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Witnesses: R. Thomas Beach

PREPARED DIRECT TESTIMONY OF R.THOMAS BEACH
ON BEHALF OF
THE SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Metering	)))))	Rulemaking 20-08-020 (Filed August 27, 2020)

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June 18, 2021

EXECUTIVE SUMMARY OF RECOMMENDATIONS

In 2005 California set a goal of a million solar roofs. But reaching that goal seemed like a dream. With this Commission's leadership, and the private investments of millions of California citizens, that dream has become reality. The California solar industry now employs 75,000 workers and has invested $70 billion dollars in the state's economy, with a majority of the state's solar jobs in the distributed solar sector.

California now has an even more ambitious goal to reach 100% clean energy by 2045. That goal cannot be achieved without new investments from millions of Californians in an array of distributed energy resources (DERs) – not just distributed generation (DG) from solar and wind, but also battery storage, electric vehicles (EVs), and electric heat pumps. The Commission has recognized clearly that California will have a high DER future. On June 14, 2021, the Commission issued a proposed new rulemaking (OIR) "to modernize the electric grid for a high distributed energy resources future." The proposed OIR recognizes that technology advancements and cost declines, as well as environmental imperatives, are driving the growth of DERs, and that the Commission's role is "to optimize the integration of millions of DERs within the distribution grid while ensuring affordable rates" (see Proposed OIR, at page 9).

The Commission's acknowledgement of a high DER future recognizes that California cannot rely solely on utility-scale electric resources to meet its 2045 clean energy goal. A significant portion of our clean energy needs must be sited in the built environment, in the load centers, if the state is also to reach its ambitious goal to conserve 30% of its lands. Customer-owned DERs such as EVs and heat pumps are necessary to reduce emissions in the transportation and building sectors. Further, to meet the severe challenges of a changing climate, California must develop a more resilient energy system, where significant electricity can be produced and stored on-site. In today's world, increasing resiliency is not just a private benefit for a select few, it is an imperative that benefits all Californians who rely on continuous electric service. Finally, as we evolve our energy systems to meet these new goals, we must ensure that clean DERs are broadly available to all Californians, including low-income consumers and disadvantaged communities.

In this context, it is critical that state policy continues to foster the sustainable growth of distributed solar resources. 10% of utility ratepayers already have made long-term investments in rooftop solar, and those customers' experience with this leading DER will shape their interest – as well as the interest of their friends and neighbors – in further commitments to other DER technologies. The NEM program is foundational to DER deployment, as it ensures that customers who invest in renewable DG receive a fair return on their investment. SEIA and Vote Solar fully recognize that the residential NEM program should be updated, for these reasons: (1)

to integrate the program with the state's efforts to encourage electrification, (2) to encourage the growth of solar-plus-storage resources that enhance the value of solar by shifting solar output to serve loads in the on-peak hours, (3) to align over time the costs and benefits of DER adoption for both participating and non-participating ratepayers, and (4) to increase access for low-income customers.

The SEIA / Vote Solar proposal. This testimony presents the recommendations of the Solar Energy Industries Association (SEIA) and Vote Solar. We propose that the new "NEM 3.0" general market tariff for residential customers should use a net billing structure. Under net billing, the customer with renewable DG would pay a different rate for energy received from the utility (i.e. imports) than for the excess generation that the DG customer delivers to the utility (i.e. exports). There are two principal pillars to the Vote Solar / SEIA net billing proposal:

- **Service on an electrification rate.** For imports from the utility, the residential DG customers of PG&E and SDG&E would be required to take service from one of the utility's available untiered time-of-use (TOU) rates designed to promote beneficial electrification. The structure of these rates will provide a strong incentive for new DG customers to include storage, which will increase significantly the value of these systems. to the grid. This requirement would take effect in 2023, at the outset of the NEM 3.0 program. The residential customers of SCE would continue to be allowed to use the residential default TOU rates, as well as SCE's electrification rate, because the design of SCE's rates has more aggressive TOU pricing, and SCE's lower residential rates present reduced concerns with non-participant impacts than the other two IOUs.

- **Five-year stepdown in compensation, focused on reducing the export rate.** The compensation for residential DG customers under NEM 3.0 would be reduced gradually over time from the level set in the current NEM 2.0 tariff, in a series of five steps. The first step, and the first significant reduction, will occur in 2023 with PG&E and SDG&E residential customers required to use the electrification rate. The remaining four steps will reduce the export rates for all three IOUs, with each step triggered when specific aggregate capacities of residential systems are installed under NEM 3.0 on each IOU system. The steps that we propose would reduce the export compensation for PG&E and SDG&E NEM customers by 50% by 2027; for SCE NEM customers, by 25% by 2027.

The goal of both the electrification rates and the export stepdowns is to bring the bill savings for DG customers into alignment, over a five-year period (2023-2027), with the benefits of this new renewable generation, as measured by the Commission's approved 2020 Avoided Cost Calculator (ACC).

To promote electrification, it is important that NEM customers be allowed to oversize their systems by up to 50%, to provide for the significant load growth that will result from the adoption of other types of DERs such as EVs and heat pumps. Excess output should be compensated based on the avoided costs in the 2020 ACC, to provide ratepayer indifference.

Vote Solar and SEIA do not recommend any changes to the current NEM 2.0 tariff for non-residential customers. The growth in this market has lagged in recent years, and the lower volumetric rates applicable to these customers do not have the same impacts on non-participants as do residential rates.

Statutory requirements. There are four statutory requirements that the Commission's adopted NEM successor tariff must meet. Our proposal satisfies all of these requirements:

1. **Ensure that customer-sited renewable distributed generation continues to grow sustainably.** It will be challenging for the industry to move to higher-cost solar-plus-storage systems while facing both reduced export compensation and the expiration in 2024 of the federal solar tax credit for residential customers. The SEIA/ Vote Solar proposal is tailored to promote the continued growth of the residential solar market by making a gradual change to compensation that will allow customers to continue to have a reasonable opportunity to invest. This testimony shows that our proposal provides paybacks of 7 to 10 years for customers who invest in solar and solar-plus-storage systems. This will support the market as it transitions to more valuable solar-plus-storage systems. Such paybacks are in line with those offered in other states that have successfully modified their NEM tariffs while maintaining market growth.
2. **Include specific alternatives designed for growth among residential customers in disadvantaged communities.** This general market tariff is designed to work in conjunction with the proposals offered by Vote Solar, GRID Alternatives, and Sierra Club that are expressly targeted to reach Environmental Justice and Social Justice communities, including disadvantaged communities. Both proposals are designed to work together to improve on California's achievement that, in 2019, 39% of new residential rooftop solar was installed on low- and moderate-income homes (those with incomes at or below 120% of the Area Median Income).
3. **Ensure that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility.** We show that the benefits of new solar and solar-plus-storage facilities – in terms of the costs that they will allow the utilities to avoid – are greater than the capital and operating costs of these systems. These resources thus pass the Total Resource Cost test and will be cost-effective additions to the utility system. This testimony also quantifies the societal benefits expected from NEM 3.0 resources, in terms of reduced damages from climate change, health benefits from cleaner air, less leakage of methane from the natural gas system, land use benefits, and local economic benefits. These

benefits total $3.8 billion per year. The Commission should weigh these benefits when considering whether our proposed NEM 3.0 tariff is equitable for all stakeholders.

4. **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.** If the Commission interprets this statute as requiring it to examine the impacts of the tariff on participating versus non-participating ratepayers, the SEIA / Vote Solar proposal produces improved scores on the RIM test over time, bringing lost revenues (i.e. bill savings) from NEM 3.0 customers into alignment, over a five-year period (2023-2027), with the benefits (i.e. the avoided costs) of this new renewable DG, as measured by the Commission's 2020 ACC. Further, the Commission should take a broader view of the equities between participating and non-participating ratepayers than just the scores on the too-stringent RIM test.

This testimony takes a close look at the contention that the present NEM 1.0 and 2.0 programs have resulted in a "cost shift" of billions of dollars per year that is borne by non-participating ratepayers. We show that this claim is significantly overstated, when one considers the full lifecycle benefits of the existing distributed solar fleet. Moreover, if California had not developed 10 GW of distributed solar, it would have had to procure a comparable amount of utility-scale renewables through the Renewable Portfolio Standard (RPS) program. RPS resources developed over the past 15 years also have resulted in above-market costs that ratepayers must bear, and we show that the level of these above-market RPS costs is comparable to the NEM cost shift. The above-market costs of both the NEM and RPS programs have resulted principally from the declining costs of renewable generation over time, not from flaws in either program. Today, California – and the rest of the world – are benefitting from the cost declines in renewable generation – at all scales – that have resulted in part from the state's past investments in these clean technologies at earlier stages in their development. Finally, we calculate that the existing NEM 1.0 and 2.0 solar fleet provide about $4.3 billion per year in societal benefits that also should be considered when evaluating "cost shift" claims.

AB 327 requires this Commission to balance two vital goals – first, aligning compensation for customer-sited renewable DG with the benefits that these systems provide to the electric system, and, second, ensuring that these resources continue to grow sustainably. Our proposal includes many of the same conceptual elements as the proposed NEM 3.0 tariff in the white paper from the Commission's consultant, Energy and Environmental Economics (E3). These common elements include a net billing structure with changes to export rates, gradualism, calibration of the proposal to the economics of renewable DG, and consideration of the links with beneficial electrification. We also strongly recommend that the Commission should use the existing electrification rates that have been developed with broad input and as a platform for many types of DERs, rather than require the solar-specific rate designs that E3 explores. The

Commission also does not need to implement the “Market Transition Credit” that E3 proposes; such a mechanism would be difficult and contentious to establish and administer. Finally, the E3 paper does not focus on the growth of the solar-plus-storage systems. Our proposal clearly recognizes that paired, high-value solar and storage systems are the future of distributed solar in California, and enabling a reasonable transition to those systems must be a key focus of the NEM 3.0 program.

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I. INTRODUCTION

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

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

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae*, which is **Attachment RTB-1** to this testimony. As reflected in my CV, I have almost 40 years of experience on rate design and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the Commission, working on the implementation of PURPA. I also served as a technical advisor to three commissioners from 1984 – 1989. Since leaving the Commission in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony, studies, or reports on numerous occasions before this Commission as well as state regulatory commissions in 18 other states. My CV includes a list of the formal testimony that I have sponsored before this Commission and in other state regulatory proceedings concerning electric and natural gas utilities.

Q: Please describe more specifically your experience on avoided costs and issues related to net energy metering and the cost-effectiveness of renewable distributed generation and other types of distributed energy resources.

A: I have worked on issues concerning the calculation of avoided cost prices throughout my career, including sponsoring testimony on avoided cost issues in state regulatory proceedings in California, Idaho, Oregon, Montana, Nevada, New Hampshire, North Carolina, and Vermont. With respect to benefit-cost issues concerning renewable distributed generation (DG), I have sponsored testimony on net energy metering (NEM) and solar economics in California and ten other states. Since 2013 I have co-authored benefit-cost studies of NEM or solar DG in Arkansas, Arizona, California, Colorado, New Hampshire, North Carolina, and South Carolina. I also co-authored the chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013.[1] Finally, since 2007, I have sponsored testimony on rate design issues concerning solar DG in general rate case proceedings in Arizona, California, Massachusetts, and Texas.

Q: Please describe your specific experience in California on rate design and the rates applicable to distributed generation (DG) and distributed energy resources (DERs).

A: Over the last 15 years, I have sponsored testimony on rate design issues concerning solar DG in numerous General Rate Case (GRC) Phase 2 proceedings at this Commission involving all three of the major California investor-owned utilities (IOUs). I also represented several solar industry groups in the CPUC's major investigation from 2012-2015 into residential rate design in California.

[1] This report was designed to provide policymakers with tools (including rate design changes) to address key questions concerning distributed generation resources. It has been published in *The*

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of the Solar Energy Industries Association (SEIA) and Vote Solar.

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

Vote Solar is an independent 501(c)(3) non-profit working through effective policy advocacy to repower the U.S. with clean energy by making solar power more accessible and affordable. We work at the state level in more than 25 states to drive the transition to a just, 100% clean energy future. Vote Solar is based in Oakland, California, and has over 12,000 members nationally, including many members in the service territories of the California IOUs.

Electricity Journal, Volume 26, Issue 8 (October 2013). It is also available at http://americaspowerplan.com/.

II. OVERVIEW OF THE ISSUES ADDRESSED

Q: What is the purpose of your testimony?

A: On March 15, 2021, Vote Solar and SEIA filed and served in this proceeding a comprehensive proposal for a new "NEM 3.0" tariff in California ("Proposal"). This Proposal is included for the record as **Attachment RTB-2**. The purpose of my testimony is to provide additional details and support for the Vote Solar / SEIA NEM 3.0 proposal, as parties were directed to do in the Scoping Memorandum dated November 19, 2020.

Q: The Scoping Memorandum, at pages 2-3, asked parties to address a number of issues in their testimony. Please outline how your testimony will address each of these issues.

A: The first issue asked "what guiding principles (including those related to Assembly Bill 327, equity, environmental goals, and social justice) should the Commission adopt" to guide this proceeding. Parties including SEIA and Vote Solar filed comments on this question, and the Commission adopted a set of guiding principles in D. 21-02-007. Each section of this testimony indicates, at the outset, the adopted guiding principles and statutory directives which that section addresses. For the remaining Issues 2 to 6, I provide below a brief outline of how that issue is addressed in this testimony.

Issue 2. What information from the Net Energy Metering 2.0 Lookback Study should inform the successor and how should the Commission apply those findings in its consideration?

Response: The NEM 2.0 Lookback study is an important source of data on the current state of the distributed solar market in California, and information from that report is used in the SEIA / Vote Solar proposal, as indicated in this testimony. That said, I caution that any assessment of the NEM 3.0 program should use forward-looking analyses of both the costs and benefits of distributed solar. As a result, there are elements of the NEM 2.0 Lookback study, including its cost-effectiveness analyses based on looking backward at historical solar costs, that are of limited relevance to this proceeding.

Issue 3. What method should the Commission use to analyze the program elements identified in Issue 4 and the resulting proposals, while ensuring the proposals comply with the guiding principles?

Response: I have analyzed the key program elements of the SEIA / Vote Solar proposal, as well as aspects of other parties' proposals, using the suite of cost-effectiveness tests in the *California Standard Practice Manual* (*SPM*). There are three essential elements in this analysis:

- **Use the full set of cost-effectiveness tests**, in order to assess the benefits and costs from the perspectives of each of the major stakeholders – the utility system as a whole, participating NEM customers, and other ratepayers. The regulator needs to balance all of these important interests in order to craft a net metering program that is truly in the public interest.
- **Employ a long-term, lifecycle analysis** of the costs and benefits – and not just single-year snapshots – because distributed resources have long economic lives, for example, 25 years for distributed solar.
- **Consider a comprehensive list of benefits and costs** that include, on the benefit side, not just the standard avoided costs for generation, transmission, and distribution, but also benefits that are specific to certain types of DERs. A timely example of such a resource-specific benefit is the resiliency provided by solar-plus-storage systems when the utility grid is unable to provide electric service.

Issue 4: What program elements or specific features should the Commission include in a successor to the current net energy metering tariff?

Response: There are three essential elements to the successor NEM tariff. First, there must be a strong **equity & inclusion element** designed to increase the ability of low-income Californians to access solar and solar-plus-storage systems. This element is presented in the direct testimony of Stephen Campbell on behalf of Vote Solar, Sierra Club, and GRID Alternatives, testimony which SEIA fully supports. Second, the general market tariff must support and be consistent with the state's efforts to **promote electrification** as a key strategy to meet California's climate goals. Customer adoption of DERs of all types will be needed to electrify – both DERs such as electric vehicles and electric heat pumps that increase loads as well as DERs such as distributed solar that allow customers to serve their own loads behind the meter, thus reducing the loads placed on the grid. This testimony will explain the need for the Commission to use the same set of cost-based, time-varying rates for all types of DERs, without discriminating by the specific type(s) of DER(s) that a customer adopts. This includes both DERs that increase loads as well as DERs that reduce or shift them. Finally, to address the balance between participating and non-participating ratepayers, the Commission should adopt **a gradual step-down in the compensation for exports to the grid from distributed solar**.

Issue 5: Which of the analyzed proposals should the Commission adopt as a successor to the current net energy metering tariff and why? What should the timeline be for implementation?

Response: This testimony will explain in detail why the Commission should adopt the SEIA / Vote Solar proposal as the general market tariff for NEM 3.0, with the implementation of the new tariff targeted for January 1, 2023.

Issue 6: Other issues that may arise related to current net energy metering tariffs and sub-tariffs, which include but are not limited to the virtual net energy metering tariffs, net energy metering aggregation tariff, the Renewable Energy Self-Generation Bill Credit Transfer program, and the NEM fuel cell tariff.

Response: SEIA and Vote Solar are proposing to change several provisions of the current NEM tariffs, in order to promote beneficial electrification. I discuss how the Commission should allow customers to oversize their solar systems in anticipation of changing their transportation and heating demands to the use of clean electricity. Net surplus generation from oversized systems should be compensated at the avoided costs in the approved 2020 Avoided Cost Calculator. SEIA and Vote Solar also support further efforts to allow customer-sited generation and storage to provide more valuable services to the grid, including the dispatch of storage by the utility or grid operator, the use of dynamic rates by all DER/NEM customers, and the provision of certain grid services that have value to the local distribution system.

III. SUSTAINABLE GROWTH OF DISTRIBUTED ENERGY RESOURCES IS NEEDED TO MEET CALIFORNIA'S CLIMATE GOALS

Theme: California's clean energy goals to reduce greenhouse gas (GHG) emissions require the state, at a minimum, to continue to achieve today's level of customer adoption of solar, storage, and other NEM-eligible renewable generation technologies.

Statutory: [Section 2827.1(b)(1)] Ensure that customer-sited renewable distributed generation continues to grow sustainably….
[Section 2827.1(b)(3)] Provide that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility.

CPUC Principles: A successor to the net energy metering tariff should…

- fairly consider all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1.
- be coordinated with the Commission and California's energy policies, and
- maximize the value of customer-sited renewable generation to all customers and to the electrical system.

A. All the Eggs in the Utility-scale Basket?

Q: Why does it continue to be important for the state's electric system that customer-sited renewable distributed generation continues to grow sustainably?

A: California has made significant progress toward reducing GHG emissions in its electric sector. The state is now depending on the use of that clean power to the electrify the state's building and transportation sectors, in order to reduce the more difficult-to-address carbon emissions from natural gas to heat buildings and liquid fuels for transportation. But this will require the continued growth of the state's renewable electric generation as electricity assumes a greater share of primary energy use. California will require an extensive and diverse mix of new renewable generation, and much of this generation will come from utility-scale renewables. However, the state would commit a serious error to rely only on utility-scale renewables. Although California, the other western states, and offshore waters have significant potential for utility-scale renewables, there are many uncertainties in the extent to which utility-scale renewables can be developed in the time frame required. These uncertainties include:

- The common and largest uncertainty for utility-scale renewables is the availability of the transmission necessary to deliver the power to load centers. The siting of new high-voltage transmission in California is difficult, time-consuming, and expensive. New lines inevitably raise significant environmental and land use issues, and provoke significant opposition from affected landowners and nearby residents. These difficulties will only be exacerbated by the state's recent experience with major wildfires sparked by transmission lines. Availability of transmission also is the key issue in accessing out-of-state renewables. The final phase of the last major transmission project to access new renewables, the Tehachapi transmission project, entered service at the end of 2016.[2] Even without major new transmission projects to access new utility-scale renewables, the IOUs' transmission costs have grown steadily in recent years. The CPUC staff has identified rapidly increasing transmission and distribution costs as a significant factor in the IOUs' high rates.[3]

- There is limited potential for further wind development in California's existing wind resource areas.[4]

- Offshore wind has yet to be sited, permitted, and developed off the West Coast of the U.S., so there are substantial unknowns in the ability to site this resourcein a timely fashion, and the costs required to do so. The deeper waters off the California coast presents cost and engineering challenges. Californians have long expressed concern with industrial development of the state's coastal land and

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[2] See project timeline at https://www.sce.com/about-us/reliability/upgrading-transmission/TRTP-4-11.

[3] See key findings at page 7 of CPUC February 2021 En Banc white paper, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Feb%202021%20Utility%20Costs%20and%20Affordability%20of%20the%20Grid%20of%20the%20Future.pdf: "The growth in rates can be largely attributed to increases in capital additions driven by rising investments in transmission by PG&E and distribution by SCE and SDG&E."

[4] The 2019-2020 Integrated Resource Planning (IRP) cycle included input assumptions for the IRP RESOLVE model which assume onshore wind potential of 2,015 to 4,544 MW. See bottom of Table 26, at pages 41-43, of https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Prelim_Results_Proposed_Inputs_and_Assumptions_2019-2020_10-4-19.pdf.

waters, and there are significant environmental issues that must be resolved before large-scale offshore wind development becomes a reality.[5]

- California has excellent solar resources across most of the state. But there are significant competing uses for the land required for utility-scale solar facilities, and the state has committed to conserving 30% of California land. Thus, there are land use constraints on utility-scale solar. As discussed in Attachment A to the SEIA / Vote Solar proposal, the land use constraints in the model that the CPUC uses for integrated resource planning (IRP) had to be relaxed by a factor of four to enable the model to run the IRP scenario to 2045 that assumes no further DER deployment (the "No New DERs" case). If the original constraints had remained, the No New DER case would have had to replace a significant amount of utility-scale solar with more expensive resources. This No New DER case was used to value DERs in the Commission's approved 2020 Avoided Cost Calculator (ACC). As a result, the current ACC undervalues DERs by an unknown amount because it may not reflect the land use constraints on utility-scale solar development.

The sustained and steady growth of DERs provides a vital and necessary hedge against the uncertainties and constraints faced by utility-scale renewables, California's distributed solar industry has demonstrated the ability to install 1.2 GW per year of new renewable generation consistently over the last five years,[6] and energy efficiency and demand response programs remain important in limiting the growth of electric usage and peak demands.[7]

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5 A Natural Resources Defense Council (NRDC) blog post notes some of the siting and permitting hurdles for offshore wind: https://www.nrdc.org/experts/sergio-sanchez-lopez/bringing-offshore-wind-californias-future

6 This is just in the service territories of the three IOUs. See https://www.californiadgstats.ca.gov/charts/. Solar DG installations over last 5 years (2016-2020) have grown from 2,240 MW at the end of 2015 to 9,220 MW at the close of 2020.

7 See the link to the "2021 Potential and Goals Interactive Results Dashboard" on the CPUC's webpage on 2021 energy efficiency potential and goals, at https://www.cpuc.ca.gov/General.aspx?id=6442464362. The 2021 results viewer indicates about 9,000 GWh of energy efficiency in 2022, increasing to about 12,000 GWh by 2030.

B. Customers Demand Resiliency and 100% Renewables

Q: The solar industry is responding to increased customer interest in and demand for solar-plus-storage systems. Is this a demand that could be met with utility-scale renewables?

A: No. The interest in solar-plus-storage is driven in significant part by customers' desire to increase the reliability and resilience of their electric service. They are responding to a world in which climate change is driving more frequent and more severe weather and wildfire events that can cause long outages in service from the utility grid, as exemplified by the Public Safety Power Shutoffs in recent years during the state's long wildfire season. At a community level, the same concern with resiliency has been expressed in the strong interest in micro-grid development.[8] Resilient backup systems at the customer or community level require both (1) a means to store energy in order to match supply with demand and (2) a source of generation to serve load and replenish the stored energy. Solar-plus-storage systems are a logical resource to meet this need due to their ability to be sized to and sited at customers' loads. They also avoid the emissions of carbon and criteria air pollutants, and the noise impacts and fire safety/carbon monoxide risks, from back-up fossil generation such as portable gasoline or diesel generators.

Q: Customer-owned solar generation can supply 100%, or more, of a customer's electric use with on-site renewable generation. Does this respond to a customer demand that cannot be served with utility-scale power?

A: Yes. Despite the falling costs of renewable generation, historically the California IOUs have been slow to meet customer demand for more clean and renewable generation, beyond the basic requirements of the state's Renewable Portfolio Standard. The IOU "green tariff shared renewables" (GTSR) programs have been small and late to develop,

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[8] See the CPUC Resiliency and Microgrid page, at https://www.cpuc.ca.gov/resiliencyandmicrogrids/, including the link to the Microgrid OIR (R.19-09-009).

have required customers to pay a premium for a larger share of renewable generation than the IOU's standard power mix, and have few relatively subscribers.[9] The IOUs' failure to meet this customer demand has resulted in both (1) the growth of Community Choice Aggregators (CCAs) committed to serving their communities with a greener mix of generation at rates competitive with the IOUs, as well as (2) strong customer demand for rooftop solar systems that can supply 100% of a customer's annual energy use, and produce long-term savings for the customer.

C. Equity, Customer Engagement, and Synergies Among DERs

Q: Are there other benefits from a strong program to encourage customer investments in renewable generation, beyond increasing the state's portfolio of clean energy more rapidly than if only utility-scale generation is used?

A: Yes. To achieve its climate goals in the building and transportation sectors, the state is depending on customers to make major future investments in other types of DERs – principally electric vehicles and electric heat pumps for space and water heating. The economics of these DERs require off-peak electric rates that are stable and low enough to make these new technologies economic.[10] Lower-income customers will require financial assistance and careful policy design to provide them with the opportunity to participate in the DER market. Customers' willingness to adopt these DERs will depend on their assessment of the equity, certainty, and stability of the Commission's ratemaking policies. Over a million California customers already have experience with significant

[9] The CPUC's GTSR page, at https://www.cpuc.ca.gov/GTSR/, notes that, as of September 2019, 163 MW of new renewables have been built to support the GTSR program. This is obviously a tiny fraction of the renewable capacity that has been deployed by the CCAs or through direct customer investment in rooftop solar.

[10] For example, assuming gasoline at $4.00 per gallon, a comparable gasoline vehicle with a fuel efficiency of 40 miles per gallon, and an EV that can go 3 miles per kWh of electricity used, the EV needs to be supplied with electricity priced at less than $0.30 per kWh to realize fuel cost savings over the gasoline vehicle (i.e. [$4.00/gallon / 40 mpg] x 3 mpkWh = $0.30 per kWh). Obviously, at lower gasoline prices, the rate for EV charging must be even lower to realize savings compared to gasoline.

investments in one type of DER – rooftop solar – and they will convey that experience – good or bad – to their friends and neighbors. How solar customers are treated in the NEM program therefore will shape not only their willingness, but all customers' willingness to invest in other DERs such as EVs and heat pumps. As a result, there are important public perception reasons for the Commission to treat customers who invest in distributed renewables equitably and consistently, so that they will continue to invest private capital in other types of DERs, and will encourage their friends and neighbors to do so as well. The benefits of positive customer engagement can be viewed through many lenses:

- **Synergies with other DERs.** Rooftop solar appeals to those who embrace the latest in technology. Interest in and early adoption of solar provides an entry into a host of other energy-saving and clean energy technologies, including technologies like EVs and heat pumps that will build load. Studies have shown that solar customers adopt more energy efficiency measures than other utility customers, which is logical given that it makes the most economic sense to add solar only after making other lower-cost energy efficiency improvements to your premises.[11] Further, if solar customers are allowed to offset their on-site usage with net metering or net billing, customers will retain the same incentives to save energy that they had before installing solar. These synergies will only grow as the need to make deep cuts in carbon pollution drives the increasing electrification of other sectors of the economy.

- **Equity for Disadvantaged Communities.** Lower-income customers in disadvantaged communities bear disproportionate burdens from both high energy costs and the health effects of pollution from fossil fuel combustion. These customers deserve to have the same opportunity as other customers – or, to make up for historical injustices and continuing environmental burdens,

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[11] See the *2009 Impact Evaluation Final Report on the California Solar Initiative*, prepared by Itron and KEMA and submitted in June 2010 to Southern California Edison and the Energy Division of the California Public Utilities Commission. See pages ES-22 to ES-32 and Chapter 10. Also available at the following link: http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=7677. Also see Center for Sustainable Energy, *Energy Efficiency Motivations and Actions of California Solar Homeowners* (August 2014), at p. 6, finding that more than 87% of solar customers responding to a survey had installed or upgraded one or more energy efficiency technologies in their homes. Available at https://energycenter.org/sites/default/files/docs/nav/policy/research-and-

a better opportunity – to improve their homes and communities with local sources of clean energy, and to use those resources to reduce and stabilize their energy bills. In urban environments, the logical resources that can be sited and used locally are distributed solar and storage systems.

- **Customer Engagement.** Customers who have gone through the process to make the long-term investments to install solar learn much about their energy use, about utility rate structures, and about producing their own energy. For example, historically NEM 1.0 customers in California elected time-of-use rates far more often than non-solar customers, without a requirement to do so. Given solar customers' long-term investments, they will remain engaged going forward. There is a long-term benefit to the utility and to society from a more informed and engaged customer base. As we have seen in the net metering debacle in Nevada in 2014-2015, this positive customer engagement can turn to customer "enragement" if the utility and regulators do not accord the same respect and equitable treatment to customers' long-term investments in solar and other DERs that is provided to the utility's investments in utility-scale generation.

- **New Competition.** Rooftop solar provides a competitive alternative to the utility's delivered retail power. This competition can spur the utility to cut costs and to innovate in its product offerings. With the widespread availability of rooftop solar, customer-sited storage, energy efficient appliances, and load management technologies, this competition will only intensify. In the now-foreseeable future, the combination of solar, storage, and load management could allow customers to "cut the cord" with their electric utility in the same way that consumers have moved away from the use of traditional infrastructure for landline telephones and cable TV – a result that would permanently balkanize the electric system into "haves" and "have-nots." This is a result that the Commission must have the foresight to avoid. Given the important long-term benefits that renewable DG can provide to the grid if customer-generators remain connected and engaged, it is critical for regulators and utilities to avoid alienating solar customers, who are among the customers most informed about utility rates and most concerned about the impacts of climate change.

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reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Ho

- **Self-reliance.** The idea of becoming more independent and self-reliant in the production of an essential commodity such as electricity, on your own property using your own capital, has deep appeal to Americans, with roots in the Jeffersonian ideal of the citizen (solar) farmer.

D. Cost-Effectiveness: Total Resource Cost Test

Q: Will it be cost-effective for the California electric system to continue to adopt policies that support the sustainable growth of DERs?

A: Yes. The basic cost-effectiveness test for DERs is the Total Resource Cost (TRC) test, which the Commission has affirmed repeatedly as the principal cost-effectiveness test for demand-side resources.[12] The TRC test measures whether the benefits of renewable DG to all customers and the electrical system approximately equal or exceed the costs of these facilities. Although the TRC is not impacted directly by the net metering tariff under which solar customers take service, the test does indicate whether these demand-side resources are beneficial to all ratepayers and the system as a whole. SEIA and Vote Solar have performed a forward-looking, life-cycle TRC analysis of distributed solar and solar-plus-storage systems. In the TRC test, the costs are the lifecycle levelized cost of energy (LCOE) from solar and solar-plus-storage resources. The benefits used in the test are the utilities' long-run avoided costs, also levelized over the life of the resources. Our proposal shows that distributed solar and solar-plus-storage resources will pass the TRC.

Q: What are the costs in the TRC Test?

A: The cost are the capital and operating costs for DERs, typically calculated as the 25-year levelized cost of energy (LCOE). We have used a pro forma cash flow analysis to project the 25-year LCOEs for residential solar and solar-plus-storage systems, with the key assumptions shown in **Table 1.**

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[12] See D. 09-08-026, at pp. 28-29; D. 19-05-019, pp. 19 and 24; and D. 21-02-007, at pp. 6-7.

Table 1: *Assumptions for the 25-year Levelized Cost of Residential Solar and Solar + Storage*

Assumption	Value
Solar Capital Costs, 2021-2030	LBNL *Tracking the Sun* 2020 data update, California Distributed Generation Statistics website
Federal ITC	26% through 2022, 22% in 2023, 0% thereafter
Solar output	NREL PVWATTS
Solar degradation	1.4% per year, per NEM 2.0 Lookback Study
Financing Cost	5%
Participant discount rate	8%, per NEM 2.0 Lookback Study
Inflation	2.2%
Financing Term	20 years
Inverter Replacement	$150 per kW-DC in Year 15
Maintenance Cost	$20 per kW-DC per year, per NREL 2020 ATB
Storage System Size	11.25 kWh
Storage Capital Cost	$750 per kWh
Storage Balance of Systems	25% of storage cost
Storage Incentive	($200 per kWh) – SGIP incentive
Storage Efficiency	85% (i.e. 15 % round-trip losses)

Q: Please comment on the noteworthy assumptions used to calculate these LCOEs.

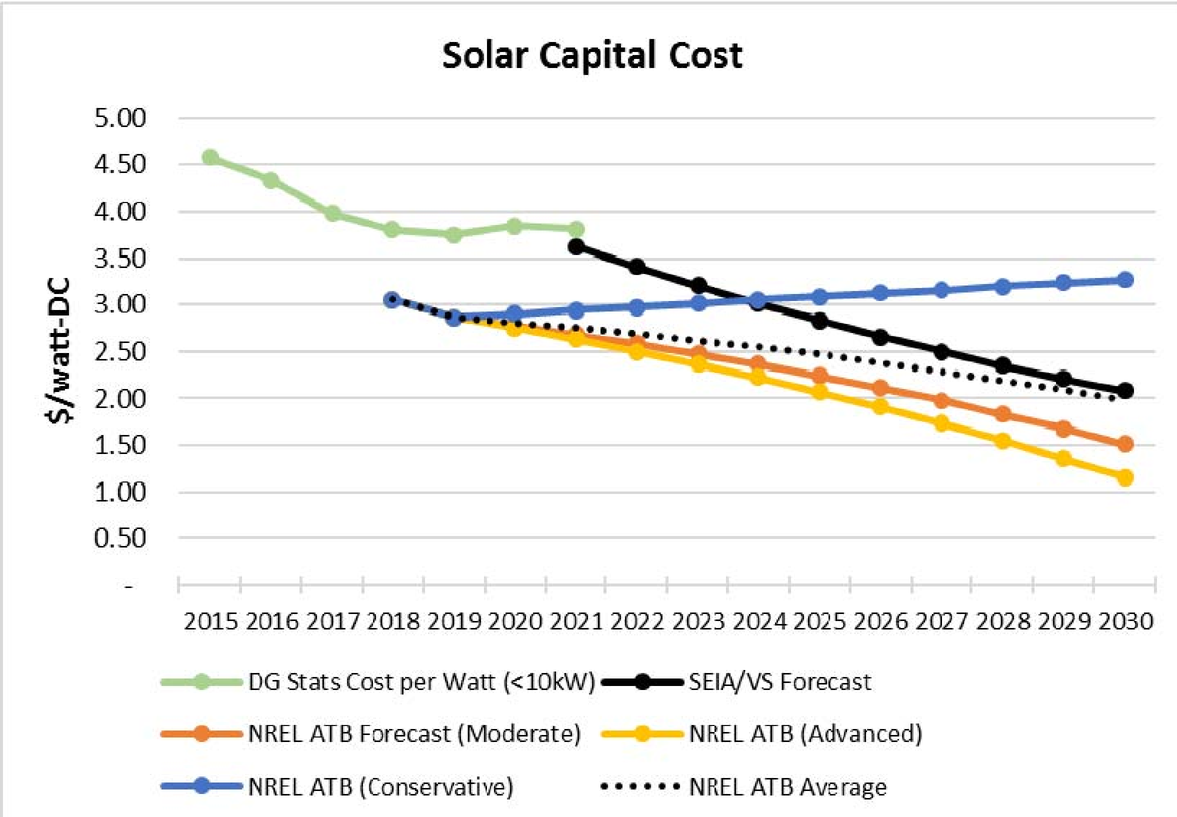
A: The key assumptions include:

- **Capital costs of residential solar** are derived from 2019-2020 actual costs reported in Lawrence Berkeley National Lab's (LBNL) 2020 data update for its annual *Tracking the Sun* reports[13] and in the California Distributed Generation Statistics website.[14] We assume that residential solar capital costs will decline at 6% per year through 2030, consistent with the historical trend in these costs.[15] Starting with recent historical costs from the California market and assuming future cost decreases in line with what the industry has achieved in the past produces, in my judgement, the most reasonable forecast of future solar costs. We have not used the cost forecasts in NREL's *Annual Technology Bulletin*, because NREL's forecast is not consistent with recent historical costs specific to California and it uses a "bottom-up" forecast by component that excludes site- and California-specific permitting and installation costs.[16] **Figure 1** compares our

[13] Available at https://emp.lbl.gov/tracking-the-sun.
[14] See https://www.californiadgstats.ca.gov/charts/, especially the "Cost per Watt" chart.
[15] See LBNL 2020 data update, at Slide 21.
[16] These issues with the *NREL ATB* forecast are discussed in more detail in the testimony of the California Solar & Storage Association. SEIA and Vote Solar are using a rate of decline in solar costs of

solar cost forecast to the recent actual cost data, and to the range and average of the *NREL ATB* forecasts. The figure shows clearly how the *NREL ATB* forecast starts well below recent actual solar costs in California.

Figure 1



- We keep **storage costs** flat at today's levels, given the uncertainty over the trajectory of future battery costs. This means that storage costs decline at 2.2% in real terms. We add a component equal to 25% of storage costs to cover the balance-of-system costs to adapt a residential customer's electric system to accommodate on-site storage.
- **Solar output** uses the industry-standard PVWATTS calculator from NREL, using these locations:
  - PG&E – San Jose
  - SCE – Riverside
  - SDG&E – San Diego

6% per year, which is consistent with the expected decline in solar costs in the *NREL ATB* forecast. See Figure 1.

- The NEM 2.0 Lookback study is the source for other important inputs such as the **degradation rate** for solar output and the solar customer's **discount rate**.

Q: How are the benefits in the TRC test calculated?

A: The principal benefits for ratepayers in the TRC are the utility costs that DERs avoid, as calculated in the 2020 Avoided Cost Calculator (ACC).[17] In D. 20-04-010, the Commission restructured the 2020 ACC to include key metrics from the IRP modeling used to develop the IRP's current CPUC-approved Reference System Plan (RSP). These metrics are taken from a No New DER case consistent with the RSP in which all of the demand-side resources included in the RSP are removed, and the case is re-run to replace those demand-side resources with additional supply-side generation. Thus, the 2020 ACC values DERs based on the costs of the supply-side resources that would be needed to replace them in the adopted RSP, plus the avoided transmission and distribution (T&D) costs to deliver that power. As a result, if a renewable DG resource is cost-effective using the 2020 ACC, that customer-generation will be less costly than supply-side resources. By assuming that DERs avoid utility-scale renewables plus avoided T&D, this structure for the ACC takes a significant step toward a common valuation method for both demand- and supply-side resources. This addresses the common complaint that distributed renewables should not be installed because they are more expensive than comparable utility-scale plants. The 2020 ACC includes hourly avoided costs over the period 2021-2050, allowing an assessment of avoided costs over the 25-year economic lives of distributed solar and solar-plus-storage systems.

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[17] This testimony uses the avoided costs from the 2020 ACC that the Commission approved in D. 20-04-010 and Resolution E-5077, after a fully-litigated major update to the ACC. On May 3, 2021, the Energy Division circulated Draft Resolution E-5150 containing a draft 2021 ACC proposing what was supposed to be a minor update to the ACC. SEIA and Vote Solar believe that the draft 2021 ACC is based on substantial changes to modeling methods that amount to an impermissible major update to the ACC. Further, the process to develop the draft 2021 ACC did not follow the process that the Commission established for minor updates to the ACC in D. 19-05-019. SEIA and Vote Solar have expressed these substantive and procedural concerns in their comments on Draft Resolution E-5150.

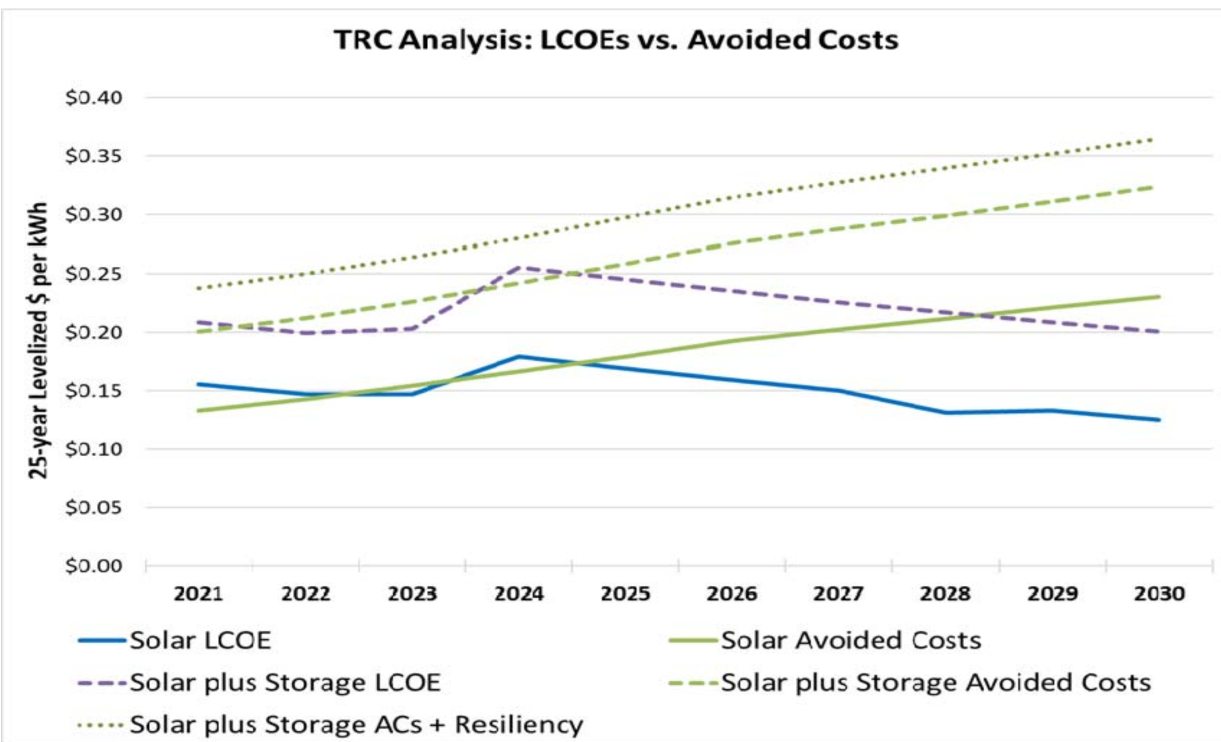
Q: Are there additional benefits specific to particular resources?

A: Yes. Solar-plus-storage systems also provide resiliency benefits to the electric system. The electric system includes not just the power grid, but also the means that customers use to obtain backup power when the grid is down. Solar-plus-storage systems provide ratepayer benefits both when the electric grid is operating and when it is down. The last several years have demonstrated that the IOU-owned grid is not capable of providing 100% reliable service 100% of the time, given today's climatic conditions – be it more frequent hurricanes and tornados, prolonged cold spells such as Texas experienced in February 2021, or the recent Public Safety Power Shut-offs during California's wildfire season. In the world of more extreme weather that we are living in and must adapt to, resilient on-site backup systems benefit all ratepayers by maintaining essential electric service to critical public safety, health, and welfare services. They allow essential economic activities to continue and provide a long-term foundation for more resilient neighborhoods. In a "black sky" event such as an earthquake or PSPS that disrupts the power grid for an extended period, customers without backup will benefit from the fact that several of their neighbors and the local community center have electricity from on-site solar-plus-storage systems. Consistent with the direction provided by Decision 20-04-020 that "consideration of the benefits of grid services provided by specific distributed energy resources should be addressed in resource-specific proceedings," SEIA and Vote Solar have provided as **Attachment B** to our proposal a discussion and quantification of the resiliency benefits of solar-plus-storage systems, Further, these systems also may benefit the electric system by avoiding direct ratepayer costs. California utilities have sought the Commission's approval to spend millions in ratepayer dollars to deploy fossil-based micro-grids to enhance resiliency; these represent ratepayer costs with significant environmental impacts that potentially are avoidable by solar-plus-storage systems installed by individual customers. For these reasons, we have also calculated TRC results for solar-plus-storage systems that include resiliency benefits.

Q: What are the results of your TRC calculations?

A: **Figure 2**, reproduced from our proposal, shows the results comparing, in each year from 2022 to 2030, the 25-year levelized LCOEs for solar (solid blue line) and solar-plus-storage (dashed purple line) systems installed in that year to the 25-year levelized benefits over the same 25-year period (green lines). The LCOEs generally decline due to expected decreases in the capital costs for solar, except in 2024 when the expiration of the federal investment tax credit (ITC) for residential solar causes the LCOEs to rise. The dotted green line shows the benefits for solar-plus-storage systems including the quantifiable resiliency benefits. Generally, distributed solar and solar-plus-storage systems pass the TRC test, by increasing margins over time as their costs fall and their benefits increase. The average TRC ratio of benefits to costs over the period is 1.30 for solar and 1.23 for solar-plus-storage. With the resiliency benefits included, the TRC score for solar-plus-storage increases to 1.41.

Figure 2



E. Societal Benefits

Q: Do distributed solar and solar-plus-storage systems also produce quantifiable societal benefits that are not included in the benefits you have used in this TRC analysis?

A: Yes, they do.

Q: Please characterize the quantifiable societal benefits of distributed solar and solar-plus-storage systems.

A: It is useful to group the societal benefits of these systems into two broad types. The first group includes **the societal benefits that also are produced by utility-scale solar generation**. These include:

- **Health benefits from reductions in criteria air pollution.** Renewable generation displaces natural gas use, thus lowering emissions of criteria air pollutants (NO_x, SO_x, and particulates). Improved air quality has significant health benefits, particularly for disadvantaged communities located near sources of fossil generation.
- **Avoided out-of-state methane leakage.** The ACC includes a direct avoided cost to capture the ability of renewable generation to avoid methane leakage that occurs from the production and transportation of natural gas upstream of the gas-fired power plants that produce electricity on the margin. This leakage can be avoided when gas use for electric generation is reduced. However, in the ACC this component is limited only to leakage from the 9% of the state's gas supplies that are produced in California and that are in the official CARB inventory of the state's GHG emissions. Clearly, there is a broader societal benefit from reducing methane leakage from the other 91% of the state's gas supplies that are produced out-of-state, but transported to and burned in California.
- **Reduced damages from climate change.** The ACC includes a GHG "compliance" component based on the costs of developing, building, and operating new renewable generation and storage to meet California's climate goals for the electric sector. We the citizens of California will be spending

that money because the estimated damages from unmitigated climate change are far higher. These damages from climate change have been quantified as the "social cost of carbon" (SCC). The societal benefit from mitigating climate change impacts is the difference between the SCC and the GHG compliance costs in the ACC.

- **Avoided water use.** Renewable generation displaces generation from thermal power plants, most typically gas-fired, and thus lowers the consumptive use of water for cooling those thermal plants. Water is a scarce resource in California. Conserving water in the electric sector through the use of renewables lowers the vulnerability of the electricity supply to the availability of water, and reduces the possibility that new water supplies will have to be developed to meet growing demand.

The second type of societal benefit is those that are **specific to distributed solar systems**, and not applicable to utility-scale renewables. These include:

- **Land use benefits.** Distributed solar can be installed in the built environment, on the customer's premises. This has the societal (environmental) benefit of avoiding the land use impacts of utility-scale solar or wind generation. As discussed above and in Attachment A of our proposal, in the long run there may be land use constraints on utility-scale development of renewables – not only in developing the solar or wind farms themselves, but also in siting the new high-voltage transmission needed to deliver that power from remote utility-scale plants.

- **Local economic benefits.** Clean distributed generation has higher costs per kW than utility-scale renewables. However, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. Utility-scale, central station power plants have significantly lower soft costs, per kW installed, and typically are not located in the local area where the power is consumed**.**

Q: For the societal benefits that also can result from utility-scale renewables, please discuss the extent to which distributed solar and solar-plus-storage systems will

produce incremental benefits of this type, beyond what California's active program to develop utility-scale renewables will produce.

A: Distributed resources will produce incremental societal benefits of the first type, beyond those provided by utility-scale renewables. There are several ways to recognize this.

First, the state's RPS program provides the statutory requirements for load-serving entities (LSEs), including the IOUs, to procure new utility-scale renewables. The annual RPS requirement is a set percentage of an LSE's retail sales, such as 33% in 2020. New customer-sited renewable generation reduces the LSE's sales, and thus reduces the LSE's RPS requirement by the required RPS percentage for that year times the annual output of the new customer-generation. But for the electric system as a whole, new distributed solar produces a net gain in renewable generation beyond just the RPS requirement, because the customer-generation is 100% renewable. For example, if the utility was required to procure RPS renewables equal to 33% of its sales in a year (2020), a customer with a net-metered solar system producing 10,000 kWh in 2020 would reduce the utility's sales by that amount, allowing the utility to avoid 3,333 kWh of additional RPS generation in 2020.[18] But the electric system as a whole would see a net gain of 6,667 kWh of renewable generation in that year (the 10,000 kWh of customer-generation less the 3,333 kWh of avoided RPS generation). This represents an additional investment in California's clean energy infrastructure from a new source of capital – customers. The customer-generation should be credited with the full societal benefits for this additional 6,667 kWh of clean energy. The decade from 2020 to 2030 is bookended by RPS goals of 33% in 2020 and 60% in 2030; from 2023 to 2030 the average RPS requirement is close to 50%. So, from this perspective, 50% of distributed renewable generation under

[18] Historically, past studies of NEM in California have recognized this benefit of rooftop solar. For example, the *2010 NEM Cost-effectiveness Evaluation*, at p. 18, noted that "… any reductions to total retail sales will reduce the required supply of renewable energy to remain compliant with the [33%] RPS target." This also was the default assumption in the "Public Tool" model built to evaluate the cost-effectiveness of NEM 2.0 proposals in R. 14-07-002.

the NEM 3.0 program will produce the same societal benefits as RPS-qualified, utility-scale renewables.

Another perspective on this question recognizes that, in recent years, the IRP planning models indicate that just meeting the RPS requirement alone will not be adequate to reach the state's GHG goals. In the RESOLVE modeling for the first two IRP cycles, the key constraint has not been meeting the RPS requirement, but achieving the state's GHG targets for the electric sector in 2030 and 2045. From a GHG perspective, a kWh of distributed solar produced at a particular time has the same impact in reducing emissions as a kWh of utility-scale renewable generation produced in the same hour. When a customer installs a distributed solar system, that output will avoid the need for a comparable amount of utility-scale generation, in terms of reaching the state's future GHG goals. From this perspective, 100% of distributed customer-sited renewables provide the same societal benefits as the same quantity of utility-scale renewables.

Q: But if customers fail to develop distributed renewables, won't the state and LSEs simply step in to procure more utility-scale renewables?

A: Not necessarily. Today, the RSP adopted in the IRP assumes that customers will install a certain amount of distributed solar and other DERs over the forecast period, and generally the supply-side, utility-scale procurement targets for LSEs follow the need assessment in the IRP that assumes those forecasted DERs will be installed.[19] The state is not procuring new utility-scale resources based on an assumptions that DERs will not materialize. For example, the Commission is not authorizing procurement based on the IRP's No New DERs scenario. The constraints on the siting of utility-scale generation, as discussed above and in Attachment A of our proposal, indicate that there are serious

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[19] For example, the Commission recently released proposed and alternate decisions in the IRP docket R. 20-05-003 authorizing mid-term procurement through 2026. Both of these proposed orders cite the amount of utility-scale resources in the RSP adopted in D. 20-03-028 as support for the adopted level of mid-term procurement. See, for example, the Alternate Proposed Decision of Commissioner

questions about the feasibility of reaching the state's climate goals without DERs. As a result, today DERs provide incremental societal benefits – comparable to an equivalent amount of utility-scale renewable generation – that would not necessarily be provided in their absence.

Q: Did you consider whether there are societal <u>costs</u> associated with DER adoption?

A: Yes, I did. One societal cost might be the drag on the California economy if DERs result in higher costs for electric service, depressing economic activity. I observe that the TRC test largely resolves this concern. It indicates that the costs to install and operate distributed solar and solar-plus-storage systems are less than the direct costs on the electric system that will be saved or avoided as a result of these resources. This indicates that the cost of electric service (both when the grid is operating and when it is not) will be lower with a robust program for customers to install distributed solar.

Q: Have you quantified the societal benefits of distributed solar and solar-plus-storage systems that you expect to be installed under the NEM 3.0 program?

A: Yes, I have. **Attachment RTB-3** discusses in detail how I quantify each of the above societal benefits. Using those quantifications, the NEM 3.0 column of **Table 2** shows my calculations of the annual value of the societal benefits from the distributed solar and solar-plus-storage systems that I expect to be installed in each year from 2023-2030, if our NEM 3.0 proposal is adopted. These benefits are presented in terms of annual dollars levelized over the 25-year lives of these systems. Table 2 also shows the similar societal benefits from the existing NEM 1.0 and 2.0 systems already in place; these societal benefits from NEM 1.0 and 2.0 systems are relevant to my discussion in Section VI.A and Attachment RTB-4 of the "cost shift" arguments of certain parties.

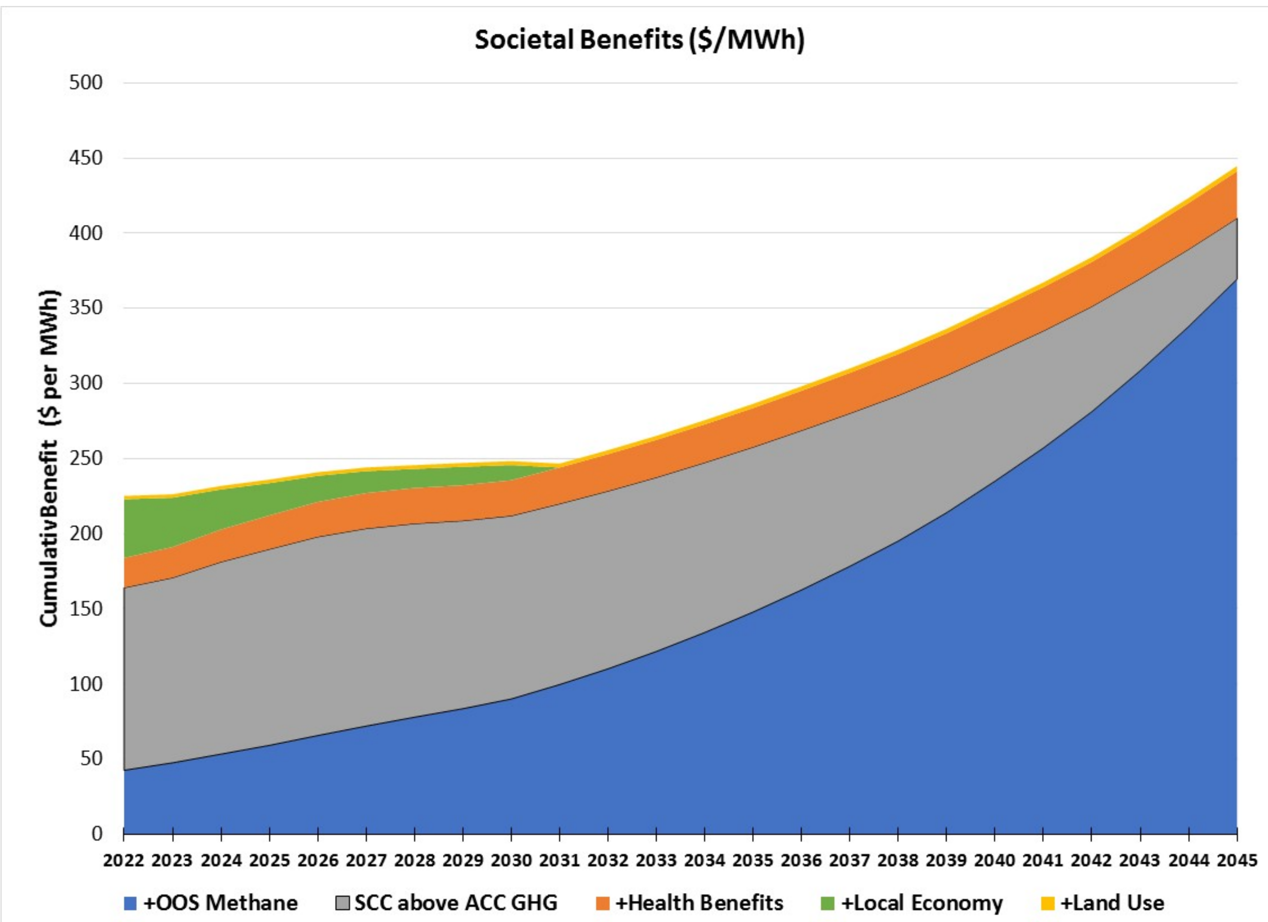
Rechtschaffen, at pp. 14-15 and 25-26.

Table 2: *Societal Benefits (25-year Levelized $Millions per year)*

Benefit	**NEM 1.0**	**NEM 2.0**	**NEM 3.0**
Period analyzed	*2021 to 2045*		*2023 to 2047*
Methane Leakage	$465	$1,161	$1,949
SCC (above ACC)	$640	$1,224	$1,234
Health Benefits	$123	$253	$308
Local Jobs	-	$117	$238
Land Use	$13	$27	$30
Total	**$1,358**	**$2,903**	**$3,796**

Figure 3 shows the societal benefits expressed in terms of $ per MWh of distributed solar output, broken down by the contribution of each benefit to the total.

Figure 3



Q: How should the Commission use these societal benefits in its deliberations in this case?

A: First, there is always likely to be issues with the long-term calculation of the direct costs and benefits of DERs. One example may be the significant (and as yet unresolved) differences in direct benefits between the adopted 2020 ACC and the draft 2021 ACC.[20] Within this range of debate over the direct benefits, the Commission must design a NEM 3.0 program whose costs are balanced by the benefits. Knowing that distributed solar also will provide major societal benefits in addition to the direct benefits, the Commission can have confidence adopting a NEM 3.0 compensation structure that is fair to all stakeholders, that reasonably balances costs with benefits given the uncertainties, and that allows the DER market to grow sustainably to meet the state's climate goals.

Second, quantifying the societal benefits provides an important indication of the relative magnitude of the different kinds of societal benefits, and it helps to avoid assigning too little (or too much) weight to benefits if they are considered only qualitatively.[21] Because calculating the value of these benefits is complicated or unfamiliar to the Commission does not mean that they should be ignored. Failing to consider these benefits for such reasons effectively assigns them a value of zero. The Commission always retains the discretion to weigh these quantifications as it sees fit.

Third, the Commission has a long-run goal of internalizing these benefits more formally into a Societal Test that starts with the TRC, then adds quantified societal benefits.[22]

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[20] As noted in Footnote 17 above, SEIA and Vote Solar strongly support the use of the fully-litigated, Commission-approved 2020 ACC, and have made clear their procedural and substantive concerns with the draft 2021 ACC in their comments on Draft Resolution E-5150.

[21] For example, my quantification of the societal benefits of distributed solar shows that the water benefits are small compared to the climate and health benefits.

[22] In D. 19-05-019, the Commission announced that staff would be testing elements of a Societal Test on both demand- and supply-side resources in 2020, and that a final evaluation report on this testing

Finally, independent of this process for the formal development of a Societal Test, important cases such as this one will continue to raise issues that require the Commission to assess the significant societal benefits of DERs and other clean energy resources. As noted above, for the Commission to ignore these benefits effectively assigns them a value of zero, which I do not believe is consistent with the underlying goals of California's clean energy policies. I respectfully recommend that this case provides an important opportunity for the Commission to engage in "learning by doing" in this area. The Commission often considers these societal benefits qualitatively in its decision-making, and the use of quantifications can help to sharpen and focus the Commission's deliberations on these benefits.

F. Sustainable Growth Requires Reasonable Economics for Participants

Q: What are the key cost-effectiveness metrics that the Commission should consider to ensure that distributed renewable generation continues to grow sustainably?

A: The key metrics are those that examine the economics for participating customers – the Participant Cost Test (PCT) and other metrics such as the payback for the customer. The PCT test is the ratio of the levelized, lifecycle bill savings divided by the LCOE of the resource. There also are a variety of payback measures – for example, the simple payback is the ratio of the capital costs divided by the year-one bill savings.

The PCT analysis for our proposal shows that the PCT results are significantly lower than the ratio of 1.8 for NEM 2.0 reported in the Lookback Study.[23] After the federal ITC drops to zero for residential customers in 2024, the PCT ratios for our proposal are in the range of 1.4 to 1.5. I calculate that simple paybacks in 2024 will average 8 years for solar-only, and over 10 years for solar-plus-storage. These lower

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would be available by mid-2021. See D. 19-05-019, at pp. 36-27. I do not know whether this work is on schedule.

[23] See page 7 and Tables 1-2 and 5-4.

PCT ratios and longer 8- to 10-year paybacks, compared to NEM 2.0, will present challenges for the industry, particularly for solar-plus-storage systems that require a larger upfront investment.

Q: Do you have significant concerns with the economics for participants under some of the other parties' proposals?

A: Yes. Many proposals in this case do not examine in detail the impacts of their proposals on participant economics or customer adoption. For example, the IOU proposal includes no PCT results, and a single table of simple paybacks that are 11-15 years for solar and 10-13 years for solar-plus-storage. The IOU paybacks are based on forecasted solar costs from the NREL ATB. For the reasons discussed above, these costs are too low, and thus the stated paybacks are too short. NREL's forecasted costs in 2021 are well below today's reported costs in the California market. The IOUs also assume a cash purchase of the system, which is an option available mostly to wealthier customers who can afford the initial cash outlay and pay enough taxes to take full advantage of the ITC. Paybacks are significantly longer if financing costs are included. The analysis from the Commission's consultant Energy & Environmental Analysis (E3) provided on May 28 also uses the NREL ATB data and assumes a cash purchase, but even with these too-low costs E3 reports that the IOU proposal for PG&E has a PCT score of 0.58 and simple paybacks for non-CARE customers of 21.0 years for solar and 16.7 years for solar-plus-storage.[24] Customers are not going to invest in solar or solar-plus-storage at simple paybacks of this length. These issues are discussed in more detail in Section IV.D below.

Q: Are there other issues with the proposals of the IOUs and other parties that bear on customer adoption?

A: Yes. The IOUs, the Public Advocates Office (PAO), TURN, and NRDC proposals for residential customers share several common elements: first, a fixed monthly grid access charge (GAC) in $ per kW based on the nameplate kW capacity of the system, and, second, an export rate that is much lower than the retail rate. Solar customers who install a small system relative to their usage will use most of the solar generation on-site, with little exported. Most of the customer's savings will be from offsetting their on-site use at the retail rate. But as the size of the solar system increases, the customer will export an increasing percentage of their solar output, at the low export rate. However, the fixed monthly grid access charge also will increase as the system size grows. As a result, at larger system sizes, the solar customer will realize few, if any, incremental savings, because the increased compensation from the low export rate is entirely offset by the growing fixed charge. The result of this structure is effectively to place an economic cap on the size of systems at just a fraction of the customer's annual usage.

Q: Can you provide an example of this?

A; Yes. **Figure 4** below plots the bill savings from the IOU proposal for PG&E as a function of system size in 10% increments, using the SEIA/Vote Solar bill savings models. With costs of $0.15 per kWh for solar and $0.20 per kWh for solar-plus-storage,[25] the figure shows that system sizes over 50% of usage will not be economic under PG&E's proposal.

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[24] See E3's May 28, 2021 report entitled "Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020" (May 2021 E3 Report), at pp. 19, 21.

[25] These are the 25-year LCOEs for solar and solar-plus-storage used in the TRC test discussed in Section III.D above.

Figure 4

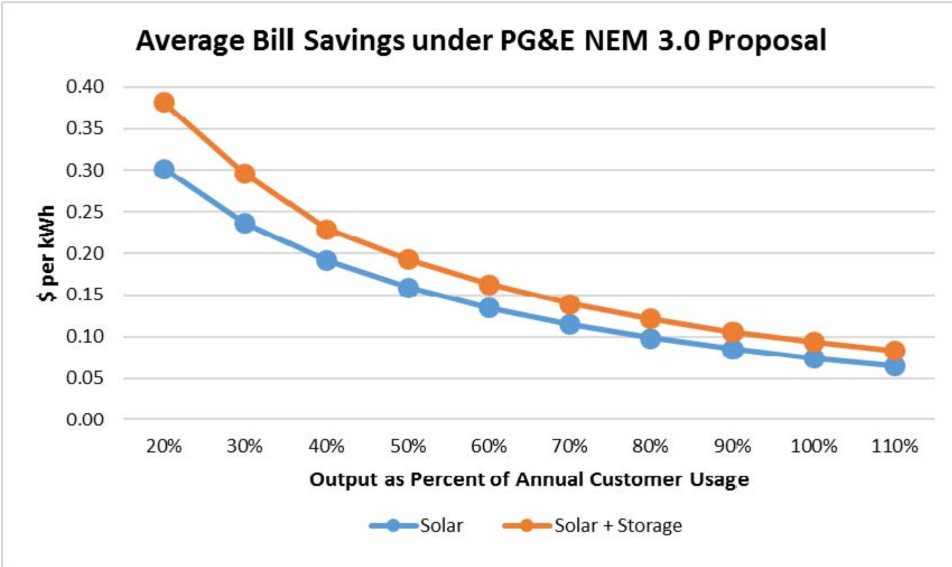
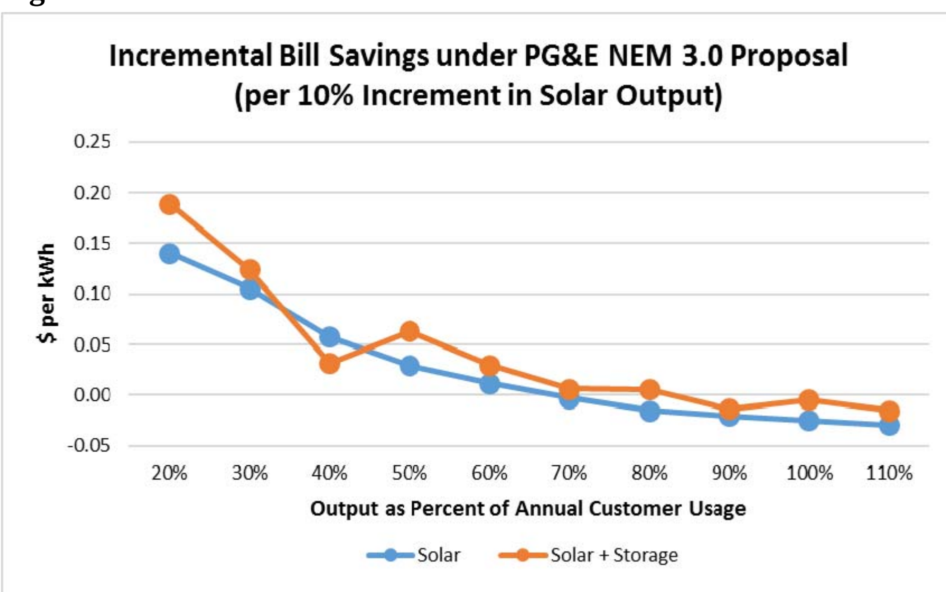


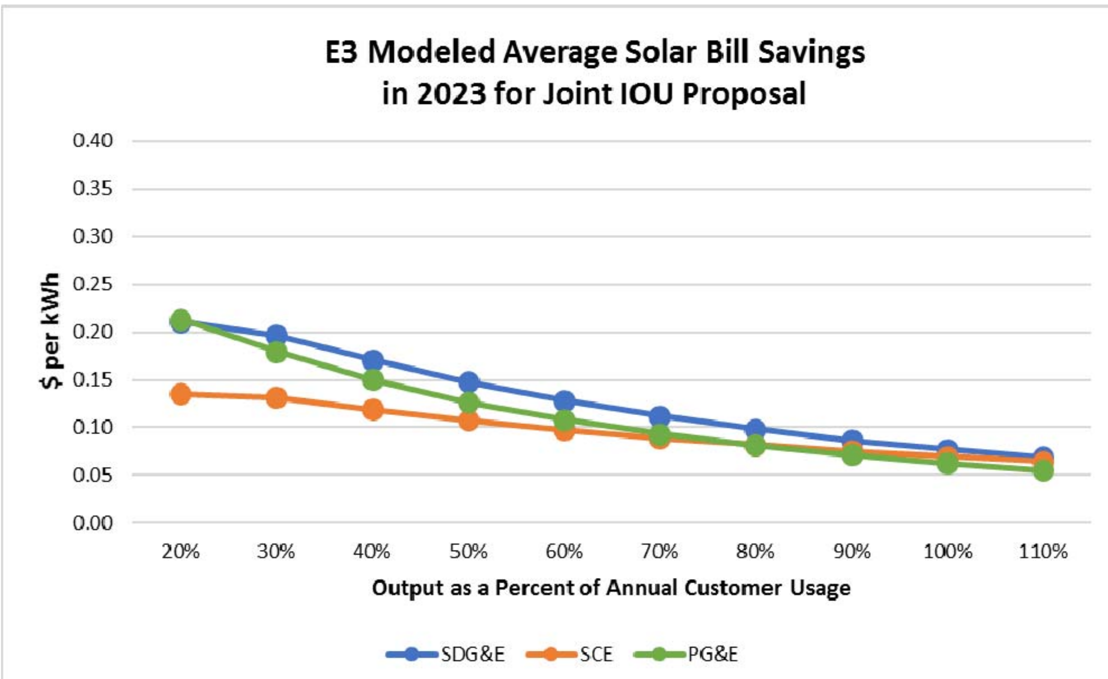
Figure 5 provides another way to look at this issue; it calculates the marginal bill savings as usage increases in 10% increments. The figure shows that there are little incremental savings once the system size is over about 30% of usage.

Figure 5



Finally, we have done the same analysis shown in Figure 5 for all three IOUs for solar systems in 2023, using the E3 model released on May 28, 2021.[26] **Figures 6 and 7** show the average and incremental bill savings for solar in 2023 for each of the IOU proposals, using the E3 model.[27] Again, using the E3 model we obtain the same result as our own bill savings model – under the IOU proposal, system sizes over 50% of usage will not be economic.

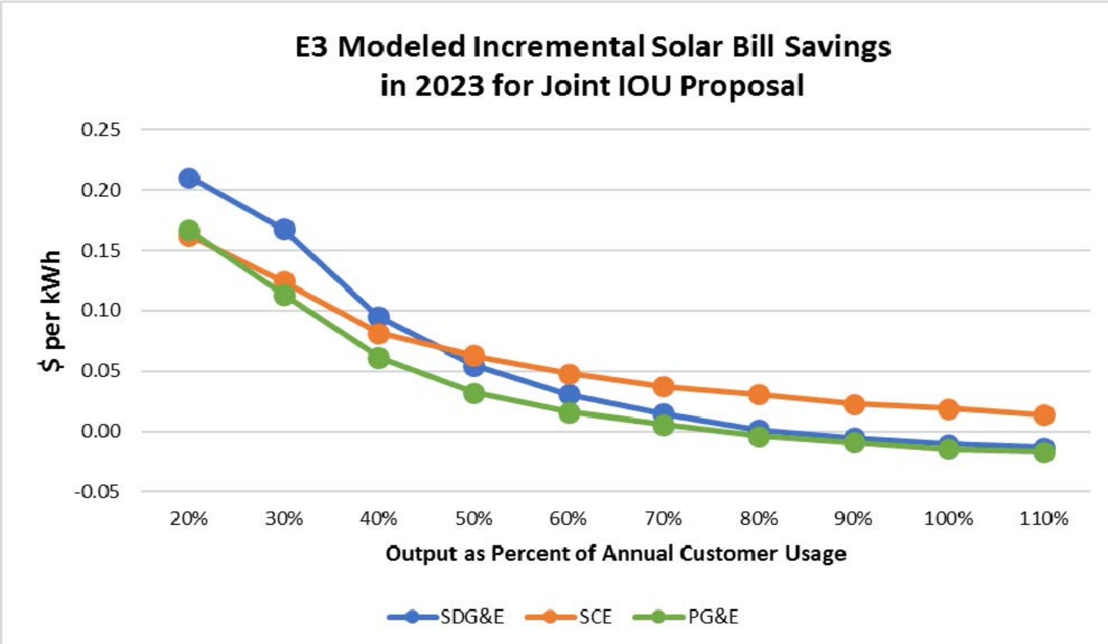
Figure 6



[26] The model in the May 28 E3 Report does not allow storage system sizes to be easily scaled along with solar system sizes, so we were not able to show solar-plus-storage savings as a function of system size.

[27] E3's analysis of bill savings for SDG&E under the IOU proposal shows significantly higher bill savings than the other IOUs' proposals. This is due to the customer realizing substantial savings simply by switching from the TOU-DR1 residential default rate to SDG&E's proposed TOU-DER rate, even without adding solar. Therefore, we are using the SDG&E TOU-DER rate as the counterfactual, pre-solar rate in order to focus the analysis on the impact of adding solar. This does not appear to be an issue for PG&E or SCE in the E3 model.

Figure 7



Under NEM 2.0, residential customers have been installing systems sized, on average, to 90% to 100% of their usage. Because this structure – using a fixed GAC based on system size – will limit the economic size of solar and solar-plus-storage systems, it would place a significant new restriction that is likely to limit the growth of the market to a fraction of what it has achieved in recent years.

Q: TURN has proposed a variation on the IOUs' structure that seeks more directly to measure a solar customer's behnd-the-meter usage, either through additional metering or engineering calculations. Does TURN's proposal also result in declining incremental bill savings as system size increases?

A: TURN's proposed structure would produce very low bill savings across all system sizes, as shown in **Figures 8 and 9**, which use the E3 model to calculate average and incremental bill savings as a function of system size for the TURN proposal. TURN's proposal would make solar systems of any size uneconomic.

Figure 8

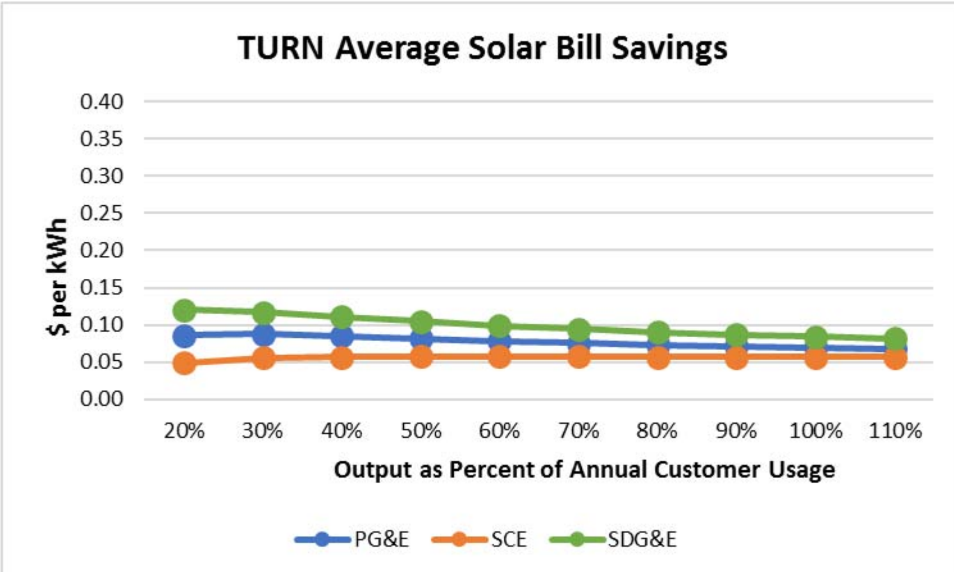
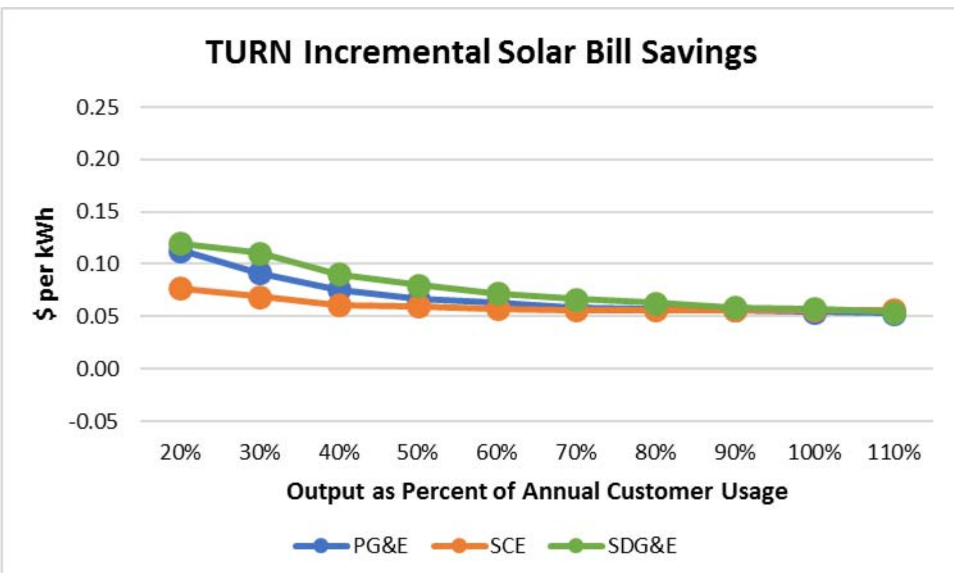


Figure 9



IV. KEY ELEMENTS OF THE SEIA - VOTE SOLAR SUCCESSOR TARIFF FOR RESIDENTIAL CUSTOMERS

Theme: Residential NEM 3.0 tariff. The successor tariff for residential customers should be updated from the NEM 2.0 tariff, for the four reasons discussed below.

Statutory: [Section 2827.1(b)(1)] Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities. [Section 2827.1(b)(4)] 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.

CPUC Principles: A successor to the net energy metering tariff should…

- be coordinated with the Commission and California's energy policies,
- maximize the value of customer-sited renewable generation to all customers and to the electrical system, and
- ensure equity among customers.

Q: What are the key considerations that inform the design of your proposed successor tariff for residential customers?

A: The key design elements are:

1. Increase access for low-income customers
2. Encourage beneficial electrification
3. Support adoption of solar-plus-storage systems
4. Re-align the participant/non-participant balance

I discuss each of these elements in more detail below.

A. Increase Access for Low-Income Customers

Q: Why is it important to increase customer access to DERs, including customer-sited generation?

A: All ratepayers should be able to be participants and investors in the full range of DERs, including DERs that produce power, that shift or store energy, or that substitute electricity for more polluting fuels. Moving towards more equitable access to DERs should be a focus in addressing concerns with the balance of equities between participants and non-participants, by ensuring that all customers can participate in beneficial electrification.

Q: What are the key elements of a successor tariff that will help to increase access?

A: There are several key problems that must be addressed to support increased access to distributed solar and storage. First, low-income CARE customers receive a substantial 35% discount on their retail rates. As a result, they realize lower bill savings when they install solar. Second, although there has been significant penetration of solar among customers of all income levels (including 5% of CARE customers), adoption is skewed toward higher-income customers.[28] Low-income customers that do not qualify for CARE also would benefit from additional bill savings. The Vote Solar – Sierra Club – GRID Alternatives proposal for ESJ ratepayers, as set forth in the testimony of Stephen Campbell, addresses both of these issues. For example, the proposal is designed to equalize bill savings between (1) residential customers with discounted rates and (2) general market customers on non-discounted rates. This will address a key disincentive to NEM participation currently faced by CARE and FERA customers – the lack of comparable bill savings compared to general market customers.

[28] See Figure 3-6, at page 33 of the Lookback Study, at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M360/K524/360524821.PDF.

B. Encourage Beneficial Electrification

Q: Please discuss the importance of your proposal to require NEM 3.0 customers to take service on an electrification rate.

A: This element will integrate the NEM 3.0 program with the state's efforts to encourage beneficial electrification. California needs customers to make long-term investments in multiple DER technologies, if it is to displace fossil fuel use in transportation and buildings, and if the state is to respond to the demand for more resilient electric service. Some DERs will increase the use of energy from the grid (EVs and heat pumps); some will reduce it (solar); some will shift it in time (storage). In the long-term, the net result of DER adoption will be a major gain for the electric industry, as clean electricity increases its share of primary energy demand, displacing natural gas, gasoline, and diesel. **Table 3** below compares California's sources of primary energy in 2010 and 2050 if the state's GHG goal is to be achieved; this projection is taken from a prominent academic study used in a California Air Resources Board (CARB) update to its AB 32 Scoping Plan.[29] By 2050, electricity will replace a significant portion of today's fossil fuel use, in transportation, industry, and buildings. Electricity is the one primary energy source that continues to grow between 2010 and 2050 at a rate of growth consistent with past levels, about 1.3% per year. The percentage of renewable generation in 2050 will need to exceed the current RPS goal of 60% renewable generation by 2030. Another similar study projects that California's electricity supply will have to double from 2020 to 2050 (an annual growth rate over 2% per year), with RPS-eligible renewable resources constituting about 80% of the electricity supply in 2050.[30]

[29] Source: J.H. Williams et al., "The Technology Path to Deep Greenhouse Gas Emission Cuts by 2050: the Pivotal Role of Electricity," *Science* 335, 53 (2012), at Table 1. Other such studies are listed and discussed in the CARB's *First Update to the Climate Change Scoping Plan* (May 2014), at pp. 32-33, footnote 61, available at http://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm.

[30] S. Yeh and C. Yang, *Modeling Optimal Transition Pathways to a Low Carbon Economy in California: Results from CA-TIMES v1.5 Energy System Model and Implications for Policymakers* (University of California, Davis), presented at the CARB Research Seminar, May 1, 2014, at Slides 19 and 27.

Table 3: *California Primary Energy Sources, 2010 vs. 2050*

Primary Energy (Exajoules)	**California 2010**		**California 2050**	
Direct Fossil Fuel Use	5.59	*64%*	0.94	*14%*
Direct Biofuel Use	0	*0%*	0.73	*11%*
Electricity	3.11	*36%*	5.14	*75%*
% Renewable	***Less than 20%***		***Up to 74%***	
Total all fuel types	8.70	*100%*	6.81	*100%*

Q: What does the fact that "the pie is growing" for electricity mean for the Commission's approach to electrification?

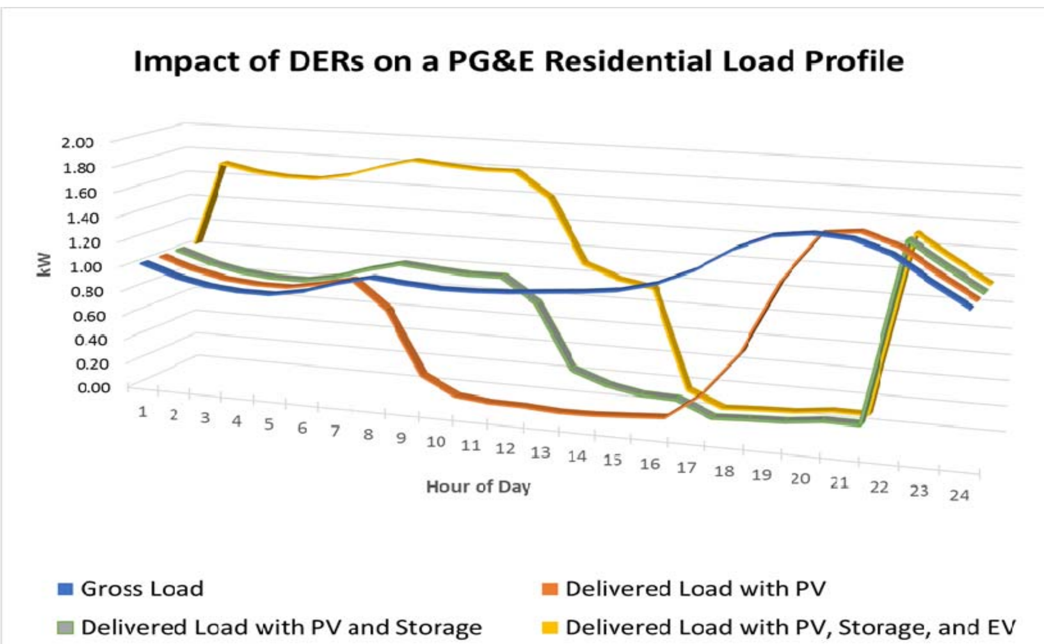
A: The wrong way to electrify is to discriminate against certain types of DER customers by imposing rate design elements that other DER customers do not face. For example, the Commission should not impose new fixed or grid access charges (GACs) on customers who adopt DERs that produce or time-shift a portion of power use, on the grounds that non-DER customers must be held harmless for that choice through strict application of the RIM test. When DER customers increase usage by purchasing EVs or heat pumps, the Commission does not require non-participants to compensate those DER customers for all of the benefits of that incremental electric use – instead, non-participants realize those benefits. The Commission does not require customers who reduce their usage through energy efficiency to compensate other customers for that loss, and the same approach should be used for solar. Overall, electric use will be expanding, so in the end the growth of all types of DERs will benefit ratepayers. This will be particularly true if all ratepayers have equitable access to DERs. The GACs proposed by the IOUs, PAO, and TURN simply will drive customers away from solar and storage DERs, even though solar provides the less-expensive, on-site, off-peak clean power needed to supply other types of DERs, and storage addresses the state's critical needs for peak capacity and improved resilience.

The reasonable way to electrify is to increase access to all DERs for all customers, and to use a simple, technology-neutral TOU rate platform for all customers and all types of DERs. The equity, simplicity, and certainty of this approach is necessary to stimulate customer confidence and encourage their long-term investments in all of these technologies.

Q: Can you provide an example comparing the benefits of the SEIA – Vote Solar proposal for a residential customer that is pursuing beneficial electrification, compared to the IOU proposal?

A: Yes. Our proposal includes an example of how the load profile for a typical residential customer of PG&E will change as that customer adopts different DERs in succession. See Figure 5 from the VS/SEIA proposal, reproduced below as **Figure 10**.

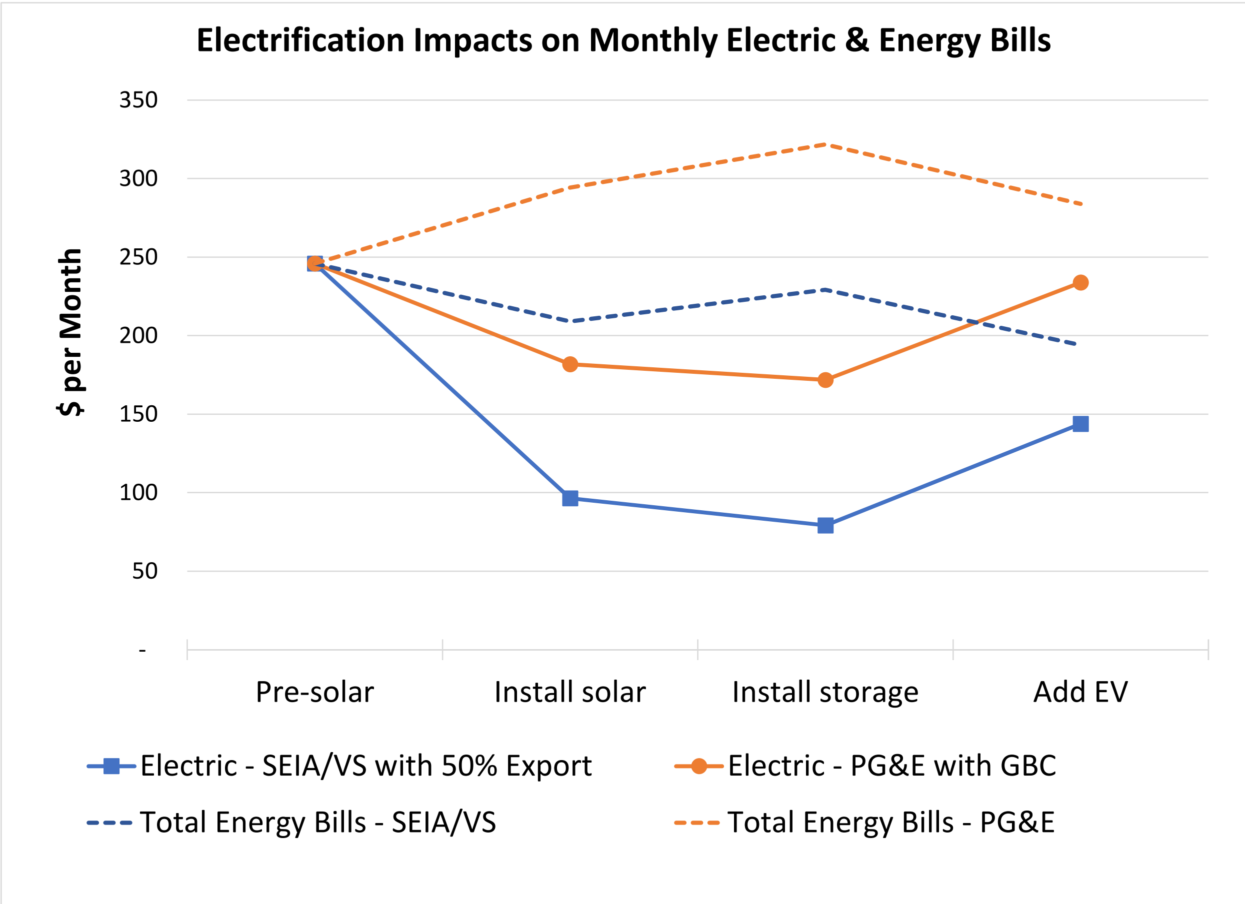
Figure 10



We have calculated monthly bills for this representative PG&E customer as the customer adopts solar, then storage, then an EV, under both the SEIA/VS (blue line) and PG&E

(orange line) proposals. See **Figure 11**. The solid lines in the figure show the customer's monthly electric bills; the dashed lines show the customer's total energy bill including both the capital and operating costs of the solar and storage. The costs after purchasing the EV include the monthly savings on gasoline for the customer, assuming that the customer purchased the EV instead of a fossil-fueled vehicle equivalent to the EV.[31] The figure shows that this customer's total energy bills increase by 15% under the IOU proposal, while they decrease by 21% under the SEIA – Vote Solar successor tariff.

Figure 11



[31] We used the same assumptions for electric vehicle adoption presented in Footnote 10 above. The fuel savings are about $100 per month, offset by $62 to $65 in incremental electric use to charge the EV.

Q: Are there other elements of your proposal that are important to encourage electrification?

A: Yes. The SEIA-Vote Solar proposal includes allowing up to 50% oversizing of solar and solar-plus-storage systems, with a reform of the rate for net surplus compensation so that it is set equal to current avoided costs for DERs. This will facilitate beneficial electrification over time, by allowing solar customers to grow their loads gradually over time, as their personal finances permit. Because the net surplus generation is compensated at current avoided costs, this temporary, short-term excess production will not burden other ratepayers. Because current avoided costs will fluctuate, and it is uncertain whether they will be adequate to cover the full solar system costs over time, customers who oversize their systems will retain a strong incentive to make sure that their usage grows over time.

C. Support Adoption of Solar-plus-Storage Systems

Q: Please discuss the importance of encouraging the growth of solar-plus-storage systems.

A: The solar industry recognizes that its future growth in California will require a steady transition to pairing solar with storage, for many reasons. First, customers are asking for storage, to increase the resiliency of their electric service and to serve their own evening loads under time-of-use rates. Second, California has a pressing near- and mid-term need for generating capacity in the evening hours when the state's critical peak loads net of solar and wind generation occur.[32] Based on our proposal, if distributed solar paired with storage gradually replaces solar-only systems over the next decade, and the industry

[32] For the state's immediate needs for new capacity in 2021-2023, see the blackouts that occurred on the CAISO system on August 14-15, 2020, as well as D. 19-11-016 directing LSEs to procure 3,300 MW of new system resource adequacy (RA) capacity in 2021-2023. For the mid-term capacity needs, the two proposed decisions released May 21, 2021 in the IRP docket R. 20-05-003 find that the CAISO system needs an additional 11.5 GW of capacity over the 2023-2026 years, in part to replace retiring nuclear and fossil thermal units.

continues to install systems at the same rate as the recent past, this growth will add 4,600 MW of additional distributed storage capacity by 2030. Third, it is clear that the value of solar-plus-storage to the electric system is substantially higher than solar alone, due to the ability of storage to shift solar output into the hours when incremental generation is most valuable. This higher value is shown clearly in our TRC analysis, in **Figure 2** above. Finally, solar paired with storage opens the door for important new grid services that could be provided by aggregations of solar-and-storage systems, including the ability to dispatch stored energy exactly when it is most needed and an enhanced ability to defer local upgrades to the distribution system.

Q: How does the requirement to take service on an electrification rate support the growth of solar-plus-storage systems?

A: Service on electrification rates with high peak-to-off-peak (POP) rate differentials are an important support for the deployment of solar paired with storage, because these rate differences are the key economic driver encouraging customers to cycle their storage regularly, charging in off-peak hours and discharging the stored energy to meet peak demands. We have included the SCE default residential TOU rate as an eligible rate for the NEM 3.0 program because it has much higher POP differences than the PG&E and SDG&E default residential TOU rates, as shown in **Table 4**.

Table 4: *Residential Default TOU POP Differences and Ratios (January 1, 2021 rates)*

Season	Metric	SCE TOU-D 4p-9p	PG&E E-TOU-C	SDG&E TOU-DR
Summer	POP Rate Delta *($/kWh)*	0.155	0.063	0.049
	POP Ratio	1.60	1.19	1.13
Winter	POP Rate Delta *($/kWh)*	0.087	0.017	0.008
	POP Ratio	1.32	1.06	1.02

Q: How should the Commission support the deployment of solar paired with storage in its design of the NEM 3.0 program?

A: It is critical for the Commission to design the NEM 3.0 program to focus on the sustainable growth of solar-plus-storage systems, giving as much, if not more, attention to the economics and cost-effectiveness of solar-plus-storage systems as to solar-only installations. This includes assessing the economics of these systems for participants.

Q: Do SEIA and Vote Solar support proposals – for example, from the PAO[33] -- that would encourage existing NEM 1.0 and 2.0 customers to move to electrification rates, such as the use of incentives for customers that add storage to their existing solar systems?

A: Yes, but SEIA and Vote Solar strongly recommend the use of carrots (voluntary incentives), not sticks (mandatory requirements), to accomplish this. For example, Vote Solar and SEIA support the policy goals underlying the Sierra Club's proposal to move existing NEM 1.0 and 2.0 customers to electrification rates by 8 years after initial energization. In particular, it is a good idea to support additional electrification investments among this group of early adopters who have already invested in DERs. However, the movement of these legacy NEM customers to an electrification rate must be done within the confines of the regulatory construct previously adopted by the Commission for these customers. These legacy customers twice have received assurances from this Commission, in D. 16-01-044 and D. 14-03-041, that the rules for the NEM 1.0 and 2.0 programs would be in place for 20 years. Many of these customers may have made these investments when solar costs, and required payback periods, were much longer than 8 years. Under the Sierra Club proposal, it is these older NEM 1.0 customers who would be required immediately to move to electrification rates with which they are unfamiliar and which may reduce the benefits that they expected. I have the same concern with PAO's proposal to require NEM 1.0 and 2.0 customers to transition to the NEM 3.0 tariff within 5 years. I agree with the Sierra Club that NEM customers have never been assured that the rate structure or levels for their chosen rate would continue,

[33] See PAO Proposal, at pp. 45-47.

but a fundamental part of the NEM 1.0 and 2.0 programs has been the customer's ability to chose among the available rates for which they qualify. For NEM 1.0 customers, this was the full universe of residential rates; for the NEM 2.0 program, it is the universe of available TOU rates. To mandate that solar customers must use a specific TOU rate would undermine the important consumer protection of this aspect of the NEM program. Finally, the Sierra Club's observation that PG&E's and SDG&E's default residential TOU rates have only mild POP differentials is correct – but this is a problem that impacts all customers and that should be addressed through changes to these IOUs' rate designs in their GRC Phase 2 cases.[34] The fact that SCE's default residential TOU rates have far higher POP differences (see Table 4) indicates that PG&E and SDG&E may be able to move to much more progressive default residential TOU rates.

Q: Will existing customers who are considering additional electrification measures have an incentive to consider moving to electrification rates?

A: Yes. For example, a NEM 2.0 customer adding an EV may be better off under an electrification rate than the default TOU rate. This is due to the additional savings for the customer from charging the EV from the grid at a lower off-peak rate. For example, **Table 5** shows a typical PG&E customer on the default TOU rate who first installs solar, then purchases an EV that is charged in off-peak hours. The calculations assume customer usage of 7,500 kWh per year and solar output equal to 100% of usage. The EV adds 4,000 kWh per year. No storage is assumed. The customer realizes $22 per month more solar savings on the default TOU rate than on the electrification rate (EV2A), but,

[34] For example, in PG&E's most recent GRC Phase 2 case, A. 19-11-009, SEIA proposed increases to the POP differences in PG&E's default residential TOU rate that were double the small changes that PG&E and PAO proposed. The Sierra Club / NRDC testimony was silent on this issue, although Sierra Club / NRDC did join the settlement on this issue that will result in larger and faster increases to the POP differences than either PG&E or PAO proposed. See *Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association*, served November 20, 2020 in A. 19-11-019, at pp. 30-31, also *Prepared Direct Testimony of Alejandra Mejia Cunningham and Erin Camp, PhD on behalf of Natural Resources Defense Council and Sierra Club*, served November 20, 2020 in A. 19-11-019. Also

once the customer purchases the EV, the customer will save $40 more per month by switching to EV2A due to its much lower off-peak rate.

Table 5: *A PG&E Solar-then-EV Customer's Monthly Bills and Savings ($/Month)*

Bill	Stays on E-TOUC	Switches to EV2A	Difference
No Solar and No EV	$179		
With Solar and No EV	$18	$40	-$22
With Solar and With EV	$96	$56	+$40
Solar Savings (no EV)	$161	$139	-$22
Solar and EV Savings	$83	$123	+$40
Cost of EV Charging	$0.25 per kWh	$0.15 per kWh	-$0.10 per kWh

D. Re-Align the Participant / Non-Participant Balance

Q: Do you agree that the NEM 3.0 program needs to re-align the balance of costs and benefits between participating and non-participating ratepayers?

A: Yes, I do. Although I do not necessarily agree with the details and magnitudes of the RIM and Participant Cost (PCT) tests reported in the NEM 2.0 Lookback Study, I agree that the results show that, under NEM 2.0, the net benefits for participants are out of balance with the net costs for non-participating ratepayers. Our NEM 3.0 proposal includes a re-alignment of these net benefits and costs to reduce the benefits for participants and the costs for non-participating ratepayers.

Q: How does the SEIA – Vote Solar proposal achieve this re-alignment?

A: First, the move in 2023 to the use of electrification rates with low off-peak rates for PG&E and SDG&E produces an immediate and significant reduction in bill savings and an improvement in the RIM scores for these utilities, as can be seen in Figure 2 and 4 of our proposal. This reduces by about 40% the difference between bill savings (the costs for non-participants) and avoided costs (the benefits for non-participants). Then, for all

see the proposed settlement of residential rate design issues in A. 19-11-019, at pp. 6-8, filed March 29, 2021, and available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M374/K606/374606778.PDF.

three utilities, our proposal would use net billing and gradually reduce export rates over the years 2024-2027, such that the costs and benefits for non-participants are in alignment by 2027. The reduction in the export rates, compared to NEM 2.0, would be 50% by 2027 for PG&E and SDG&E, and 25% for SCE, with the stepdowns based on adoption of solar and solar-plus-storage, under following schedule.

Table 6: *Stepdown Schedule for Export Rates*

Step	**Export Percentage**		**Cumulative MW at the End of Each Step**			***Expected Year for Each Step***
	PG&E and SDG&E	**SCE**	**PG&E**	**SCE**	**SDG&E**	
1	Electrification rate	Electrification rate	375	260	145	*2023*
2	95%	95%	750	520	290	*2024*
3	85%	90%	1,125	780	435	*2025*
4	70%	85%	1,500	1,040	580	*2026*
5	50%	75%	1,875	1,300	625	*2027*

Q: Please describe some of the important assumptions used in your analysis that this re-alignment can be achieved by 2027?

A: First, we assume that rates increase at 3.5% per year through 2030, following the 2021-2030 rate forecast presented by the CPUC Energy Division at the February 21, 2021, Commission *en banc* hearing on electric rates in California. We have used the lower end of the range of Energy Division's rate escalations for the three IOUs, because the *en banc* also recognized the potential for electrification to moderate future rate escalation. After 2030, we assume rates increase with inflation.[35] We also assume that solar output is subject to 1.4% per year degradation in output based on data presented in the NEM 2.0 Lookback Study.[36]

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[35] See Slides 3 and 16 of the Energy Division's presentation of its white paper, available at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Rates%20En%20Banc_white%20paper_v.2.0.pdf.

[36] See the Lookback Study, at p. 63.

Q: Why is it reasonable to allow a 5-year period in which to improve the balance between participating and non-participating ratepayers?

A: There are many reasons to allow an extended period over which there can be a steady improvement in this balance through a gradual reduction in export rates.

- The initial move to required electrification rates for PG&E and SDG&E results in an immediate and significant improvement for these two utilities whose residential rates are substantially higher than SCE's.
- This approach allows time for the industry to transition to the use of solar-plus-storage systems whose benefits are higher.
- The 2020 ACC shows that avoided costs increase over time, which makes sense due to the increasing challenge and costs of reducing remaining GHG emissions in the electric sector as the penetration of renewables increases.
- A gradual change avoids disrupting the DER market and provides time for the equity elements of the NEM 3.0 program to increase access to all types of DERs for all ratepayers.
- As discussed above, there are significant additional societal benefits from continued DER deployment – on the order of $3.8 billion per year, per Table 2 above; these benefits accrue to all ratepayers.
- This stepdown in export rates is designed such that solar and solar-plus-storage systems pass the RIM test by 2027. The stringency of the RIM test, and the fact that it is not used for other types of DERs, should moderate how the Commission assesses the RIM tests conducted for this proceeding.

Q: Pages 30-31 of the Vote Solar- SEIA proposal have an extensive discussion of how the Commission should weigh the results of the RIM test in this case. Please expand upon that discussion in the context of the supporting details provided in this testimony.

A: The RIM test provides one perspective on the balance of equities between participating and non-participating ratepayers. However, this balance also should include other important factors:

- A key mitigation for any inequity revealed by the RIM test is to ensure that **all ratepayers have reasonable access** to distributed solar systems or similar programs (such as community solar). Thus, the component of the NEM 3.0 program for low-income ratepayers is particularly important. The Vote Solar – Sierra Club – GRID Alternatives proposal will ensure that low-income customers realize the same or greater economic benefits from installing solar and solar-plus-storage as more advantaged customers.
- This testimony has quantified the **societal benefits** from distributed solar. These societal benefits accrue to all ratepayers, including non-participants. As the RIM test is a measure of equity for non-participants, the Commission should weigh these societal benefits in its assessment of the impacts on non-participants.
- The RIM test is not used in California, or virtually any other state, to assess the cost-effectiveness of energy efficiency (EE) programs. It is sometimes argued that EE programs are different than rooftop solar, because EE measures produce smaller reductions in customer usage, the reductions are permanent, and EE does not allow a customer to reduce their usage from the grid to low levels. **None of these distinctions between EE programs and rooftop solar are valid.** The non-participant impacts of any demand-side program depend on its cumulative impacts. The overall impacts of both EE programs and rooftop solar are substantial in magnitude.[37] Both rooftop solar systems and more efficient appliances have relatively long economic lives. In terms of allowing customers to reduce their use of the grid to low levels, several important points must be made:
    - First, even a residential customer with a solar system that generates energy equal to 100% of the customer's load will still take significant service from the grid. Typically, only about 50% of that generation will serve the on-site load, so the customer still will take service, running the meter forward and paying the full retail rate, for half of their electric usage. For the remaining output, it is the solar customer that is providing a service

[37] This can be measured by observing the incremental amounts of Behind the Meter Photovoltaics (BtM PV) and Energy Efficiency (EE) that are removed in 2030 in the No New DER scenario of the Reference System Plan (RSP). For 2030, about 49 GWh of demand-side measures are removed in the NoNewDER case. These reductions consist of 26 GWh of EE and 23 GWh of BtM PV, as shown below. See RESOLVE_Scenario Tool 2020-03-23, Case "46MMT_20200207_2045_NOOTCEXT_RSP_PD," "Loads - Forecast" tab, rows 55-74.

(exported generation) to the grid. The key question for NEM programs is how to compensate those exports.

- Second, it is not uncommon for other types of DERs also to have major impacts on customers' bills to energy suppliers. Fuel switching can have major impacts similar to solar, except on natural gas utilities or oil companies. Installing an electric heat pump can reduce a residential gas bill by 80% or more. EV adoption can drop gasoline bills to zero. Customers installing heat pumps or buying EVs are not required to keep non-participating natural gas or gasoline customers whole. And unlike the natural gas utilities or oil companies, the electric utility has an opportunity to offset revenue lost to one type of DER (solar) with incremental revenues from other types of DERs (EVs and heat pumps).

For these reasons, and as discussed on pages 30-31 of our proposal, the Commission should take a broader view of the equities between participating and non-participating ratepayers than just the scores on the stringent RIM test.

Q: The other side of the participant / non-participant balance is the impact on participating customers who install solar or solar-plus-storage. How should the Commission assess the impacts of the NEM 3.0 program on participants?

A: The Commission should use a variety of metrics to assess whether customers will have a reasonable opportunity to continue to install solar and solar-plus-storage under the adopted NEM 3.0 program. These metrics should include:

- Sophisticated **models of solar adoption** such as NREL's dGEN tool that the California Solar & Storage Association (CALSSA) is using.
- **Comparisons to other states** that have modified NEM and that either continue to show sustainable growth in installations or, conversely, have experienced a significant contraction in the solar market. SEIA is sponsoring the testimony of Sean Gallagher and William Giese to address the experience in other states that have modified their NEM program. I also address below the experiences of several other states, based on my own knowledge and experience.
- Analysis of data on simple or more complex **paybacks** for participating customers.

Q: Mr. Beach, you have significant experience working on NEM and distributed solar issues in other states. What are the key attributes of successful NEM reforms in other states?

A: Changes to NEM that have worked in other states generally feature known and gradual reductions in export compensation. For example, Arizona has indexed export rates to utility-scale solar costs subject to a maximum drop of 10% per year in the export rate. The export rates used in Arizona are fixed for 10 years, so customers know the long-term export rate that they will receive. As another example, Nevada's successful re-start of its NEM program in 2017 has used a capacity-based stepdown in the compensation for net monthly exports. This mechanism is similar to our proposal in this case, using a percentage of the retail rate as the price and a capacity-based structure to step down the percentage. Appendix 1 to the IOU Proposal is a study of NEM reforms in other states; Figure 1 of that study shows that distributed solar has continued to grow in Nevada and Arizona after their NEM reforms.

Q: What characterizes the states in which changes to NEM have resulted in market disruptions?

A: States that have tried a significant drop in compensation for solar customers all at once have not had positive experiences. Examples of this are Hawaii's end to net metering in 2015 and the debacle in Nevada in 2015-2016. Mr. Giese discusses the Hawaii experience; Mr. Gallagher discusses the Nevada example, which is also summarized in Attachment C of the SEIA / Vote Solar proposal.

Q: Is there an example of a state that has recently reformed NEM that has considered compensation structures similar to those proposed in this case?

A: Yes. South Carolina recently undertook a comprehensive review of its net metering program, pursuant to recent legislation, Act 62.[38] Like AB 327, Act 62 required the South Carolina commission to balance the conflicting goals of addressing any cost shift due to NEM with providing a reasonable opportunity for customers to install distributed solar. One major South Carolina utility, Dominion Energy South Carolina (DESC), proposed a new tariff very similar to the IOU proposal in this case – a high monthly fixed charge, a significant Grid Access charge based on the size of the solar system, low export rates, and a TOU rate design specific to solar customers. The DESC-proposed tariff would reduce a typical solar customer's bill savings by 55% compared to full retail NEM, with a customer payback of over 20 years. The South Carolina commission rejected this DESC proposal. Instead, the Commission adopted a proposal that I advanced on behalf of a coalition of solar parties.[39] This proposal features the use of an existing time-of-use rate and a minimum bill, with an expected payback under 10 years.[40] The other major IOUs in the state, Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), took a different tack. The Duke utilities negotiated a settlement with solar parties after an extensive stakeholder process. The settlement includes a new residential tariff with the following features:

- A volumetric TOU rate design with significant POP differences;
- An overlay of critical peak pricing (CPP) rates that apply on a limited number of on-peak hours called in advance;
- Monthly netting of imported and exported power within TOU periods, with net exports credited at avoided cost;
- A monthly grid access fee (GAF) applicable only to the small number of residential systems larger than 15 kW, and
- A monthly minimum bill

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[38] See Act 62, at: https://legiscan.com/SC/text/H3659/2019

[39] The Commission's full order in the DESC docket is at: https://dms.psc.sc.gov/Attachments/Order/a69c88df-baf9-4e19-a789-affc2d006ee9.

[40] See *Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, The Solar Energy Industries Association, and the North Carolina Sustainable Energy Association*, submitted January 22, 2021 in Docket No. 2020-229-E.

The Duke utilities also committed to propose an incentive of $380 per kW-DC for solar customers who agree to install another DER – a smart thermostat that the utility can use to reduce the customer's demand during a limited number of peak events. The South Carolina commission has approved the Duke settlement.[41]

Q: Please comment on the use of data on the payback period for solar investments.

A: The payback is an estimate of the number of years until a solar customer has recovered the cost of their original investment. There are a variety of payback metrics, and so payback data needs to be used carefully, with the calculation method and data sources explained clearly. The easiest payback to calculate is the simple payback, typically calculated as the ratio of (1) the capital cost plus application / interconnection costs, minus tax credits and incentives, to (2) the first-year bill savings.

The simple payback understates the actual economic payback, because it ignores costs for financing and O&M, and does not consider the time value of money. Financing is critical in reaching low- and moderate-income customers, who will be more likely to consider the impact of the solar investment on their monthly energy costs and who want the comfort that their monthly bill savings will cover the payment on the solar system. For a financed system, a comparable metric to the simple payback for a cash purchase is the point where the customer's cumulative savings equals the remaining loan payments. This is the point where the customer could use the accumulated savings to pay off the remaining loan – in other words, the point where the customer's savings become greater than their obligations. Based on the cash flow model that we use to calculate solar LCOEs, this point is about 60% longer than the simple payback for a cash purchase. The simple payback also assumes only that the customer realizes the <u>return of</u> the money invested, without a <u>return on</u> that investment. Customers have other investment options on which they can earn a return. On the other hand, the simple payback may be understated because bill savings typically increase, although those increases are offset by

[41] See the South Carolina order for DEP/DEC, at

performance degradation over time. The cash flow model that we use to calculate solar LCOEs indicates that a more complex payback calculation that considers these additional factors is about 40% longer than a simple payback for a cash purchase.

Q: Please comment on the simple payback calculations in E3's May 28, 2021 report entitled "Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020" (May 2021 Report) that compared the NEM 3.0 proposals.

A: My principal concern with E3's payback analysis is its use of solar costs in 2023 and 2030 from the NREL ATB report. For the reasons discussed above, the starting point for the NREL forecast (2021) shows that it significantly understates actual solar costs in California. I have substituted my forecast of solar and solar-plus-storage costs into E3's model; **Figures 12 and 13** shows the resulting simple paybacks in 2023 (blue lines). It is important to recognize that these paybacks will become significantly longer in 2024 due to the expiration of the federal ITC for residential solar. The orange lines in Figure 11 shows what the paybacks will be without the ITC. In particular, the loss of the ITC adds about 2 years to the paybacks for solar-plus-storage systems under the SEIA / Vote Solar proposal.

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https://dms.psc.sc.gov/Attachments/Matter/9852b5f3-525f-4ba2-b140-501e089a2edc.

Figure 12

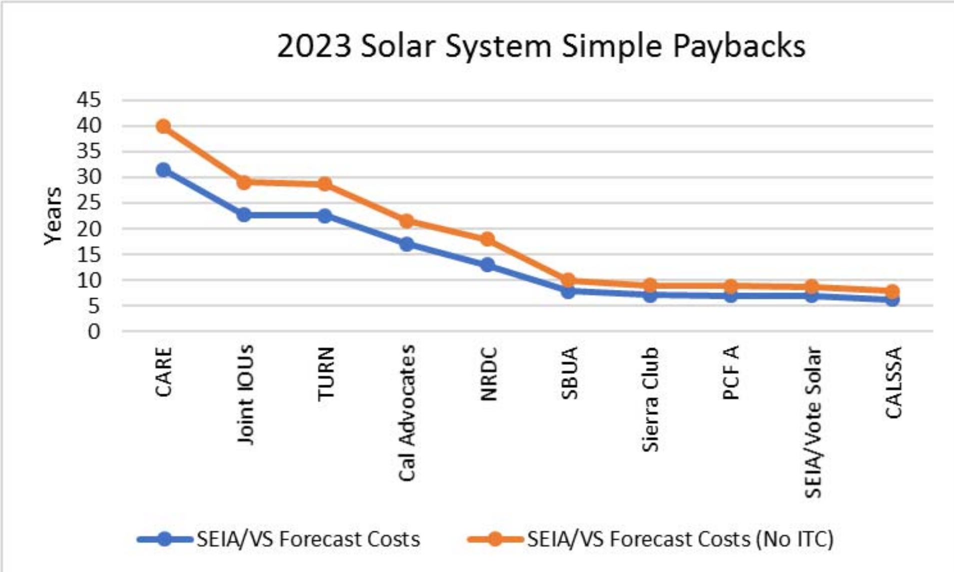
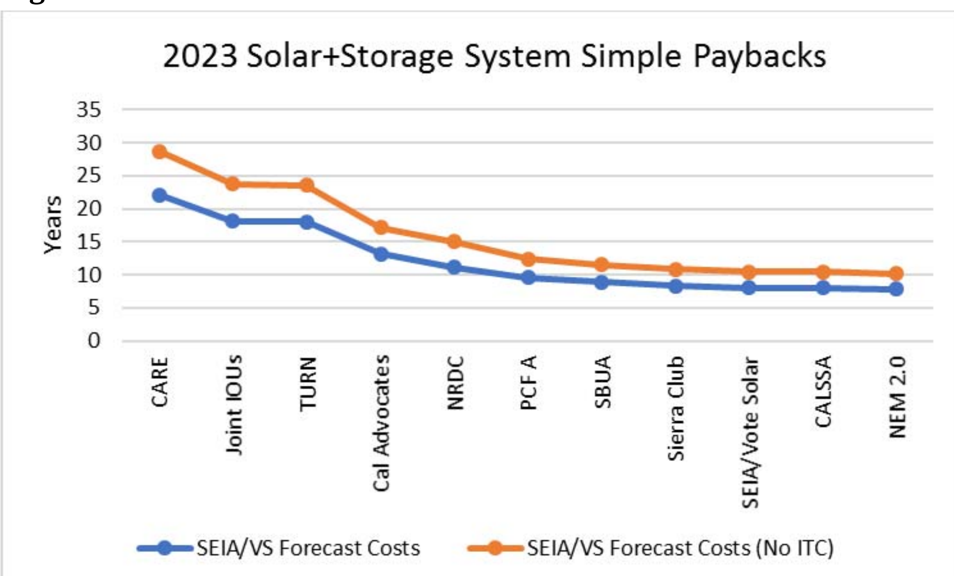


Figure 13



Q: What are reasonable simple paybacks for solar and solar-plus-storage systems?

A: I generally agree with E3 that the simple payback of 7.5 years that E3 used in its January 2021 white paper entitled "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California" is reasonable for solar systems, and consistent with paybacks in other active and growing solar markets in the U.S. A longer payback for solar-plus-storage, up to 10-11 years, may be appropriate given the additional resiliency benefits of adding storage. These paybacks are at the high end of typical paybacks for other DERs such as investments in energy efficiency.[42]

Q: Figure 3 in the Joint IOUs' proposal compares the paybacks that they calculate for their proposal to the supposed paybacks in other states that have reformed NEM. Please comment on this figure.

A: First, I note that the IOUs' paybacks of 11 years for SDG&E and 15 years for SCE and PG&E are far below E3's calculation in its May 2021 Report of a weighted average payback of 21 years for the Joint IOUs' proposal for solar installed in 2023. When we substitute our higher solar costs into E3's model, the payback for solar under the Joint IOU proposal increases to 23 years. For solar-plus-storage systems installed in 2023, I estimate that the IOUs' simple payback period would be 18 years. Second, the IOUs' Figure 3 shows paybacks that are too long for several of the modified NEM programs of other utilities in the U.S. I participated in the development of the settlement with the Duke utilities in South Carolina, and I was a witness for the solar industry in the South Carolina commission's review of this agreement, which that commission has now approved.[43] The Duke settlement in South Carolina has a simple payback of 7.8 years for Duke Energy Progress (DEP) and 10.0 years for Duke Energy Carolinas (DEC). In addition, the settlement is linked to a significant upfront incentive for customers who install a smart thermostat that the utility can use to reduce the customer's demand during a limited number of peak events. When this incentive is included and amortized over 10 years, the payback drops to 6.5 years for DEP and 8.0 years for DEC.

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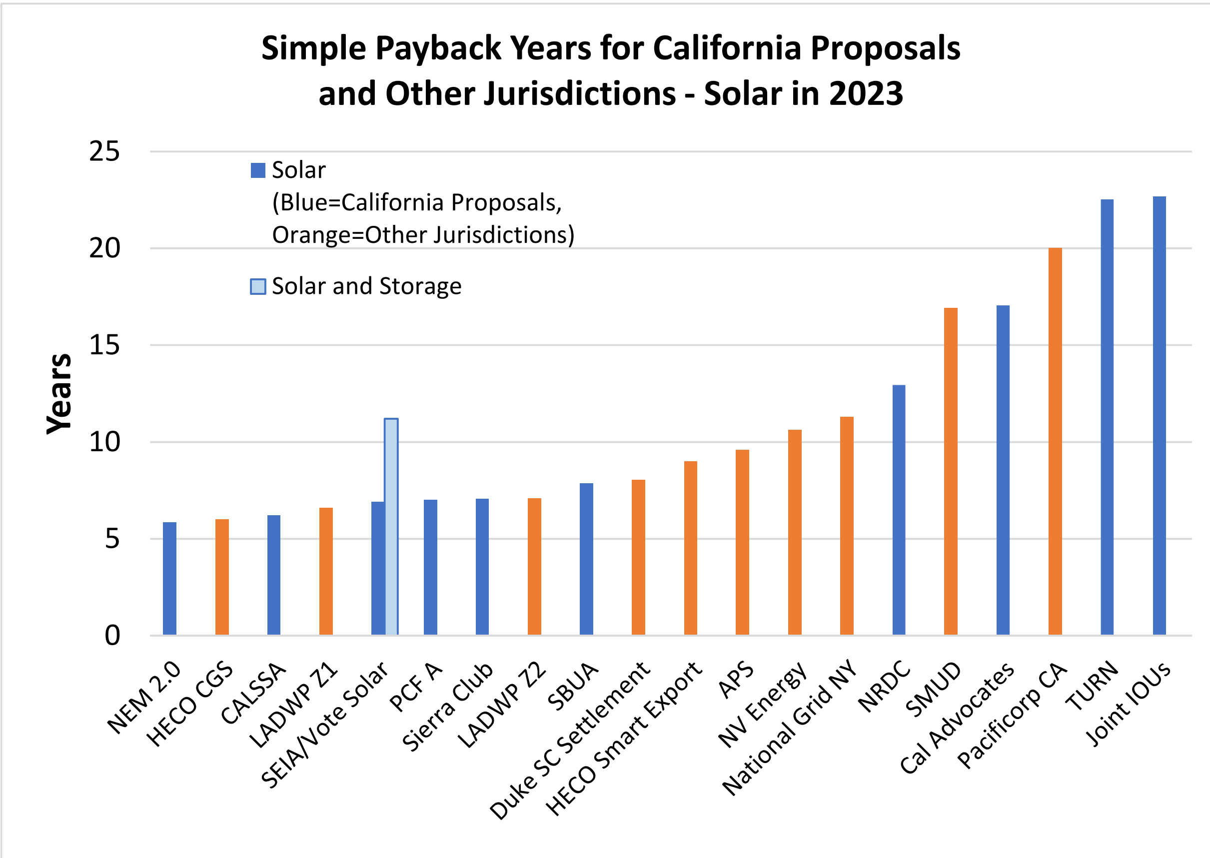
42 See, for example, DB Climate Change Advisors and the Rockefeller Foundation, *United States Building Energy Efficiency Retrofits: Market Sizing and Financing Models* (March 2012), at p. 8, available at https://www.rockefellerfoundation.org/report/united-states-building-energy-efficiency-retrofits/.

43 See the stipulation attached to the South Carolina Public Service Commission Order 2021-390, at: https://dms.psc.sc.gov/Attachments/Order/823ec8b8-881b-4cba-82f9-1b5b5c6d7a50.

Figure 14 is a revised version of the IOUs' Figure 3 incorporating the above changes, and also including many of the proposals in this case. For the SEIA – Vote Solar proposal, we show the paybacks for both solar and solar-plus-storage systems. For all of the other proposals, the paybacks are for solar-only systems.

Figure 14: *Simple Solar Paybacks in 2023*



Q: In re-aligning the balance between participating and non-participating customers, what should be the most important feature in the design of the NEM 3.0 program?

A: The most important design element should be gradualism. The move to electrification rates for residential NEM customers of PG&E and SDG&E will be a significant first step in changing the balance between participants and non-participants. The compensation for exports then should be reduced gradually. Many residential customers still are making the transition to default TOU rates, and initially may be reluctant to adopt electrification rates that have even more challenging TOU rate differences. The solar industry recognizes the need to move to solar-plus-storage systems as its primary product, but this transition also will require time. The scheduled step-down in the ITC to zero for residential customers at the end of 2023 is another hurdle that the industry must manage in the next several years. Gradual change in the compensation for solar customers is important to ensure that distributed solar continues to contribute to meeting the state's climate goals, without the damaging disruptions to the market that occurred in Hawaii and Nevada. Measured change will allow potential customers for residential solar to gain experience under TOU rates and ensure that the industry has time to shift their basic product to solar-plus-storage. All utility customers need the ability and the confidence to make significant investments in many types of DERs, without a concern that abrupt policy shifts will undermine their personal investments in a clean energy future.

V. THE COMMERCIAL & INDUSTRIAL MARKET

Theme: Continue NEM 2.0 in the C&I market

Q: Why should the Commission continue NEM 2.0 in the non-residential market?

A: The C&I solar market in California is not growing. Over the last two years (2019-2020), C&I installations have declined by 27% compared to the prior three years.[44] This decline has coincided with the implementation of the statewide 4p-9p on-peak period with lower off-peak rates in the midday hours. C&I TOU rates also are markedly lower than residential rates, as most C&I rates include demand charges that solar customers are unlikely to be able to reduce significantly. The all-volumetric small commercial rates, or the medium & large C&I rates with reduced demand charges (such as the Option R rates available to solar customers), are less attractive today due to the change to the 4p-9p on-peak period. **Table 7** shows the data that PG&E provided in discovery, of the kW of solar capacity installed by its C&I customers, by rate schedule. PG&E's A-series of C&I rates (A1, A6, and A10) are now closed, and the solar customers on those rates are on legacy TOU periods. The B-series of rates are those with the 4p-9p on-peak period. As the table shows, there has been little uptake of solar by customers on the new B-series of rates, with just 3% of PG&E C&I solar customers on such rates.

Table 7: *PG&E C&I Solar Customers*

Rate Schedule	Type	CEC kW-AC	Share
A1	Small	135,233	12%
B1		**13,914**	**1%**
A6	Medium	531,111	48%
B6		**5,976**	**1%**
A10		113.767	10%
B10		**5,857**	**1%**
AG4A-B	Large	85,241	8%
AG5B		31,245	3%
AG5C		27,078	2%
E19		112,145	10%
E20		50,370	5%
Total		*1,111,937*	*100%*

The NEM 2.0 Lookback study shows that the cost-effectiveness of solar in the non-residential market should not be a focus of the Commission's concern. Non-residential distributed solar in the commercial, agricultural, and industrial sectors generally passes the Total Resource Cost test.[45] From a system/TRC perspective, larger C&I solar systems are less expensive per kW installed. From a cost-of-service perspective, after installing solar, non-residential customers continue to pay rates that fully cover their costs.[46] Although the C&I rate structures result in lower bill savings, the benefits of a

[44] See Figure 6 of the SEIA – Vote Solar proposal.
[45] See the Lookback Study, at p. 90 (Table 5-7).
[46] *Ibid.*, at p. 98. Table 5-11 shows that non-residential NEM customers pay more than their cost of service (i.e. 152% for PG&E, 108% for SCE, and 166% for SDG&E).

distributed solar system serving a C&I customer are no different than one serving a residential customer.

The non-residential market needs time to allow storage systems to become more widely deployed, allowing C&I customers to shift solar output into the evening peak period. This includes replacing backup fossil generators with the cleaner solar-plus-storage alternative, to meet the high value that commercial customers place on uninterrupted service. Given the recent slowdown in the non-residential market, the Commission should not take further steps in this proceeding to reduce the compensation for exports from C&I solar. The non-residential market should remain under the current NEM 2.0 tariff and associated rules.

VI. CONSUMER PROTECTION AND CERTAINTY

Theme: the NEM 3.0 tariff should be administered to provide consumer protection and the certainty necessary for ratepayers' long-term investments in DERs.

Statutory: [Section 2827.1(b)(2)] Establish terms of service and billing rules for eligible customer-generators.

CPUC Principles: A successor to the net energy metering tariff should…

- be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities, and
- enhance consumer protection measures for customer-generators providing net energy metering services.

A. Treatment of NEM 1.0 and 2.0 Customers

Q: Several parties are proposing significant changes to the NEM 1.0 and 2.0 programs. NRDC would levy a new fee of $2.50 per watt-DC solely on NEM 1.0 and 2.0 customers to provide $130 million per year in funding for low-income solar

programs.[47] The Sierra Club has proposed to require NEM 1.0 and 2.0 customers to move to an electrification rate after 8 years.[48] TURN proposes that NEM 1.0 and 2.0 customers should fund a portion of a "market transition credit" (MTC) incentive for new solar customers.[49] Are these proposals consistent with the Commission's legacy policies for these customers?

A: No, they are not. The Commission's legacy policies for NEM 1.0 and 2.0 customers are designed to provide those solar customers with adequate bill savings to allow "a reasonable opportunity to recoup the costs of their investment in those systems."[50] The Commission recognized that this reasonable opportunity should reflect the customer's expectations when it makes the investment, finding that "adopting a transition period that denies customer-generators the opportunity to realize their expected benefits would not be in the public interest, to the extent that it could undermine regulatory certainty and discourage future investment in renewable distributed generation."[51] The Commission also clarified that it is reasonable for the "expected benefits" to include a return on, as well as the return of, the customer's investment.[52] Although I agree with the Sierra Club that the Commission has made clear that the rates and rate designs to which NEM customers are subject can and will change over time, the Commission has also protected NEM customers from abrupt changes in rate structure that would jeopardize their reasonable opportunity to realize the expected benefits of their investments. For this reason, the Commission allowed NEM customers to remain on the legacy TOU periods for the TOU rates they had chosen, with legacy rates that largely preserved the past rate

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47 See NRDC Proposal, at pp. 15-16 and Appendix A.

48 See Sierra Club Proposal, at pp. 2-3 and 5-7.

49 See TURN Proposal, at pp. 21-22.

50 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."

51 *Ibid*., at p. 20.

structure, for five years for residential customers and ten years for C&I customers.[53] The NRDC, Sierra Club, and TURN proposals go beyond these legacy policies on NEM structure and rates to make more fundamental changes to the NEM 1.0 and 2.0 tariffs. NEM 1.0 allows a customer to choose any rate for which they otherwise qualify; NEM 2.0 allows them to choose any TOU rate. Under the NRDC and TURN proposals, NEM 1.0 and 2.0 customers alone would have to pay a new charge that is not part of the existing retail rate under which they take service. The Sierra Club proposal would change the NEM tariffs to limit NEM 1.0 and 2.0 customers, after a certain period, to taking service under one or two specific TOU rates. Each of these proposals goes beyond making changes to the level or design of the rates that NEM customers have chosen – these proposals would force them to pay entirely different rates. There would be adverse impacts on NEM 1.0 and 2.0 customers from this forced rate switch, as follows.

- **Sierra Club.** A typical NEM 2.0 solar customer of PG&E that is forced to switch from the default E-TOU-C rate to the EV2 electrification rate would see their bill savings immediately drop by 24% as a result of the imposed switch.
- The **NRDC** equity fee would require a PG&E solar customer to pay 11% more for the energy it receives from PG&E than a comparable non-solar customer. If a rate element to fund a $130 million per year were assessed across all IOU non-CARE residential customers, rates would rise by only 1%.[54] The rate increase would be even smaller if the program were funded by all IOU ratepayers. Clearly, the impact of this fee on NEM 1.0 and 2.0 customers would be much larger than if these funds were collected more broadly from electric ratepayers.
- **TURN** advertises that its proposal would add $4 per month to the monthly bills of non-CARE residential NEM 1.0 and 2.0 customers, to fund 25% of a $200 million annual Market Transition Credit (MTC). This would reduce a typical NEM 2.0 customer's bill savings by just 2%. However, TURN's testimony is unclear on

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52 *Ibid*.

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

54 Assuming an average non-CARE residential rate of 23 cents per kWh and 53,000 GWh per year of non-CARE residential usage, $130 million would increase the average non-CARE residential rate by 1.1%.

> the size of the MTC that it is proposing; elsewhere TURN mentions an additional $600 million annual MTC for non-CARE customers. TURN also suggests that NEM 1.0 and 2.0 customers could fund as much as 50% of the MTC. 50% of an $800 million MTC would reduce NEM 2.0 customer's bill savings by 16%.

The new charges and forced rate change that Sierra Club, NRDC, and TURN propose not only could jeopardize a solar customer's expected benefits, but would produce noticeable drops in benefits that would undermine many customers' confidence in the NEM program and, by extension, in other programs that promote DER adoption.[55] As a result, such changes could deter customers from making new investments in other DER technologies, as potential DER customers see the Commission changing the deal that customers thought they had when they invested in solar.

Q: Do SEIA and Vote Solar oppose more funding for the purposes of the NRDC Equity Fund – "to meet pressing needs of low-income Californians and achieve energy equity through actions such as advancing solar panels installation, providing additional discounts on energy bills, and supporting policy goals aimed to achieve an equitable decarbonization"?

A: No. To the contrary, we would support more than NRDC's $130 million per year for these important purposes, funded by all ratepayers or by taxpayers. The LMI Equity proposal that we support would add significant additional support for solar installations among low-income customers.

Q: The Public Advocates Office (PAO), with NRDC support, have proposed to offer NEM 1.0 and 2.0 customers incentives to adopt storage. Do you support this concept?

A: Yes. It is far better to use carrots, rather than sticks, to convince existing solar customers to add storage, or to use electrification rates. I note that solar customers who add storage also are more likely to adopt electrification rates, which are well-suited to cycle the storage – charging at low off-peak rates and discharging at the high on-peak rate. As noted above, significant movement to electrification rates also may occur as existing solar customers adopt other types of DERs such as EVs and heat pumps. These customers may recognize that electrification rates with low off-peak rates are a better fit for their new, higher electric use.

Q: The IOUs calculate a multi-billion "cost shift" from NEM 1.0 and 2.0 customers, as shown in Figure 6 of the IOU proposal. Parties have used these alleged cost shifts to assert that NEM 1.0 and 2.0 customers have received excessive benefits, justifying proposals such as those advanced by the IOUs, PAO, NRDC, TURN, and Sierra Club. Please provide your perspective on this cost shift.

A: The IOUs, PAO, TURN, and NRDC all argue that there is today a multi-billion dollar per year cost shift that unfairly benefits existing NEM 1.0 and 2.0 solar customers, with the shift coming from other, non-participating ratepayers. The IOUs have calculated that the magnitude of the cost shift to existing solar customers will average almost $3.0 billion per year from 2022-2030.[56] The size of the IOU-calculated cost shifts suggests that drastic action is needed to reduce the compensation to solar customers under NEM 3.0, and also motivates the TURN and NRDC proposals for new fees on NEM 1.0 and 2.0 customers.

I have taken a close look at the IOU cost shift calculations. I conclude that they are overstated, and, more important, present a conceptually flawed perspective that wrongly attributes the cost shift to the NEM program. The IOU cost shift calculation also fails to include the significant important societal benefits of the existing 10 GW of distributed renewables installed under NEM 1.0 and 2.0. The full details of this analysis are in **Attachment RTB-4**. Here are my key conclusions.

- The "cost shift" that the IOUs calculate represents the above-market costs of existing distributed solar installed under NEM 1.0 and 2.0. These above-market costs result

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55 See TURN Proposal, at pp. 17-22

56 From the IOU workpapers to their NEM 3.0 proposals. PG&E calculates an annual average cost shift from 2022-2030 of $1,680 million/year; SCE $780 million/year, and SDG&E $520 million/year.

principally from the rapidly-declining costs of rooftop solar over the last 15 years, not because solar customers have been overcompensated through the NEM program.

- The state's Renewable Portfolio Standard (RPS) program for utility-scale renewables also includes significant above-market costs for exactly the same reason – the rapidly declining cost of renewables since 2005. Thus, the above-market costs for the NEM program would exist – and at approximately the same level – even if utility-scale solar had been developed instead of customer-sited solar.
- The IOUs' calculated cost shift is overstated by almost 60%, because it fails to reflect the lifecycle benefits of the existing rooftop solar fleet or to recognize that any cost shift will decline as rate design changes over time and as customers adopt new technologies such as on-site storage. These corrections to the IOUs' numbers bring the above-market "cost shift" from the NEM program down to the same level as the above-market costs of the RPS program.
- The investments of over a million California customers in their own renewable generation, plus the growth of CCAs, has put the state years ahead of the state's Renewable Portfolio Standard (RPS), the statutory requirement for the utilities to adopt renewable generation. The 10.3 GW of existing rooftop solar installed under NEM 1.0 and 2.0 now produces about $4.3 billion per year in additional, quantifiable societal benefits that policymakers should consider in weighing the overall economic and societal impacts of customers' investments in solar DG, as shown in Table 2 above.

SEIA and Vote Solar recognize that the compensation for future solar customers under NEM 3.0 needs to be re-calibrated today, due to increasing rates, the growing penetration of renewable resources, changing conditions on the CAISO grid, and the need to further reduce carbon emissions through electrification. This re-calibration should be forward-looking, should make gradual changes, and should apply only to new customers, in order respect the substantial and beneficial investments made by existing solar customers. In reforming the NEM program, it remains essential for the Commission to keep the promises and policy commitments that it has made to NEM 1.0 and 2.0 customers.

B. Changes to Certain NEM Terms of Service

1. Netting interval

Q: The IOUs propose to determine a solar customer's imports and exports by instantaneously netting imports from exports. Please respond to this proposal.

A: Customers should be able to understand and be comfortable with the data that the utility uses to bill them. Generally, the data that the utility provides to residential customers on its website shows hourly data that has been netted over that metered interval.[57] One hour is the established metered interval for residential customers. Non-residential customers – particularly those C&I customers that are billed demand charges based on maximum monthly usage in any 15-minute period – are familiar with the 15-minute metered interval used to bill them.[58] The netting interval should remain consistent with the data and metered interval that is familiar and readily available to the customer – hourly for residential, 15-minute for C&I.

2. Monthly billing, not a monthly true-up

Q: Your proposal would move to monthly billing as the default for NEM customers, instead of the current default process of annual billing with one annual true-up. Please explain how your "monthly billing" proposal differs from the IOU proposal for a "monthly true-up."[59]

A: There is a major difference. Under the NEM program in California to date, customers have been allowed to carry forward credits from one month to the next, at the dollar value of the credits based on the TOU period in which the net credit was produced. Then there is an annual true-up, at which time the customer pays any net bill for the year, adjusted

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[57] Based on my experience as a PG&E NEM customer. PG&E does make data netted over 15 minutes available to residential customers, but this data must be downloaded through the "Green Button" feature.

[58] See D. 17-05-034, at p. 3: "Residential NEM customers have a metered interval of one hour, while non-residential customers' metered interval is 15 minutes," citing Resolution E-4792, at p. 17.

for the monthly minimum bills that the customer has already paid. If there is a net credit for the year, it is set to zero. The annual true-up is also where it is determined whether the customer's output for the year exceeds his or her usage; if it does, the customer is eligible for net surplus compensation (NSC) for the excess output, pursuant to AB 920. The IOU proposal would make a significant change in this billing, by moving to performing the true-up on a monthly basis.

The IOUs propose that, in any TOU period in which the customer has net exports for a month, those net exports would be compensated at the low NSC rate. With today's TOU periods, a significant share of solar output occurs during the midday off-peak TOU period, and it is likely that customers will have excess off-peak production in many months. The result of this is that a significant share of solar output would be priced at the NSC rate, even for solar customers whose annual output is much less than their usage. We calculate that the monthly true-up alone would reduce bill savings for a typical PG&E residential solar customer by 5%. The impact for solar-plus-storage customers would be twice as much – a 10% reduction – because storage shifts a significant amount of off-peak power to the on-peak period, resulting in exports of on-peak generation in excess of usage in some months. However, the monthly true-up would re-price this valuable additional on-peak generation at the low NSC price – a price far less than what it is worth to the grid.

Thus, the IOU proposal would undervalue this solar output – the NSC rate is well below both on- and off-peak avoided costs in the 2020 ACC – and such undervaluing is inconsistent with the Commission's jurisdictional authority to set an NCS rate based on avoided costs under PURPA as discussed in Decision 11-06-016.

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[59] See IOU Proposal, at pp. 17-18.

In contrast, SEIA and Vote Solar have proposed to move to a system in which the default method is monthly billing with an annual true-up. Customers would be billed monthly for the minimum bill plus any net charges for that month, less any net credits carried over from prior months. Net credits for a monthly billing period would continue to be carried over to the next month. There would be a single annual true-up in April that would continue to consider all payments made for the past 12 months as well as any remaining net charges or credits. Any net bill credits for the year would continue to be zeroed out at the annual true-up. This approach has the benefit of spreading out the payments for customers with small systems relative to their usage, who under the current approach can be surprised by a big true-up bill at the end of the year. We propose to change to monthly billing as the default process for residential and small commercial customers, with an annual true-up for all customers in April.

I also recommend retaining the option for customers to elect to continue with the present method of annual billing with an annual true-up. There are customers with seasonal usage that benefit from this approach, as the Commission found when it rejected the idea of monthly true-ups for NEM 2.0 in D. 16-01-044:

> The annual true-up should be continued in the NEM successor tariff. It preserves the value of net metering for all customers, but is particularly important for customers that have large seasonal variations in their electricity usage, such as agricultural operations and schools. Requiring true-ups on a monthly basis would cause significant losses for those customers, who rely on the annual cycle to even out the economic impact of their highly variable usage. Even customers without such sharp variations in their usage would stand to lose value under a monthly true-up, since some seasonal variation is present in all customers' usage patterns. No compelling reason has been presented by the IOUs to change this intuitively sensible feature of the existing NEM tariff.[60]

This rationale for keeping the option of annual billing with an annual true-up continues to make sense today.

[60] See D. 16-01-044, at p. 95.

3. Use of solar-only fixed charges

Q: A number of parties are proposing monthly fixed charges that would apply only to solar customers.[61] Please provide your views on the use of these solar-specific fixed charges.

A: For the reasons I have explained above, the Commission should adopt a single TOU rate platform that is applicable to all types of DERs necessary to promote beneficial electrification – including DERs that both increase or reduce the use of power from the grid. For this reason, SEIA and Vote Solar have proposed to use the Commission's new electrification rates as a foundation for the NEM 3.0 program. Several of these rates include significant fixed charges that are higher than the existing $10 per month minimum bill.[62] I do not oppose the use of fixed charges in these rates, provided they are consistent with the Commission's rate design policies, including cost causation principles, and are generally available to residential customers who install a broad range of DERs. From a cost causation perspective, the fixed charges in residential rates should be limited to those costs that do not vary with usage and that provide customers with access to the grid.[63] Fixed charges allow for a reduction in volumetric rates – which are important for DERs that increase electric use – but they are regressive, lack time sensitivity, and fail to send a price signal to reduce or time-shift electric use. As a result, fixed charges are harmful to those DERs that reduce or shift the use of energy from the grid. I am hopeful that the use of a standard set of electrification rates that are broadly applicable to many types of DERs will bring balance to the use of fixed charges.

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[61] See the proposals of the IOUs, NRDC, and PAO for a monthly fixed "grid benefits charge" that is based on the installed capacity of the solar array. In addition, PG&E and SDG&E are proposing new E-DER and TOU-DER rates applicable to solar customers that would have much higher monthly fixed charges ($20.66 and $24.10 per month, respectively) than any other residential rate schedule.

[62] For example, the SCE TOU-D-PRIME rate has a $12 monthly fixed charge, and the PG&E E-ELEC rate proposed in the residential settlement in A. 19-11-019 has a $15 per month fixed charge.

[63] See D.17-09-035, at p. 40: "In sum, a fixed charge should include only a portion of revenue cycle services costs and all meter capital costs and portions of service drop and final line transformer costs, as set forth in Table 2. Fixed charges cannot cover any costs that vary with demand and must exclude

Q: The IOUs, PAO, TURN, and NRDC all propose the use of substantial fixed "grid benefit" or grid access charges (GACs) based on the nameplate capacity of a customer's solar system. Please critique the use of this type of solar-specific fixed charge.

A: First, it is a misnomer to call these GACs grid "benefit" charges. The use of the word "benefit" suggests that DER customers need to pay an additional fixed charge due to the benefit that they derive from the presence of the grid, even if they are not using the grid. In fact, all utility customers benefit from the presence of the grid, but customers pay for that benefit only when they actually use the grid to import electricity into their premises. There is little difference between a non-solar customer who turns off all lights and appliances and raises the thermostat when leaving home in the morning, resulting in little energy use during the middle of the day, and a solar customer whose array also results in their home taking no power from the grid in the midday hours. Neither customer should pay a charge simply for "grid benefits" when they are not taking power. When both customers return home in the evening, both will increase their usage, drawing power from the grid, running their meters forward, and paying rates that fully compensate the utility for the costs of the grid on that day, even when it was not being used by either customer. Both the non-solar and the solar customers should pay the same rates for the same service that the utility provides when either customer's meter runs forward. To charge solar customers merely for the presence of the grid, when they are not actually taking power from the grid, would be unduly discriminatory compared to the treatment of non-solar customers who only pay for the grid when they actually use it to consume kilowatt-hours.

The solar customer probably will produce more power than the home uses in the middle of the day, exporting power to the grid. In this case, for this exported power, it is

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transmission charges and all non-bypassable charges such as public purpose program charges. The EPMC the solar customer that is providing a generation service to the utility, for which the utility compensates the solar customer at the prevailing export rate. The central issue in net metering is what to pay the customer for this exported power.

The utility takes title to the exported power at the customer-generator's meter. Generators – either this residential solar customer or a large merchant power plant – are not responsible for and do not have to pay the utility to deliver the generation that they sell to the utility at the meter.[64] Once the power passes the meter, the kilowatt-hours are the utility's kilowatt-hours to be delivered to other customers, and the utility is fully compensated for that delivery service by the neighbors who runs their meters forward in consuming the exported solar power. For exported power, it is not the solar customer that is using the utility grid; instead, the grid is being used by the neighbor that is consuming that exported power.

At the end of the month, the solar customer will receive a bill that nets, or offsets, (1) the charges to the solar customer for the service that the customer received from the utility when the meter ran forward against (2) the payment from the utility for the service (exported generation) that the utility received from the solar customer. Just because this net bill may be low, or even zero, does not mean that the solar customer has not paid fully for the service that the customer has received from the utility. There are no uncompensated "grid benefits" that the solar customer somehow has received even when it was not using the grid.

From this perspective, there is no need for solar customers to pay a GAC, and it would be unduly discriminatory compared to other non-solar customers for the utility to levy such a charge. As designed by the IOUs, TURN, PAO, and NRDC, the GACs are

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scalar will not be applied when calculating fixed costs for purposes of setting a fixed charge."

[64] The only exception to this is the costs of interconnection, which are the upfront cost to connect the generator to the grid in a location with adequate capacity to accept the generator's power.

designed to collect utility costs based on power produced by the customer's solar array, behind the meter (BTM), and then consumed by the customer's own load, also behind the meter. The GACs result in charging solar customers for grid costs for power which never touches or uses the grid, and which does not cause any grid costs to be incurred. The GAC's sole purpose is to collect grid costs that the customer would have incurred if it had not installed solar. The utility cannot charge non-solar utility customers when they do not use the grid as much as they have in the past – for example, if they go on an extended vacation or install more efficient light bulbs or appliances. Yet the proposed GACs would do exactly that – charge solar customers for grid services that they do not use only because they are serving their own load with their own BTM generation. TURN's proposal is very explicit about this, and goes so far as to propose to require the installation of a second meter to measure and to bill the customer for their private use of their own solar generation, on their own premises, to serve their own BTM loads.[65] The IOU, PAO, and NRDC proposals for GACs try to do the same thing by using the size of the customer's solar system as a very rough proxy for the amount of solar power that the customer consumes behind the meter.

Q: What is your understanding of the statutory standards for the rates charged to solar customers?

A: Solar customers are qualifying facilities (QFs) under PURPA.[66] The FERC rules implementing PURPA require that the rate for sales to QFs "shall be just and reasonable and in the public interest; and shall not discriminate against any QF in comparison to rales for sales to other customers served by the electric utility." The rules specify that the rates for sales to QF shall be considered non-discriminatory if they are "based on accurate data and consistent systemwide costing principles" and the rates "apply to the utility's

[65] See TURN proposal, at p. 25.

[66] For a customer installing a renewable DG facility with a net power production of 1 MW of less, it is my understanding that the designation as a qualifying small power production facility (and therefore a QF) is automatic with no filing at the Federal Energy Regulatory Commission (FERC) required.

other customers with similar load or other cost-related characteristics."[67] The proposed GACs clearly would impose higher fixed charges on solar customers, even if those customers have exactly the same usage and load profile for sales from the utility as do other, non-QF customers.

Q: Are there significant cost causation issues with the GAC proposals?

A: Yes. The utilities have no data on how much power a solar customer consumes behind the meter. As a result, the proposed GACs are based on the nameplate capacity of the solar array, which is used as a rough proxy for solar output. This is a highly inexact metric for the power used behind the meter, which also is influenced heavily by numerous factors that are not considered:

- The size of the solar system relative to the customer's usage
- Whether the system includes storage to shift solar output, and how the storage is operated
- Orientation and tilt
- Solar insolation at the site, versus the reference site used to estimate output
- Degradation of output over time
- The customer's load profile, including vacation / low use periods
- Whether the system is operating, or down for maintenance/repairs

There are clear examples of how any fixed GAC based on installed capacity will overcharge solar customers. When the solar customer goes on vacation, they will have to pay the full GAC for that month, even though their usage of solar power behind the meter may drop substantially that month. If the system is down for a period to replace the inverter, the customer will still pay the GAC as though the system is operating.

Q: Are fixed monthly GACs consistent with the Commission's Rate Design Principles, as set forth in D. 15-07-001, at page 28?

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67 See 18 CFR §292.305(a).

A: No. A GAC is a fixed charge which a DG customer can do nothing to avoid except by (1) not installing DG or (2) adopting DG but not interconnecting to the grid, i.e. "cord cutting." Neither result is economically beneficial for the state, for the electric system as a whole, or for other ratepayers. A central theme that runs throughout the Commission's Rate Design Principles is that rates should encourage and enable customers to take actions that benefit the grid as a whole. All of the following principles reinforce this theme:

- 4. Rates should encourage conservation and energy efficiency.
- 5. Rates should encourage reduction of both coincident and non-coincident peak demand.
- 6. Rates should be stable and understandable and provide customer choice.
- 9. Rates should encourage economically efficient decision-making.

Q: Does a fixed monthly GAC based solely on installed capacity recognize that different DG systems can have significantly different values to the grid and other ratepayers?

A: No. The proposed GACs do not recognize or provide incentives for customers to install systems that provide greater value to the grid. For example:

1. If possible, **facing the panels to the west** instead of the south increases late afternoon output and the capacity value of a solar system.
2. **Smart inverters** provide grid support benefits and may enable greater coordination between the customer's generation and loads.
3. Most important, **including storage** will firm the intermittent solar output and significantly increase a system's value to the grid by shifting solar output to the hours when it is most valuable.

The proposals in this case would not reduce the GAC should the customer take any of these steps that would increase the value of their renewable generation.

Q: Can customers take steps to increase the value of their systems, even after they are installed and operating?

A: Yes. Once the system is operating, a GAC provides no additional incentive for the DER customer to shape its load in ways that also might benefit the system, such as by adding or operating storage to shift generation to peak periods.

VII. GRID SERVICES

Q: Please discuss the new opportunities for solar-plus-storage systems to provide a variety of grid services.

A: New grid services will be possible with an expanding fleet of distributed storage charged by on-site solar. The SEIA / Vote Solar proposal encourages the Commission to continue and to expand the ongoing work to develop these new grid services. This work includes:

- The new pilot grid services tariff that the Commission recently approved in D. 21-02-006.
- The aggregation of distributed solar-plus-storage into virtual power plants (VPPs) that can provide dispatchable Resource Adequacy (RA) capacity, with visibility to system operators. There is ongoing work in Track 4 of the RA proceeding directed at developing the means for aggregated BTM resources to participate in RA markets.
- Allowing all solar and solar-plus-storage customers to access dynamic rate tariffs, including Critical Peak Pricing rates (CPP). These are the customers who are likely to be willing and best able to respond to such changing rate signals. I address this dynamic pricing issue in more detail below.

The transition away from traditional NEM to net billing will require substantial investment in storage as well as solar. Developing new opportunities for storage to provide innovative grid services will be an important means to support these investments and to provide additional value to the electric system. But I caution that the ability to provide these new and enhanced services will depend on whether the industry continues to grow sustainably and can make the transition to solar-plus-storage as its central product.

Q: With respect to allowing solar and solar-plus-storage customers to access dynamic rate tariffs, are their inconsistencies among the IOUs in whether NEM customers can elect CPP rates?

A: Yes. Today, SCE allows residential NEM customers to participate in its CPP rates, while PG&E and SDG&E do not. PG&E allows some non-residential NEM customers to elect Peak Day Pricing rates (PG&E's version of CPP), but in general the IOUs do not allow their NEM customers to use CPP rates on all optional commercial and industrial rate schedules. I recommend that all NEM customers – residential and non-residential – in all three IOU service territories, should be allowed to elect CPP or PDP rates on any rate option that they select. NEM customers are among the more engaged and informed of utility customers, due to the significant investment they have made in renewable on-site generation and (in most cases) their significant experience living with TOU rates. NEM customers should have the same opportunity as other customers to participate in CPP programs and respond to CPP price signals on extreme peak days. Further, NEM customers with solar-plus-storage systems that can be discharged during critical peak periods are among the most valuable customers that the utilities have at such times.

Q: Will NEM customers have the same economic incentive to respond to CPP rates by reducing or shifting their loads as non-NEM customers on the same rate schedule?

A: Yes. On the margin, a solar customer sees the same price signal and has the same incentive to reduce usage during a CPP event as any other non-solar customer on the comparable rate schedule, even if the solar customer is exporting power to the grid at that time. For example, even though my own west-facing PV system often can produce more power than my home consumes during the initial hours of PG&E's summer on-peak period, I retain a strong incentive to shift any available loads out of all hours of the on-peak period. If I do not run appliances between 4 p.m. and 6 p.m., I send additional solar kWhs out to the grid, earning additional net metering credits at close to the PG&E summer on-peak rate. Then I pay the much lower off-peak rate when I run appliances in the off-peak hours of the late evening, morning, or midday. Thus, even as a solar customer, I continue to see the same TOU or CPP price signal as non-solar customers on PG&E's residential TOU rate, and have the same incentive to shift my loads to off-peak periods. CPP rates simply represent a re-design of the on-peak TOU energy rates, with the highest on-peak rates more narrowly and accurately focused on the CPP event days when there is the greatest need to minimize on-peak use. The high event-day rates are offset by lower rates on non-event days, on a revenue-neutral basis.

Q: Are there benefits to the system if all DER customers are allowed to use CPP rates?

A: Yes. First, as noted above, like all customers, DER customers have the potential to reduce or to shift some of their end-use loads out of the CPP event period. Second, because the CPP rate structure focuses on the use of very high on-peak rates on CPP event days, solar – and, increasingly, solar-plus-storage – customers will have an incentive to make certain that their systems are working properly, any storage is fully charged, and they are on-line during all CPP event days (which are likely to be hot, sunny days without the cloud cover that would moderate temperatures), notwithstanding the fact that only a small share of solar output occurs during the 4 p.m. to 9 p.m. peak period.[68] More important is the consideration that, as more customers install solar-plus-storage systems, CPP rates will provide a powerful incentive for customers to discharge their stored energy to the maximum extent possible during CPP events.

Q: Has SEIA or Vote Solar recently raised these CPP-related issues with the Commission?

A: Yes. SEIA filed testimony recommending the more uniform availability of CPP rates for NEM customers in R. 20-11-003, the OIR on emergency actions to ensure reliable

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[68] Typical rooftop solar systems in California only produce 5% to 7% of their annual output during the 4 p.m. to 9 p.m. peak period in the four summer months (June – September). It is important to recognize that solar PV systems are not dispatchable, so a solar customer cannot make his solar panels

electric service in the summer of 2021. Unfortunately, in R. 20-11-003 the IOUs generally opposed these sensible reforms that could produce additional demand reductions in the summer of 2021. SCE suggested that these CPP issues should be reviewed in this case.[69] D. 21-03-056 took no action on and mentioned but did not discuss SEIA's recommendations.[70]

VIII. IMPLEMENTATION PLANS AND TIMELINES

Q: What are your principal concerns with the implementation of the NEM 3.0 program?

A: My first concern is to avoid disruption and uncertainty in the DER market. In this proceeding, the IOUs originally proposed an immediate cut-off date for the NEM 2.0 program, before the full details of the NEM 3.0 program are known.[71] Such a result will present great uncertainty for prospective customers, disrupting the market. Adoption of proposals such as those of TURN and NRDC, which lack important details, are likely to require protracted implementation proceedings, again with little certainty for prospective customers.[72] In contrast, the SEIA and Vote Solar proposal will not require a formal

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produce more power on CPP event days. Solar output depends on the availability of sunshine, not on whether a CPP event has been called.

69 See SCE rebuttal testimony, served January 19, 2021, in R. 20-11-003, at pp. 6-7.

70 See D. 21-03-056, at pp. 13-14.

71 See *Joint Opening Comments of Southern California Edison Company, Pacific Gas And Electric Company, and San Diego Gas & Electric Company on Order Instituting Rulemaking To Revisit Net Energy Metering Tariffs Pursuant To D.16-01-044, And To Address Other Issues Related To Net Energy Metering*, at pp. 10-11.

72 See, for example, the repeated references in TURN Proposal to further implementation proceedings. See pp. 16-17: "In a subsequent implementation phase, the IOUs should be directed to provide a granular breakdown of costs included in distribution and transmission rates so the Commission will be able to assess the portion of such rates that should be collected in the form of a monthly charge on self-consumption." Pages 52-53 of the TURN proposal provide the extensive list of issues that would need to be worked out in an implementation phase, including such basic and contentious issues as how to calculate and fund the Market Transition Credit, how to calculate the amount of solar production used BTM, how to implement an export rate methodology that uses actual CAISO market prices, and how to dispatch BTM storage units under certain system conditions.

implementation phase. Similar to the implementation of the NEM 2.0 tariff, the SEIA and Vote Solar proposal can be implemented through an advice letter process.

Q: How should the implementation of the NEM 3.0 program take place?

A: Implementation of the successor tariff should be undertaken in measured steps to ensure, to the extent possible, a smooth transition. We favor the same process used for NEM 2.0, where there was a gap between the time that the industry knew the final Commission-approved terms of the NEM 2.0 tariff, and the time when new NEM customers would be required to take service under that tariff.[73] This gap between approval and customers taking service under the new tariff gave the industry time to make the necessary preparations to offer what was, in essence, a new product.

All of the parties appear to have proposed major changes in the NEM tariff structure, with the range of proposed changes much more substantial than the ones made in the NEM 2.0 proceeding. This degree of change necessitates that the IOUs be provided more time than under NEM 2.0 to submit advice letters proposing a NEM 3.0 tariff based on the Commission decision. With additional time, the IOUs can ensure a complete advice filing, thus mitigating the need for supplemental filings which often slow down the process. Further, the IOUs have recognized that they are in the midst of making changes and improvements in their billing systems, saying that NEM 3.0 could not be fully implemented until 12-24 months from the date of the decision.[74] Finally, given the scope of the likely tariff changes, the industry needs a reasonable amount of

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[73] When implementing the NEM 2.0 tariff, the Commission directed the IOUs to file advice letters with their respective NEM successor tariffs within 30 days of the Commission decision approving the tariff. This resulted in the IOUs' advice letters being filed at the end of February 2016 and a Commission resolution approving the advice letters, with certain modifications, being adopted at the end of June 2016. However, the tariffs were not to go into effect until the statutory MW cap on the NEM program was reached in each of the IOUs' respective service territories, or July 1, 2017, whichever was earlier. *See* D. 16-01-044, Ordering Paragraph No. 1, also Resolution E-4792 (issued June 23, 2016), at p. 31, Ordering Paragraph No. 5.

[74] See IOU Proposal, at p. 45.

time to train their sales force and customer service representatives on the new structure as well as to make changes to their marketing materials and associated contracts. The Commission itself will need to revise its Solar Consumer Protection Guide to reflect the program modifications.

A number of the general market proposals (SEIA/Vote Solar, Sierra Club, and the IOUs) recommend that NEM 3.0 customers who are not low-income take service under an electrification rate schedule. While PG&E currently has one such schedule (EV2) and one pending approval in Phase 2 of its current General Rate Case (E-ELEC), SDG&E presently does not have a residential electrification rate. SDG&E is scheduled to file for approval of such a rate schedule on September 1, 2021 in a rate design window application. Under the Commission's Rate Case Plan, such applications are intended to be processed more expeditiously than general rate cases.[75] Thus, a necessary piece to implement the SEIA and Vote Solar proposal would be not be available in the SDG&E service territory until summer 2022. If there is a delay in the approval of an electrification rate for SDG&E, I propose, as a backup plan, that the existing schedules DR-SES and EV-TOU-5 should be made available to the initial NEM 3.0 customers in SDG&E's territory.

Q: Does this conclude your testimony in this case?

A: Yes, it does.

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[75] *See* Decision 07-07-004, Attachment A, p. A-8 (providing a five month schedule for Rate Design Windows proceedings, but historically these proceedings have taken longer)

Attachment RTB-1

CV of R. Thomas Beach

Attachment RTB-2

Vote Solar / SEIA NEM 3.0 Proposal

Attachment RTB-3

Quantifying the Societal Benefits

of Distributed Resources

Quantifying the Societal Benefits of Distributed Solar & Storage

SEIA and Vote Solar have advocated for many years that policymakers should acknowledge, quantify, and consider in their decision-making the important societal benefits of renewable technologies. These include the solar and storage resources that can be developed and deployed at many scales and in many locations on the electric grid, including both behind-the-meter (BTM) and in-front-of-the-meter (IFOM). For example, decisions on the cost-effectiveness of BTM distributed energy resources (DERs) should include consideration of both direct ratepayer benefits and the societal benefits enumerated below.

SEIA and Vote Solar have separated the societal benefits of BTM solar into two categories. The first category is the societal benefits that will be provided by solar and other renewable resources at any scale, whether customer-sited BTM or wholesale IFOM resources. The 2020 Avoided Cost Calculator (ACC) that the California Public Utilities Commission (CPUC) recently approved in D. 20-04-010 and Resolution E-5077 is based on modeling of the cost of additional utility-scale renewable and storage resources that would be required to replace the DERs included in the CPUC's most recently-adopted Integrated Resource Plan. These additional utility-scale renewable resources will provide significant societal benefits by displacing fossil generation, and so would the DERs that avoid them. Both types of renewable resources should be attributed with the same societal benefits that result from the reduction in natural gas-fired generation produced by either type of resource.

The second category are the several societal benefits that will result <u>only</u> from distributed BTM solar and storage, and that are not produced by utility-scale IFOM resources. These include (1) the land use benefits that will result because distributed solar and storage are installed in the built environment and do not require dedicated parcels of land removed from another productive use and (2) the local economic benefit of spending a portion of the costs of distributed resources in the community where they are sited.

A. Societal Benefits of All Types and Scales of Solar & Storage

1. **Use of a Societal Discount Rate.** Solar and storage are long-lived clean energy resources, with useful economic lives of 25-30 years for solar and at least 10 years for storage. The use of a lower societal discount rate places greater weight on the long-term benefits of these resources. In D. 19-05-019, the CPUC approved the use of a societal discount rate of 3.0% per year. This is a real, not nominal, discount rate.

2. **Health Benefits from Reduced Criteria Air Pollution.** Renewable generation displaces natural gas use, thus reducing emissions of criteria air pollutants (NO_x, SO_x, and particulates). D. 19-05-019 approved an initial SCT that includes health benefits from reduced criteria air pollution (initially $6 per MWh of output from DERs that displaces gas-fired generation). This result is based on a conservative application to

California of the U.S. Environmental Protection Agency's COBRA model. SEIA has also run the COBRA model for California with settings that focus only on those counties that host significant gas-fired power plants; SEIA's modeling obtained a significantly higher value of $15 per MWh.[76] The Energy Division's most recent research on this benefit, using more granular modeling, is even higher, at $21 per MWh of avoided gas-fired generation, which is the value that we have used.[77]

3. **Social Cost of Carbon.** The SCT adopted in D. 19-05-019 also includes the social cost of carbon (SCC) to measure the avoided damages from mitigating carbon emissions and the associated climate change. Societal benefits should include a recent estimate of the amount by which the social cost of carbon exceeds the carbon compliance costs included in the 2020 ACC. A recent estimate of the SCC for the U.S. is the 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*.[78] The societal benefits of mitigating climate change is the difference between the SCC and the compliance costs to meet the state's carbon reduction goals, as modeled by the marginal GHG emission values from the IRP.

4. **Reduced Out-of-state Methane Leakage.** The 2020 ACC includes a direct avoided cost for avoided in-state methane leakage upstream of gas-fired power plants. This leakage can be avoided when gas use for electric generation is reduced. Displacing gas use for electric generation also reduces out-of-state (OOS) methane leakage, because 91.3% of California's gas supplies are imported from outside the state.[79] These reductions in methane leaks are a societal benefit (and thus are not included in the ACC) because, unlike in-state methane leaks, OOS leakage is not in the CARB's official GHG inventory for California. This societal benefit is 10.5 times (10.5 = 91.3% OOS gas / 8.7% in-state gas) larger than the in-state methane leakage component of the 2020 ACC.

5. **Less consumptive water use for power plant cooling.** Renewable resources reduce consumptive water use by displacing marginal thermal generation that consumes water for cooling. It is straightforward to estimate the water use at conventional thermal power plants: the CEC has estimated that a California combined-cycle plant uses 0.68 acre-feet

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76 See *Comments of the Solar Energy Industries Association on the Staff's Amended Proposal for a Societal Cost Test*, filed April 20, 2018 in R. 14-10-003, at pp. 8-9.

77 See presentation by E3 and the University of California, Irvine, at the December 9, 2020 workshop in R. 14-10-003, at Slides 18-25.

78 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.

79 According to the *2020 California Gas Report*, at Table 17, in 2019 California-sourced natural gas supplied 8.7% of the state's natural gas demand (531 MMcfd out of 6,100 MMcfd).

per GWh.[80] Studies also are available that quantify the value of these water savings at power plants. A California Energy Commission (CEC) study calculated the "effective cost" of water use at a natural gas plant by calculating "the additional cost of using dry cooling expressed on an annualized basis divided by the annual reduction in water requirement achieved through the use of dry cooling."[81] The CEC found that the effective cost of saved water using this metric ranges from $3.40 to $6.00 per 1,000 gallons, or $1,110 to $1,955 per acre-foot with a mid-point of $1,530 per acre-foot. Similarly, a 2014 study by Energy and Environmental Economics (E3) calculated the avoided cost of water in California based on the cost of the embedded energy in water and the avoided costs to develop new water supplies.[82] They found an avoided cost of water ranging between $442 (imported groundwater), $1,093 (treated wastewater) and $2,349 (desalinated water) per acre foot. We eliminate the option of importing groundwater, because California's crisis of dwindling and over-used groundwater is well-known.[83] We average the remaining two estimates with the midpoint of the CEC's study, for an avoided cost of water of $1,660 per acre-foot. The result is an avoided cost benefit of $0.0007 per kWh ($0.70 per MWh) from reduced water use:

$$\frac{0.68 \text{ acre} - \text{feet}}{\text{GWh}} \times \frac{\$1{,}045\ (2012\$)}{1 \text{ acre} - \text{foot}} \times \frac{1 \text{ GWh}}{10^6 \text{ kWh}} = \$0.0007\ per\ kWh$$

This figure is consistent with the U.S. Department of Energy's estimate of water use benefits of $0.0006 to $0.0017 per kWh from dramatically increasing the use of the nation's wind resources.[84]

80 California Energy Commission, *Estimated Cost of New Renewable and Fossil Generation in California* (March 2015, CEC-200-2014-003-SF), at pp. 138, 145, B-17 and B-18, plus associated cost of generation spreadsheet model.

81 In other words, if water supply in the region with the power plant is or becomes constrained, what would it cost (in terms of the direct cost as well as the cost of lost generation efficiency) to convert the plant to run on dry cooling? *See* California Energy Commission, *Cost and Value of Water at Combined Cycle Power Plants.* CEC-500-2006-034 (April 2006), p. 4. Available at http://www.energy.ca.gov/2006publications/CEC-500-2006-034/CEC-500-2006-034.PDF.

82 Cutter, Eric, Ben Haley, Jim Williams and C.K. Woo, "Cost-effective Water-Energy Nexus: A California Case Study." *The Electricity Journal*, 27 (5), July 2014. Available at https://ethree.com/documents/E3_Energy_Water_EJ_web.pdf.

83 *See, e.g.*, Justin Gillis and Matt Richtel, "Beneath California Crops, Groundwater Crisis Grows." *The New York Times* (April 5, 2015). http://www.nytimes.com/2015/04/06/science/beneath-california-crops-groundwater-crisis-grows.html?_r=0.

84 U.S. Department of Energy, *Wind Vision*, at Chapter 3, p. 74. Available at http://energy.gov/eere/wind/wind-vision.

B. Societal Benefits Unique to Distributed Solar & Storage

6. **Land Use Benefits.** Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station solar plants require larger parcels of land, and are located where the land has other uses for agriculture or grazing. Today, the land typically must be removed from this prior use when it becomes a solar farm. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year. The lost value of the land depends on the alternative use to which it could be put. The U.S. Department of Agriculture has reported the average value of farm and ranch land in California in 2019 as $10,000 per acre.[85] Assuming 3.5 acres per GWh per year, a $10,000 per acre value of land, and a 25-year loan at an interest rate of 4% per year to finance the land purchase, distributed solar provides a land use benefit of $2.20 per MWh of solar output.

   There also are limits on the ability of California to meet its long-term GHG reduction goals solely with utility-scale solar generation. The No New DER case for the 2020 ACC that excludes all customer-sited DERs requires on the order of 130 GW of in-state utility-scale solar by 2045, according to the RESOLVE modeling of this case. This may exceed the in-state development potential for these resources when environmental constraints on land use are considered.[86] The substantial new transmission needed to access this level of utility-scale solar development also will present land use conflicts. These possible constraints have been highlighted recently, and perhaps further constrained, by Governor Newsom's executive order to conserve 30% of California's lands by 2030[87] and by the new temporary endangered species status for Joshua trees in the inland southern California regions that are prime locations for solar power plants.[88] Distributed solar provides a solar resource that is not subject to these land use constraints.

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85 See https://downloads.usda.library.cornell.edu/usda-esmis/files/pn89d6567/g732dn07g/9306t9701/land0819.pdf.

86 The 2017 RESOLVE documentation shows the statewide utility-scale solar technical potential as low as 74 GW when environmental screens are applied. See Table 17 on pp. 31-32 of the inputs and assumptions documentation, available at https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentB.RESOLVE_Inputs_Assumptions_2017-09-15.pdf. The 2019 RESOLVE model relaxed these constraints, but instead used transmission additions to constrain solar development; the result was very large transmission additions in certain areas that themselves would likely raise land use issues.

87 See https://www.desertsun.com/story/news/environment/2020/10/07/newsom-signs-order-conserve-30-california-land-and-coastal-water/5914049002/.

88 See https://www.latimes.com/environment/story/2020-09-22/western-joshua-trees-granted-temporary-endangered-species-protections.

7. **Local Economic Benefits.** Distributed generation has higher costs per kW than central station renewable generation. However, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – is spent in the local economy, and thus provides a local economic benefit in excess of what would be spent on wholesale, central station renewable generation. These local costs are an appreciable portion of the "soft" costs of DG. Obviously, such local spending is particularly important for disadvantaged communities. Central station renewables that qualify for the RPS program often are not located in the local area where the power is consumed, and a portion of RPS resources are located outside of California.

   There have been a number of studies of the soft costs of solar DG, as the industry has focused on reducing such costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following **Tables 8 and 9** present this data, from detailed surveys of solar installers conducted by two national labs (LBNL and NREL), on the soft costs that are likely to be spent in the local area where the DG customer resides. This tally of the share of solar PV costs that is spent locally is conservative in that it does not consider the local economic benefits of the major solar companies that are headquartered in California, which leads the nation by a considerable margin in solar installations of all types and which is home to a significant number of major rooftop solar companies.

Table 8: *Residential Local Soft Costs*

Local Costs	**LBNL – J. Seel et al.** [89]		**NREL – B. Friedman et al.**[90]	
	$/watt	***%***	***$/watt***	***%***
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition: marketing & other	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting, inspection, interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

89 J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrence Berkeley National Lab, February 2013), at pp. 26 and 37.

90 B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

Table 9: *Commercial Local Soft Costs*

Local Costs	NREL – B. Friedman et al.			
	Small Commercial		Large Commercial	
	$/watt	*%*	*$/watt*	*%*
Total System Cost	4.97	100%	4.05	100%
Local Soft Costs				
Customer acquisition: marketing & other	0.13	3%	0.03	1%
Installation labor	0.39	8%	0.17	5%
Permitting, inspection, interconnection	0.01	0.2%	0.00	0%
Permit fees	0.07	1%	0.04	1%
Total local soft costs	**0.60**	**12%**	**0.24**	**6%**

It can be argued that these economic benefits could be offset if distributed solar results in higher overall economic costs for electric service, such that the higher costs for electricity are a drag on the local economy. Across the economy of all ratepayers – both solar customers and non-participating ratepayers – the added costs are the capital and operating costs of the solar facilities, while the benefits are the direct utility costs avoided by distributed solar. This is the comparison measured by the Total Resource Cost test. So long as distributed solar passes this test, there will not be an adverse impact on the economy from higher energy costs due to the use of distributed solar.

This local economic benefit occurs almost entirely in the year when the DER capacity is built. As shown in the above tables, the dollars spent in the local economy are 22% of residential solar costs, 12% of small commercial costs, and 6% of large commercial costs. We have assumed that these benefits are realized in the year that a system is installed.

Attachment RTB-4

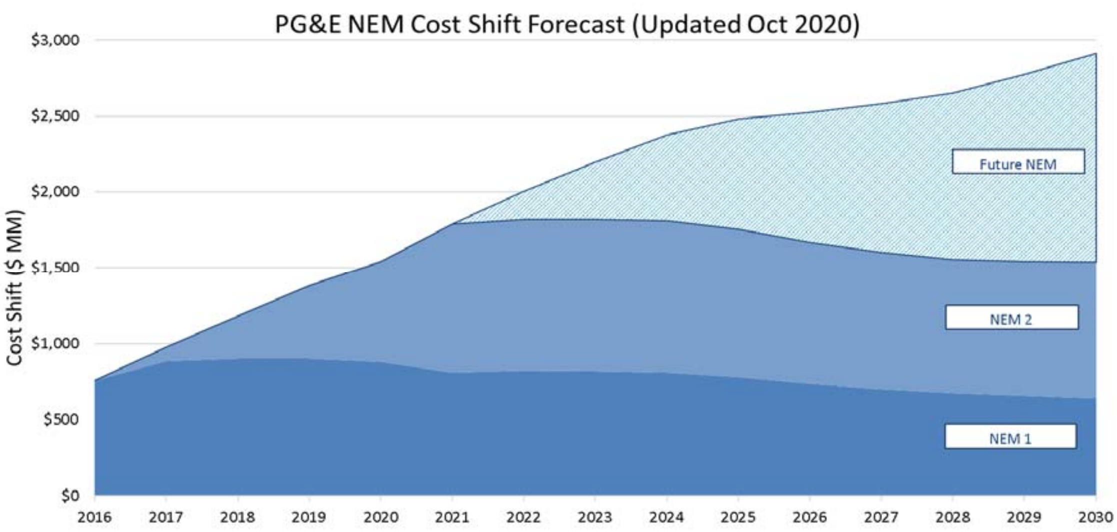
Analyzing the “Cost Shift” Argument

Analyzing the "Cost Shift" Argument

1. Background

California's investor-owned utilities (IOUs) and several consumer groups argue that there is today a multi-billion dollar per year "cost shift" that unfairly benefits customers who have installed solar and other distributed generation (DG) resources, with the money coming from other, non-participating ratepayers. The IOUs have calculated that the magnitude of the cost shift to existing solar customers will average almost $3.0 billion per year from 2022-2030.[91] This cost shift allegedly benefits the NEM 1.0 and 2.0 customers who have installed 10.3 GW of distributed solar on the IOU systems over the last two decades. The IOUs expect this cost shift to continue at roughly the same level for the rest of the decade, and to increase if new solar customers are allowed to take service under the NEM 2.0 tariff. The following **Figure 1** shows PG&E's calculation of these supposed cost shifts on its system from 2016-2030.

Figure 1



The size of the IOU-calculated cost shifts suggests that drastic action is needed to reduce the compensation to solar customers under NEM 3.0. And although no parties are proposing to change the net metering rules for NEM 1.0 and 2.0 customers during the approved 20-year legacy period after their systems entered service, TURN and NRDC have proposed new fees on NEM 1.0 and 2.0 customers. TURN proposes that NEM 1.0 and 2.0 customers should fund a portion of a "market transition credit" (MTC) incentive for new solar customers, while NRDC would levy a fee on NEM 1.0 and 2.0 customers to support low-income solar programs.

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91 From the IOU workpapers to their NEM 3.0 proposals. PG&E calculates an annual average cost shift from 2022-2030 of $1,680 million/year; SCE $780 million/year, and SDG&E $520 million/year.

2. Key Points

- We have analyzed the IOU cost shift calculations, and conclude that they are conceptually flawed, overstated, and fail to include important societal benefits of renewable DG.
- The "cost shift" that the IOUs calculate represents the above-market costs of existing solar DG installed under NEM 1.0 and 2.0. These above-market costs result principally from the rapidly-declining costs of rooftop solar over the last 15 years, not because solar customers have been overcompensated.
- The state's Renewable Portfolio Standard (RPS) program for utility-scale renewables also includes significant above-market costs for exactly the same reason – the rapidly declining cost of renewables since 2005. Thus, the above-market costs now attributed to the NEM program would have existed – at approximately the same level – even if utility-scale solar had been developed instead of customer-sited solar. Without rooftop solar, the above-market costs would have resulted from the RPS program instead of from NEM.
- The IOUs' calculated cost shift is overstated by almost 60%, because it fails to reflect the lifecycle benefits of the existing rooftop solar fleet or to recognize that any cost shift will decline as rate design changes over time and as customers adopt new technologies such as on-site storage. These corrections to the IOUs' numbers bring the above-market "cost shift" from the NEM program down to the same level as the above-market costs of the RPS program.
- The investments of over a million California customers in their own renewable generation has put the state well ahead of the state's Renewable Portfolio Standard (RPS), the statutory requirement for the utilities to adopt renewable generation. The 10.3 GW of existing rooftop solar now produces about $4.3 billion per year in additional, quantifiable societal benefits that policymakers should consider in weighing the overall economic and societal impacts of customers' investments in solar DG.
- The solar industry recognizes that the compensation for <u>future</u> solar customers needs to be re-calibrated today, due to increasing rates, the growing penetration of renewable resources, changing conditions on the CAISO grid, and the need to further reduce carbon emissions through electrification. This re-calibration should be forward-looking, should make gradual changes, and should apply only to new customers, in order respect the substantial and beneficial investments made by existing solar customers.

3. **Any "cost-shift" to existing distributed solar customers results largely from the declining cost of solar, and is no different than the existing above-market costs from utility-scale RPS contracts. The IOUs' alleged cost-shift fails to reflect this reality.**

The cost of solar generation at all scales has declined rapidly over the last 15 years. This is true of both residential rooftop solar (see **Figure 2**) and utility-scale solar (**Figure 3**).[92]

Figure 2 – *Residential Rooftop*

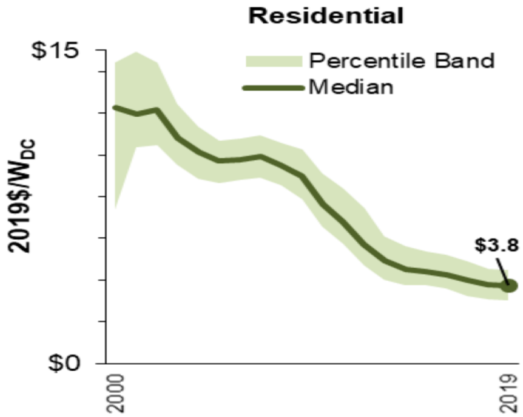
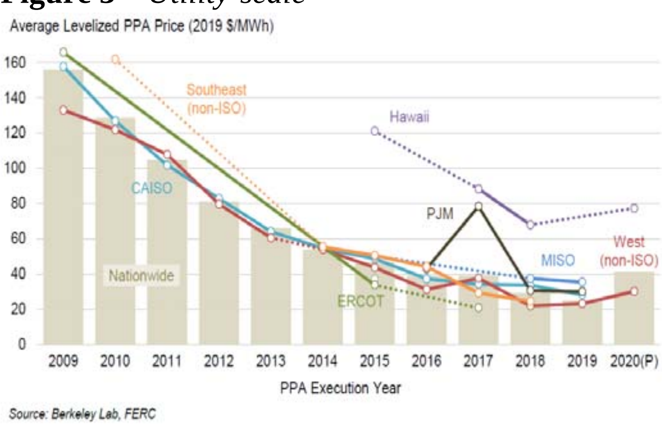


Figure 3 – *Utility-scale*

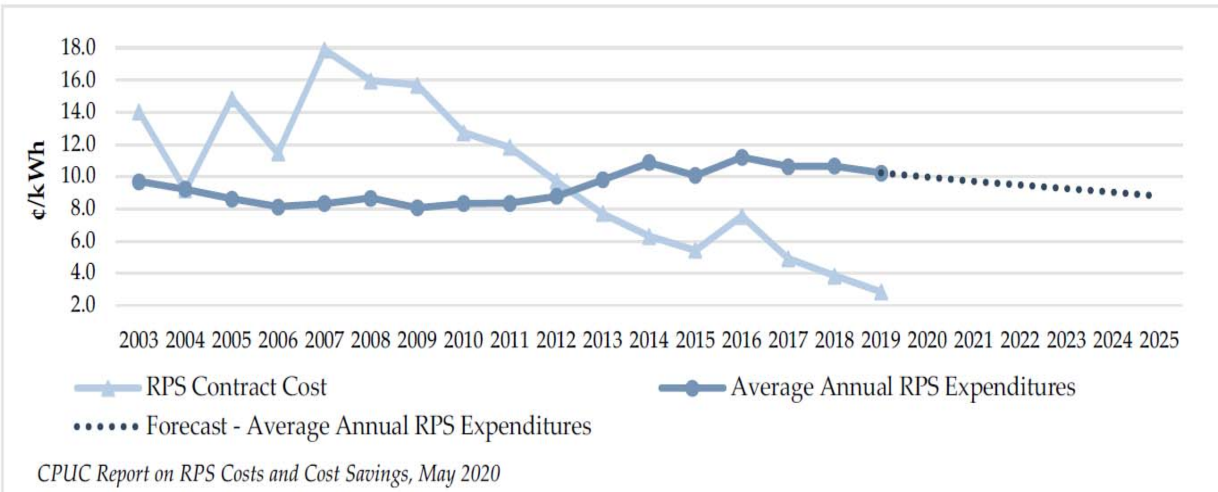


One result of the rapid decline in utility-scale solar costs is that the IOUs' generation portfolios now include significant above-market costs for higher-cost renewable generation (primarily solar and wind resources) that they have procured since 2004 to meet their past RPS

[92] These figures are from the most recent (2020) LBNL reports on the costs of distributed solar (Figure 2 is LBNL's Slide 21) and utility-scale solar (Figure 3 is LBNL's Slide 31).

targets. These above-market costs for past RPS purchases are well-documented in the CPUC's annual "Padilla Report" on RPS costs. **Figure 4** is from the most recent 2020 Padilla report, and shows that, in 2019, the average cost of RPS generation in the IOUs' portfolio was 10.2 cents/kWh, while the market cost of new RPS contracts in that year had declined to just 2.8 cents/kWh.[93] Thus, the IOUs' 2019 portfolios of RPS generation included about 7.4 cents/kWh of above-market costs.

Figure 4 – *2020 Padilla Report: RPS Contract Costs vs. Portfolio Cost*



The above-market costs of RPS renewables contracted in the past are the primary contributor to the IOUs' above-market generation costs as measured by their Power Charge Indifference Adjustment (PCIA) rate component. For example, in PG&E's rates effective January 1, 2021, the PCIA contributed $2.8 billion, or about 3.6 cents/kWh, to PG&E's revenue requirement. Assuming that 40% of IOU generation is RPS power that incurs 7.4 cents/kWh in above-market costs, it is easy to see that most of the PCIA costs are attributable to the above-market cost of the utility-scale renewables in the IOUs' RPS portfolios.[94]

If the IOUs had procured utility-scale renewables instead of the 10.3 GW of distributed solar that customers have developed over the last 15 years, the IOUs would have incurred additional above-market generation costs comparable to those in their existing portfolios of utility-scale renewables. They also would have incurred additional transmission costs to move

93 Figure 4 is Figure 2 on page 7 of the 2020 Padilla Report. See also pp. 2 and 5-7. Available at https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2020%20Padilla%20Report.pdf.

94 40% of 7.4 cents per kWh is 3.0 cents per kWh.

this incremental utility-scale generation to load centers – costs that are not included in the PCIA or the Padilla Report.[95] The fact that there are above-market costs for utility-scale renewables in no way suggests that the IOUs' procurement of RPS power has been excessive or imprudent. Generally, the utilities have procured RPS generation in compliance with (and even at times in advance of) the program's requirements. Instead, the above-market costs are due to the rapid decline in solar costs over this period. Indeed, California is the fifth largest economy in the world, and the state's aggressive programs to promote the deployment of renewables have played an important role in driving down the costs of renewable generation in the U.S. and worldwide, to the benefit of future ratepayers.

In the same way, policymakers also should expect and accept that customer-sited solar installed in California over this period has resulted in above-market costs for ratepayers. Over this period, the cost of residential solar also has dropped significantly, as shown in Figure 2. Compensation for solar customers under NEM 1.0 needed to be based on full retail rates in order to support the higher capital costs for solar in this early period of the market's development. In addition, during much of the NEM 1.0 period, distributed solar also received declining incentive payments through the California Solar Initiative (CSI). As the cost of rooftop solar dropped, the CSI incentives phased out and the Commission adopted the NEM 2.0 program in 2016. NEM 2.0 reduced the compensation for solar customers by requiring them to use TOU rates and removing certain non-bypassable charges from export credits. The change to a 4p to 9p on-peak period also has reduced compensation for NEM 2.0 customers. As with RPS generation, the above-market costs seen today for existing NEM 1.0 and 2.0 customers are largely the result of declining solar costs, and not the result of overcompensating solar customers.

When viewed in the light of this history, the IOUs' cost shift calculations for existing solar customers are founded on a false premise. The IOU calculations compare the primary costs of net metering – the lost revenues from solar customers producing their own power – to avoided costs from the 2020 Avoided Cost Calculator (ACC). But the 2020 ACC determines the avoided costs of <u>future</u> distributed renewable resources – the ACC model is based on the utility-scale renewable generation, storage, and T&D facilities that will not have to be built over the next 30 years due to forecasted distributed resources. The 2020 ACC is the right metric to determine the avoided costs of future solar systems installed under the upcoming NEM 3.0, but it is not the right metric for the costs avoided by NEM 1.0 and 2.0 systems – existing facilities that in many

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[95] For example, SCE reported in 2016 that, to meet the state's 33% by 2020 RPS goal, it would incur $6.4 billion in transmission costs to access about 25,000 GWh per year of annual RPS generation (based on SCE's 2012-2016 annual bundled sales of about 75,000 GWh per year). If one annualizes these capital costs with a real economic carrying charge, then adds O&M, the resulting cost is about 3 cent/kWh. See the Commission's 2016 RPS report to the Legislature, at p. 9, available at

cases have operated for years. In fact, existing NEM customers – and in particular NEM 1.0 customers whose systems mostly date from the years before 2017 – have avoided much more expensive renewable generation than measured by the forward-looking avoided costs for renewables in the 2020 ACC.[96] **As a result, if we are going to compare NEM 1.0 and 2.0 costs to the costs of current and future renewables using the 2020 ACC, then policymakers should be prepared to accept a similar level of above-market costs to those experienced today under the RPS program – the program that would have applied if NEM 1.0 and 2.0 generation had not been built.** As discussed in the next section, the current level of above-market costs for distributed solar under NEM 1.0 and 2.0, per unit of solar output, is not substantially different than the above-market costs incurred to date for RPS generation.

4. The IOU cost-shift calculations are overstated by almost 60%.

There are several ways in which the IOU cost shift calculations for NEM 1.0 and 2.0 customers are excessive. The IOUs end their calculations at 2030, whereas NEM 1.0 and 2.0 systems will produce significant power for many years after 2030. The NEM 1.0 and 2.0 fleets have average remaining lives of 17 and 22 years, respectively, assuming a 25-year useful life for distributed solar. The 2020 ACC shows that avoided costs escalate significantly after 2030, as it becomes progressively more difficult and costly to remove GHG emissions from the electric system. Thus, the IOUs significantly undervalue NEM 1.0 and 2.0 generation by ending the analysis in 2030. In addition, the IOUs use the current mix of rates chosen by NEM 1.0 and 2.0 customers. Over time, rate design will continue to evolve to reflect changing system conditions, and customers are likely to accept more aggressive TOU rate designs that will allow them to use less expensive off-peak power to electrify their homes, businesses, and vehicles. This will further reduce the cost shift calculated using today's mix of rates. Finally, existing solar customers may add storage to manage TOU rates and/or to improve the resiliency of their electric service. This will also increase the value of their solar systems and reduce any cost shift.

We have re-calculated the IOU cost shift numbers to address each of these issues. First, we included the full life-cycle benefits of NEM 1.0 and 2.0 systems based on the 2020 ACC. Second, we assumed that over time these customers will take service under an electrification rate, either by choice or because default rates evolve to approximate today's electrification rates. Third, we assume that that 25% of these customers will add storage. These changes reduce the

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http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Pub%20Util%20913.3%20Report%20-%20Final%20-%20Print%20-%20Revised.pdf.

[96] For example, we have used the LBNL data on the history of solar PPAs in California shown in Figure 3 to calculate that, if NEM 1.0 generation from 2008-2016 had been replaced with utility-scale solar PPAs, the weighted average price for those PPAs would have been 120% higher (i.e. more than double) the reported 2019 cost of utility-scale solar in California.

levelized above-market costs from NEM 1.0 and 2.0 customers by 58%, to a total of $1,260 million per year. This amounts to a "cost shift" of about 7 cents/kWh in above-market costs, similar to the current above-market costs of 7.4 cents for the RPS program, as shown in the 2020 Padilla Report.

5. Customer adoption of on-site renewables has put the state ahead of RPS requirements, resulting in $4.3 billion/year in societal benefits.

Customer adoption of 10.3 GW of customer-sited solar has put the state well ahead of where it would be if it relied only on utility-scale solar installed under the RPS program. Customers who serve their own loads with solar (and who export excess generation to serve their neighbors' loads) have reduced the serving utility's sales. This has decreased the utility's RPS requirement by the current RPS percentage (for example, 33% of sales in 2020) times the solar DG output of NEM 1.0 and 2.0 systems. Thus, a portion of renewable DG output (33% in 2020) has taken the place of utility-scale RPS generation. The remaining clean DG output (67% in 2020) has increased the penetration of renewables serving overall end-use electric demand and reduced emissions from the "brown" power that otherwise would be needed to serve that load. Thus, there have been significant incremental environmental and societal benefits from existing NEM 1.0 and 2.0 generation that should be considered in evaluating whether the above-market "cost shift" from existing solar generation is justifiable.

California's GHG reduction goals have now replaced the RPS targets as the binding constraints in future resource planning. From a GHG perspective, the existing NEM 1.0 and 2.0 solar fleets produce the same societal benefits as a comparable amount of utility-scale solar.

These incremental environmental and societal benefits can be quantified using the methodologies presented in Attachment RTB-3. The Commission has adopted an initial quantification of many of these benefits in D. 19-05-019, is working to refine these calculations,[97] and is studying their use in the current Integrated Resource Planning (IRP) proceeding R. 20-05-003. The point of this quantification is to place the above-market costs for this generation into the larger context of the broad public interest in increasing the penetration of renewable generation, at all scales, in California.

The following are the incremental environmental and societal benefits from the 67% of renewable DG output that has avoided the additional use of, and emissions from, brown power:

- **Social cost of carbon.** In D. 19-05-019, the Commission recognized the social cost of carbon (SCC) as a measure of the benefit of avoiding the damages associated with climate change.

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[97] The Commission's Energy Division and its consultants reported on this further work in a workshop in R. 14-10-003 held on December 9, 2020.

- **Health benefits from reductions in criteria pollutants.** Renewable generation displaces natural gas use, thus reducing emissions of criteria air pollutants (NOx, SOx, and particulates).

- **GHG reductions from reduced out-of-state methane leakage.** The 2020 ACC includes a direct avoided cost for avoided in-state methane leakage upstream of gas-fired power plants. This leakage can be avoided when gas use for electric generation is reduced. Displacing gas use for electric generation also reduces out-of-state methane leakage, because 92% of California's gas supplies are imported from outside the state.

There are also certain societal benefits that result only from the use of local, distributed generation sited in the built environment, and that are not produced by utility-scale renewables. These benefits should be attributed to 100% of the output of solar DG, not just to the 67% of existing solar DG that increases the penetration of renewables. These include:

- **Reduced land use for power generation.** Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station solar plants require larger single parcels of land, and are more remotely located where the land has other uses for agriculture or grazing. This estimate may be highly conservative, given that there are probably significant land-use constraints on the ability of California to meet its long-term GHG reduction goals solely with utility-scale solar and wind generation.

- **Benefits for the local economy**. Distributed generation has higher costs per kW than central station renewable generation. However, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in excess of what would be spent on wholesale, central station renewable generation. These local costs are an appreciable portion of the "soft" costs of DG. Central station renewables that qualify for the RPS program typically are not located in the local area where the power is consumed, and a portion of RPS resources are located outside of California.

Table 2 above presents our quantification of these societal benefits, using the methods discussed in Attachment RTB-3. We summarize these results again in **Table 10**.

Table 10: *Societal Benefits of NEM 1.0 and 2.0 (25-year Levelized $Millions/year)*

Benefit	**NEM 1.0**	**NEM 2.0**	**Total**
Period analyzed	*2021 to 2045*		
Methane Leakage	$465	$1,161	$1,626
SCC (above ACC)	$640	$1,224	$1,865
Health Benefits	$123	$253	$376
Local Jobs	-	$117	$117
Land Use	$13	$27	$40
Total	**$1,358**	**$2,903**	**$4,261**