for Residential Solar+Storage, 2030 CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	PG&E	6.8	$ 1,269	2.16	0.38	0.83
	SCE	6.5	$ 754	2.26	0.61	1.40
	SDG&E	4.4	$ 1,923	3.36	0.32	1.09
Cal Advocates	PG&E	9.4	$ 746	1.62	0.50	0.83
	SCE	8.1	$ 402	1.87	0.75	1.40
	SDG&E	5.8	$ 1,254	2.57	0.42	1.09
CALSSA	PG&E	6.6	$ 1,333	2.24	0.36	0.83
	SCE	7.0	$ 616	2.09	0.67	1.40
	SDG&E	4.5	$ 1,831	3.24	0.33	1.09
CARE	PG&E	14.4	$ 0	1.16	1.00	1.18
	SCE	8.8	$ 0	1.77	1.00	1.79
	SDG&E	10.8	$ 0	1.49	1.00	1.52
CCSA	PG&E	8.0	$ 281	1.64	0.97	1.63
	SCE	5.0	$ 382	2.67	0.91	2.46
	SDG&E	5.7	$ 421	2.22	0.92	2.09
Joint IOUs	PG&E	15.6	$ 211	0.96	0.85	0.83
	SCE	11.0	$ 13	1.34	1.03	1.40
	SDG&E	7.9	$ 718	1.87	0.57	1.09
NRDC	PG&E	8.8	$ 557	1.67	0.70	1.18
	SCE	7.7	$ 183	1.87	0.95	1.79
	SDG&E	5.4	$ 1,099	2.72	0.55	1.52
PCF A	PG&E	7.7	$ 1,085	1.89	0.45	0.83
	SCE	7.8	$ 506	1.88	0.71	1.40
	SDG&E	5.2	$ 1,674	2.81	0.38	1.09
SBUA	PG&E	6.6	$ 1,333	2.24	0.36	0.83
	SCE	7.0	$ 616	2.09	0.67	1.40
	SDG&E	4.5	$ 1,831	3.24	0.33	1.09
SEIA/Vote Solar	PG&E	6.6	$ 1,333	2.15	0.38	0.83
	SCE	7.0	$ 616	2.06	0.68	1.40
	SDG&E	4.5	$ 1,831	3.16	0.34	1.09
Sierra Club	PG&E	6.5	$ 1,346	2.11	0.38	0.83
	SCE	6.5	$ 754	2.24	0.62	1.40
	SDG&E	4.3	$ 1,968	3.24	0.33	1.09
TURN	PG&E	6.6	$ 674	1.62	0.72	1.18
	SCE	5.9	$ 207	1.72	1.03	1.79
	SDG&E	3.3	$ 1,200	2.67	0.56	1.52

Table 12: Results for Commercial Solar, 2023 Non-CARE

Proposal	IOU	Payback Period (years)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	4.7	$ 3,586	3.11	0.12	0.38
	SCE	6.7	$ 2,001	2.20	0.27	0.61
	SDG&E	4.1	$ 3,927	3.54	0.12	0.41
Cal Advocates	*PG&E*	7.8	$ 1,809	1.79	0.21	0.38
	SCE	9.4	$ 1,151	1.52	0.40	0.61
	SDG&E	7.4	$ 1,869	1.98	0.21	0.41
CARE	*PG&E*	24.0	$ 0	0.37	1.00	0.38
	SCE	21.1	$ 0	0.60	1.00	0.61
	SDG&E	24.9	$ 0	0.41	1.00	0.41
CCSA	*PG&E*	10.6	$ 284	0.92	0.69	0.65
	SCE	8.6	$ 390	1.17	0.88	1.04
	SDG&E	9.6	$ 403	1.04	0.67	0.71
Joint IOUs	*PG&E*	30.1	$ (180)	0.37	1.00	0.38
	SCE	22.5	$ (58)	0.57	1.05	0.61
	SDG&E	22.3	$ 93	0.54	0.75	0.41
SBUA	*PG&E*	4.7	$ 3,586	3.11	0.12	0.38
	SCE	6.7	$ 2,001	2.20	0.27	0.61
	SDG&E	4.1	$ 3,927	3.54	0.12	0.41

Table 13: Results for Commercial Solar+Storage, 2023 Non-CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	6.3	$ 3,687	2.14	0.21	0.46
	SCE	7.5	$ 2,525	1.82	0.40	0.73
	SDG&E	6.0	$ 3,701	2.24	0.23	0.52
Cal Advocates	*PG&E*	8.4	$ 2,534	1.61	0.28	0.46
	SCE	8.7	$ 2,022	1.64	0.44	0.73
	SDG&E	8.1	$ 2,567	1.74	0.30	0.52
CARE	*PG&E*	15.9	$ 487	0.86	0.83	0.71
	SCE	14.5	$ 452	1.18	0.87	1.03
	SDG&E	18.0	$ 452	0.90	0.84	0.76
CCSA	*PG&E*	10.2	$ 249	1.26	0.90	1.14
	SCE	7.3	$ 811	1.67	0.99	1.65
	SDG&E	9.5	$ 572	1.31	0.92	1.22
Joint IOUs	*PG&E*	32.0	$ 61	0.48	0.95	0.46
	SCE	18.5	$ 442	0.79	0.92	0.73
	SDG&E	21.0	$ 565	0.71	0.73	0.52
SBUA	*PG&E*	7.2	$ 3,094	1.85	0.25	0.46
	SCE	8.2	$ 2,234	1.75	0.42	0.73
	SDG&E	6.6	$ 3,265	2.08	0.25	0.52

Table 14: Results for Commercial Solar, 2030 Non-CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	*PG&E*	2.5	$ 5,310	5.79	0.12	0.73
	SCE	3.6	$ 2,846	4.11	0.29	1.22
	SDG&E	2.2	$ 5,588	6.59	0.13	0.84
Cal Advocates	*PG&E*	4.5	$ 2,743	3.34	0.21	0.73
	SCE	5.2	$ 1,617	2.87	0.42	1.22
	SDG&E	4.0	$ 2,822	3.75	0.22	0.84
CARE	*PG&E*	26.3	$ 0	0.72	1.00	0.73
	SCE	13.7	$ 0	1.21	1.00	1.22
	SDG&E	22.6	$ 0	0.83	1.00	0.84
CCSA	*PG&E*	11.1	$ 685	1.14	0.68	0.78
	SCE	8.1	$ 579	1.53	0.85	1.31
	SDG&E	9.1	$ 803	1.37	0.65	0.90
Joint IOUs	*PG&E*	22.9	$ 84	0.69	1.04	0.73
	SCE	14.2	$ (33)	1.07	1.13	1.22
	SDG&E	15.3	$ 291	1.02	0.81	0.84
SBUA	*PG&E*	3.2	$ 4,110	4.64	0.15	0.73
	SCE	4.3	$ 2,153	3.43	0.35	1.22
	SDG&E	2.4	$ 5,152	6.15	0.13	0.84

Table 15: Results for Commercial Solar+Storage, 2030 Non-CARE

Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
	PG&E	4.4	$ 4,721	3.32	0.24	0.80
NEM 2.0	SCE	5.3	$ 2,576	2.78	0.47	1.31
	SDG&E	4.2	$ 4,385	3.48	0.27	0.94
	PG&E	6.2	$ 3,053	2.45	0.33	0.80
Cal Advocates	SCE	5.9	$ 2,111	2.54	0.51	1.31
	SDG&E	5.5	$ 3,004	2.69	0.35	0.94
	PG&E	13.0	$ 0	1.28	1.00	1.29
CARE	SCE	8.2	$ 0	1.89	1.00	1.89
	SDG&E	11.4	$ 0	1.40	1.00	1.41
	PG&E	7.9	$ 621	1.66	0.98	1.64
CCSA	SCE	5.3	$ 646	2.33	1.02	2.39
	SDG&E	6.9	$ 662	1.84	0.96	1.79
	PG&E	27.3	$ (248)	0.55	1.44	0.80
Joint IOUs	SCE	13.8	$ (265)	1.07	1.22	1.31
	SDG&E	16.0	$ 143	0.93	1.00	0.94
	PG&E	5.3	$ 3,780	2.84	0.28	0.80
SBUA	SCE	5.5	$ 2,409	2.71	0.48	1.31
	SDG&E	4.6	$ 3,947	3.24	0.29	0.94