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R.20-08-020 Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Metering

Corrected Joint IOU Rebuttal Testimony of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) on Issues 2-6 of Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles

Before the

Public Utilities Commission of the State of California

Rosemead, California
July 16, 2021

IOU-02: Corrected Joint IOU Rebuttal Testimony of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) on Issues 2-6 of Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles

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I.

EXECUTIVE SUMMARY

The NEM program was historically designed to jump start the solar rooftop industry, starting 25 years ago.[1] As the Solar Energy Industries Association (SEIA) and Vote Solar (VS) admit in their Opening Testimony, the California net energy metering program has been wildly successful: 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."[2]

There is near unanimity, even among parties representing the financial interests of the solar industry, that a cost shift exists and that at least some degree of reform is necessary.[3] Reform is needed to fix two major defects of the NEM subsidy: (a) the ability of solar customers (under today's rate design and NEM tariff structure) to avoid paying their share of the cost to provide them with service; and (b) the fact that solar customers' exports to the grid are compensated at the full retail rate — a rate much higher than the price the utility pays for other power supply.

NEM customers pay too little for their use of the grid, and they are paid too much for the power they supply to it. Our proposal seeks to correct these disparities for customers that adopt distributed generation in the future. At this time, we do not propose to modify existing tariffs for legacy customers.

Supporters of serious NEM reform span a wide range of interests and perspectives: consumer advocates like California Public Advocates (CalPA or CalAdvocates), The Utility Reform Network (TURN), small businesses (Small Business Utility Advocates), environmental advocates like Natural Resources Defense Council (NRDC) and Sierra Club, and the Coalition of Utility Employees (CUE). A common motivating factor for reform is to ensure that California makes progress on its clean energy

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1 CUE Opening Test., p. 10:9-10.

2 SEIA/VS, T. Beach, p. i.

3 SEAI/VS, Opening Test. of T. Beach, P. i. ("SEIA and Vote Solar fully recognize that the residential NEM program should be updated.") CalSSA, page 4. ("CALSSA agrees with other parties that it is appropriate for NEM export compensation in daytime hours to decline, but the reduction must be gradual over time.")

commitments while also addressing high electricity costs, the energy burdens on low-income consumers, and the need to move from a relatively blunt policy instrument originally designed to stimulate the early stages of a solar market and industry to one where the next generation of adopters of rooftop solar no longer receive significant subsidies paid for by non-participating consumers. The Commission should not ignore this overwhelming theme of and call for meaningful reform by so many diverse parties. The legislature's mandate in enacting AB 327 also calls for reform. Only the solar parties would have the Commission implement marginal changes in the program and do so over an extended period of time.[4]

It is generally unfair to ask non-participating customers to continue to subsidize new solar installations. Consumers are more accustomed to the idea of solar energy, and the solar industry is so much more mature, successful, and profitable than 25 years ago when NEM was implemented in California. What was appropriate for nascent markets and technologies is neither appropriate nor necessary for continued deployment of rooftop solar by new adopters in California. At this point in the evolution of the solar market, the solar industry should be able to sustain itself — in the context of declining costs for solar projects and solar paired with storage, and the fact that such projects are no longer novel with the public — without relying upon a wealth transfer to adopters of rooftop solar from non-participating customers, the majority of whom are middle-class and lower-income customers. The Commission therefore should not — and need not — continue the outsized and outdated subsidy to continue the growth of the solar rooftop industry.

Reform of the tariff is needed now for customers adopting new distributed generation installations. After 25 years of the NEM program, and after 5 years of NEM 2.0, reform needs to happen coming out of this proceeding, and not incrementally or gradually over the next decade, as some parties suggest. The total amount of the NEM subsidy is \$3.4 billion per year and growing. Without reform and with new customers signing on to NEM service, that number climbs to \$10.7 billion by 2030. On average, that equates to a bill increase of ~\$250 per year for nonparticipating customers in SDG&E's territory, where rooftop solar penetration is the highest (~\$555 by 2030).

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[4] SEIA/VS, T. Beach, pp. ii, iii, 6, 36-40, 46; CSSA, pp. 5-7, 10.

The utilities have interconnected only 150,000 or less than 10% of total NEM systems for low-income customers.[5] NEM customers are disproportionately wealthy, resulting in lower-income customers having to absorb the increasing costs to subsidize solar deployment. That is why our proposal seeks to significantly reduce the subsidy for next-generation adopters of solar by reducing compensation for their surplus energy exports to the avoided-cost rate and by imposing a grid charge to such customers (except for lower-income customers, for whom the proposal provides a deep 80 percent discount on the grid charge).

To put the size of this cross-subsidy from poorer to wealthier customers in context: the NEM cost shift dwarfs the dollar amount of bill assistance provided to low-income customers. Specifically, the NEM subsidy, which the Joint Utilities' customers provide to approximately 1.1 million NEM customers, is more than twice as large as the CARE subsidy provided to 2.8 million income-eligible customers. With the added and serious financial stress that the pandemic and related economic hardships have caused for many Californians, it is now time (and long overdue) for the Commission to relieve low-income customers of the cost burden of over-generous subsidies for adoption of rooftop solar systems.

Moreover, despite the overwhelming evidence that the cost shift is real,[6] parties advocating for the solar industry advance numerous specious arguments as a distraction to the size of the cost shift. For example, they make obvious false equivalences between NEM, on the one hand, and energy efficiency (EE) programs and the Renewables Portfolio Standard (RPS) procurement programs, on the other. Chapter 6 below, explains in detail why these programs are not analogous to NEM, do not create a cost shift, and have no bearing on the issue presented in this proceeding.[7]

Although most of the solar-industry advocates acknowledge that some level of cost shift exists, their proposals actually perpetuate the cost shift due to a very-gradual transition away from the current

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[5] See IOU-specific CARE NEM participation in Chapter 1 of the Joint Utilities Opening Testimony.

[6] See, e.g., TURN Opening Testimony, pp. 3,7, 9; NRDC Opening Testimony, p. 27; CalPA Opening Test., pp. 2-21, 3-28. See cost-shift discussion in Chapter 2, below.

[7] SEIA/VS, T. Beach, Executive Summary, p. iv.

NEM model — apparently distrusting the willingness of new customers to purchase their products and services, and/or their own companies' ability to adapt to and innovate in the context of a changing market. Such lack of faith is curious in light of the major solar companies' expression of confidence to investors.[8]

The gradual transition proposed by solar-industry advocates would be unfair to low-income consumers in particular. Low-income customers should be the singular focus on any going-forward subsidies for new adopters of rooftop solar that are paid for by non-participating customers. Our proposal builds on that principle, both in terms of the core design of the successor tariff but also in terms of the transitional discount and innovative STORE proposal for income-eligible consumers.

The solar parties in fact call for at least a five-year transition period during which subsidies would remain available to customers that newly adopt rooftop solar[9] and that such a transition is warranted "to address the balance between participating and non-participating ratepayers."[10] Continuing the transition for new adopters of rooftop solar for yet another five years beyond the Commission's approval of NEM 2.0 in 2016 would be profoundly unfair to non-participants.

Maintaining the *status quo* is contrary to AB 327's reform directives and is unreasonable because it will not only harm customers but also undermine the state's equity, energy, and environmental policy goals. Contrary to the stated position of SEIA/Vote Solar that "SEIA and Vote Solar fully recognize that the residential NEM program should be updated", their proposal does not do so in any meaningful way and indeed would create tension with the goals of electrification and increasing access to affordable energy (much less to solar power) to low-income customers.[11] If any subsidy is to continue, it must be one that either (a) encourages and incentivizes electrification, such as NEM systems paired with energy storage, and/or (b) focuses on making rooftop solar and/or storage more attractive to income-qualified customers. Our proposal focuses on ensuring that the goals of NEM tariff reform, equitable energy

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[8] See Chapter 2 of Opening Testimony of the Joint Utilities.

[9] SEIA/VS, T. Beach, Executive Summary, p. ii.

[10] SEIA/VS, T. Beach, 6:6-8.

[11] SEIA/VS, T. Beach, Executive Summary, pp. i-ii.

access and electrification are aligned rather than at odds with one another (as are the proposals of the solar industry advocates).

Realizing the state's carbon, electrification, and equity goals for 2045 requires that the Commission reject any proposals that do not meaningfully and significantly reduce or eliminate the cost shift and that are not cost-based. A subsidy program like NEM that increasingly drives up utility bills for those who can least afford it will stall the state's important and ambitious objectives. There are enough challenges for electricity customers to absorb (e.g., related to grid modernization, wildfire prevention and response) without also continuing the cost burden of NEM 1.0 and 2.0. For that reason, the Commission must implement reforms as expeditiously as possible and without adopting any of the dilatory proposals made by parties representing the solar industry.[12]

Clearly, reform tariffs are likely to be more complicated than the original simple structure of the NEM program. While that simple ratemaking policy approach may have suited a market in start-up mode, it is no longer appropriate today (25 years later) in the context of market transformation and technology cost changes. In fact, retaining the NEM 2.0 tariff going forward would provide false information to the new NEM customer about his/her reliance on the grid for both imports and exports of power to the home. (And of course, the current NEM 2.0 tariff also sends inappropriate pricing messages to those on that rate that they provide greater value to the system than consume from taking service from the utility.)

The Commission should resist those proposals that add unnecessary, confusing, and administratively complex techniques such as SEIA/VS's proposed vintaging of different export costs and triggers for step-down of compensation levels as the market meets certain adoption targets.[13]

The Commission faces an important task of transitioning NEM, a once-constructive policy instrument, to the next phase. That next phase should continue to enable consumers that want to and can

[12] In addition to our proposal, TURN, CalPA, NRDC and others advocate for reform to NEM to significantly alleviate or eliminate the cost shift onto non-participants.

[13] SEIA/VS, T. Beach, 44-45.

adopt on-site distributed generation to do so, but not to do so at the expense of consumers who bear the monthly challenges of paying for basic services.

Our proposal provides the Commission with the means to make that transition.

II.

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?

A. The Commission Should Recognize the Cost Shift and the Detrimental Impact on California's Policy Goals

The NEM 2.0 Lookback Study (Lookback Study) concluded that NEM 2.0, like NEM 1.0 before it, is not cost effective and induces cost shifts that increase electric bills for non-participating customers.

Following the Lookback Study, subsequent reports directed by the Commission highlighted similar conclusions, including the February 2021 CPUC Staff Whitepaper on Electric Costs and Affordability as well as E3's comparative analysis of party proposals published in May 2021 (conducted at the request of the CPUC staff).

On top of these Commission directed reports, the Next 10/Energy Institute at UC Berkeley Haas School of Business paper on electricity rates in California also points to a large NEM cost shift that is creating upward rate and bill pressure for non-participating customers.

These Commission and third-party analyses and studies clearly identify there is a large and growing cost shift created by the current NEM program and that reform is desperately needed.

1. There is Overwhelming Agreement that the Cost Shift is Real

Many parties have either endorsed the findings of the Lookback Study or have prepared estimates of the cost shift that offer important conclusions along the same lines.

In light of these studies, it's clear that the NEM 1.0 and NEM 2.0 tariffs have resulted in the majority of residential customers supplying subsidies to those residential customers that have adopted rooftop solar. However important and valuable such support has been in the past, there can be no dispute that such cross subsidies (otherwise known as cost shifts[14]) have occurred and, without significant changes in the NEM 2.0 tariffs, will continue to grow into the future.

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[14] For example, the 2021 CPUC Staff white paper on the affordability of the Joint Utilities' electricity rates defined the cost shift this way: "NEM cost shift reflects the cost shift created by residential NEM customers that non-NEM customers (also referred to as "nonparticipating" customers) may be paying in higher rates.

(*Continued*)

Even solar parties concede there is a cost shift but minimize it by overstating societal benefits,[15] as discussed more fully below in Chapter 3.

Analyses prepared by third parties, by intervenors, and by entities in other jurisdictions agree that under traditional NEM rate designs, there is a real transfer of wealth from those customers (especially residential customers) that do not adopt rooftop solar to those that do.

It is time for tariff reform for California's large investor-owned electric utilities.

a) <u>Third-Party Analyses Prove the Cost Shift is Real</u>

As explained in Chapter 3 of our Opening Testimony, multiple studies published in 2021 show significant amounts of costs shifted from our residential NEM customers to non-participating customers.[16]

The Lookback Study, which was conducted at the request of the Commission, found overall that "NEM 2.0 participants benefit from the structure, while ratepayers see increased

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NEM Cost Shift = NEM Customer Bill Savings – Avoided Costs where "Bill Savings" is the yearly dollar amount that NEM customer avoid paying because of their self-generation and netting (compensation) and "Avoided Costs" are fixed and variable costs of service that the utility should avoid incurring as a result of distributed generation." Source: Bridget Sieren-Smith, Ankit Jain, Alireza Eshraghi, Simon Hurd, Julia Ende, and Josh Huneycutt, "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates and Equity Issues Pursuant to P.U. Code Section 913.1," California Public Utilities Commission, February 2021 (hereafter "CPUC Staff 2021 White Paper on Electric Costs"), p. 28, .

[15] *See*: Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar, p. 63:8-11 and Attachment RTB-4. Mr. Beach states his view that the cost-shift estimates prepared by the IOUs are overstated by 60%.

The Clean Coalition acknowledges a cost shift. Prepared Direct Testimony of Ben Schwartz on Behalf of the Clean Coalition, p. 3:39-42.

The Silicon Valley Leadership Group does not address the size of the cost shift but rather argues that the "cost shift argument is a large enough concern to eliminate NEM altogether." Opening Prepared Testimony of The Silicon Valley Leadership Group [Witness Tim McRae], p. 4:5-6.

The California Solar and Storage Association refers to "purported lost revenues" and "purported cost shifts" and addresses reasons why, in the view of the witnesses, that there are avoided cost benefits that were not taken into account in estimates of the cost shift. Prepared Direct Testimony of Brad Heavner and Joshua Plaisted on Behalf of the California Solar and Storage Association, pp. 98:13-15, 103:10-13, and 125:2-7.

[16] Joint Utility Opening Testimony, pp. 80-83.

rates" and the cost to the electric utilities' customers exceed the value of the energy produced by NEM customers.[17]

Using the Commission's Standard Practice Manual (SPM) to evaluate the cost-effectiveness of the NEM 2.0 program, the Lookback Study analysis indicates that participants receive more value than their costs (see the participant cost test (PCT) results below in Table II-1 excerpted from the Lookback Study[18]), while other customers get less value than they pay (see the ratepayer impact measure test (RIM) below). In this analysis, participants have costs of $12.0 billion, compared to the $21.3 billion in monetary benefits they receive. By contrast, non-participants see a net cost impact of $13 billion in their electricity bills (which results from their costs of $20.6 billion less benefits of $7.6 billion).

Even using the total resource cost (TRC) test, NEM 2.0 produces fewer benefits ($8.0 billion) than costs ($9.5 billion)[19], for a net cost of $1.5 billion. In the table below, a benefit-cost ratio less than 1.0 indicates a net cost.

[17] Lookback Study, p. 1.

[18] Lookback Study, Table 5-1. Note that the original table in the Lookback study includes all four tests provided in the CPUC SPM: Participant Cost Test; Total Resource Cost Test; Ratepayer Impact Measure Test; and Program Administrator Cost Test. The Table II-1 omits the Program Administrator Cost Test because it is not informative with respect to NEM 2.0 cost effectiveness. (See Direct Testimony of Michele Chait on Net Energy Metering Reform Proposals Submitted on Behalf of The Utility Reform Network, page 3:25-26.)

[19] It is important to note this analysis is based on the 2020 ACC and benefits would be lower with the updated 2021 ACC.

Table II-1
Lookback Study Summary of Cost Effectiveness of NEM 2.0
Using Three Benefit-Cost Tests

Utility	Weighted Average Benefit-Cost Ratio		
	Participant Cost Test (PCT)	Total Resource Cost Test (TRC)	Ratepayer Impact Measure Test (RIM)
PG&E	1.81	0.80	0.33
SCE	1.54	0.91	0.49
SDG&E	2.03	0.84	0.31
Total	1.77	0.84	0.37
	Total Net Present Value ($ Billion)		
Benefits	$21.329	$7.960	$7.576
Costs	$12.041	$9.462	$20.583

Separately, the CPUC Staff 2021 White Paper on Electric Costs explained that "[a]ll residential non-NEM or non-participating customers, including California Alternate Rates for Energy (CARE) customers, shoulder an additional rate burden as a result of the cost shift from NEM customers. Potential equity concerns related to the NEM cost shift include the following:

- As of November 2020, PG&E had approximately 519,000 residential NEM customers and 1.3 million CARE customers. Of these CARE customers, only about 5 percent are NEM participants, meaning approximately 95 percent of CARE customers did not participate and therefore bear the cost responsibility of compensating NEM customers.
- SCE had, as of December 2020, approximately 361,000 residential NEM customers and 1.5 million CARE customers. Of these CARE customers, only 4 percent participate in NEM, meaning over 1.4 million CARE customers, or about 96 percent, shoulder the additional cost burden from all NEM customers.
- As of November 2020, SDG&E had approximately 199,000 residential NEM customers and 320,000 CARE customers. Of these CARE customers, only 8 percent are NEM participants. CARE customers are currently seeing bills that are 13 percent higher because of the NEM cost shift."[20]

20 CPUC Staff 2021 White Paper on Electric Costs, pages 28-29. (Footnotes in the original text have been omitted here.)

The most recent analysis of NEM impacts that was commissioned by the CPUC (and conducted by E3[21]) also found there is a large and growing cost shift created by NEM 2.0. Per E3's analysis, if no change were made to NEM 2.0, a new solar customer interconnecting in 2023 would shift ~$1,860 of utility costs from participants to non-participants in the first year after interconnection. That number would grow over 40%, to approximately $2,625 per new solar customer interconnecting in 2030.[22] Additional results from the E3 comparative analysis can be seen in Chapters 3 and 5 of this Rebuttal Testimony.

In their 2021 analysis of "Designing Electricity Rates for An Equitable Energy Transition," Professor Severin Borenstein and co-authors at the Energy Institute at Haas concluded that "greater adoption of behind-the-meter ([BTM]) solar photovoltaic ([PV]) panels—which represented more than 15 percent of the residential electricity consumption across the PG&E, SCE, and SDG&E service territories in 2019—has disproportionately shifted cost recovery onto non-solar customers adopters."[23] The authors estimate that there are "economically significant annual bill increases for both CARE and non-CARE customers. The impacts are particularly striking in SDG&E territory where residential PV generation accounted for more than 20 percent of residential consumption in 2019. Non-CARE and CARE rates increase by five cents and three cents, respectively. This translates into annual average bill increases of approximately $230 and $124 for non-CARE and CARE customers."[24] The authors report the corresponding figures for PG&E and SCE in a chart, which appears to show annual

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21 E3's "Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020 – A Comparative Analysis". May 28, 2021.

22 Represents E3's calculated cost shift of solar only, non-CARE customers; dollar amounts reflect the average of the Joint IOUs. E3 used average residential system sizes of 4.7 kW-DC for PG&E and 4.4kW-DC for SDG&E and SCE, lower than the average system sizes seen in each respective IOU's service territory resulting in lower than average cost shift per customer estimates.

23 Severin Borenstein, Meredith Fowlie, and James Sallee, "Designing Electricity Rates for An Equitable Energy Transition," Energy Institute at Haas, U.C. Berkeley and Next 10, February 23, 2021, page 4 (hereafter "2021 Energy Institute Study"), https://www.next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdf.

24 2021 Energy Institute Study, page 28.

average bill increases of approximately $145 and $100 for PG&E's non-CARE and CARE customers, and approximately $95 and $65 for SCE's non-CARE and CARE customers.[25]

b) **Many Intervenors Agree the Cost Shift is Real**

Several consumer-advocate and environmental-advocate intervenors in this proceeding also agree that the current NEM 1.0 and 2.0 tariffs create a "massive"[26] cost shift from non-participants to NEM customers. In the words of a witness from one of these organizations, Alec Ward of California Public Advocates (CalPA), "nonparticipants are not served at just and reasonable rates" because of the unfair cost burden they bear.[27]

In addition to pointing to the analyses and findings of the Lookback Study, CalPA made its own estimates which concluded that the cost burden that results from existing NEM 1.0 and 2.0 customers will amount to $41.1 billion over the remaining years of their NEM service.[28] CalPA reports the "combined total cost burdens of the NEM 1.0 and 2.0 tariffs are $1.774 billion per year for PG&E, $1.024 billion per year for Southern California Edison (SCE), and $574 million per year for SDG&E. These amounts represent a recurring annual transfer of revenues from nonparticipants to existing NEM customers that is not supported by any avoided costs. […] The current policy is unsustainable and if left unchanged, the total cost burden of the NEM 1.0, NEM 2.0, and successor tariffs (assuming no reform), that nonparticipants will pay for, will grow to $6.9 billion per year by 2030 in today's dollars" (2021$).[29]

Pointing to the low benefit/cost ratios for the NEM 1.0 and 2.0 programs using either the RIM or the TRC cost-effectiveness test, CalPA concludes that "ratepayers are spending

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[25] 2021 Energy Institute Study, p. 28, Figure 5. The numbers referenced in the sentence above are based on a visual interpretation of the numbers in Figure 5, which were not provided in any written text to accompany the figure.

[26] Footnote on massive: Direct Testimony of Michele Chait on New Energy Metering Reform Proposals Submitted on behalf of The Utility Reform Network (TURN), p. 3:3.

[27] Prepared Testimony [of Alec Ward] for a Successor Tariff to the Current Net Energy Metering Tariffs of the Public Advocates Office of the California Public Utilities Commission, p. 2-16, lines 3-10.

[28] CalPA Testimony of B. Gutierrez and N. Chau, p. 1-7: lines 6-11, and CalPA Chapter 2, generally.

[29] CalPA Testimony of B. Gutierrez and N. Chau, p, 2-18: lines 5-14.

billions of dollars on a program with costs that greatly outweigh the benefits."[30] CalPA further states that "NEM creates a subsidy for customers who can afford to install rooftop solar, or other BTM generation. This subsidy is not explicit but is built in to the NEM tariff and results in a cost burden that drives unreasonable increases to overall electricity rates. This cost burden also discourages sustainable growth in BTM generation adoption, because without a policy shift, the cost burden due to BTM generation will exacerbate electric service equity and affordability issues to the point where continued incentives for adoption of vehicle and building electrification will be impossible without creating additional cost burdens on lower income customers."[31]

Another of California's premier consumer-advocate groups, TURN, also recognizes the cost-shift. As TURN points out: the "results of the NEM 2.0 Lookback Study demonstrate the massive cost shift associated with both the NEM 1.0 and 2.0 tariffs, the failure of NEM customers to adequately contribute to their cost of service, and the over subsidization of participants. These results highlight the importance of major reforms to balance the interests of participants and non-participants. The low levels of NEM participation by CARE customers, when compared to non-CARE customers, demonstrates the need for new tariff structures that protect lower-income ratepayers from cost shifting and will result in enhanced participation by CARE customers."[32]

Informed by the results of the Lookback Study, TURN recommends that the Commission rely upon the PCT and RIM tests as the appropriate tests in evaluating which successor proposal(s) properly balances the interests of participants and all customers.[33] NRDC also advocates that the RIM test is the right one to evaluate the impact of NEM proposals on rates.[34]

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30 CalPA Testimony (A Ward), p. 2-15:16-24.

31 CALPA (Ward Testimony), p. 2-16:7-14 (footnotes in the original are omitted).

32 TURN Testimony, p. 3:3-5.

33 TURN Testimony, p. 3:21-23.

34 Opening Testimony of Mohit Chhabra Sponsored by the Natural Resources Defense Council (NRDC) on the Net Energy Metering Successor Tariff Proposal, p. 8:8-10.

As recommended by these parties, using the types of analyses described in the Lookback Study, and then using that framework to compare the alternative successor tariff proposals can shed important light on the fairness questions related to reducing, if not eliminating, the cost shift.

c) <u>Proposals tied to retail compensation do not fix the cost-shift problem</u>

The Lookback Study compares the RIM benefit/cost ratios for each of the Joint Utilities under NEM 1.0 and NEM 2.0.[35] As shown in Table 1-6 of the Lookback Study, not only are these RIM ratios less than 1.0 for all of the utilities for both residential and non-residential customers, but also the benefit/cost ratios for NEM 2.0 are lower than those for NEM 1.0 in all such cases.

The Lookback Study relied on the NEM 1.0 cost-effectiveness and cost-of-service results from the E3 2013 California Net Energy Metering Ratepayer Impact Evaluation for NEM 1.0 cost-effectiveness and cost-of-service results.[36] Although the results are not precisely comparable, the Lookback Study found that "the NEM 1.0 RIM benefit-cost ratio inferred from the E3 study is similar to the results calculated in this study for NEM 2.0 across utilities and customer sectors."[37]

These results indicate that the changes in the NEM 2.0 tariff that improved non-participant equity were insufficient to counteract the effects of other factors and changes (such as lower avoided costs, larger PV system sizes) that degraded the benefit/cost ratios. The Lookback Study explains that like NEM 1.0, the NEM 2.0 tariff compensates customer generators for their exports to the grid at the full retail rate, even though NEM 2.0 introduced "charges intended to align NEM customer costs more closely with non-NEM customer costs."[38]

An important take-away from the Lookback Study's analysis is that the design of NEM 2.0, with a structure built on compensating exports at the retail rate, did not meaningfully address the cost shift problem, which of course has grown significantly over time. The Commission's decision in NEM 2.0 to transition NEM by adding other tariff elements (e.g., "a one-time interconnection fee,

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[35] Lookback Study, Section 1.6 (pp. 11-12).

[36] Lookback Study, p. 11, citing to California Net Energy Metering Ratepayer Impacts Evaluation. Energy and Environmental Economics. October 28, 2013. https://www.cpuc.ca.gov/General.aspx?id=8919.

[37] Lookback Study, p. 11.

[38] Lookback Study, pp. 15-16.

...non-bypassable charges, and [a] transfer to a time-of-use (TOU) rate"[39]) failed to significantly change benefit/cost ratios for non-participating customers compared to NEM 1.0.

From a rate-design policy point of view, the Commission should keep this in mind as it reviews proposals (e.g., the SEIA/VS proposal) that would maintain the tariff structure with export compensation tied directly to retail rates (or would only introduce a gradual percentage reduction relative to the full retail rate, as SEIA/VS propose through a "stepdown schedule"[40]). Hypothetical future changes to rate structures (e.g., an assumed introduction of residential class fixed charges or voluntary migration to "electrification" rates[41]) are unlikely to mitigate the cost shift and increasing burden on nonparticipating customers. Unless the new tariff embodies significant structural changes to fully delink export compensation from the retail rate and tie that compensation to avoided costs and include some method(s) of fixed cost recovery, then the reform tariff will not fix the cost-shift problem.

d) Other Jurisdictions Have Recognized that NEM Results in a Wealth Transfer and that the Cost Shift is Amplified as Penetration Levels Rise

Other states that have undertaken NEM reform did so in large part to address the kinds of cost shifts that were analyzed in the Lookback Study. (See Chapter 2 of the Joint Utilities' Opening Testimony, on actions in these other states.)

When discussions began around 2013 to reform Hawaiian Electric Companies' NEM tariff, for example, the utility estimated the annual cost shift per non-participating customer to be $31/customer.[42] The Hawaii Public Utilities Commission (PUC) approved the implementation of alternative tariff options in 2015 and then again in 2018.[43] Notably, at the time that Hawaiian regulators

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[39] Lookback Study, p. 16.

[40] SEIA/VS (Beach) Direct Testimony, Table 6 (p. 45).

[41] SEIA/VS (Beach) Direct Testimony, pp. 36-44 generally.

[42] Hawaiian Electric Companies propose plan to sustainably increase rooftop solar," Hawaii News Now, January 20, 2015, https://www.hawaiinewsnow.com/story/27896485/hawaiian-electric-companies-propose-plan-to-sustainably-increase-rooftop-solar/; Sherilyn Wee and Makena Coffman, "PV Growth in Hawaii?" University of Hawaii Economic Research Organization, October 13, 2014, https://uhero.hawaii.edu/pv-growth-in-hawaii/

[43] See Chapter 2 of the Joint Utilities' Opening Testimony.

approved changes in NEM tariffs, the penetration rates were relatively high (e.g., in 2015, net-metered residential PV penetration rates for the four electric utilities in Hawaii ranged from 10.5% to 18%, compared to 7.7% for SDG&E and 5.3% for PG&E at the time).[44]

In the 2020 South Carolina Public Service Commission (PSC) proceeding in which Duke Energy Carolinas proposed a successor tariff to its NEM program, Duke estimated a cost shift of $35-$40 per month per NEM solar customer (and then compared it to the cost-shift estimate of $45 per month per NEM solar customer that had been prepared by E3).[45] As explained in Table II-1of the Joint Utilities' Opening Testimony, the customer participation rate for NEM in South Carolina was 1.4% at the time that, in 2021, the South Carolina PSC approved a settlement agreement (to which Vote Solar was a signatory) to reform the NEM tariff and to greatly reduce the cost shift.

By contrast, the Joint Utilities' NEM program has much-higher participation rates than in South Carolina, especially among residential customers: As of the end of 2020, 10.6%, 8.4% and 15.4% of PG&E's, SCE's and SDG&E's residential customers are on NEM rates.[46] These penetration rates approach those of Hawaii's utilities at the time the regulators determined there needed to be meaningful reforms in the NEM program.

While NEM might initially have had minimal cost shift impact when penetration rates were low in California, that is no longer the case for the Joint Utilities.

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[44] Galen Barbose, "Putting the Potential Rate Impacts of Distributed Solar into Context," Energy Analysis and Environmental Impacts Division Lawrence Berkeley National Laboratory, January 2017, page 10, https://www.osti.gov/servlets/purl/1469160/.

[45] Direct Testimony of Brian Horii on Behalf of the South Carolina Office of Regulatory Staff, Docket No. 2019-182-E in re: SC Energy Freedom Act-Net Energy Metering, page 13:18-19, https://dms.psc.sc.gov/Attachments/Matter/877d4dcb-257a-4031-be67-71b292e2262e.

[46] See Table II-1 of the Joint Utilities' Opening Testimony.

2. The Wealth Transfer Causes Real Harm to Customers and the State

a) The Cost Shift Harms California's and the Commission's Equity Goals

The demographic analysis in the Lookback Study, when combined with the study's findings that NEM 2.0 is not cost effective for non-participants, support a conclusion that the program imposes a wealth transfer from lower-income to higher-income customers.[47]

In Section I of California Utility Employees' testimony, Dr. Earle provides a detailed and succinct explication of the fundamental unfairness of the now-massive cost shift that results from the NEM 2.0.[48] He summarizes his bottom line on the inequities of the current (and future) rate impacts by pointing out that the "enormity of the wealth transfer from non-NEM customers to NEM customers is compounded by income and racial disparities in the wealth transfer."[49]

The solar advocates have not provided sufficient justification for why, after 25 years of full net metering to start up the market in California, the interests of solar adopters should outweigh those of other households, and in particular, the interests of residential electricity customers for whom paying their basic electricity bills is a burden.

The cost shift to date from the legacy NEM 1.0 and 2.0 program adds to California's growing energy affordability problem, as explained in the Joint Utilities' Opening Testimony.[50] Continuation of the current rate structure (as recommended by the Environmental Working Group[51]) or approval of multi-year process for lowering NEM's export rate from the retail rate

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[47] Lookback Study, pp. 4 ("NEM 2.0 projects overall are not cost-effective from the perspective of ratepayers."), 5 (Table 1-2, which shows that solar and solar paired with storage have benefit/cost ratios lower than 1.0 for each utility under both the Total Resource Cost (TRC) test and the Ratepayer Impact Measure (RIM) test), and 39 ("In general, we observed that a higher fraction of NEM systems have been installed in more affluent ZIP codes with higher percentages of homeownership than California's population on average.").

[48] Testimony of Robert Earle on Behalf of the Coalition of California Utility Employees, Section I (pp. 1-13). *See*, for example: "The NEM 2.0 Lookback Study documents the damage done to ratepayers by NEM 2.0 with an average RIM of 0.37.6 In other words, for every dollar NEM has cost ratepayers, they have received an astoundingly low 37 cents of benefits. Ratepayers have wasted almost 2/3 of the money they have spent on NEM 2.0."

[49] CUE Testimony, p. 6.

[50] Joint Utilities' Opening Testimony, pp. 49:5 through 52:15, for example.

[51] EWG Testimony, p. 28:6.

to avoided cost (as recommended by SEIA/VS and CALSSA) would undermine efforts to address the energy-burden challenge faced by many Californians.

The Commission staff recognized in its 2021 evaluation of utility rates, costs and equity issues, that the "need to improve the safety and reliability of the electric system while meeting California's climate goals and various statutory mandates will require careful management of rate and bill impacts to ensure that electric services remain affordable. As California continues transitioning to a more robust distributed energy resources marketplace with greater deployment of electric vehicles, it will be essential to employ aggressive actions to minimize growth in utility rate base and to protect lower-income ratepayers from cost shifts and bill impacts."[52]

In short, the staff assessment concluded that the "CPUC faces multiple intersecting policy mandates that require a delicate balance to avoid unintended consequences. If handled incorrectly, California's policy goals could result in rate and bill increases that would make other policy goals more difficult to achieve and could result in overall energy bills becoming unaffordable for some Californians."[53]

The Commission should take steps in the current NEM successor tariff proceeding to relieve low-income customers of the cost burden of shouldering further, overly generous subsidies for adoption of rooftop solar systems. Otherwise, the decision in this proceeding will undermine the ability of the State and the Commission to advance its equity goals.[54]

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[52] Bridget Sieren-Smith, Ankit Jain, Alireza Eshraghi, Simon Hurd, Julia Ende, and Josh Huneycutt, "Utility costs and affordability of the grid of the future an evaluation of electric costs, rates and equity issues pursuant to P.U. Code Section 913.1," February 2021, page 7 (Problem Statement) (hereafter "Smith et al. Affordability Analysis", 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.

[53] Smith et al. Affordability Analysis, page 3.

[54] https://www.next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdfhttps://www.next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdf.

b) The Cost Shift Drives Up Electricity Prices, Harming the State's Climate Goals that Depend Upon Electrification of Vehicles and Buildings

The solar parties assert that their proposals support beneficial electrification and that reform will hurt electrification (because, in their view, rooftop solar will not be deployed to help meet the increased load from electrification).[55] These parties, however, have it backwards. California's electrification agenda will be undermined if the NEM cost shift continues to grow with the addition of newly subsidized solar installations and if its continuing adverse impacts on electricity rates are not addressed in this proceeding. If electricity rates are higher because of new NEM subsidies to more customers who adopt rooftop solar in the future, then there will be a higher financial hurdle for consumers when they are deciding whether to purchase an electric vehicle or replace household equipment that uses natural gas or oil with an electric appliance.

Delay in reforming NEM undermines the goal of increased beneficial electrification.

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55 SEIA/VS Beach Testimony, pages iii, 5:28-6:3, and 34:22-24; CSSA Testimony, pp. 2:17-19 and 3:4-8, e.g., Environmental Working Group Testimony, p. 16:11-18.

III.

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?

Compliance with AB 327 requires the Commission to balance competing interests. In comparing the various proposals, the Commission will need to identify how best to balance those interests because it may not be possible to perfectly meet each of the Legislative mandates. In addition to the Legislative mandates, the Commission has identified principles to guide this decision and has conducted a Lookback study to assess the impact of NEM reform effected by D.16-01-044. Finally, the Commission has instituted various programs to address the AB 327 requirement to ensure growth in DACs (D.18-06-027).

The Commission should follow Legislative direction and its own guidance when comparing and evaluating NEM successor tariff proposals. As the Lookback Study demonstrates, the Standard Practice Manual tests can provide critical information about what it means to support sustainable growth and the balancing of costs and benefits for all customers and the electric grid. Specifically, the PCT can be an indicator of relative market activity (PUC 2827.1(b)(1)) and the RIM test – because it measures the rate impact and, therefore, the cost shift – can be a strong indicator of the relative effect different proposals have on the transfer of support from non-participating customers to those that adopt rooftop solar in the future (PUC 2827.1(b)(4)). The Commission should recognize that NEM reform can include exceptions for certain customers to serve equity issues, specifically a carve-out for low-income customers can continue the path of D.18-06-027 as it addresses equity issues (Guiding Principle (b)).

Specific methods for comparing proposals and interpreting Legislative directives and use of Guiding Principles are described below.

A. The Commission Should Reject the Proposals from SEIA/VS and CALSSA Because These Proposals Maintain an Unsustainable and Unreasonable Status Quo

1. SEIA/VS's TRC Analysis is Inconsistent with TRC Findings in Objective Studies and Are Therefore Not Cost Effective

The TRC test is not impacted by successor tariff rate designs or tariff structures.[56] Nonetheless, SEIA/VS maintain that the TRC is best suited to measure the overall impact to all ratepayers.[57] If all ratepayers shouldered the same costs and accrued the same benefits from all rooftop solar, this statement might have some merit; however, previous studies of the NEM program have shown that NEM beneficiaries are overwhelmingly wealthy, single-family homeowners with access to credit.[58] These customers accrue the substantial benefit of very low bills, while all remaining ratepayers' bills go up as a result of the program. This tradeoff between participating and non-participating customers is key to determining an equitable and sustainable successor tariff, which is why the TRC alone cannot be the determinative cost-effectiveness test.

The TRC can indicate whether a demand-side program is cost-effective to the grid relative to other resource options. Studies performed for this proceeding have shown that standalone rooftop solar fails this test. Results from the Lookback Study, E3's cost-effectiveness analysis and TURN's cost-effectiveness analysis all show the same result: residential PV is not cost-effective from a TRC perspective.[59] SEIA/VS, however, show an "average forward-looking TRC" greater than 1.0, meaning the benefits outweigh the costs. There are two primary reasons for this inconsistent finding: 1) SEIA/VS use the 2020 ACC in its analysis, not the 2021 ACC used by E3 and TURN and 2) the average TRC is skewed by including systems installed in the late 2020s. By doing this, SEIA/VS's analysis captures the tail end of the 2020 ACC solar valuation, which was very high compared with other ACC

[56] See E3 Cost-Effectiveness report, p. 5.

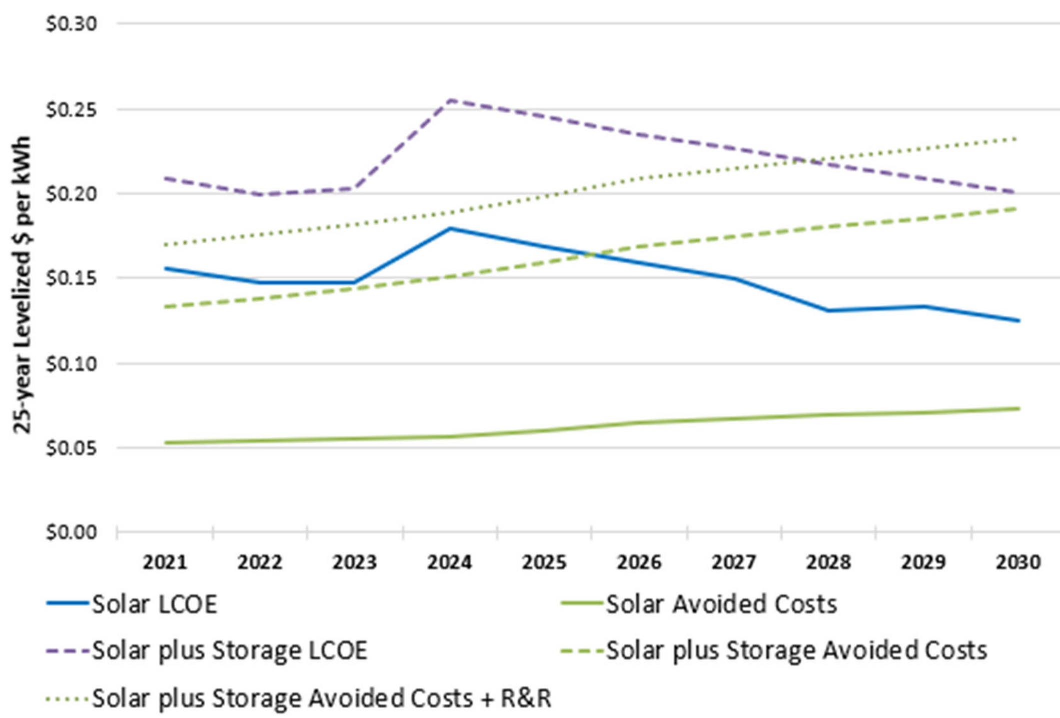
[57] SEIA/VS Opening Testimony, p. 14:15-16.

[58] Verdant "Net-Energy Metering 2.0 Lookback Study, p. 32.

[59] Verdant's analysis, though it does show a TRC below 1.0 for residential customers, uses the 2020 ACC for the system-wide benefits, rather than the 2021 ACC. It is also a retrospective analysis, meaning it does not forecast future costs. All other analyses are forward-looking.

vintages.[60] SEIA refused to update its analysis in response to a discovery request, so we updated SEIA/VS's analysis with the 2021 ACC Results. As seen in Figure III-1 below, the Levelized Cost of Electricity (LCOE) is greater than the adopted 2021 ACC avoided costs over the entire period shown in the chart. Thus, both standalone solar and solar plus storage never pass the TRC test within the time horizon.

Figure III-1
SEIA TRC Analysis: LCOEs vs 2021 Avoided Costs



The Joint Utilities note one final concern with SEIA/VS's TRC analysis: they claim that reliability and resiliency benefits for solar + storage systems should be included in the TRC and even show a TRC sensitivity with reliability and resiliency included. To the extent individual solar + storage residential customers can power their homes and appliances during outages, this is a private benefit that only those customers accrue. It is not a socialized grid benefit.[61] SEIA/VS made many of the same

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[60] See Joint Utility Opening Testimony, Table III-26 showing ACC vintages over time.

[61] There can be broader societal benefits in some circumstances, such as powering critical infrastructure facilities that provide public services during outages. As part the R.19-09-009 Resiliency and Microgrids (*Continued*)

claims, and indeed used many of the same calculations, to assert that these benefits should be included as new categories of avoided costs in the IDER rulemaking.[62] These arguments were rebutted by other parties and rejected by the Commission. In making its finding, the Commission noted:

"We agree with TURN that SEIA/Vote Solar's proposal has not shown any deferred or avoided costs to utility ratepayers, but rather has shown only that ratepayers who use these technologies receive additional participant benefits. We underscore, however, that participant benefits are not a type of avoided cost".[63]

SEIA/VS do not provide any new evidence or add anything substantive to the record in this proceeding to demonstrate these purported benefits save all ratepayers money. If anything, these benefits should be included as a benefit in the PCT, not the TRC. Therefore, their modified TRC analysis should be afforded no weight.

2. <u>The SEIA/VS Attempt to Dismiss the Utility Cost Shift Analysis is Unconvincing</u>

Appendix RTB-4 of SEIA/VS's opening testimony attempts to dismiss the utility cost shift forecasts as "conceptually flawed, overstated, and fail to include important societal benefits of renewable DG." SEIA's attempted dismissal is unavailing, and their most substantive point is rendered moot by the 2021 ACC.

First, SEIA/VS misinterpret the cost shift forecast as "[representing] 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." This is wrong. The utility cost shift analysis is a version of the RIM test, showing the impact of NEM on customer bills for each year of the forecast period, rather than showing a levelized net present value of the impacts as done by the Lookback Study's RIM test. The underlying costs of distributed solar have nothing to do with the calculation; indeed, part of the problem of NEM

Working Group, the Commission is currently getting feedback from a broad group of stakeholders on approaches to valuing resiliency for critical facilities and vulnerable populations.

[62] See SEIA/VS Opening Testimony in IDER 2020 ACC Major Update proceeding.

[63] D.20-04-010, pp. 69-70.

compared to Renewable Portfolio Standard policies is that there is no mechanism for "procurement costs" to decline as underlying technology costs decline. As SEIA/VS point out, the average cost of a utility scale solar PPA in 2016 was a third the cost of a similar PPA from 2010. While there were similar cost declines for distributed solar over that same time period, the compensation per kWh did not decrease like utility-scale solar PPAs. A NEM customer that installed a system in 2010 receives approximately the same compensation today as a NEM customer that installed a system 2016.

Following their misinterpretation of the utility analysis, SEIA/VS propose three changes to "correct" it:

1) Use long term levelized avoided costs from the 2020 ACC instead of forecasted avoided costs in each forecast year;
2) Assume that all customers are currently taking service on electrification rates; and
3) Assume 25% of existing NEM 1.0 and 2.0 customers currently have storage.

The first change is moot – the long run levelized value of solar is not meaningfully different than the short run value in the 2021 ACC. Even if this wasn't true, SEIA/VS miss the point of the cost shift forecast, which is to show the actual rate impact in each year. That the Joint Utilities' analysis ended in 2030 is not an attempt to hide benefits that could accrue between 2031-2045, but a recognition that near-term forecasts are more reliable than long term forecasts.

The other two changes are inaccurately characterized as representing gradual trends, yet SEIA/VS model them as occurring instantaneously. In response to discovery, SEIA/VS took no position on if it would support changes to rate design necessary for its second assumed change to be meaningfully true on any timeframe, let alone an immediate transition, and would only say that they expected about 25% of existing customers to have storage by 2030.[64] While changes to the rates on which legacy NEM customers are required to take service can mitigate a portion of the existing cost shift, SEIA/VS oppose Sierra Club's proposal in this proceeding to do just that. Further, while storage retrofits could have positive impacts on the cost shift for other customers, SEIA/VS exaggerate any

[64] Appendix B: SEIA/VS Response to Joint Utility DR-007.

potential benefits by including participant resiliency benefits and pretending that these retrofits have already occurred instead of taking place over many years.

Each of the three changes that SEIA/VS propose is either moot or not based on reasonable assumptions. SEIA/VS's failed critique demonstrates that the utility cost shift analysis is fundamentally sound, and that urgent action is needed to correct this inequity.

3. Solar Parties' Proposals Include Transition Periods that Perpetuate the Cost Shift

While the large, growing and unsustainable cost shift continues to increase the electric bills of non-participating customers, the solar parties' proposals substantially delay aligning rooftop solar compensation to its market value and perpetuate a growing and unstainable cost shift to non-participating customers. Not only do these proposals delay desperately needed reform, but they also suggest maintaining 20-year legacy periods locking-in above market compensation paid for by non-participating customers for decades to come. This is in direct contradiction with what even the solar parties suggest should be done. In their opening testimony, SEIA/VS state "The solar industry recognizes that the compensation for future 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."[65] These statements from solar parties signal that significant changes to the NEM program in California are needed. However, when their proposals are analyzed, it is easy to see that the solar parties are suggesting little change to NEM 2.0, which continues to unfairly increase the bills of non-participating customers.

We calculated the cost shift created by new residential solar customers in SDG&E's service territory, the IOU with the highest penetration of rooftop solar customers, from CALSSA and SEIA/VS' proposals relative to the current NEM 2.0 tariff starting in 2023. The results of our analysis highlight that the CALSSA and SEIA/VS proposals continue to create a large and growing cost shift not much different from NEM 2.0. We calculate CALSSA's proposal would reduce the SDG&E 2030 annual residential cost shift by only 11% while SEIA/VS's proposal would reduce the SDG&E 2030

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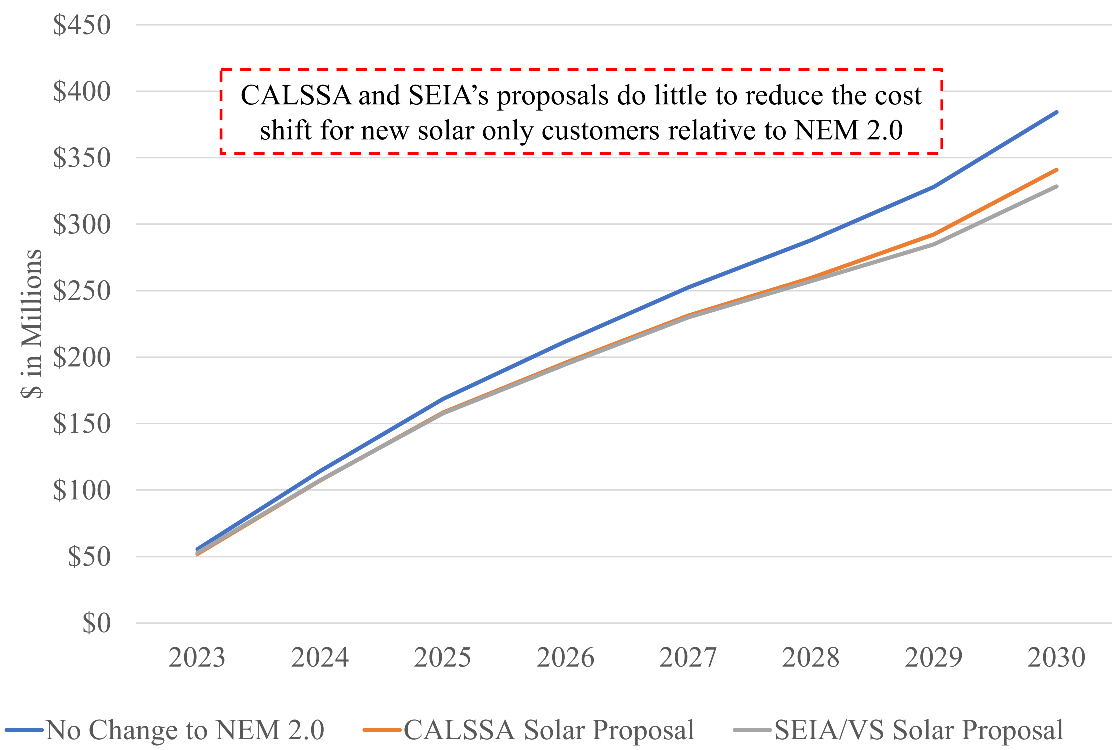
[65] SEIA/VS, T. Beach, Attachment RTB-4 p. 2.

annual residential cost shift by only 15%.[66] In discovery, SEIA/VS confirmed this fact, stating that their proposal would raise rates for nonparticipants for "several years".[67]

Figure III-2
SDG&E Total Residential Cost Shift Comparisson



Directionally similar results were also found by E3 in its Commission directed comparative analysis.[68] Through this analysis, E3 reviewed party proposals to help the CPUC understand how proposals "approach reducing the cost misalignment under NEM 2.0". Five metrics were provided, including the calculated first-year cost shift created per participating customer. The results of this study also highlight that proposals from SEIA/VS and CALSSA do little to reduce the cost

[66] Analysis calculates estimated residential customer cost shift created from new solar-only customers starting in 2023.

[67] Appendix B: SEIA/VS Response to Joint Utility DR-005.

[68] E3's "Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020 – A Comparative Analysis".

shift. While these above-market subsidies would remain for 20 years, paid for by non-participating customers, E3 calculates these customers would see payback periods around 5 years.

The 2023 non-CARE, solar only results from the E3 report for these proposals relative to the current NEM 2.0 tariff are summarized in Table III-2 below.

Table III-2
Comparison of Select Party Proposals
2023 Non-CARE Solar Only

Proposal	Cost Shift Per Customer	Cost Shift Reduction vs NEM 2.0	Payback Period	Legacy Period
NEM 2.0	$1,851	-	~4 Years	20 Years
CALSSA	$1,721	7%	~5 Years	20 Years
SEIA/VS	$1,577	15%	~5 Years	20 Years

Source: E3's "Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020 – A Comparative Analysis". Results reflect averages of three IOUs from E3's June 15, 2021 report that incorporates minor modeling revisions; page 53.

As highlighted in Table III-2 above, as compared to NEM 2.0, the proposals from CALSSA and SEIA/VS would introduce minimal changes to the NEM 2.0 tariff that is shifting costs and increasing electric bills for non-participating customers.

Although E3 calculates the proposals from CALSSA and SEIA/VS could reduce (on a going-forward basis) the cost shift resulting from new customer adoption of solar relative to NEM 2.0 in later years, there can be no doubt that significant cost shifts would still remain. By 2030, E3 calculates CALSSA's and SEIA/VS's proposals will still be shifting on average over $1,300 per new customer and would shift costs to non-participating customers until 2050.[69] This is unstainable and highlights these proposals will continue to perpetuate the issues currently present in today's NEM tariff.

[69] CALSSA appeared to disagree with E3's analysis of their proposal in 2030, saying "The model incorrectly interprets CALSSA's proposal for export compensation in 2030 to be ACC values rather than the percentages of retail rates specified in Step 5 of the proposal," so it may be even less effective than indicated. E3 Comparative Analysis, June 15 Update, p. 48. In addition, E3 used average residential system sizes of 4.7 kW-DC for PG&E and 4.4kW-DC for SDG&E and SCE, lower than the average system sizes seen in each respective IOU's service territory resulting in lower than average cost shift per customer estimates.

While solar parties state NEM should be "recalibrated" to better align with the resource's market value, their proposals suggest a different story. The results of the E3 analysis along with our own cost shift analysis demonstrate that these proposals do very little to reduce the cost shift faced by millions of Californians who cannot or choose not to install solar.

4. The Solar Parties' Erroneous Societal Cost Analysis of Their Proposals is Designed to Maintain the Status Quo by Overstating Societal Benefits

The Solar Parties' representations regarding societal benefits are unsupported, refuted by objective sources, and overstated, as described further below. By objective calculations of the TRC, it is clear that standalone solar resources are not cost-effective from an overall system perspective. Solar parties are trying to obscure this fact by pointing to a myriad of additional benefits of their technologies, many of which are not unique to distributed generation or incremental to the ongoing push towards renewable energy on the grid. As discussed in section c above and further below in section IV.B, the solar parties' proposals are not cost based and would maintain a substantial cost shift from participating to non-participating customers. These purported benefits should not be used to maintain this inequitable status quo.

a) Background of the Societal Cost Test (SCT)

In its initial report on the SCT in 2017, the Commission discussed the policy rationale for including societal benefits in its decision-making. The intent was and is to clearly and explicitly value those benefits of Commission DER policies and programs with California energy policy.[70] The Commission noted the sheer volume of possible values is daunting, so the Commission chose to focus on only those values mandated by California policy.[71] Further, the Commission recognized the asymmetry between societal costs (borne entirely by ratepayers) and societal benefits (accruing to ratepayers and society at large).[72]

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[70] *See,* ALJ Hymes' Feb 9, 2017 Ruling Taking Comment on Staff Proposal Recommending a Societal Cost Test, Attachment A: Distributed Energy Resources Cost Effectiveness Evaluation: Societal Test, Greenhouse Gas Adder, and Greenhouse Gas Co-Benefits, An Energy Division Staff Proposal, p. 2. January, 2017.

[71] *Ibid.,* p. 2.

[72] *Ibid., p. 6.*

Because of this complexity, the Commission chose to take a gradual approach by quantifying, and ultimately adopting, a three-part societal cost test to be tested in the IRP proceeding.[73] These three elements are 1) a societal discount rate, 2) a social cost of carbon (SCC) in place of the adopted GHG Adder in the ACC, and 3) air quality co-benefits. In adopting this test, the Commission stressed the importance of having a common resource valuation method so that these societal benefits could be applied with an even hand to all resource types, thus ensuring a least-cost pathway to meeting California's energy policy goals.[74] This work has not been completed, yet the Solar Parties through their opening testimony have attempted to anticipate the outcome of the Commission's measured approach by deviating from the Commission-approved SCT values and proposing new values that have little merit and would not meaningfully change the cost-effectiveness of rooftop solar.

b) <u>SEIA/VS's Application of Societal Benefits is Inappropriate and Inconsistent with Prior Commission Guidance on the SCT</u>

As noted above, the SCT has not been approved for use in demand-side proceedings. Nonetheless, SEIA/VS use a heavily modified societal benefits analysis in their opening testimony. The only element of SEIA/VS's analysis that is consistent with prior guidance on the SCT is in applying a 3% real discount rate to future benefits. The remainder of these benefits are discussed below. SEIA/VS's use of the 2020 ACC instead of the 2021 ACC, various calculation errors, and use of other inputs that are misaligned with previous Commission guidance on the SCT results in exaggerated benefits. While we disagree with the inclusion of these benefits for reasons outlined in the rest of this chapter, simply updating and correcting SEIA/VS's analysis demonstrates that the benefits are far lower than SEIA/VS claimed in their opening testimony, and cannot possibly justify the inequitable status quo.

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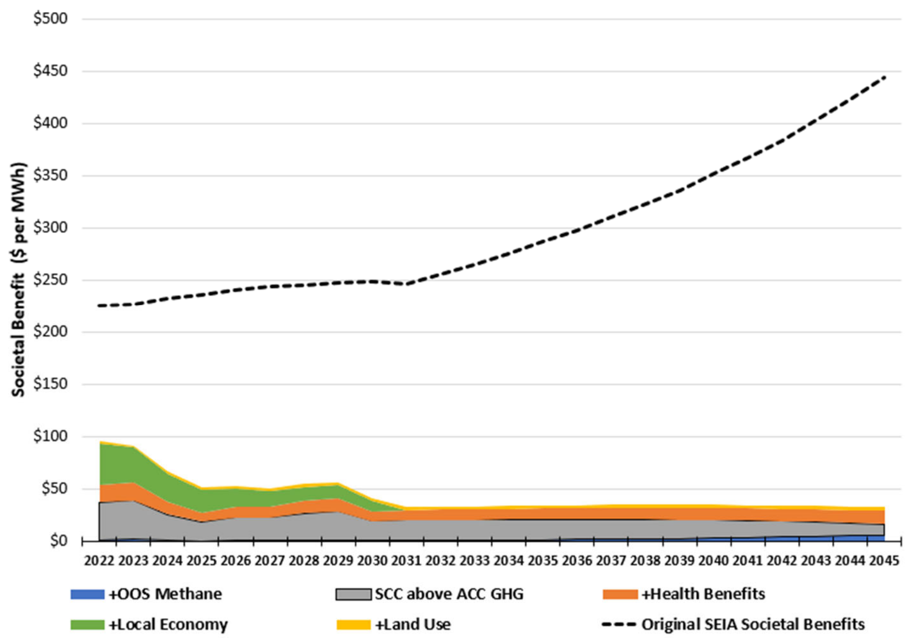
[73] D.19-05-019, OP 4-7.

[74] D.19-05-019, pp.29-30.

Figure III-3
Corrected SEIA/VS Figure 3 – Societal Benefits



Social Cost of Carbon. SEIA/VS present the societal benefits of using a Social Cost of Carbon (SCC), which is meant to capture the societal damage costs above and beyond the already high costs to meet electric sector GHG planning targets above and beyond compliance with the cap-and-trade program. SEIA/VS deviate from guidance in D.19-05-019 by not using Commission-approved SCC values used by the US EPA and developed as part of the Interagency Working Group (IWG) tasked with estimating these values for the federal government.[75] Rather, SEIA/VS use a far higher value from one study, stating only it is a "recent estimate".[76] SEIA/VS does not justify this deviation from these Commission-adopted values, even though more recent guidance from the IWG reaffirmed use of these values for use in regulatory cost-benefit analyses pending further study.[77] These

[75] The 2017 SCT staff proposal at pp. 10-11 outlined 7 guiding principles, one of which is to use existing public agency tools and calculators where available, noting: "To the extent tools exist from the EPA or elsewhere, they should be used."

[76] See SEIA/VS Attch RTB-3 p. 2.

[77] See Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, at p. 3. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

analyses present average SCC values using different discount rates, and a “high impact” value representing the 95th percentile of the estimated impact. Updating SEIA’s calculations to use the Commission approved “High Impact” SCC and the 2021 ACC’s marginal avoided emissions significantly lowers the amount of this benefit.

Table III-3
Social Cost of Carbon Values, \$/Metric Tonne of CO_2, Nominal

Year/Source	Interim Values from SCT Decision D.19-05-019	SEIA/VS Values
2020	$157	$417
2025	$194	$465
2030	$234	$518
2035	$285	$578

Reduced Out-of-State Methane Leakage. Here SEIA/VS deviate from two recent cost-effectiveness decisions, the first being the 2020 decision that adopted in-state values for avoided methane leakage in the ACC,[78] the second being the 2019 SCT decision, which did not discuss or adopt any out-of-state societal costs.[79] As a general matter, avoided methane leakage was added to the ACC in response to the increased statewide focus on programs designed to reduce natural gas consumption by replacing natural gas appliances with electric appliances.[80] While the Commission acknowledged that avoided methane leakage costs should also be attributed to distributed energy resources like behind-the-meter solar that “indirectly” reduce natural gas consumption through reduced electricity consumption,[81] SEIA/VS’s proposal to increase these ***indirect*** avoided costs tenfold is an inappropriate misapplication of the Commission’s policy on this issue.

[78] See D.20-04-010 Appendix A p. 49.

[79] See D.19-05-019.

[80] See D.20-04-010 at p. 62. See also D.20-04-010 at p. 64, which explains that “adding the value of avoided methane leakage would have the largest impact on programs designed to eliminate the use of natural gas appliances, which is consistent with the Commission’s current advancement toward electrification.”

[81] See D.20-04-010 p. 65.

Even if this out of state benefit were included, SEIA/VS miscalculate it by using the ratio of total gas volumes procured out of state (~91.3%) to the total gas volumes procured in state (~8.7%), which increases the methane leakage component in the ACC by a factor of 10.5.[82] This is erroneous because the ACC documentation bases its methane avoided cost on the percentage of methane leaked along California's system, which is 0.7%, not the volume of gas procured.[83] The ACC also states a national average methane leakage percentage of approximately 2.4%.[84] Therefore, the correct factor to roughly approximate the change to the ACC value for this national benefit would be 3.4:1 (2.4 divided 0.7). SEIA/overstate this calculation in their opening testimony by almost a factor of three. This is compounded by other errors, such as double counting in-state leakage reductions, continued use of the 2020 ACC and inappropriately using the 20-year GWP value instead of the CARB recommended 100-year GWP value. After making these corrections, the benefit of reduced OOS methane leakage is barely visible in SEIA/VS's graphic.

Air Quality Benefits. To quantify air quality benefits, SEIA/VS do not use the interim $6/MWh figure adopted in the SCT decision, but rather use a higher value of $21/MWh, citing to an updated, yet draft, analysis from the IDER proceeding. There has not been formal opportunity to comment on this updated analysis, however, the Joint IOUs submitted informal comments to ED staff that this figure needs refinement. Specifically, the value should not apply equally to all hours. It should be scaled based on when thermal resources are most likely to be utilized to meet peaking demand and thereby increase emissions. SEIA/VS apply this benefit to all rooftop generation regardless of time period, which overstates the emissions benefit of reducing midday load. The utilities did not make any updates to SEIA/VS's calculation of this benefit, other than updating to use the 2021 ACC's marginal avoided emissions.

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[82] See SEIA/VS Attch RTB-3 p. 2.

[83] *See* 2021 ACC Documentation, p. 81.

[84] *Ibid*, p. 81.

Water Use. SEIA estimates that the benefit of reduced water use from displacing a natural gas fueled combined cycle power plant is $0.0007/kWh.[85] Arriving at a benefit per kWh of distributed solar generation would require further discounts to this relatively small benefit; perhaps recognizing this, SEIA did not bother to quantify the total benefits from this category. It is unclear how much this benefit is already embedded in the operating costs of natural gas facilities. That said, the utilities agree with SEIA/VS that, regardless of the theoretical merits of this societal benefit stream, the value is likely to be de minimis.

c) SEIA/VS Fail to Prove DERs Provide Incremental GHG-Free Generation

SEIA/VS admit that all the societal benefits discussed in the previous section are not unique to distributed generation, but can also come from utility scale solar.[86] All of these categories of benefits relate to reducing reliance on carbon-emitting resources, and therefore any non-emitting resource (e.g., wind, hydro, etc.) could also be ascribed these same benefits. Nonetheless, SEIA/VS claim a portion of these benefits are incremental by stating RPS requirements are only a fraction of the utility's retail sales, while DG is 100% renewable.

Interestingly, SEIA/VS acknowledge quickly thereafter that RPS requirements alone will not be sufficient to meet GHG goals, and that the GHG reduction requirements are driving the renewable build in IRP planning. The IRP model produces the per ton cost of meeting these GHG constraints (known as the "shadow price" of GHG), which is directly used in the ACC to value DER contributions to meeting this constraint. Thus, by design, supply and demand side resources are ascribed the same value per unit of GHG reduction. SEIA/VS acknowledge as much, stating, "From this perspective, 100% of distributed customer-sited renewables provide the same societal benefits as the same quantity of utility-scale renewables."[87] The Joint Utilities agree that to the extent there are additional societal benefits from marginal renewable electric generation, those benefits should be applied equally to all resources per unit of generation produced. However, SEIA/VS's testimony

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85 See SEIA/VS attachment RTB-3, p.3.

86 See SEIA/VS p. 20.

87 See SEIA/VS p. 23.

quantifies and presents these benefits as though they are incremental to the benefits that would be achieved with other forms of renewable energy. This argument should be rejected, and as noted above, societal benefits should be considered within the IRP proceeding to correctly and accurately value the contribution of each technology towards meeting our climate goals.

d) SEIA/VS Claim Two Unique Societal Benefits from Distributed Generation, Both of Which are Overstated

Land Conservation and Use. SEIA/VS set up an artificial dilemma for the Commission to consider in this case by pointing to land constraints in California, and concludes that California, "would commit a serious error to rely only on utility-scale renewables."[88] In Attachment A to its March 15 proposal, SEIA/VS point to IRP planning modeling, arguing that California would have to impinge environmentally protected areas to build the necessary large-scale renewables to meet carbon reduction goals.[89] However, SEIA/VS does not calculate this societal value associated with protecting these lands. Instead, they calculate a $0.0022/kWh benefit to DG, based on the cost of farm and ranch land in California that may be used to host utility scale solar. In essence, SEIA/VS argues that utility-scale solar power plants are "located where the land has other uses for agricultural zoning."[90] By making this argument, SEIA/VS suggests that the problem created by utility-scale solar is not that it has negative impacts on conservation (as SEIA/VS suggests in its discussion of IRP assumptions of land use), but instead that utility-scale solar plants displace land uses that are of higher economic value, in this case farming.

First, the cost of land would clearly be included in the costs of utility scale solar, so this value is double counting costs already accounted for in the IRP and ACC. Second, the small magnitude of the SEIA/VS calculated land use benefit undermines their position that land use constraints are a critical point in favor of continuing the status quo.

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[88] SEIA/VS BEACH TESTIMONY, page 7:31-32.

[89] SEIA/VS BEACH testimony, Attachment RTB-2, Attachment A.

[90] SEIA/VS BEACH Testimony, Attachment RTB-4, p. 4.

Regarding the analysis of IRP land constraints, SEIA/VS set up a false comparison by comparing the utility-scale solar buildout in the IRP's 2019-2020 RSP, including the alternative "No New DER" scenario, to the land constraints in prior RESOLVE vintages from the 2017-2018 planning cycle. First, the "No New DER" the Commission has stated that "…the No New DER scenario is not a utility planning tool, and is not intended to reflect what is likely to occur, but rather what would have to occur if we had no DER programs."[91] Clearly energy efficiency, distributed generation and demand response programs will continue to be a part of utility planning and portfolios, so it is not instructive to compare the counterfactual case to real land use constraints. Second, the adjustments to RESOLVE's land use constraints were not "arbitrary" as claimed by SEIA/VS[92], but were intentional to reflect updated modeling assumptions regarding longer-term goals out to 2045, which was not explicitly modeled in the 2017-2018 IRP round, and that IRP modeling effectively enforces these land constraints with transmission limits.

The *Power of Place, Land Conservation and Clean Energy Pathways for California* report prepared for the Nature Conservancy provides more context around this discount adjustment, noting that the EPIC-funded CEC Deep Decarbonization study for 2050 targets used an 80% discount factor, rather than the 95% factor used in the first round of the CPUC IRP modeling, which primarily focused on 2030 targets.[93] The report also provides sensitivity analyses of this discount, including replacing the discount completely and using more granular site suitability modeling.[94] The study concludes "California can achieve renewable and carbon-free electricity goals with minimal impacts to the west-wide network of natural and working lands."[95] This is achieved by utilizing both more stringent land use constraints, expanding procurement of electricity from a wider geography and

[91] Resolution E-5150, p. 27.

[92] SEIA/VS BEACH Testimony, Attachment RTB-2, A-3.

[93] Power of Place, Land Conservation and Clean Energy Pathways for California, p. 14. The discount factor is applied to the total potential solar availability in a given geographic zone. For example, if 100 GW could be developed in a given area, only 20 GW (100 * 0.80) would be selectable in the modeling.

[94] *Ibid*, p. 9.

[95] *Id.*, p. 43

greater resource diversity.[96] All of these are relevant concerns for long-term, inter-agency planning studies such as the IRP, the CAISO's Transmission Planning Process, and ongoing CEC research on SB 100 goals, however this does not justify the SEIA/VS concern that reforming the NEM tariff will jeopardize all of these efforts.

Local Economic Benefits. SEIA/VS claim that the fact that distributed solar costs more than utility scale solar should be counted as a benefit, at least to the extent these additional "soft costs" are incurred locally. By this logic, there is no societal benefit to reducing distributed solar soft costs, nor any societal cost to increasing distributed solar soft costs. This is clearly flawed logic. That issue aside, SEIA/VS acknowledge that this claim could only be true if distributed solar passes the TRC test. As put by SEIA/VS, failure to pass the TRC test would mean "higher overall economic costs for electric service, such that the higher costs for electricity are a drag on the local economy."[97] As demonstrated by the Lookback Study, E3's Comparative Analysis, and the updated SEIA/VS analysis updated with the 2021 ACC, distributed solar does not pass the TRC test.

5. <u>The Value of Solar Parties' Proposals is Unsupported by the RIM Test</u>

The solar parties attempt to minimize or misrepresent RIM test results, even though this is the only cost-effectiveness test that considers non-participant impacts. SEIA/VS argue that the test is too stringent and that the Commission should include societal benefits in its assessment of non-participant impacts.[98]

This argument should be viewed with skepticism primarily for reasons described by ED Staff in its proposal on the SCT. Quantifying societal benefits is challenging enough—understanding how these benefits will accrue to different groups of ratepayers and to society at large is nearly impossible. SEIA/VS is using the promise of large societal benefits to mask the fact that non-solar ratepayers are bearing a disproportionate cost of maintaining the grid through higher rates. Secondarily,

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[96] *Id.,* p. 28.

[97] SEIA/VS Opening Testimony, Appendix RTB-3, p. 6.

[98] SEIA/VS Opening Testimony, p. 48.

as noted above, SEIA/VS vastly overstate the aggregate value of these societal benefits by using outdated avoided cost data, selectively choosing inputs and making erroneous assumptions.

CALSSA designs its proposal to reach a RIM score of 0.9, arguing that other categories of benefits such as land use conservation and resiliency should be assumed to push the score above 1.0.[99] CALSSA argues their proposal reaches this benchmark, but their analysis is deficient in two ways. First, CALSSA does not use the 2021 adopted ACC, which would lower the stated RIM values. Secondly, CALSSA computes RIM bill savings based only on exported PV generation, not total generation (self-consumption + exports). This is not only inconsistent with most other party analysis that computes bill savings (lost revenue from the RIM perspective) based on total generation, but also does not follow Standard Practice Manual guidance to calculate, "...decreased revenues for any periods in which load has been decreased...".[100] CALSSA defends this choice by stating that customers are not obligated to take service from utilities.[101] While this is true, nearly all PV customers do take service from their utility provider, and the grid is built to support those customers when their systems are not sufficient to serve load, or when excess generation is flowing back to the grid. The current retail rate credit structure allows customers to bypass paying their portion of these costs, which should be accounted for in the RIM.

B. SEIA/VS's Assertions Regarding Damage to the Industry are Not Consistent with the Evidence in Jurisdictions that Have Reformed Their NEM Tariffs

The solar parties' Opening Testimony[102] paint a dramatic and gloomy picture of what they believe will happen to the solar market in California and to the state's ability to meet its climate objectives if the Commission adopts the type of tariff reforms proposed by such a diverse set of parties as CalPA, TURN, NRDC, and the Joint Utilities. The Commission should not equate meaningful NEM reform with an anticipated collapse of customer-sited solar PV.

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[99] CALSSA Opening Testimony, p. 83.

[100] Standard Practice Manual, p. 13.

[101] CALSSA Opening Testimony, p. 80.

[102] SEIA/VS, Gallagher Testimony, p. 2 and generally.

There are many factors that support a more positive post-reform outlook. These are discussed at length in Chapters 1 and 2 of the Joint Utilities' Opening Testimony. It is particularly surprising in light of those factors — SEIA's public declarations of market confidence, solar companies' statements to investors, the outlook for cost declines in solar and storage technologies, the appetite of so many consumers for clean energy solutions, and the state's climate goals — that the solar parties present arguments and positions that reflect such a lack of confidence about consumers' interest in their products and/or the industry's ability to adapt their own business models and product offerings to competitive realities in 2022 and beyond.

The Commission should not lose sight of the significant need for reforms as it reviews the testimony of SEIA/VS witnesses Mr. Gallagher and Mr. Geiss, who describe their concerns that significant changes in the NEM 2.0 successor tariffs will damage California's solar market and industry and who point to the experience of other states in support of their position.[103]

Hawaii: For example, Mr. Geiss's testimony focuses on the situation in Hawaii leading up to that state's regulatory decision in 2015 to replace the utility's NEM tariff with other options, and his conclusion that the absence of a "reasoned transition" led to a "dramatic impact on the Hawaiian solar market" at the time and since then.[104] He focuses on what he considers to be similarities between the Hawaiian tariff design elements and those proposed by the Joint Utilities, and between the "robustness" of the solar markets in Hawaii (as of the mid-2010s) and in California (as of 2021).[105]

He spends less time, however, on another set of similarities and differences that are relevant for the Commission's decision to adopt significant tariff reforms in this proceeding. In terms of similarities, Hawaii was (like California) experiencing a number of rising problems associated with the pace at which Hawaii customers were adopting solar under the original NEM tariff and which affected the need for timely reforms of that program.

[103] Prepared Direct Testimony of Sean Gallagher on Behalf of the Solar Energy Industries Association and Vote Solar (generally) and Prepared Direct Testimony of Will Giese on Behalf of the Solar Energy Industries Association and Vote Solar (generally).

[104] SEIA/VS Geiss Testimony, pp. 2:18 through 3:4.

[105] SEIA/VS Geiss Testimony, p. 4:4-10.

First, the majority of customers of Hawaiian Electric Company (HECO) were subsidizing the adoption of solar by a much smaller group of customers, and the cost shift was growing.[106]

Second, the state's regulators found that there were adverse cost consequences to the utility's system supply and other customers' rates as a result the accelerated pace of PV adoption:

> *Interconnection of distributed solar PV systems, and more importantly, the unscheduled and uncontrolled export of excess solar energy onto the grid, could eventually create curtailment risks for existing and future utility-scale solar PV, wind, and other renewable energy projects. This occurs because the total amount of variable renewable energy that could be accommodated reliably on each island grid, at the system level, is limited. When variable energy congestion occurs due to excess energy at the system level, utility-scale renewable energy projects would be curtailed due to the current technical inability to curtail distributed generation exports onto the grid. This can also result in loss of grid access to the reliability capabilities that are inherently provided by utility-scale wind and solar PV projects pursuant to generator performance standards set for in interconnection requirements.*
>
> *As a consequence, distributed solar PV customers effectively have a higher priority and preferential grid access than do the utility-scale projects, which serve all customers, because the utility is forced, by technical default, to curtail the purchase of low-cost, wholesale renewable energy that otherwise may provide economic savings to utility customers.[fn 69 omitted] In its place, the utility is effectively required to 'purchase', at retail rate levels, uncontrolled solar PV energy exported onto the grid by distributed solar PV customers…."*[107]

Third, the Hawaii PUC had concluded in 2014 that "the commission believes it is unrealistic to expect that the high growth in distributed solar PV capacity additions experienced in the 2010 - 2013

106 Herman Trabish, "Hawaiian Electric's plan to end solar net metering, explained," Utility Dive, January 26, 2015, https://www.utilitydive.com/news/hawaiian-electrics-plan-to-end-solar-net-metering-explained/356432/· " '88% of the utility's ratepayers subsidizing the 12% who have net energy metered systems,' Mangelsdorf said. He believes utility's concern about that shift of costs for system maintenance is reasonable. 'The cost of NEM was $38 million in 2013 and it is estimated at $53 million in 2014. These are not trivial dollars.' "

107 Order No. 32053 Ruling on RSWG Work Product, in the Matter of the Public Utilities Commission Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, April 28, 2014, pages 41-42.

time period can be sustained, in the same technical, economy and policy manner in which it occurred, particularly when electric energy usage is declining, distribution circuit penetration levels are increasing, system level challenges are emerging and grid fixed costs are increasingly being shifted to non-solar PV customers."[108] Questions about the sustainability of full net energy metering were as prevalent in Hawaii at the time as they now are in California.

Next, Hawaii's transition to a successor tariff was not the abrupt event that Mr. Geiss outlines. NEM had been in place for many years (as it has been in California), and there were many signals that change would need to occur. The Hawaii PUC, HECO and stakeholders had been exploring reliability considerations and tariff designs for several years[109] by the time the Hawaii PUC made its decision to adopt alternatives to the NEM tariff in 2015. The Hawaii PUC also understood that there would need to be changes in the solar industry itself and were wide-eyed about the need for transitions, as they explained in a 2014 order: "The commission submits that the distributed solar PV industry in Hawaii will, out of necessity due to their accomplishments thus far, have to migrate to a new business model, not unlike what is expected for the HECO Companies as a result of disruptive technologies. The distributed solar business model will need to shift from a customer-value proposition predicated upon customers avoiding the grid financially - but relying upon it physically and thereby creating circuit and system technical challenges - to a new model where the customer-value proposition is predicated upon how distributed solar PV benefits both individual customers and the overall electric system, and

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108 Order No. 32053 Ruling on RSWG Work Product, in the Matter of the Public Utilities Commission Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, April 28, 2014, page 49, https://puc.hawaii.gov/wp-content/uploads/2014/04/Order-No.-32053.pdf.

109 *See*, for example, the procedural background discussion in the Hawaii PUC's Order No. 52757 in the Matter of Public Utilities Commission Instituting a Proceeding to Investigate Distributed Energy Resource Policies, Docket No. 2014-0192, March 31, 2015, https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15D01A84805H58433.

hopefully becomes a key contributor to Hawaii's grid modernization, and most importantly as a consequence, customers are compensated by the utility for the grid value created."[110]

With this context, there were many similar circumstances that were motivating tariff-reform actions in Hawaii and in California, and that ultimately led Hawaii regulators to introduce tariff changes in 2015. In California in 2021, the cost shift is much larger than it was in Hawaii in the years leading up to 2015, notably on a per-customer basis. The costs of rooftop PV systems (and utility-scale solar) are lower now than they were then. The solar industry is more mature. (*See* the discussion in Section B.4 of Chapter 2 of the Joint Utilities' Opening Testimony.) California started a transition from NEM 1.0 five years ago, and a decision in 2021/2022 to introduce NEM 2.0 reforms would not be abrupt.

Finally, although Mr. Geiss views the impact of Hawaii's 2015 NEM reforms as devastating for the solar market, in fact the policy changes did not wipe out the Hawaiian market for rooftop solar. Although the figure on page 12 of his testimony shows a reduction in the year-over-year growth in solar capacity adopted in Hawaii after 2015, it nonetheless shows that from the point of view of cumulative capacity additions, consumers continued to install solar capacity under the new tariffs. That is consistent with the trends noted in Figure II-10 (Residential Solar Net-Metered Capacity Over Time (Pre- and Post-NEM Reforms)) in the Joint Utilities' Opening Testimony.

The Commission should take away from Hawaii's experience that NEM is a very effective tool to accelerate the early stages of a solar market but that it should be reformed to lessen the cross-subsidies after the industry matures so that the interests of non-participating customers are brought more into balance with the interests of customers who adopt solar systems.

Utah: This same conclusion should also be drawn by reviewing the information Mr. Gallagher presents on the trends in annual amounts of solar capacity adopted by residential customers in Utah in the years before and after changes in the NEM tariff.[111] Note that the penetration rate for rooftop solar

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[110] Order No. 32053 Ruling on RSWG Work Product, in the Matter of the Public Utilities Commission Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, April 28, 2014, page 50, https://puc.hawaii.gov/wp-content/uploads/2014/04/Order-No.-32053.pdf.

[111] See SEIA/VS Gallagher Testimony, page 16.

as of the end of 2019 in Utah — 3% of residential customers — is far below the levels in California, where the much-higher adoption levels are driving enormous cost shifts.

New York: Mr. Gallagher finds New York's approach attractive because, in his view, the state's utility regulators have favored a simple NEM design for "mass market" residential and small commercial customers in addition to offering a Solar Value Stack option since 2017, and because "the approach taken by New York recognizes the need for gradualism and allowing the market time to adjust to changes in the underlying compensation structure".[112] Mr. Gallagher considers New York to be one of the strongest markets in the U.S.[113]

It is perhaps not surprising that most adopters of rooftop solar in New York prefer to use the full retail NEM tariff rather than the Solar Value Stack, which is designed to provide compensation to customers with on-site solar for the value of the services they provide to the grid. Apparently, the compensation levels in the Solar Value Stack are lower than payment levels under NEM's full retail rate, which seems to suggest that the NEM tariff overcompensates for solar customers' exports to the system.[114] When New York utilities begin to implement new tariffs in 2022, the customer benefits charge for NEM customers is higher than it is for customers on the Solar Value Stack tariff, which suggests the same conclusion about the NEM tariff.[115]

Perhaps most important in the context of the relevance of New York's approach to California as of 2021, the penetration rate for residential customers as of 2019 was 1.7% (compared to the penetration rates of 10.6%, 8.4% and 15.4% for PG&E's, SCE's and SDG&E's residential customers, respectively).[116] New York may have the ability to extend a transition to a NEM successor tariff,

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[112] SEIA/VS Gallagher Testimony, page 8:2-12.

[113] SEIA/VS Gallagher Testimony, page 7:10-11.

[114] "New York's new net metering to cut solar savings," Solar Reviews, updated April 25, 2021, https://www.solarreviews.com/blog/new-york-changes-net-metering-vder.

[115] "New York's new net metering to cut solar savings," Solar Reviews, updated April 25, 2021, https://www.solarreviews.com/blog/new-york-changes-net-metering-vder.

[116] These figures are calculated using Energy Information Administration 861 data on sales to ultimate customers (bundled and delivery) and NEM data. https://www.eia.gov/electricity/data/eia861/. See also Table II-1 in the Joint Utilities' Opening Testimony.

whereas California faces a more urgent need to address the inequities resulting from the large cost shift from participants to non-participants.

South Carolina: Notably, Mr. Gallagher does not mention the lessons that should be taken away from the recent approval of a NEM-reform settlement agreement by regulators in South Carolina. As described in Section B.3 (and Table II-3) of the Joint Utilities' Opening Testimony, the new Duke Carolinas successor tariff includes a package of provisions: monthly netting of exports; time-varying prices using four time periods; export compensation set at avoided costs; minimum bills; increased basic facilities charge; grid access fees; and grandfathering of existing NEM customers only until 2025 or 2029 (depending upon when they installed their PV system).

One of the signatories to this agreement was Vote Solar. It would be surprising to learn that Vote Solar thinks that tariff reforms like the ones implemented in South Carolina would damage the solar market if the organization were able to sign on to and recommend that regulators approve such changes.

IV.

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

A. The Joint Utilities' Proposed Reform Tariff Ensures Fair Compensation And a Cost Based Approach to Significantly Reduce or Eliminate the Cost Shift

Our proposal is the most effective at mitigating the current inequities of the NEM tariff. There is broad consensus among parties in Opening Testimony that the successor tariff should require cost-based TOU rates, set export compensation according to the latest avoided cost calculator (ACC), and include a grid benefits charge. In this chapter, we highlight where consensus exists and respond to critiques from other parties regarding the design of our successor tariff proposal.

1. Other Rate Requirements

There is broad consensus that the Reform Tariff should generally: require residential customers take service on cost-based TOU rates that better align price signals with grid needs, maximize benefits to all ratepayers, and further the state's electrification and GHG reduction goals.[117] The current residential default tiered TOU rate structures are not cost based. The Joint Utilities' proposal to default Reform Tariff customers to cost based non-tiered TOU rates with fixed charges is fair and justified. Our Reform Tariff default rates include modest fixed charges that result in lower overall volumetric rates. Lower volumetric rates have the potential to encourage electrification, as the average price per kWh is lower. Requiring Reform Tariff customers to take service on our proposed default Reform Tariff rates also will reduce the cost shift from these customers, and ensure that they pay the average residential cost of service for meters, service drops, transformers, and revenue cycle services, including but not limited to billing and call center costs. The default rates proposed by the Joint Utilities are fair, appropriate, and based in cost-causation principles.

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117 Opening Testimony of NRDC, at 16-17, Opening Testimony of CalPA at 3-14, Prepared Testimony of Sierra Club (Vespa) at 5, Prepared Direct Testimony of SEIA/Vote Solar (Beach) at 41.

Fixed customer charges, like those proposed by the Utilities, will lower the volumetric rate for participating customers and encourage electrification, a goal many parties support.[118] SEIA/VS state they "do not oppose the use of fixed charges in 'electrification rates' provided they are consistent with the Commission's rate design principles, including cost causation principles, and are generally available to residential customers who install a broad range of DERs."[119] They also agree, as does Sierra Club, that fixed charges allow for a reduction in volumetric rates that can be beneficial for DERs that increase electric usage.[120]

The main objections from solar parties are that the residential fixed charges in the proposed default Reform Tariff rates: 1) are discriminatory and should be applicable to all residential customers; and 2) will have a significant negative impact on beneficial load shifting.[121] Both these claims are false.

a) <u>The Proposed Fixed Charges are Not Discriminatory</u>

First, CALSSA claims that the Commission should not assess a fixed charge on Reform Tariff customers, and that it should address fixed charges for all residential customers in a subsequent proceeding.[122] The Commission should reject this argument as a distraction. There is no guarantee that the Commission will adopt residential fixed charges in the future, although CALSSA claims to have foresight that it will.[123] There is consensus among many parties in this proceeding that Reform Tariff customers should take service on "electrification" rates that have fixed charges.[124] Both

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[118] Opening Testimony of Sierra Club, pp.1-2, Opening Testimony of SEIA (Beach), p.ii, Opening Testimony of NRDC, p.11.

[119] Prepared Direct Testimony of SEIA/Vote Solar (Beach), p.67.

[120] *Id.*, and Prepared Testimony of Sierra Club (Vespa), p.2.

[121] Prepared Direct Testimony of CALSSA, pp. 11-12, Prepared Direct Testimony of SEIA/VS (Beach), p. 67.

[122] Prepared Direct Testimony of CALSSA, p. 109.

[123] *Id.*, p.108.

[124] The other feature of these "electrification" rates, as described by SEIA/VS and Sierra Club, are a large peak-to-off-peak (POP) differential.

Sierra Club's and SEIA/VS's first "steps" of their proposals would require Reform Tariff customers to take service on these "electrification" rates that have fixed charges.[125]

CALSSA states "the Joint IOUs provide no justification or explanation for why it is appropriate to charge solar customers these high fixed charges without charging the same to other customers that use the same amount of electricity."[126] Our proposals are based on average residential cost of service; if all residential customers had a cost-based fixed charges, they would be at, or above, the amounts proposed by each utility. Because the Joint Utilities are proposing their respective default Reform Tariff rates also be available on an optional basis to all residential customers, these charges are not discriminatory.

The Commission should not limit fixed charges to the $10-15 range, as suggested by SEIA/Vote Solar and Sierra Club.[127] SEIA/VS cites D.17-09-035 in reference to what should be included in a fixed charge in this proceeding.[128] However, D.17-09-035 only applies to residential *customer class default fixed charges*, and is not applicable here. As stated in Opening Testimony, PU Code § 2827.1(c)(7) specifically allows for the Commission to approve fixed charges for solar customers that are different from non-solar residential customers, so even if the Commission adopted PG&E's and SDG&E's proposed default rates only for Reform Tariff customers, it would be justified.[129]

SDG&E is required to file an application for an "electrification" rate by September 1, 2021.[130] Likewise, PG&E currently has a pending settlement agreement for the E-ELEC rate, which is similar to the E-DER rate.[131] However, the Commission should not defer adoption of SDG&E's and PG&E's proposed rates, TOU-DER and E-DER, in this proceeding, with the expectation

[125] Prepared Testimony of Sierra Club (Vespa), p. 1, Prepared Direct Testimony of SEIA/Vote Solar (Beach), p. 41.

[126] Prepared Direct Testimony of CALSSA, p. 108.

[127] Prepared Direct Testimony of SEIA/Vote Solar (Beach), p. 67.

[128] Prepared Direct Testimony of SEIA/Vote Solar (Beach), pp. 67-69 (footnote 63).

[129] Joint Utility Opening Testimony, p. 109.

[130] D.20-03-003, OP 10.

[131] A.19-11-019.

that a different rate will be approved. The exact structure of these future rates is still unknown, whereas the Commission has the discretion to adopt a rate design in the instant proceeding that will reduce the cost shift from Reform Tariff customers and incentivize electrification. Adopting Schedules TOU-DER and E-DER here will allow the Commission to enhance customer choice and explore different structures in SDG&E's upcoming application.

b) <u>Parties Exaggerate the Impacts of Fixed Charges on Load Shifting</u>

SEIA/VS state that fixed customer charges are also harmful to DERs that reduce or shift the use of energy from the grid.[132] CALSSA states that fixed charges discourage load-shifting because they are unavoidable, and that "[c]ustomers will not invest in energy storage to shift load when the value of doing so is muted by a $24 per month fixed charge."[133] However, these parties fail to provide any evidence that the proposed fixed charges will have a material impact on load shifting: their claims are purely speculative. Additionally, because the rate levels of the utilities are already above the national average and continue to feel upward pressure (which NEM contributes to at the tune of $3.4 billion per year, and increasing), a modest fixed charge that lowers volumetric rates several cents per kWh is unlikely to have a significant impact on conservation or load shifting, will send more accurate price signals to customers,[134] and will result in more equitable rates for low usage customers, including solar customers.[135] Additionally, customers at utilities in California with lower rates pay comparable monthly fixed charges, and customers still adopt solar in those jurisdictions. For example, Sacramento Municipal Utilities District assesses a $22.25/month System Infrastructure Fixed Charge and has a residential average rate of $0.165/kWh.[136] Even with cost-based fixed charges, the Joint Utilities' proposed default rates have average rates higher than $0.165/kWh. The price signals in the utilities'

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[132] Prepared Direct Testimony of SEIA/Vote Solar (Beach), p. 67.

[133] Prepared Direct Testimony of CALSSA, p. 108.

[134] D.15-01-007, FOF 175.

[135] D.15-01-007, FOF 163.

[136] A customer in SMUD's service territory using 750 kWh per month has an average bill of $124, equivalent to an average rate of 16.53 cents/kWh. https://www.smud.org/en/Rate-Information/Compare-rates.

proposed residential default Reform Tariff rates still provide a significant incentive for customers to shift load outside of peak hours.

As seen below in Table IV-4, the on-peak summer rate for SDG&E's proposed TOU-DER rate is over 54 cents/kWh, a level that still incentivizes load shifting. Without the monthly fixed charge, the on-peak summer rate would be over 60 cents/kWh. An on-peak rate of 54 cents/kWh still provides a strong price signal to shift load outside of the summer peak hours. Therefore, claims that fixed charges—because of the related reduction in volumetric rates—will have a material negative impact on load shifting are unfounded and unproven.

Table IV-4
SDG&E Proposed TOU-DER and Illustrative Comparison with No Fixed Charge

Charge	Unit	Proposed SDG&E: TOU-DER	Illustrative Comparison: No Fixed Charge
Basic Customer Charge	$/month	24.10	0.00
Energy Charges:			
Summer:			
On-Peak	¢/kWh	54.4	60.2
Off-Peak	¢/kWh	28.1	33.9
Super Off-Peak	¢/kWh	22.0	27.8
Winter:			
On-Peak	¢/kWh	24.1	29.9
Off-Peak	¢/kWh	23.1	29.0
Super Off-Peak	¢/kWh	22.1	27.9

Sierra Club recommends the Commission approve SDG&E's proposed default residential Reform Tariff rate, with certain adjustments.[137] Sierra Club proposes to lower the TOU-DER fixed charge from $24.10 to $14.10, but does not provide cost-based or policy justification, other than to "align [with] the DG-ST fixed charge component of the E-ELEC and TOU-Prime rates".[138] Sierra Club is mistaken in thinking that lowering the fixed charge would align SDG&E's default Reform Tariff rate fixed charge with the other two utilities. All three utilities have different cost structures, cost recovery, and rate levels. The

[137] Direct Testimony of Sierra Club (Vespa), p. 19.

[138] *Id.*

rates that SDG&E and PG&E have presented in Opening Testimony are aligned in concept with SCE's existing PRIME rate, as the fixed charges proposed by SDG&E and PG&E and presented by SCE only recover marginal customer costs, scaled to current revenue requirements.[139] Per the Commission's Rate Design Principles (RDP), rates should be based on marginal costs and avoid cross-subsidies. As SDG&E has the highest rates of the three utilities, it would require the highest fixed charge to reduce its volumetric rates commensurately to PG&E and SCE.

2. Export Compensation

The Commission should reject the proposals made by SEIA/VS, CALSSA, and others to continue to tie the compensation NEM customers receive for energy exports to retail rates. There is no reasonable rationale for tying compensation to anything other than the actual value of that generation. The Commission should instead adopt our proposal to pay exported energy at the amount that Commission has determined it is worth.

a) Broad Group of Parties Support Using the 2021 ACC to Calculate an Export Compensation Rate

In addition to the Joint Utilities, diverse parties including TURN, NRDC, CalPA, Sierra Club and CCSA, all support direct use of the most recent ACC to inform export compensation.[140] SEIA/VS and CALSSA appear to conceptually support using the ACC to inform compensation, but instead propose export compensation remain tied to retail rates. For example, CALSSA's proposal to step down export compensation as a percentage of retail rates was "designed . . . to approach the 25-year levelized value of exported energy from the Avoided Cost Calculator using all default inputs."[141] This design was informed by the 2020 ACC, rather than the 2021 ACC. In a response to discovery, CALSSA

[139] SCE's current PRIME customer charge was initially based on the SCE's underlying marginal cost studies presented in the 2018 GRC Phase 2. As a result of the 2018 GRC Phase 2 Residential Settlement Agreement, the PRIME fixed charge is not scaled in the attrition years. SCE proposes to remove this restriction in its 2021 GRC Phase 2 to better align PRIME's fixed and volumetric charges to cost.

[140] TURN Opening Testimony, p.45, NRDC Opening Testimony, p.15, Sierra Club Opening Testimony, M. Vespa, p.4, and CCSA Opening Testimony, Smithwood, p.29, CalAdvocates, p.3-16.

[141] Prepared Direct Testimony of CALSSA, p. 13.

refused to update their proposal to match their expressed design intent.[142] Likewise, SEIA/VS states that the "goal of both the electrification rates and the export step-downs 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)."[143] In response to discovery, SEIA/VS refused to provide any updates to their analysis or proposals using the approved 2021 ACC.[144] It is unclear why the solar industry refuses to follow through on their previously stated goals for the successor tariff. Regardless, the CPUC should accept the consensus in word, if not in deed, of this broad array of parties that export compensation should be based on the most current ACC.

b) <u>The Avoided Cost Calculator Values Should Be Weighted by an Export Profile</u>

In opening testimony, we proposed that the ACC outputs should weighted by an export profile to determine the rates in a given time period. Public Advocates Office proposes to use a solar profile during off-peak periods, and a simple average during peak periods. [145] While the result of this approach is not far off from the utility proposal, we believe our approach is simpler and better ensures that customers will be compensated according to the value of their generation. Public Advocates Office argues that a simple average in the peak period will encourage storage but acknowledge this will tend to overcompensate standalone solar customers.[146] By contrast, the utility proposal ensures that Reform Tariff customers will be accurately compensated as the export profile of these customers evolves over time.

CCSA proposes an alternative methodology that would provide inaccurate compensation. Their environmental adder is a simple average of the ACC GHG Adder and Rebalancing

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[142] Appendix B: CALSSA Response to Joint Utility DR-004.

[143] Prepared Direct Testimony of SEIA/VS (Beach), Executive Summary, p. ii.

[144] Appendix B: SEIA/VS Response to Joint Utility DR-007.

[145] Public Advocates Office Opening Testimony, p. 3-16.

[146] Public Advocates Office Opening Testimony, pgs. 3-18-19.

values within the peak and off-peak periods.[147] They define the peak period as only July through September weekdays, from 5-9 PM. This amounts to peak 264 hours, so the off-peak rate represents an average of the remaining 8496 hours of the year. This includes many hours when solar resources will be producing little to no energy. For generation, transmission, and distribution capacity, CCSA appears to sum the total of these values in all hours of the year, and then divide by 264 hours to arrive at a "peak" rate for each category.[148] This is inappropriate, as these values are non-zero in the off-peak period. That CCSA's peak adder, which ranges between \$0.80/kWh to \$1.30/kWh by utility, is vastly higher than any current retail peak rate among the utilities demonstrates that their methodology is inappropriate.[149] All told, this weighting proposal will tend to overcompensate the resources CCSA designed their proposal for, and should be rejected.

c) **The Wholesale Prices Hybrid Option Has Merit and Should be Considered but only in the Future**

TURN and CCSA propose to use CAISO day-ahead pricing instead of the ACC's forecast of energy, cap and trade, and ancillary services benefits.[150] This has conceptual merit, as it would ensure that compensation is tied to the exact market value of the generation. That said, we have concerns that, at this time, this proposal to directly use wholesale market prices for a mass market program is not practical to implement. Some of these concerns are outlined in Chapter 5. The Commission should revisit this idea when (or if) real time pricing rates are widely available, and these practical implementation issues have been resolved.

[147] CCSA Opening Testimony of Mark Fulmer, pgs. 14-15.

[148] CCSA Opening Testimony of Mark Fulmer, pgs. 8-13.

[149] CCSA Opening Testimony of Mark Fulmer, p. 18, Table 2. Note that these rates do not include CAISO day ahead market prices.

[150] TURN, p.45, CCSA, M. Fulmer, pp. 4-5.

d) Export Compensation Should Be Informed by the Most Recent ACC, not Inherently Speculative Long-Term Forecasts

TURN, CalPA, NRDC, CUE, and Sierra Club all agree that export compensation should be based on a short-term forecast of the ACC, rather than the 25-year forecast preferred by the solar industry. As stated by CUE, "the very nature of forecasts is that they are inevitably either higher or lower than actual results except by chance. Forecasts closer in time to the actual event take into account more recent information and so are better than forecasts further away in time."[151] Indeed, the significant change in the forecasted value of solar between the 2020 and 2021 versions of the ACC illustrates the folly of basing compensation on such a long-term forecast. The utilities believe that the 2021 ACC is much more accurate than the 2020 ACC. However, if we are incorrect and reality hews to the 2020 ACC's predictions, our proposal (because of its annual update cadence) ensures that future solar customers will be appropriately compensated. Not so for the solar industry proposals. First, the solar parties now refuse to update their proposals to account for the 2021 ACC; one could reasonably infer from this that compensating customers based on actual value is a low priority for them. However, if they were consistent with their stated goals of their proposal and set their export compensation to reach the 25-year levelized average of the 2021 ACC and it turned out that the 2020 ACC was correct, their proposal would prevent participating customers from being compensated accordingly.

Further, basing compensation on a 25-year forecast are inconsistent with the context of SEIA/VS's and CALSSA's proposals, which would fix the terms of export compensation for 20 years, and with the context of the distributed solar industry, which rarely has financing arrangements longer than 20 years. Under their proposals, export compensation in years 1-20 would be based in part on value that could hypothetically be provided by the systems in years 21-25. In those later years those systems would not be paid at those rates, but at whatever the prevailing DER compensation scheme is in the 2040s. While PV systems can last 25 years or more, it is unclear that a given system will still be active in years 21-25. For example, a customer with a typical 20-year Power Purchase Agreement

[151] CUE Opening Testimony, p. 14.

(PPA) may benefit from making their PPA provider remove the system at the provider's expense at the end of the contract term so that the customer can upgrade to the latest technology. It makes no sense to pay someone today for a service they could hypothetically, but are under no obligation to, provide in the future.

e) Use of a 25-year forecast to determine compensation is also inconsistent with CPUC practice for PURPA standard offer avoided cost contracts, which sets payments by use of a three-year historic average of CAISO day-ahead market energy prices and a five-year average of historic resource adequacy prices.[152]

Currently, capacity prices are updated annually for PURPA contracts and energy prices are fixed for a period of 7 years for existing facilities and 12 years for new facilities.[153] The CPUC has issued an Amended Scoping Memo and Ruling to revisit the fixed energy price component on the contract in response to FERC Order 872.[154]

f) Export Compensation Should Immediately Transition for Future NEM Customers to a Cost and Value Based Rate

Dilatory proposals from the Solar Parties to step export compensation down over time are unreasonable given the magnitude of the wealth transfer and the NEM program's failure to provide non-participating customers with value, as demonstrated by the E3 and the Lookback Studies. If there is any transitional step-down process, AB 327's objectives will never be realized. However, if the Commission adopts a transition, it should not create any vintages. The new rate should apply to all participating customers.

g) Export Compensation should be based on Actual Exports

The utilities, Public Advocates Office, and TURN propose to base compensation on actual exports as measured by the utility meter. This is opposed by the solar industry, which would

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[152] D.20-05-006, Ordering Paragraphs 1 and 2.

[153] D.20-05-006. Ordering Paragraphs 9 and 10.

[154] R.18-07-017. January 11, 2021. "Amended Scoping Memo and Ruling of the Assigned Commissioner." p. 3.

prefer to maintain the current method of determining non-bypassable charge obligations under NEM 2.0, where imports and exports are netted within a metering interval.

CALSSA argues that currently available meter data does not break out the import and export channels of meter readings, making it impossible for solar firms to estimate actual exports for the purposes of providing savings estimates and for customers to see what their hourly exports are when they install. As of last week, this is no longer true for PG&E. PG&E's "Share My Data" portal now allows individual meter channel data to be provided to customers. SCE is rolling out similar capabilities this month, and SDG&E's portal already allows customers to view either the net or separate imports and exports.

CALSSA also claims that the "reduction in customer savings under this proposal would be large and unknowable."[155] This is incorrect. For PG&E NEM 2.0 customers, intra-interval netting reduces the amount of kWh deemed to be exported by 6.6% for residential customers and 3.6% for non-residential customers, relative to actual metered exports.

Further, this attempt to retain intra-interval netting is at odds with CALSSA's position that the Commission must ignore any impact of displaced behind-the-meter energy consumption. One cannot argue there is a bright line at the meter, yet also request that line be blurred. This inconsistency demonstrates that there is no such line, and the Commission should use the tools at its disposal to resolve the inequities of the status quo.

h) Under a Cost-Based Approach, Net Surplus Compensation Should Not Change Because it is Already Cost-Based

SEIA/VS propose to change the current net surplus compensation methodology to a solar weighted average of the ACC in the near term. The current methodology to set net surplus compensation is required by law, as will be discussed further in briefing.

[155] CALSSA Opening Testimony, p. 116.

3. The Joint Utilities' Proposed Reform Tariff's Netting Intervals and True-Up Periods Provide Customers with More Accurate Price Signals and Have Greater Potential to Incentivize Load Shifting

Generally, many parties agree, and as stated in our Opening Testimony,[156] the current NEM billing setup creates customer confusion and consumer protection issues. CalPA, like the Utilities, is proposing "instantaneous netting", or using recorded metered imports and exports, recognizing that netting "is a NEM [billing] construct that does not reflect the physical reality that all Channel 2 meter readings are exported to the grid".[157] The Joint Utilities' proposal for netting and true-ups provides a balance of price signal granularity and ease of customer understanding. TOU period export compensation is superior to hourly export compensation because the latter would greatly complicate the bill structure and make it harder for customers to understand. To support Guiding Principle F (regarding tariffs that are both transparent and understandable), the customer bill would need to be modified to show costs for each hour, which would greatly lengthen the bill and make it harder to find key details. Our proposal will help participating customers understand the temporal value of their onsite generation while still maintaining a reasonable level of simplicity and an accessible tariff.

a) Current Netting Policy is a Complicated, Unnecessary Billing Construct

SEIA/VS propose to maintain the current netting intervals, but provide no rationale for this proposal, other than to state that "One hour is the established metered interval for residential customers" and "Generally, the data that the utility provides to residential customers on its website shows hourly data that has been netted over that metered interval."[158] As stated previously, all three utilities either already or will soon have the capability for solar customers to see and share both channels of data. Regardless, SEIA/VS's assertion may be the case for *current* NEM customers, but not for prospective solar customers, who only see one channel of import data with no netting. It is unlikely that non-solar customers are intimately familiar with the complicated billing concept of "netting". That

[156] Joint Opening Testimony, p. 193.

[157] Opening Testimony of CalPA at 3-6.

[158] SEIA, at 64.

netting is done a certain way under the NEM 2.0 tariff is not an argument for its continuation in the Reform Tariff. The current netting policy, to net imports and exports within each metered interval, is a billing construct to measure the kWh consumption to which non-bypassable charges should be applied. It is not something that needs to or should be continued.

CALSSA also proposes to maintain the current netting policy, stating that the Joint Utilities' proposal would be unfair to [solar] customers.[159] However, the Commission must consider what is fair to all customers, including those who are non-participants. CALSSA's argument for maintaining current policy is that the Utilities' and CalPA's proposals would be too complicated to implement. However, the Utilities' and CalPA's proposals are much less complicated than CALSSA states. As explained by CalPA, "The IOUs' meters automatically perform instantaneous netting of customers' exports and consumption and do not require any modifications to implement this practice under net billing."[160]

The Commission should adopt a policy where all recorded imports on the first meter channel are charged the retail rate and all recorded exports on the second meter channel are compensated at the ECR rate as described by the Utilities in Opening Testimony. This policy will likely be both easier for customers to understand and to bill: imports and exports are completely separate, and each are charged or credited at a different rate.

b) <u>Annual True-Ups Have no Cost Basis and do not Sufficiently Incentivize Load Shifting or Paired Storage</u>

SEIA/VS propose to maintain the annual true-up policy, stating that it is likely that customers would have excess generation in certain months and the monthly true-up would reduce the value proposition for the customer.[161] However, SEIA/VS offer no evidence that the value of the energy in one month is equal to the next month, and that this is the best, or even a good, value proposition for all customers and the grid. CALSSA also proposes to continue the current annual true-

[159] Opening Testimony of CALSSA, at 115.

[160] Prepared Testimony of CalPA, p. 3-6.

[161] Opening Testimony of SEIA/VS (Beach), pp. 64-67.

up policy, stating that "solar conditions have a natural annual cycle."[162] SEIA/VS and CALSSA appear to view netting and true-up policy through a single lens, from the new participating-customer's perspective. However, the Commission should also be considering the value this solar generation has to the grid and to non-participating customers. Customers are not storing their generation from high-production months to use in low-production months. As stated in the Joint Utilities' Opening Testimony, excess generation in March and April does nothing to offset the same solar customer's consumption in months where prices are higher and there is more demand on the grid.[163] Compensation for solar generation should reflect this, and the Joint Utilities' proposal will help customers understand the temporal value of their generation.

The Commission has indicated that it is interested in the ability of DER load shifting and management to benefit the grid and to act as deployable resources. The practice of trueing up a solar customer at each billing cycle provides a bigger incentive for that customer to respond to price signals and to elicit the desired response of greater load shifting. Customers will not have credits from high production months carried over to offset charges during times of grid stress.

SEIA/VS also propose to change the annual true-up date for all new residential and small commercial customers to April but offer little explanation for this proposal.[164] It is likely that this billing arrangement would only benefit the customer, not the grid, by allowing the customer to offset any remaining charges with excess generation that is characteristic of the March and April months.

Our proposal will also encourage customers to pair batteries with their rooftop solar installations, and export less to the grid during the daytime when renewables are more available, storing their onsite generation to use during peak hours when it is most beneficial for both the grid and for the customer to avoid peak charges. Adopting the Joint Utilities' proposal for netting and true-ups is

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[162] Opening Testimony of CALSSA, p. 117.

[163] Joint Utility Opening Testimony, p. 134.

[164] Opening Testimony of SEIA/VS, p. 66.

one way for the Commission to ensure that Reform Tariff customers receive more granular price signals and choose to generate in a way that benefits the grid, and therefore, all customers.

4. <u>Grid Benefits Charges (GBCs), Paying Nonbypassable Charges (NBCs) and Shared Charges Are Reasonable</u>

The Commission should reject arguments from parties that GBCs are unnecessary and discriminatory. All customer generation should be compensated at the value it is deemed to be worth, whether it is exported or used onsite. Adopting this policy would be fair to both customer generators and to nonparticipating customers. Just because a customer consumes the self-generated kWh instead of exporting does not change the value of the kWh.

Customers that generate supply should not be able to avoid paying for costs of the grid and public policy programs by consuming onsite. Whether or not a customer self generates, that customer should still be responsible for supporting system-wide fixed grid costs, energy efficiency programs and other policy mandates, as their generation does not reduce these fixed costs. As described in this testimony, a customer-generator reducing load intermittently is not the same as adopting energy efficiency measures, and cannot be compared as such. The Commission should adopt our proposed GBC that recovers the difference between the retail rate and the value of the self-consumed generation, to ensure that all customer generation is valued appropriately and nonparticipant indifference is achieved.

As outlined in the Utilities' Opening Testimony,[165] the fixed cost recovery components of the proposed Reform Tariff recover separate and distinct costs associated with providing reliable and safe energy, as well as state programs such as low-income and energy efficiency programs, to the utilities' customers; there is no double recovery of costs.[166] Additionally, the proposed GBC has been reduced by ACC values, and therefore accounts for the value that distributed solar generation provides

[165] Joint Utility Opening Testimony, at 100.

[166] Note that if the Commission decided to adopt a fixed charge that differs from what the Joint Utilities propose in their residential default rates, or no fixed charge at all, these costs should be recovered through an increased GBC to ensure appropriate and full cost recovery.

per the 2021 ACC. The decision adopting the NEM Successor Tariff (NEM 2.0) made important strides in determining that some charges for shared costs should be non-bypassable and not subject to full retail netting.[167] The Commission should build on this decision in the Reform Tariff by approving a tariff design that fully recovers all shared policy and fixed costs.

Because exports to the grid (as well as imports from the grid) are expected to decrease with paired storage, the Commission must include some form of fixed cost recovery in order to meaningfully address the cost shift to non-participating customers. SEIA/VS state that the Commission should focus the design of the Reform Tariff on growth of solar+storage systems, giving just as much, if not more, attention to the economics and cost-effectiveness of these installations as standalone solar.[168] However, their proposal fails exactly in what they urge the Commission to do: SEIA/VS's estimated paybacks for solar+storage exceed standalone solar. The Joint Utility GBC proposal incentivizes customers to pair their solar installations with storage because our proposed GBC assessment is the same for standalone solar and solar+storage such that solar+storage customers have a shorter payback.

a) Diverse Parties Agree That a GBC Structure is Necessary

In addition to the Joint Utilities' proposal, several other parties advocate for including a GBC as a necessary component of the Reform Tariff. CalPA outlines the distinction between costs recovered through a GBC and costs tied to customer consumption: "The GBC should include the customers' responsibility for fixed distribution system costs – or the total costs of the system that are above marginal costs – as well as transmission costs. The costs above marginal costs include costs to maintain, replace, and upgrade distribution capacity and to provide sufficiently reliable and safe electric service, which are critical components of cost of service for all ratepayers and are not affected by customers' consumption or generation decisions."[169] CalPA also emphasizes why an adjustment to export compensation alone will not be sufficient to address the cost shift: "[a]s demonstrated in the prior section, setting the ECR at avoided costs only reduces the successor tariff's cost burden relative to the

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[167] D.16-01-044, COL 4.

[168] Direct Testimony of SEIA/VS (Beach) at 40-42.

[169] Prepared Testimony of CalPA at 3-24.

current NEM structure by 36.9%. This is because changing the ECR only addresses the cost burden generated by net exports. Consequently, there are still significantly large cost burdens remaining even with net billing. In fact, even with net billing, NEM customers are underpaying the costs they impose on the system."[170]

NRDC also supports a GBC and explains its necessity: "[b]ecause electric rates recoup all costs of service through volumetric rates, and the costs to generate electricity are a small fraction of total rates, NEM customers will not pay their share of the cost of service if they avoid all bill payments on self-consumption of distributed generation. A grid benefit charge (GBC) will ensure that NEM customers pay their share of the cost of service."[171]

A GBC is also a pillar of TURN's proposed Reform Tariff,[172] stating: "[t]his charge is designed to recover the amount of non-generation costs that would be paid by the participating customer but for the operation of the BTM resource. Unless these costs are collected through a separate charge, the unrecovered amounts would be shifted to all customers including non-participants."[173] We agree that when self-consuming, a NEM customer is only providing their own energy needs, they are not providing public policy services, transmission and distribution infrastructure and maintenance, wildfire mitigation or other services that the utility continues to provide to all customers, including those with NEM.[174] The range of interests represented by CalPA, NRDC, and TURN further confirms that the GBC serves a distinct purpose that cannot be achieved through other rate elements and should be adopted as part of the Commission's decision.

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170 *Id.*, at 3-23.

171 Opening Testimony of NRDC at 18. NRDC states that it supports CalPA's proposed GBC.

172 In TURN's testimony, the GBC calculation is based on individual customer consumption instead of an estimated class average and is referred to as the Self-consumption charge for Nonbypassable, Unavoidable and Shared costs (NUS). However, the intent behind the charge is consistent with the Joint Utilities, CalPA, and NRDC.

173 Direct Testimony of TURN at 13.

174 The Joint Utilities have proposed that the GBC should be reduced by the value of the ACC. To the extent that distributed solar resources result in avoided costs per the ACC (including transmission and distribution), these values are accounted for in the reduction of the GBC.

In addition to intervenors in the proceeding, E3's Whitepaper recognizes a GBC as one mechanism for designing cost-based rates and notes that a GBC serves as an alternative to higher energy or demand charges. E3 states: "A rate component such as a grid access charge (GAC) is a fixed monthly charge that can collect the remaining fixed costs which are not recovered through more traditional fixed charges, shifting fixed cost recovery away from energy and demand charges."[175] Demand charges vary which can create confusion and be more difficult for customers to understand, and higher energy charges work against electrification goals that are intertwined with NEM. The GBC is the most appropriate fixed cost recovery mechanism for the Reform Tariff.

b) Solar Party Arguments Against GBCs are Flawed

Parties opposing a GBC argue that the costs it would collect are fixed for all customers, not just NEM customers.[176] While it is true that there are fixed costs to serve all customers, NEM customers are able to avoid payment of these costs in a way that non-NEM customers cannot, and as a result, are not paying their fair share of fixed costs. Fixed costs are currently recovered in residential volumetric kWh rates, which, although not cost-based, was more practical at a time when one-way grid imports were the default supply option for most residential customers. In a system of imports and exports, both utilizing the grid, volumetric cost recovery based on imports alone is insufficient. The same costs exist in both scenarios, but because customers are now self-generating, they avoid importing kWh and therefore avoid paying for the costs of the grid that they are still connected to, rely on, and benefit from.

Parties rely on several unfounded claims to dispute the need for a grid benefits charge. These claims are addressed below.

[175] Alternative Ratemaking Mechanisms for Distributed Energy Resources in California, E3 at 21.

[176] Opening Testimony of CALSSA at 90.

(1) Solar Argument 1: Existing Charges are Sufficient to Recover Grid Costs:

CALSSA suggests that where grid costs are not being sufficiently recovered, an increase in the minimum bill or a fixed charge that applies to all customers is more appropriate than a GBC. "As long as minimum bills are set to recover the customer-specific costs of grid access, there is no need for DER-specific rates, charges and classes."[177] However, CALSSA fails to provide any support for its claim that minimum bills are sufficient to cover grid costs. The Joint Utilities calculate applicable distribution customer access costs to be significantly higher than the current minimum bill,[178] and these costs are not the only grid and policy costs that current NEM customers unfairly avoid paying for. NEM customers are able to avoid paying for upstream distribution costs, transmission charges, fixed costs of generation, and others. Further, the NEM 2.0 Lookback study examines residential cost of service before and after installing a NEM 2.0 eligible system and finds that while there are modest reductions in cost of service, post-installation bills are far below the estimated cost of service.[179]

(2) Solar Argument 2: Behind-the-Meter Generation and Self-Consumption Do Not Impose Costs:

Unlike energy efficiency measures[180] that sustainably reduce load in a way that the utility can respond to over a long-term investment planning cycle, NEM self-consumption creates temporary, intermittent, declines in utility load but does not consistently decrease the demand imposed on the system. As a result, the utility must maintain the same system capacity necessary to meet demand in the event a customer's solar output is reduced or stops completely, which it does reliably, on a daily basis, when the sun sets. Additionally, certain infrastructure and resources are

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177 *Id.*, at 99.

178 See IOU Reform Tariff Opening Testimony Workpapers.

179 Verdant NEM 2.0 Lookback Study, Figure 1-3, at 11.

180 See further discussion of the distinctions between energy efficiency and distributed generation in Chapter 6 of the Joint Utilities' Rebuttal Testimony.

built to meet peak and net-peak load. As the system peak moves later in the day, incremental solar generation during the middle of the day, when utility-scale solar resources are already plentiful and being curtailed, has diminishing value both in an oversupplied market and as a GHG-displacing resource.

Solar customers placing stress on the grid when they are not self-generating are still imposing costs. Solar customers who use electricity at night or when it is cloudy (when the sun isn't shining) use the distribution and transmission grid like a non-solar customer. They benefit from the same public policy programs, wildfire mitigation, local reliability, and other functions as non-solar customers do.

An example of this can been seen below in Table IV-5. Residential NEM customers have higher maximum noncoincident demands and higher coincident peak demands, on average, than non-NEM residential customers. This may not be due to the fact they are NEM customers; it is possible that there are other factors causing NEM customers to have higher demands, for example, they were larger customers and had higher demands to begin with, on average. However, that does not change the fact that on average, NEM customers have higher coincident and noncoincident demands than non-NEM customers, are higher cost-of-service customers, and place more stress on the grid. The coincident peak period is 4PM – 9PM, a time when the sun is in the process of setting or not shining at all. The demands shown below reinforce that solar customers continue to rely on and use the grid after adopting NEM.

Table IV-5
SDG&E 2018 NEM and Non-NEM Customer Maximum
Non-Coincident and Coincident Peak Demand

Max kW	NEM	Non-NEM
Non-Coincident Demand	6.1	4.2
Coincident Demand	5.7	5.0

(3) Solar Argument 3: Previous Decisions have Waived Similar Charges for NEM Customers:

CALSSA argues that AB 327 does not require ratepayer indifference for NEM and that the Commission has previously exempted NEM customers from standby charges.[181] However, AB 327 in fact explicitly states that fixed charges that are specific to NEM customers are allowable.[182] In D.16-01-044, the Commission included the addition of NBCs when it reformed NEM 1.0. Previously providing an exemption from a charge does not bind the Commission to maintaining that exemption in future decisions.

(4) Solar Argument 4: Exports do Not Impose Cost and NEM Customers Only Benefit From the Grid When They are Importing Energy:

SEIA/VS assert that customers only use and benefit from the grid when they import energy, and that there are no costs avoided by NEM customers when they export. and that any costs are appropriately allocated to other customers who then consume the exported energy. As Mr. Beach states: "the utility is fully compensated for that delivery service by the neighbors who runs [sic] 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."[183]

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[181] CALSSA Opening testimony at 102.

[182] AB 327 Sec. 5, 739.9 (e).

[183] Opening Testimony of SEIA/VS (Beach), p. 69.

SEIA/VS fail to present any factual evidence or analysis in support of the statement that customers do not use the grid when they export and that exports do not impose costs on the grid. Beyond the incorrect assertion that importing energy is the only time when customers derive value from the grid, NEM leads to grid strain by creating a two-way flow of energy, which creates additional operational challenges with transformer overloads and voltage on the distribution grid. As discussed in this testimony, there are technical grid implications from exported energy to the grid, including but not limited to issues with voltage regulation, which can require upgrades of distribution infrastructure that are socialized among all customers.

Moreover, their argument confirms the Utilities' chief critique of the current NEM program –the resulting inequitable cost shift, which does not result in an under collection of utility revenue but rather a shifting of costs to non-participating customers. SEIA/VS also acknowledge that the current rate of export compensation is not accurate by proposing a change to export rates. Paired with the explanation of how non-NEM customers compensate the utility for all grid services associated with delivery of exported energy, SEIA/VS all but directly confirm the mechanics of the NEM cost shift.

(5) <u>Solar Argument 5: The GBC Calculation is Imprecise</u>

SEIA/VS argue that the GBC as proposed in our Opening Testimony would be too imprecise, and that the utilities have no idea how much a customer generates.[184] However, when asked if SEIA/VS would be willing to share data or ask its members to share data to enhance the precision of such a charge, it stated that it would not be willing to approach member organizations for data regarding customer generation behind the meter.[185] The Utilities currently employ a similar process when estimating behind-the-meter generation for standby customers in order to assess non-bypassable charges. Standby customers are able to install a second meter to measure generation if they prefer exact measurements, rather than estimates.

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[184] *Id.*, at 71.

[185] Appendix B: SEIA/VS Response to Joint Utility DR-007.

The Joint Utility proposal balances customer understanding, precision, and implementation considerations. As stated in our Opening Testimony, we will update the estimate of onsite consumption annually[186] by customer class to ensure that on average, customers are paying the correct amount. This is consistent with ratemaking principles, where rates are designed based on the customer class's average cost of service.

c) Other States Have Adopted GBCs

Utilities in some other jurisdictions have been allowed to introduce GBCs as part of successor tariff structures to NEM. Here are a few examples.

Quite recently, on May 19, 2021, the South Carolina Public Service Commission approved a settlement proposal between Duke Energy, and various groups representing solar and environmental interests (including Vote Solar).[187] This "Solar Choice" tariff includes a $/kW monthly Grid Access Fee for residential systems sized greater than 15 kW-dc.

In July 2020, the New York Public Service Commission approved a "Customer Benefit Contribution" DG capacity-based charge estimated at $0.69 to $1.09 per kW of installed DG capacity, depending on the utility.[188]

In 2017, the Arizona Corporation Commission approved a settlement proposal for APS' retail rates, with multiple options for customers that adopted rooftop solar after the new rates went into effect; the approved rate options include either a grid access charge or a demand charge for DG customers.[189]

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[186] Opening Joint utility Testimony at 138.

[187] Docket 2020-264-E/2020-265-E submitted by Duke Energy Carolinas, Duke Energy Progress, North Carolina Sustainable Energy Association, Southern Environmental Law Center on behalf of South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Upstate Forever; and Vote Solar. See: https://dms.psc.sc.gov/Attachments/Matter/f7ef21b9-d3c3-464c-9e71- f498d50e168a.

[188] Opening Joint Utility Testimony, Appendix B, p. B-28.

[189] Opening Joint Utility Testimony, Appendix B, pp. B-7 and B-8.

In 2016, the People's Energy Cooperative in Minnesota put in place a Distribution Generation Grid Access Fee for customers with new or expanded DG systems. The monthly access fee is $2.00 per kW for facilities above 3.5 kW, upon to a maximum fee of $37.00 per month.[190]

Table II-3 in the Joint Utilities' Opening Testimony provides information about these rate-design elements for selected investor-owned and publicly owned utilities.

d) Solar Parties Agree That a GBC is a Preferred Cost Shift Mitigation Mechanism

Mr. Beach's (SEIA) criticism of GBCs should fall flat, as these positions are a change from his previous statements to the CPUC. While under cross examination in the previous NEM Successor Tariff OIR, he was asked, in his professional judgement, which of the reform proposals was "least objectionable."[191] He stated that the grid benefits charge proposal of CalPA[192] (then called an "Installed Capacity Fee") would be preferable compared to mechanisms such as reduced export compensation, monthly netting, and rate requirements. Notably, SEIA's proposal here features versions of all three elements that their own expert denigrated, while excluding the one that he supported.

e) Walmart Misunderstands the Utility Proposal

Walmart opposes the non-residential GBCs proposed by the utilities. Some of their objections appear to be the result of misunderstanding the utility proposal.

The first is that they appear to interpret the utility proposal as applying the same GBC to bundled and unbundled customers. This is not the case – for unbundled customers, their GBCs would no longer include recovery of generation costs net of generation commodity avoided costs, but instead be based on the PCIA vintage of that customer.

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[190] "As of July 1, 2015, Minnesota Statute 261B.164 authorizes electric cooperatives and municipal utilities to charge a cost recovery fee on distributed generation facilities. This enables cooperatives to recover some of the cost shift that has been occurring between distributed generators and the rest of cooperative membership." https://peoplesenergy.coop/sites/peoplesrec/files/PDF/2016%20Bill%20Inserts/DistributedGenerationFee%20INSERT%203-16.pdf

[191] R.14-07-002 Hearing Transcript, Volume 3, pgs. 498-499.

[192] CalPA was known as Office of Ratepayer Advocates, or "ORA" at this time.

Second, they argue that transmission and distribution related costs should be excluded for customers which have demand charges recovering those costs. The utilities agree – for example, the GBC for PG&E's B-20 rate only recovers generation and NBC related costs, as distribution and transmission costs for B-20 are exclusively recovered through demand and fixed charges.

B. <u>Solar and Other Party Proposals Are Not Cost Based, Which Is Inconsistent With Commission Rate Design Goal</u>

The Commission should reject proposals that are not cost-based and do not provide value-based compensation. Parties that have "stepdowns" in retail rate export compensation are not cost-based, and continue to provide an embedded subsidy to solar customers, while perpetuating the cost shift. Likewise, parties who propose to leave some level of cost shift to improve the value proposition for the adopting customer are kicking the can down the road. As rates increase, the cost shift will increase, and the Commission may find itself in the same position in some time, with a large cost shift from distributed solar.

If the Commission determines that it is necessary for customers to achieve a targeted payback, e.g., 10 years, then the Joint Utilities strongly agree with TURN that it should adopt a cost-based structure right away but provide an up-front incentive to customers. The Commission should not adopt a proposal that is "middle ground" and leaves a level of embedded cost shift. An up-front incentive or market transition credit is transparent to all parties – participants, nonparticipants, utilities, and the Commission. It will allow the Commission to clearly see how much ratepayers are subsidizing distributed solar customers, rather than allowing an embedded cost shift tied to retail rates to grow over time. A cost-based approach is consistent with the Commission's Rate Design Principles that rates should generally avoid cross subsidies and that incentives should be explicit and transparent.

C. Proposals to Oversize Systems Are Contrary to Sound Public Policy Because of the Harm They Will Cause to the Electric Grid System and Consumer Protection Objectives

1. Public Policy Implications of the SEIA/VS Proposal to Allow Oversizing of PV Systems

In anticipation of residential customers' increased loads over time from electrification actions, SEIA/VS and Sierra Club recommend that the Commission allow customers on their proposed successor tariff to oversize their systems when they install rooftop solar or rooftop solar paired with storage.[193]

As a matter of individual customer choice, it may seem rational for a residential customer to want to oversize the installation of PV equipment so that the solar system can handle provision of service to future loads. Doing so might avoid the inconvenience and additional cost of upgrading a system later to accommodate the incremental loads, in the event that the customer decided to buy an EV and charge it at home, or convert the home heating system to electricity in the future. In fact, customers have the option to oversize a PV system today, although not if they take service under the NEM tariff. Customers currently may choose to oversize their systems by becoming a seller of power to the utility under its PURPA tariff provisions. But in the context of proposals by SEIA/VS and CALSSA to use a multi-year process to phase out of the current NEM pricing structure, allowing oversizing as a matter of policy would worsen the cost shift problem to the detriment of broader electrification and equity goals.

Even recognizing the importance of beneficial electrification going forward, sound ratemaking principles suggest that the CPUC should exercise extreme caution when considering whether to allow oversized BTM generation for NEM customers. In the 25 plus years that California has supported NEM to promote customer choice and renewable resource development, for good reason, the Commission has done so by restricting the size of on-site generating equipment to customers' historical onsite load. Prior to departing from history (something the Commission may not have the legal option

[193] This testimony is limited to the factual reasons why the Commission should reject such proposals. Any discussion of the illegality of such proposals for net billing arrangements would be address in the Joint Utilities' legal briefs.

to do), the CPUC must consider several things. First, none of the parties promoting oversized systems has included a requirement that the customer install the future load. In every instance, oversizing is proposed to encourage electrification, but not to guarantee it. In the absence (or in advance) of those on-site loads materializing, then the oversized on-site generating capacity will mean greater exports to the grid and greater pressure on the local distribution system, and give preference to the use of existing distribution capacity to the customer with oversized equipment as compared to another customer that subsequently adds on-site generation on its premises. This raises fairness questions in addition to the engineering and economic consequences that oversizing might have on assuring that the local distribution system can handle the additional excess generation (as discussed in the subsequent section below). This is not, therefore, just a question of the appropriate pricing of exports, but rather the incremental effect of that oversized load on the carrying capacity and upgrades needed on the distribution system.

There are other issues that the Commission should consider when deciding whether to allow some degree of oversizing.

- First, the suggestion by SEIA/VS to compensate net exports at avoided costs would overstate the value of this extra supply from DG. The ACC includes benefits not provided by random exports to the grid. The customer with oversized equipment would likely eliminate payments for use of the utility's system (even though the exports fundamentally *depend* upon being able to use the utility's system). Despite obvious reliance on the grid, these customers would pay nothing for that service, and other non-participating customers would have to pick up these costs.

- Second, the power purchased by the utility from the customer with oversized solar equipment would not qualify for satisfying the utility's RPS requirements. Oversizing can lead to a utility to pay for energy they cannot use to meet RPS requirements, and in so doing, the utility and its other customers would pay higher prices for non-qualifying renewable energy than the price they would pay for utility-scale renewable supply.

- Third, as observed by the Hawaii PUC when it approved NEM reforms for HECO: "the unscheduled and uncontrolled export of excess [rooftop] solar energy onto the grid, could eventually create curtailment risks for existing and future utility-scale solar PV, wind, and other renewable energy projects....When variable energy congestion occurs due to excess energy at the system level, utility-scale renewable energy projects would be curtailed due to the current technical inability to curtail distributed generation exports onto the grid. This can also result in loss of grid access to the reliability capabilities that are inherently provided by utility-scale wind and solar PV projects pursuant to generator performance standards set for in interconnection requirements. As a consequence, distributed solar PV customers effectively have a higher priority and preferential grid access than do the utility-scale projects, which serve all customers, because the utility is forced, by technical default, to curtail the purchase of low-cost, wholesale renewable energy that otherwise may provide economic savings to utility customers…."[194]

2. Technical Grid Implications of the SEIA/VS Proposal to Allow Oversizing of PV Systems

To elaborate on these system concerns, first one must understand the process by which NEM generators interconnect. Interconnection Studies for NEM projects are currently performed utilizing the Fast Track procedures identified in Rule 21. These procedures are in place to ensure the orderly, rational, and safe interconnection of those Generating Facilities over which the Commission has jurisdiction and includes NEM Generating Facilities and Non-Export Generating Facilities. Rule 21

[194] Order No. 32053 Ruling on RSWG Work Product, in the Matter of the Public Utilities Commission Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, April 28, 2014, pages 41-42.

recognizes the need for analysis of these resources, including NEM, to ensure overall system reliability and safety of the electric grid is maintained by outlining a two-step Fast Track Interconnection Review process for eligible resources. To initiate the interconnection of a Generating Facility, the applicant is required to submit an Interconnection Request providing detailed information related to the project including make, model and the number of inverters or generating units, transformers, and other pertinent information such as solar panel or battery storage specifications. Once the application is deemed valid, a queue position is assigned which is used in properly evaluating potential incremental impacts attributed to the project based on the assigned queue position. To maintain an orderly interconnection process, any oversizing or increases to existing projects must submit a new interconnection request which would be queued based on deemed valid date. The queue date is essential in order to properly ascertain impacts to the electric system corresponding to such increases and to properly define corresponding mitigations required as a result of the project including the oversizing or increases to the existing resources.

Once an Interconnection Request is deemed valid and complete, Fast Track evaluation is undertaken to determine if the project can be interconnected without the need to perform a Detailed Study. The first step of the Fast Track review consists of an Initial Review and, if required, a second step or Supplemental Review. The need to undertake a Supplemental Review Screens N through P is determined based on the results of Initial Review Screens A through M. Resources that have already been interconnected were evaluated based on the technical data and sizing of the project as previously submitted.

Allowing these existing projects and new projects to "oversize" could result in the failure of Rule 21 Initial Review Screens D, F, G, K, L and M and failure of Supplemental Review Screens N, O, and P, which would drive the following quick review outcomes.[195]

[195] SCE Rule 21: Generating Facility Interconnections: https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/rules/ELECTRIC_RULES_21.pdf. Screen D is covered on Sheet 115 and Screen K is covered on Sheet 121.

- Failure of Screen D would drive the need to upgrade the existing service transformers or secondary conductors which may not be necessary if the project(s) were "right sized"
- Failure of Screen K may drive the need to evaluate Screen L where "right sizing" the project may not exceed the threshold needed to evaluate Screen L
- Failure of Screen F, G, L and M would drive requirement for Supplemental Review
- Failure of Screen N could drive the need to reconductor a line segment identified to be thermally overloaded whereby "right sizing" the project(s) may not drive such need
- Failure of Screen O could drive the need to install a voltage regulator to address voltage performance outside of Rule 2 limits where "right sizing" the project(s) may not drive such need
- Failure of Screen P could drive the need for circuit breaker replacements, installation of reverse power relays, installation of new or upgrades to existing Remote Automatic Reclosers, among other upgrades, where "right sizing" the project(s) may not drive such need

Likewise, customers installing solar generation who also contemplate future load growth might prefer to reduce total installation costs by oversizing their system. If no protection for nonparticipants is instituted, these customers have essentially reduced their own risk by increasing costs for nonparticipants.

Based on the current Rule 21 Tariff, the cost to upgrade the existing service transformers or secondary conductors may be shifted to the non-participating ratepayers for NEM-1 and NEM-2 if the NEM-2 project is less than or equal to 1 MW and the service transformer is also used to provide service to other customers. Likewise, the cost of all other Distribution Upgrades, beyond the existing service transformers or secondary conductors, required to support interconnection of NEM are shifted to the non-participating ratepayers for NEM-1 and NEM-2 if the NEM-2 project is less than or equal to 1 MW as the current tariff shifts these costs to non-participating customers.

The Commission must reject any proposal to oversize existing resources without the submittal of an Interconnection Request and the performance of an evaluation so as not to jeopardize system reliability. Doing so can create the following unsafe system conditions:

- Existing protection settings are based on the technical details of the distribution circuit and corresponding generation resources as defined in original interconnection requests. If increases are allowed without a proper evaluation, protection may be subjected to miscoordination or may not be set properly to enable proper detection of end of line fault conditions. Such conditions could needlessly disconnect customers, including the oversized NEM project and could expose the public to adverse impacts.
- Increases to voltages beyond acceptable Rule 2 limits resulting from over sizing could result in unsatisfactory performance of equipment, including potential of equipment ignition
- Increased output from oversized project(s) may drive thermal overloads on overhead conductors, underground cable, connectors, and terminal equipment which can lead to failure

Finally, the allowance of oversizing without the submittal of a new Interconnection Request will impact the overall operational performance of the grid with the increased production in NEMs potentially driving thermal overloads in facilities greater than 50 kV that could result in the unexpected curtailment of other FERC jurisdictional resources to mitigate any such created problems. Such conditions would be defined in the Fast Track Review and drive the need to perform a Detail Study which would define appropriate mitigation to these issues.

D. Application of Smart Inverter Communications Capabilities are Necessary in this Proceeding

CALSSA states that the communications and cybersecurity requirements for all DERs interconnected under the Reform Tariff in the Joint Utilities' March 15 proposal[196] are unnecessary. CALSSA at 77:

> *The communications and smart inverter requirements contained in the Joint IOU proposal are actively being considered elsewhere. A few paragraphs in a NEM proposal should not circumvent the lengthy processes that have taken place or are underway in more relevant proceedings. Cybersecurity and communications capabilities are important issues that are squarely in scope in R.17-07-007. The Commission in that proceeding has made certain communications requirements mandatory as a condition of interconnection and has the ability to do so again for additional capabilities. There is no need to address such issues in this proceeding.*

The Commission should reject CALSSA's statements that the communications and smart inverter requirements in our proposal should be disregarded in this proceeding. The requirements the Joint Utilities have proposed are straightforward, reasonable, and their application is not being considered elsewhere. Our proposals also set the stage for future potential DER grid services and integration of DERs into system load management. Stakeholders should be seeking to work together to improve cybersecurity and communications to the benefit of all, not obstruct implementation of reasonable safety measures.

CALSSA is correct that communication and cybersecurity smart inverter requirements have been considered in other proceedings, such as R.17-07-007 (the Rulemaking addressing Rule 21 interconnection issues).[197] However, in the case of R.17-07-007, these requirements have only been considered based on theoretical capabilities, not their practical application to DERs being installed today. Activation of these communications is not currently within the scope R.17-07-007. As a result, this proceeding is an appropriate venue to require the application of these solutions to solar and storage

[196] These requirements are unchanged in the Joint Utility Opening Testimony.

[197] Resolutions E-4832, E-4898, E-5000, and E-5036. See also: D.21-06-002, R.21-06-017.

DERs on the Reform Tariff as it is foundational to the continued deployment of behind-the-meter renewable resources.

Within R.17-07-007, stakeholders have acknowledged the need for end-to-end testing of the smart inverter communication solutions to ensure that these capabilities will work as advertised when they are ultimately activated.[198] Likewise, the consensus viewpoint of stakeholders is to take an extremely minimalistic viewpoint in the discussion of smart inverter cybersecurity and seek to limit discussion of this topic in the current ongoing Smart Inverter Working Group (SIWG) cybersecurity discussions, in compliance with Resolution E-5000 Ordering Paragraph 4. Sunspec leadership have even suggested during SIWG calls that "organizational reputation" is a sufficient incentive to keep smart inverters safe without additional compliance requirements. Time and again, we have seen this is not the case, including recent attacks on the nation's energy infrastructure (e.g., Colonial Penn Pipeline), to say nothing of cyberattacks on electric grids sponsored by nation states.

In SDG&E's service territory, the single largest generating resource is BTM residential/small commercial solar systems. This resource continues to grow rapidly and its operation is opaque to our system operators. The vast majority of these distributed systems are controlled by inverters sourced from only a few vendors. Both from a grid service opportunity perspective and from a risk management perspective, getting a handle on these resources is key for the state achieving its policy goals.

For DERs to be able to respond on a scale necessary to deliver planned grid services, they need to be both visible and secure to the utility. Without this visibility and security, these DERs cannot be deployed in a coordinated, effective manner, and therefore, cannot be relied on as a reliable resource. The US Office and Science and Technology goes further and recognizes the impact that security-compromised devices can have on the broader electric system[199]:

> *DER devices may have remotely accessible functions, which can provide an attacker with large-scale access to many DER. For example, many current*

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[198] See Resolution E-5000.

[199] https://www.osti.gov/servlets/purl/1374586#:~:text=Abstract%3A%20The%20increased%20penetration%20of,growing%20risk%20from%20cyber%20attacks

> *manufactures or third-party DER operators could have access to large numbers of DER. If these systems have the capability to control the DER, attacks could then have broader impact across many different distribution grids*.

The Commission should not defer the discussion regarding activating of communications and cybersecurity. This proceeding is an appropriate place to initiate the activation of these requirements. Otherwise, California risks allowing the very resources state policy wishes to leverage to remain hidden from the grid at large. The Commission should adopt the Joint Utilities' proposed reasonable and rational measures.

From a cost perspective, our proposals have a minimal impact. All inverters being deployed in California at this time have been attested by their manufacturer to be capable of communications. To enable choice and minimize costs to customers, the Utilities have offered three methods of exchanging data with smart inverters. No new dedicated communications links are required to support these communications with smart inverters as customers can leverage their existing internet connections or those already put in place by manufacturers and aggregators to collect data from installed systems.

V.

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?

A. The Commission Should Reject any Proposals that Parties Cannot Prove will Significantly Reduce or Eliminate the Cost Shift

The most urgent and compelling rationale for reforming the NEM 2.0 tariff is to eliminate, or at least significantly reduce, the cost shift that burdens the electricity rates of non-participating customers. The Commission should keep this bottom line as the North Star in reviewing NEM successor tariff proposals in this proceeding. Without addressing the cost shift problem in a meaningful and structural way, the overall program, California will find itself in the same unsustainable place it is today, with a massive and growing cost shift whose impacts undermine the state's energy-affordability and climate objectives. This is an important lesson that should be learned from the adoption of the NEM 2.0 tariff five years ago. The Commission should therefore reject any proposals that parties cannot significantly reduce or eliminate the cost shift.

1. The Commission Should Select the Joint Utilities' Proposal Over Other Party Proposals that Also Mitigate the Cost Shift

a) The Joint Utilities' Proposed Reform Tariff Accomplishes the Required Significant Reduction of the Cost Shift

As discussed in our Joint Opening Testimony, the design of the current NEM tariff creates a cost shift between participating and non-participating customers for two key reasons[200]. First is the fact that the compensation NEM customers receive for excess generation greatly exceeds the value the generation provides to the system. Second is that NEM customers, in particular residential NEM customers, can bypass payment of infrastructure and public policy costs designed to be recovered from all customers. These costs are fixed and do not vary with a customer's volumetric kWh consumption. However, because these fixed costs are primarily embedded in volumetric rates, NEM

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[200] Joint IOU Opening Testimony, Chapter 3.

customers can avoid paying them without proportionately reducing the utility's fixed cost spending, shifting these costs to non-participating customers. Our Reform Tariff proposal includes key elements designed to work together to reduce this cost shift from new solar customers including export compensation that reflects the value of the resource as calculated by the CPUC's approved Avoided Cost Calculator and fixed cost recovery of infrastructure and public policy costs. Our proposal is designed to result in a near zero cost shift from new standalone solar customers and a dramatically reduced cost shift from new solar paired storage customers. Additional detail on our Reform Tariff proposal can be found in Chapter 4 of our Joint Opening and Rebuttal Testimonies.

In its May 28th comparative analysis, E3 reached a similar directional conclusion. According to E3's calculations, relative to NEM 2.0, our proposal dramatically reduces the per customer cost shift in 2030.[201]

The following sections of this chapter help explain other benefits of our Reform Tariff proposal.

b) <u>Our Proposed Reform Tariff is Superior to CalPA's Proposal Because CalPA's Proposal Does Not Sufficiently Mitigate the Cost Shift</u>

We generally agree with CalPA's proposal to (1) transition new customers to a reform tariff as soon as possible, (2) subsidize and incentivize paired storage at some level, and (3) focus on low income customers. Our proposed Reform Tariff, however, better recognizes the perpetual harm caused by customers newly taking service on the Reform Tariff. CalPA's proposal results in a reduction of the 2030 annual cost shift of only 51%202, while the Utilities' Reform Tariff virtually eliminates the cost shift associated with standalone solar (~97% for SCE). The Reform Tariff is more effective in reducing the cost shift primarily because of the Utilities' proposed export compensation rate and GBC

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[201] E3's "Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020 – A Comparative Analysis". Pages 38 and 39. The average Joint Utilities solar only and solar paired with storage first-year cost shift in 2030 is reduced by ~83% and ~74%, respectively, relative to NEM 2.0.

[202] CalPA, p. 3-16. CalPA's estimated reduction includes the reduction in cost shift from moving NEM 1.0 and 2.0 customers to their successor tariff, but would allow NEM 1.0 and 2.0 customers to continue shifting costs. The Joint Utilities' proposal would eliminate the cost shift from NEM 1.0 and 2.0 after their legacy period ends and they begin taking service on the Reform Tariff.

structures. As discussed in the Utilities' Opening Testimony[203], the Reform Tariff export compensation rate is based on a solar export weighting of the 1-year levelized ACC avoided costs in each TOU period. This method provides a more accurate representation of the value of exported energy when compared to methods that use solar profile weighting or a simple average within the TOU period. Additionally, export weighting based on recorded exported energy allows the weighting factors and, by extension, the ECR, to gradually adjust as customer preferences transition from standalone solar to paired storage systems.

The Reform Tariff's GBC is designed to account for the full extent of costs avoided by rooftop solar. Similar to the Utilities' GBC proposal, CalPA proposes to assess the GBC monthly, based on installed system capacity. Their charge would recover costs associated with transmission and distribution service, in addition to non-bypassable charges. The Utilities' GBC proposal, however, is more effective in reducing the cost shift by setting compensation at the value of the generation produced and consumed onsite, and by its inclusion of generation cost recovery. Specifically, generation capacity costs for ramp and peak and energy costs are generally not avoided by standalone solar systems. Thus, inclusion of generation energy and capacity cost in the Reform Tariff GBC appropriately recovers cost for services provided.

For these reasons, the Commission should adopt our Reform Tariff proposal, as a more effective rate design for reducing the cost shift associated with future solar customers.

c) <u>Our Proposed Reform Tariff Proposal is Superior to TURN's Proposal</u>

Although we conceptually support TURN's transparent Market Transition Credit, and non-bypassable, unavoidable, and shared (NUS) costs recovery, the Utilities' Reform Tariff offers greater transparency and ultimately a better customer experience. TURN proposes to use the hourly day-ahead market price (scaled up to include costs associated with ancillary services and losses) for the energy value portion of the export compensation rate. The balance of TURN's export compensation rate would be based on the most current ACC values for transmission, distribution, and generation capacity.

[203] Joint Opening Testimony, p. 123.

While this approach has the advantage of aligning export compensation with periods of extreme grid conditions, a day ahead notice may not be received in a sufficient amount of time to drive behavioral changes outside of the normal daily pattern. To make this an effective approach, significant system enhancements and process changes must be deployed in order for the Utilities to receive day-ahead market prices, calculate the day ahead rates, and communicate the next day's prices to customers such that an action can be taken in response. At a later date, the bill would be rendered and presented to customers, further diminishing the effectiveness of a day-ahead price signal. This would significantly add to the cost of TURN's proposal and the time needed to implement. The Utilities' Reform Tariff, by contrast, uses export compensation rates that are set and adjusted on a similar frequency to all other rates on a customer's bill. The Utilities use the 1-year levelized ACC avoided costs as the basis for the export compensation rate. The Reform Tariff export compensation rates are then reduced to TOU period specific rates, a familiar format to most customers on TOU pricing schedules. Customers will have the ability to see the export compensation rates far in advance and use them to plan an initial purchase or develop new behavioral patterns that provide consistent load reductions or shifts. The Commission should adopt the Utilities' export compensation rate proposal for its transparency and potential for an improved customer experience.

d) <u>Our Proposed Reform Tariff Proposal is Superior to NRDC's Proposal</u>

Overall NRDC's proposal takes incremental steps towards reducing the current cost shift associated with the NEM 2.0 structure. NRDC's proposals for net billing, a market transition credit, non-bypassable charge recovery, and an equity fund make progress towards bringing greater equity and access to solar compensation and adoption. However, NRDC's proposal for export compensation diminishes some of the potential gains obtained through other elements of the proposal. The Utilities' proposed export compensation rate is more effective by adjusting the level of compensation on an annual basis and by not providing legacy treatment.

We agree with NRDC on the use of the most recent ACC avoided costs as the foundation of solar export compensation. However, the benefits of using timely ACC values are reduced when those values reflect a broader 3-year average, are updated on a 2-year cycle, and are locked in over a ten-year period. The Utilities' proposal would instead base the export compensation rate on solar export weighted 1-year ACC avoided costs. We would then update the export compensation rates on an annual cycle and would not provide legacy treatment with each update. The measures taken in the Utilities' proposal ensure more accurate and timely alignment of costs and benefits related to export compensation. Additionally, vintaging of export compensation rate creates customer confusion and complicates the billing process as discussed in section V.B. The Commission should adopt the Utilities' export compensation rate structure to ensure a better alignment with benefits to the grid provided by BTM solar resources and the compensation these resources receive.

e) <u>Our Proposed Reform Tariff Proposal is Superior to Sierra Club's Proposal</u>

Conceptually, we agree with Sierra Club's proposal that all Reform Tariff customers take service on an electrification rate. As discussed throughout our Opening Testimony, electrification rates provide a cost-based signal forming the foundation of a reform net billing tariff. Sierra Club however misinterprets the underlying cost causation principles that results in each utility's specific pricing. In recommending SDG&E and PG&E adjust their fixed charges to the level of SCE's, Sierra Club is ignoring the cost-based drivers and overall authorized rate levels that set the relationship between fixed and volumetric charges.

Sierra Club and the Utilities default electrification rate proposals are based on the premise that electrification rates provide more accurate price signals for customers to respond to current grid conditions – lower electricity prices during periods of generation oversupply, and high electricity prices during peak grid conditions. The pricing profile is partially achieved by matching energy and capacity (transmission, distribution, and generation) pricing to their corresponding high and low-cost periods. A key to achieving this favorable pricing profile is the recovery of fixed costs through a fixed charge component instead of recovering fixed costs through volumetric energy charges. Each of the utilities has gone through the rigor of determining and then allocating cost recovery for their electrification rates based on marginal cost rate design principles[204]. Differences between the resulting rates reflect differences in the values of underlying cost drivers and the respective utility's overall revenue requirement. Recognizing residential rates already deviate from a purely cost based approach, deviating further from a cost-based relationship between volumetric and fixed charge recovery only dilutes the pricing signal and potentially makes electrification rates less advantageous to DER adopters.

Sierra Club's testimony[205] highlights how electrification rates are advantageous to customers with or without solar when viewed from the perspective of whole house energy costs. In particular, electrification rates incentivize customers to fuel switch (i.e., from gas to electricity). EV adoption provides the single largest benefit of the electrification technologies shown in Sierra Club's Table 10[206], due primarily to the low charging rates realized through the cost-based functionalization in TOU-D-PRIME that is not exhibited in the default residential TOU rate. Sierra Club's proposal to artificially set the fixed charges for PG&E and SDG&E to the same levels as SCE's PRIME, which reflects a settled position and lower revenue requirements, will have the effect of muting the electrification pricing signal Sierra Club points out as an advantage to solar and non-solar customers. The Commission should adopt the Utilities' proposal for the Reform Tariff underlying cost-based rate to ensure a strong accurate pricing signal is sent to encourage future electrification.

2. <u>Proposals with Dilatory Transition Periods Perpetuate the Cost Shift</u>

In light of clear evidence of a growing and unsustainable cost shift created by NEM 2.0 that continues to increase the electric bills of non-participating customers, CALSSA, SEIA/VS and Sierra Club propose NEM reform tariffs that continue to be tied to retail rates and that potentially step-

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204 While TOU-D-PRIME is the result of a settlement agreement in SCE's 2018 GRC Phase 2, TOU-D-PRIME's basic structure and pricing differentials are consistent with SCE's original marginal cost-based proposal. Changes were made to the seasonal differentials and an equalization of the super-off and off-peak rates was adopted with the intent of simplifying the rate to improve customer acceptance. While initially set near the marginal cost level, the fixed charge is not adjusted in the attrition years. The result of this limitation is that all rate adjustments since its March 2019 introduction have been to volumetric rates reducing the overall effectiveness of the rate to encourage electrification.

205 Sierra Club, E. Camp, p.16.

206 Sierra Club, E. Camp, p.22.

down over several years.[207] These proposals would delay aligning the value of behind the meter generation to its market value by at least 5 to 10 years (or longer if capacity triggers are not met).[208]

Multiple step-downs designed in this manner further exacerbate the cost shift, create negative consequences for both customers and utilities, and fail to align with Guiding Principle B, which aims to ensure equity among customers. Further, these proposals would maintain 20-year legacy periods, locking-in above market subsidies paid for by non-participating customers for decades to come.

We calculated the cost shift created by new residential solar customers in SDG&E's service territory, the IOU with the highest penetration of rooftop solar customers, from CALSSA, SEIA/VS and Sierra Club's proposals relative to the current NEM 2.0 tariff starting in 2023. The results of our analysis highlight that these proposals tied to retail rates and long transition periods continue to create a large cost shift not much different than NEM 2.0. We calculate CALSSA's proposal would reduce the SDG&E 2030 annual residential cost shift by only 11%, SEIA/VS' proposal would reduce the SDG&E 2030 annual residential cost shift by only 15% and Sierra Club's proposals would reduce the SDG&E 2030 annual residential cost shift by only 45%.[209] While Sierra Club's proposal does offer a larger cost shift reduction relative to the other transition proposals, it's clear a large and growing cost shift remains relative to the Joint IOU's Reform Tariff proposal.

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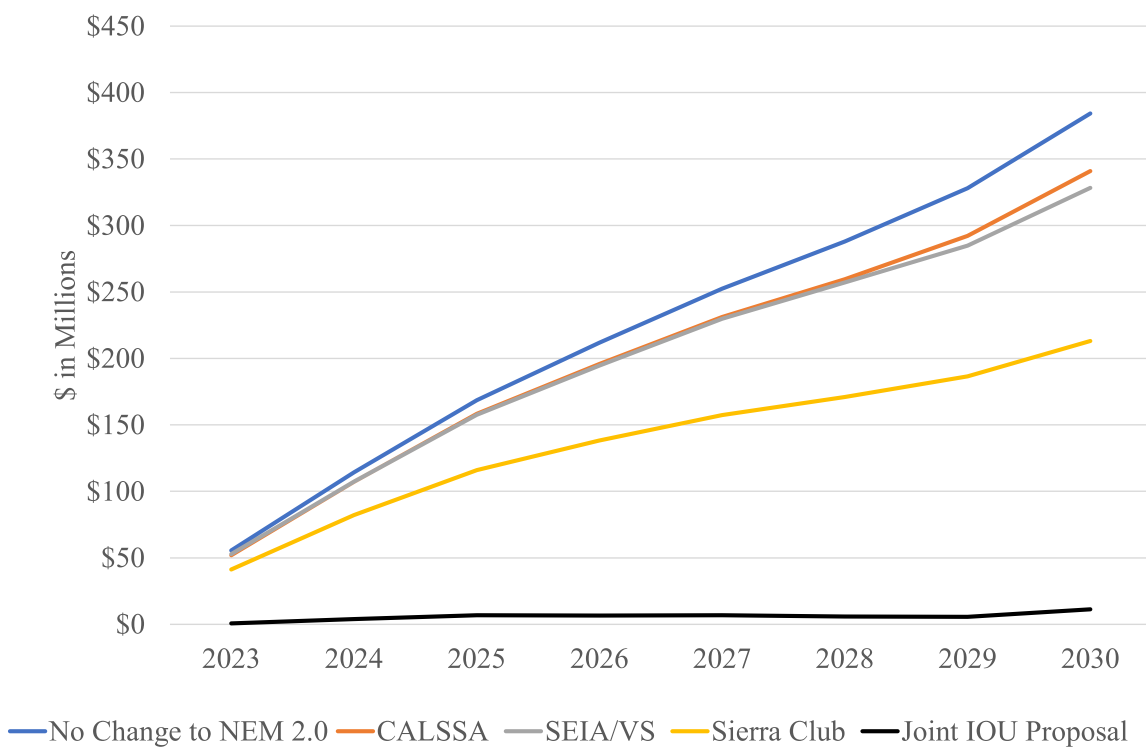
[207] CALSSA Opening Testimony, page 6; SEIA Vote Solar Opening Testimony, page ii; Sierra Club Opening Testimony of Matt Vespa, page 3.

[208] Based on the 2020 CEC IEPR mid-demand forecast scenario, complete step-downs are not achieved for CALSSA, SEIA/VS or Sierra Club's proposals in SDG&E's service territory.

[209] Analysis calculates estimated residential customer cost shift created from new solar-only customers starting in 2023 and does not factor in any changes to legacy customers.

Figure V-4
2030 Total SDG&E Residential Cost Shift Reduction



E3 reaches a similar conclusion in its May 28th comparative analysis directed by the Commission. On average, E3 calculates CALSSA, SEIA/VS and Sierra Club's proposals will still be shifting ~$1,280 per new customer to non-participating customers in 2030 which is ~3 times the per customer cost shift E3 calculates for our proposal, on average.[210]

The results of the E3 analysis along with our own cost shift analysis demonstrate that these proposals do very little to reduce the cost shift created by new participating customers and continue to shift costs to non-participating customers similar to NEM 2.0.

[210] E3's "Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020 – A Comparative Analysis". Results reflect averages of three IOUs from E3's June 15, 2021 report that incorporates minor modeling revisions; page 57.

3. The Commission Should Reform Non-Residential NEM

Most parties do not address non-residential customers. Public Advocates Office, like the utilities, proposes that non-residential customers be compensated at avoided costs for exports and pay a GBC.[211] SEIA/VS and CALSSA both argue that non-residential customers should retain the existing "NEM 2.0" tariff indefinitely.[212] SBUA argues that non-residential customers with maximum demands less than 500 kW should retain existing NEM rules, while larger non-residential customers should transition to monthly netting.[213] None of these proposals to retain the status quo try to justify that retail rate compensation for exports for commercial customers does not burden other customers, but instead make deceptive claims regarding non-residential market growth.

a) It is Unreasonable to Treat Commercial and Residential Customers Differently on The Issue of NEM Reform

Parties selectively cite the Verdant "NEM 2.0 Lookback Study" as evidence that no change to non-residential NEM tariffs is needed. They only cite the results of the non-residential cost-of-service study, which show that non-residential customers, to varying degrees by utility, pay more than their cost-of-service both before and after NEM participation. This study is of limited use in developing the successor tariff compared to the standard practice manual cost-effectiveness tests. Whereas the standard practice manual tests have recent Commission decisions affirming their use and defining standard inputs, Verdant's cost-of-service methodology (while informed by the IOUs' GRC Phase 2 cost-of-service studies) is not as vetted. By definition, total cost-of-service equals total bills, and some customers will overpay and others will underpay. A particular customer group that may be overpaying by this metric does not mean that they cannot still be causing significant cost shifting to other customer groups, contrary to legislative intent.

Second, these parties ignore the far more rigorous standard practice manual results of the Verdant Lookback Study. As seen in Figure V-5 excerpted from the Lookback Study,

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[211] Prepared Testimony of CalPA at 3-45.

[212] Prepared Direct Testimony of SEIA/VS (Beach) at 56-58 and Prepared Direct Testimony of CALSSA at 17.

[213] Prepared Direct Testimony of SBUA at 32.

non-residential NEM 2.0 generation is only slightly less burdensome than residential NEM 2.0 generation from a RIM (aka cost shift) perspective. Since the Lookback Study used the 2020 ACC, these RIM scores would be even lower if updated to use the 2021 ACC. This is validated by E3's most recent Cost Effectiveness Analysis, which found that NEM 2.0 for small commercial customers results in RIM scores of 0.12 for PG&E and SDG&E, and 0.27 for SCE.

Figure V-5
Excerpt from NEM Lookback Study, Cost Effectiveness Results Summary by Sector and Utility

TABLE 1-3: SUMMARY OF COST-EFFECTIVENESS RESULTS BY CUSTOMER SECTOR AND UTILITY

Utility	Customer Sector	Weighted Average Benefit-Cost Ratio			
		PCT	TRC	RIM	PA
PG&E	Agriculture	1.72	1.19	0.41	590.70
	Commercial	1.79	1.12	0.37	437.07
	Industrial	1.47	1.17	0.51	6,128.90
	Residential	1.83	0.69	0.31	28.77
SCE	Agriculture	1.23	1.43	0.85	337.88
	Commercial	1.32	1.35	0.72	96.86
	Industrial	1.16	1.34	0.87	880.11
	Residential	1.62	0.80	0.43	8.20
SDG&E	Agriculture	1.51	1.25	0.53	821.47
	Commercial	1.87	1.18	0.37	1,344.24
	Industrial	1.57	1.21	0.49	16,696.43
	Residential	2.08	0.76	0.29	100.09
Total		1.77	0.84	0.37	22.98

Figure V-6
Excerpt from Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020, June 15, 2021 Update

Table 24: Updated Results for Commercial Solar, 2023 Non-CARE

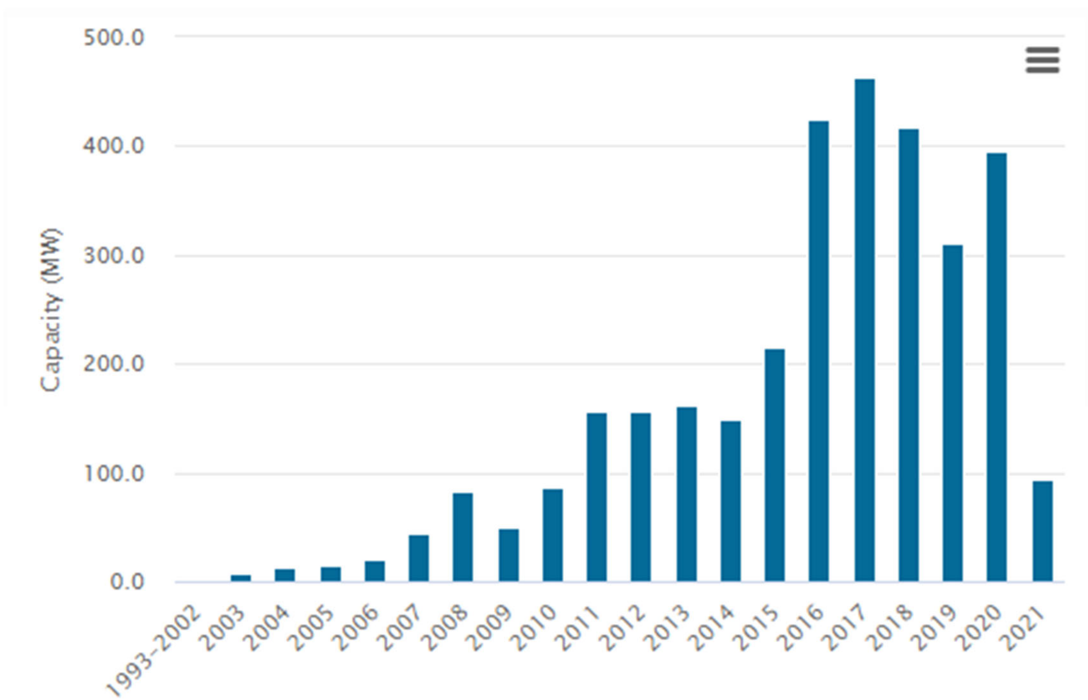
Proposal	IOU	Payback Period (yr)	1st Year Cost Shift	PCT	RIM	TRC
NEM 2.0	PG&E	4.7	$ 3,586	3.11	0.12	0.38
	SCE	6.7	$ 2,001	2.20	0.27	0.61
	SDG&E	4.2	$ 3,873	3.50	0.12	0.41
Cal Advocates	PG&E	7.8	$ 1,809	1.79	0.21	0.38
	SCE	9.4	$ 1,151	1.52	0.40	0.61
	SDG&E	7.4	$ 1,869	1.98	0.21	0.41
CARE	PG&E	24.0	$ 0	0.37	1.00	0.38
	SCE	21.1	$ (0)	0.60	1.00	0.61
	SDG&E	24.9	$ (0)	0.41	1.00	0.41
CCSA	PG&E	10.6	$ 284	0.92	0.69	0.65
	SCE	8.6	$ 390	1.17	0.88	1.04
	SDG&E	9.6	$ 403	1.04	0.67	0.71
Joint IOUs	PG&E	30.1	$ (180)	0.37	1.00	0.38
	SCE	22.5	$ (58)	0.57	1.05	0.61
	SDG&E	22.3	$ 93	0.54	0.75	0.41
SBUA	PG&E	4.7	$ 3,586	3.11	0.12	0.38
	SCE	6.7	$ 2,001	2.20	0.27	0.61
	SDG&E	4.2	$ 3,873	3.50	0.12	0.41

b) <u>Solar Parties Incorrectly Claim Non-Residential Market is in Decline due to NEM and Rate Changes</u>

Both SEIA and CALSSA claim that the non-residential solar market has already entered a decline due to NEM 2.0 and/or changes in time-of-use rate eligibility. These claims are not true. The Commission should ignore these claims, and reform NEM for non-residential customers just as it should for residential customers.

SEIA presents a graph showing the growth of residential and non-residential solar amongst the three IOUs, claiming that the implementation of NEM 2.0 in 2017 is partly responsible for a decline in 2019 and 2020.[214] First, SEIA's claim that NEM 2.0 had a significant impact on the market is undermined by their own analysis. NEM 2.0 was implemented in 2016 for SDG&E and PG&E, and mid-2017 for SCE. If NEM 2.0 had a negative impact on the non-residential market, one would not expect 2017, the first year NEM 2.0 was in force for the majority of the non-residential market, to be the peak adoption year. Second, it appears the vintage of the data depicted in the graph does not include the entirety of 2020, as it shows that approximately 325 MW of non-residential solar was installed in 2020. As seen Figure V-7 below, taken from the same source cited by SEIA, the full year 2020 adoption was actually 396 MW for non-residential solar. While non-residential adoption in 2020 is still lower than the 2017 peak of 464 MW, it is in line with 2016 and 2018 adoption, and nearly double that of 2015.

Figure V-7
PG&E, SDG&E, and SCE Non-Residential Adoption in MW, from California Distributed Generation Statistics



SEIA also presents a table based on data requested from PG&E showing that very few solar customers have taken service on the updated "B-series" non-residential rates (B1, B6, B10,

[214] SEIA/VS Opening Testimony, Attachment RTB-2, p. 26, Figure 6.

B19, and B20), which feature accurate time-of-use periods. [215] This is meant to argue that the new rates have significantly reduced the willingness to adopt solar. What SEIA fails to mention is that they requested this data in January 2020, two months before the updated B-series rates became mandatory for most customers. SEIA also neglects to mention that many existing and prospective solar customers are entitled to remain on the outdated time-of-use rates as late as 2027, due to the legacy provisions granted in D.17-01-006 and expanded in D.17-10-018. In a discovery response, SEIA acknowledged that its witness was aware of the March transition date, and was SEIA's technical consultant for the proceeding which resulted in these legacy provisions. Given that SEIA's witness was well aware of the context, it is unclear why this table was presented without it.

CALSSA cites interconnection application volume data showing a 25% reduction in non-residential applications in 2020 compared to 2018 and 2019. [216] Unfortunately, the data provided to CALSSA incorrectly excluded PG&E applications that had yet to reach the permission-to-operate (PTO) stage of the interconnection process. The utilities have provided corrected data to CALSSA. In addition, CALSSA excluded agricultural applications from their graph for PG&E and SDG&E and military applications for SCE. It is unclear why they excluded these types of non-residential customers, as they faced the same TOU updates. A corrected version of the graph is displayed below in Figure V-8. This shows that, despite the COVID-19 pandemic, 2020 applications ("Corrected, Total" in the figure) were slightly higher (~2%) compared to 2018 and 2019. [217] While there was a reduction in applications in Q3 2020, it strains credulity to assert this reduction had more to do with a change that occurred in 2017 than the COVID-19 pandemic.

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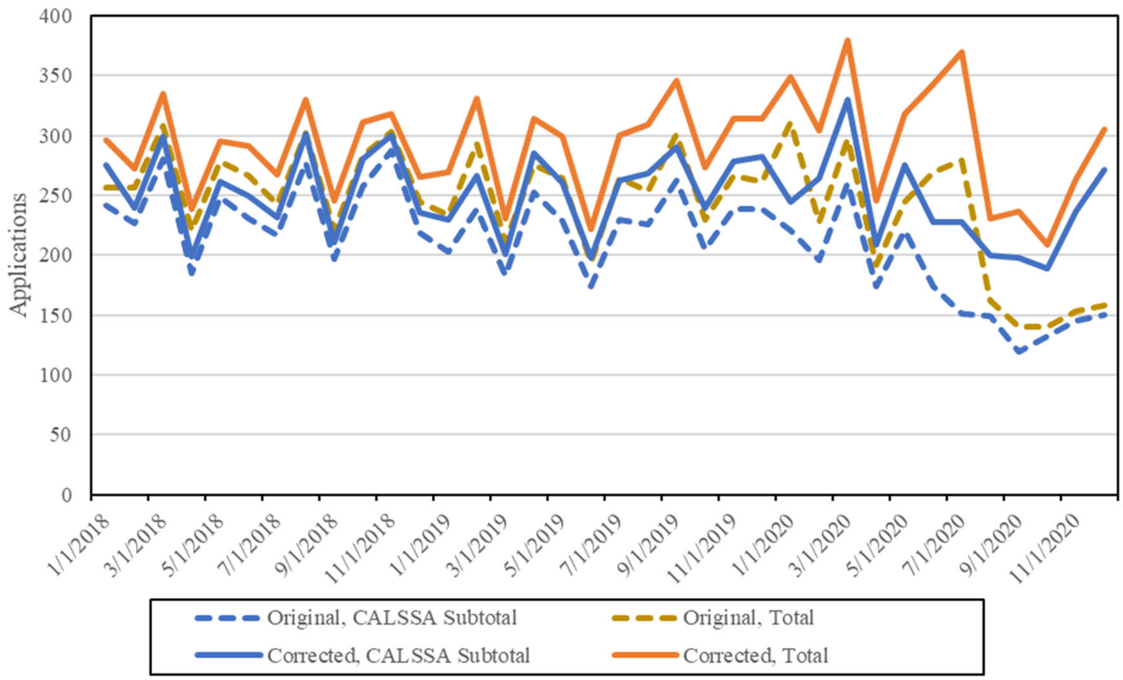
[215] SEIA/VS Opening Testimony, p. 57.

[216] CALSSA Opening Testimony, p. 18.

[217] Excluding segments of the non-residential sector as done by CALSSA results in a 6% application reduction in 2020.

Figure V-8
PG&E, SDG&E, and SCE Non-Residential Solar Applications, 2018-2020

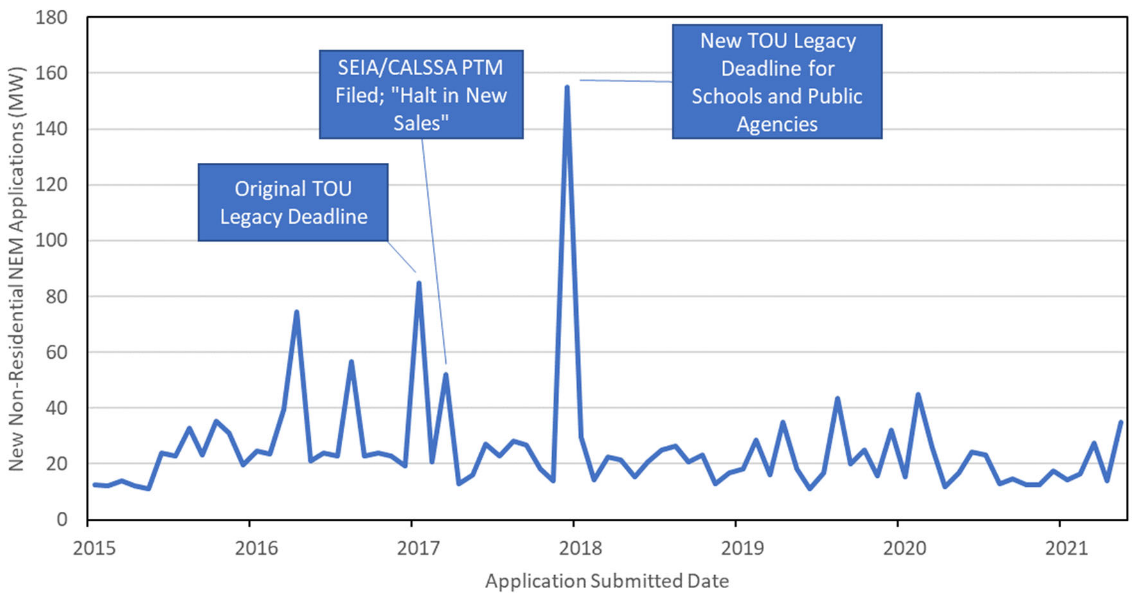


That the non-residential market has been fairly stable since 2017, in spite of NEM 2.0 implementation and updates to TOU rates, is at odds with what SEIA and CALSSA have previously claimed to the Commission. In their joint petition for modification of D.17-01-006 to request further expansion of legacy treatment under outdated legacy time-of-use rates, dated March 2, 2017, they said that "[t]he solar industry serving commercial customers is already experiencing a halt in new sales."[218] This date is marked on Figure V-9 below, showing new non-residential interconnection application volumes for PG&E in MW from 2015 to present. The Commission largely rejected the requested relief to reopen legacy eligibility until after updated TOU rates were adopted, instead only reopening the application deadline for schools and public agencies through the end of 2017. In opposition to the then Proposed Decision making this change, the utilities argued that this would result in a surge of speculative interconnection applications by solar firms, rather than protecting customers that had already made substantial investments or financial commitments. SEIA/VS and CALSSA denied this would

[218] Petition for Modification of Decision 17-01-006, by SEIA and CALSEIA (now CALSSA), p.2.

happen, saying "the APD will not result in a surge of new applications by entities that have not commenced the process towards solar installation" and that "[g]iven the bureaucracy under which schools and public agencies operate, affording a 60-day extension for submission of the initial application will only benefit those schools and agencies that have already commenced the planning process towards solar installation."[219]

Figure V-9
PG&E Non-Residential Solar Applications, 2014-2020



As clearly seen by the December 2017 application volume in Figure V-9, an unprecedented surge of applications did occur. In fact, one of the same solar industry representatives which provided an attestation within the petition for modification openly advertised that they could file speculative interconnection applications and then run solicitations for schools and public agencies interested in installing solar in response to the new eligibility window.[220] SEIA and CALSSA were mistaken in the past, which the Commission should consider here.

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[219] SEIA and CALSEIA Reply Comments on D.17-10-018, p. 3-4.

[220] See "Declaration of Tom Williard of Sage Renewables," Attachment B-2 of Petition for Modification of Decision 17-01-006, and Sage Renewables' press release issued after the adoption of D.17-10-018, available at https://www.sagerenew.com/press/tou-december25

4. **The Commission Should Consider Whether Changes to Legacy Treatment Is Appropriate**

Several parties propose changes to the legacy treatment for NEM 1.0 and NEM 2.0 customers. CalPA proposes to transition all NEM 1.0 and 2.0 customers to its Reform Tariff Proposal over a 5-year period while offering a declining battery storage incentive to opt into the Reform Tariff proposal over this time.[221] NRDC supports CalPA's proposal and proposes an additional Equity Fee for all NEM customers.[222] TURN proposes a new surcharge applied to existing non-CARE NEM 1.0 and 2.0 residential customers to collect up to 50% of the costs of its proposed market transition credit.[223] Sierra Club proposes moving all residential NEM 1.0 and 2.0 customers to "electrification-friendly rates" eight years after system interconnection.[224]

The Utilities agree with CalPA, TURN, Sierra Club, and NRDC that NEM 1.0 and NEM 2.0 customers represent most of the cost shift for the foreseeable future.[225] To be clear, we are not proposing changes to NEM 1.0 and 2.0 customer legacy treatment. However, we outline several important considerations for the Commission, if it were to contemplate changes to NEM 1.0 and 2.0 customer legacy treatment as part of a comprehensive reform to the NEM program.

Firstly, the Commission must consider the maximum cost of any incentive (*i.e.*, a "worst case" scenario). CalPA is proposing to offer a storage rebate for existing NEM 1.0 and 2.0 customers with standalone solar systems who choose to switch to the Reform Tariff, or a transition bonus for customers who are unable or do not wish to install storage.[226] This storage incentive would offer a $3,200 rebate for NEM 2.0 customers and $2,880 for NEM 1.0 customers for the first two years, with the amounts declining over the remaining three years.[227]

[221] Prepared Testimony of CalPA, at 4-3.

[222] Opening Testimony of NRDC, at 15 and 21.

[223] Direct Testimony of TURN, at 6.

[224] Prepared Testimony of Sierra Club (Vespa) at 1-3.

[225] Joint Opening Testimony of SCE, PG&E and SDG&E, at 78-79.

[226] Prepared Testimony of CalPA, at 4-2 – 4-3.

[227] Prepared Testimony of CalPA, at 4-3 – 4-4.

CalPA provided a "worst case" scenario estimate of the incentive, where all NEM 1.0 and 2.0 customers take the maximum incentive in the first two years, calculating a total program cost of $2.8 billion,[228] which could be justified, depending on the reduction in cost shift of the Reform Tariff, but the cost of the storage incentive program would likely need to be recovered over several years to avoid rate shock. It would not be justified, however, if the Commission adopts a new tariff where these NEM 1.0 and 2.0 customers are still able to shift costs to nonparticipating customers because these customers would have benefitted from both the NEM cost shift to date and the storage incentive. With rates expected to increase over time, the Commission may find itself in a similar position in a few years, addressing a significant cost shift from all existing rooftop solar customers. As stated in our Opening Testimony, if the Commission decides to adopt a tariff where participating customers still shift costs to nonparticipating customers, existing NEM 1.0 and 2.0 customers should transition to our Reform Tariff at the end of their legacy period, which has no cost shift for standalone solar customers.[229]

Sierra Club proposes that all existing residential NEM customers transition to an "electrification-friendly rate" eight years after interconnection.[230] Most of these rates have a large time-of-use (TOU) differential and a fixed charge. Sierra Club contends that moving NEM customers to a different underlying rate structure is consistent with Commission precedent,[231] a view with which we agree. Moving NEM customers to more cost-based rates with lower volumetric rates would reduce the cost shift from these legacy customers and could support the State's electrification efforts. If the Commission chooses to tackle the cost shift associated with legacy treatment, Sierra Club's proposal is a reasonable incremental change that aims to advance electrification and increase equity between participating NEM customers and nonparticipants. If the Commission wishes to adopt a transition that is more aggressive than the Sierra Club proposal given the significance of the NEM 1.0 and NEM 2.0 cost shift, the Commission could require the transition to more cost-based rates in a shorter timeframe.

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228 Id., at 4-6.

229 Joint Opening Testimony of the SCE, PG&E, and SDG&E, at 110.

230 Direct Testimony of Sierra Club (Vespa), at 1-3.

231 Id., at 4.

These customers will also continue to see significant bill savings and will continue to receive significant subsidy even after a transition to more cost-based rates so a transition period of less than 8 years could also be reasonable.

NRDC proposes an assessment of a $2.50 "equity fee" per kW-dc of installed capacity on all existing NEM tariffs that will be a source of funding for its proposed "Equity Fund", which will be designed to "bring clean energy benefits to qualifying low-income customers."[232] A $2.50/kW-dc charge for NEM 1.0 and 2.0 customers is unlikely to have a significant impact on their payback period. A customer with a 7 kW-dc system would pay an equity fee of $17.50/month. As many NEM 1.0 and 2.0 customers have already achieved payback, and new NEM standalone solar customers today have payback periods of 3-5 years, it could be reasonable to assess a charge of this type. However, if the Commission were to adopt this proposal, we recommend the Equity Fund be allocated to existing program budgets, as proposed by TURN (described below). This would reduce the amount of funding needed to be collected from ratepayers (particularly nonparticipants) and ensure a total lower overall cost shift, not simply shift the NEM cost shift from one set of customers to another.

TURN proposes a portion of the costs of its proposed "Market Transition Credit" (MTC) be collected from existing non-CARE NEM 1.0 and 2.0 customers through a new surcharge.[233] Although the utilities are not proposing a MTC, if the Commission did adopt one, this surcharge would reduce the overall cost shift by reducing the amount of funding collected from nonparticipating customers for the MTC. Funding an MTC for low-income customers by charging non-low-income NEM 1.0 and NEM 2.0 customers is logical and fair because these customers have been subsidized by non-participating low-income customers and have contributed to the adoption imbalance between low- and higher-income customers to date. A charge similar to NRDC's would likely not have a significant adverse impact on NEM 1.0 and 2.0 customers' value proposition.

[232] Opening Testimony of NRDC, at 21.

[233] Opening Testimony of TURN, at 55. TURN states that this monthly charge could be fixed per customer or based on $/kWh of NEM customer usage, and existing CARE NEM customers would be exempted.

In sum, if the Commission decides to adopt one of these proposed changes to NEM 1.0 and 2.0 customers, it should aim to reduce the overall NEM cost shift and reduce the current burden on nonparticipating customers.

B. The Commission Should Reject Burdensome And Costly Implementation Proposals That Will Cause Customer Confusion

1. The Commission Should Reject Complex Vintaging or Multiple Step Down Proposals Because They Will Cause Customer Confusion, as Well as Costly Implementation Problems for the Utilities

Several parties, such as SEIA/Vote Solar, Sierra Club, and CALSSA, propose multi-phase step downs in the export credit value spanning 5-10 phases. For the reasons explained above in Chapter 5.A, dilatory vintage and step-down proposals perpetuate the cost shift. They also create complex and costly implementation problems for the utilities and will cause customer confusion.

a) Multiple Step-downs and Vintages Cause Customer Confusion

These proposals violate Guiding Principle F, which requires the successor tariff to be transparent, understandable to all customers and uniform, to the extent possible, across all utilities. Multiple different "vintages" for customers would create customer confusion and uncertainty about their specific rate structure. Imagine a customer trying to look up on a utility website their version of NEM (NEM 1.0, NEM 2.0, or one of the 10 versions of the Reformed Tariff). Will the customer remember 10 years from now when they installed solar and be able to easily find their rate information? In addition, providing trigger-based thresholds would mean that each utility could easily be in a different threshold level, which would lead to a lack of uniformity across utilities and could lead to confusion amongst developers as well, who would have to use different formulas, depending on the customer.

b) Vintaging and Step Downs are Difficult and Costly to Launch and Maintain

Multiple vintages **increase the cost to both implement and maintain** multiple different rate structures. Many parties, such as CALSSA, falsely assume that their proposals will be easier to implement than the Joint Utility proposal[234], but this is not correct, as it creates multiple new rate structures that each must be built, maintained, and updated for 20 or more years starting from the final decision.

Rate transitions require significant operational adjustments for the utilities. Each utility must implement and test billing system changes, and both utilities and vendors must update informational materials and communicate accurately about NEM bill savings given the tariff changes. Because NEM is a tariff modifier that could apply to multiple rate schedules, even minor changes to the NEM tariffs can take several months or longer to implement. NEM changes may need to be tested across multiple utility rates, which is a costly and time-consuming process.

c) <u>Transitions triggered by capacity caps rather than clear calendar dates would create unpredictability and customer confusion</u>

A number of parties propose a transitional "glide path" for certain NEM successor tariff components. CALSSA, SEIA -Vote Solar, Sierra Club have suggested that NEM tariff pricing changes should be triggered when the amount of interconnected solar in a particular utility's service area reaches a given capacity.[235]

Multiple step-downs based on capacity triggers create uncertainty and are also **difficult to execute** upon, as there is not a date known well in advance when the change would be made. With a MW capacity cap, the unclear timing of transitions creates unnecessary unpredictability. A lack of clarity on when transitions will occur can cause customer confusion regarding what version of NEM they will be placed on and adds significant operational and ME&O challenges for the utilities and industry stakeholders. CALSSA and other parties acknowledge this and propose conversion to a date three months in advance once the trigger is likely to be met.[236] There can be significant month-to-month variability in solar capacity interconnections that limits the ability of utilities to forecast when a MW cap

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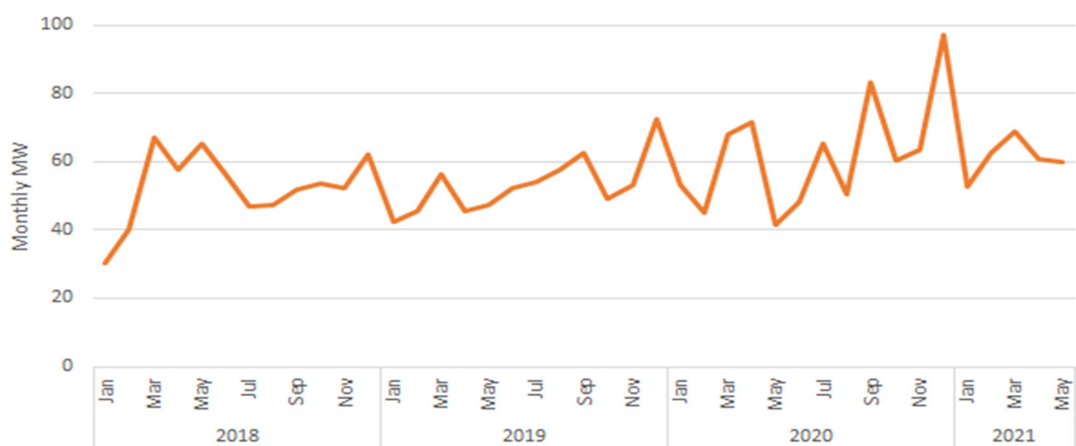
[234] CALSSA Opening Testimony, page 121.

[235] CALSSA Opening Testimony, page 7; SEIA Vote Solar Opening Testimony, page 45; Sierra Club Opening Testimony, page 32.

[236] CALSSA Opening Testimony, page 40.

will be reached, as shown in Figure V-10 for PG&E. Furthermore, the parties who proposed step downs did not clarify whether the transition would be triggered if the capacity reached did not match the utilities' forecast.

Figure V-10
Incremental Monthly MW of Solar Interconnected in PG&E's Service Area



It is important to note that technology projects involving structural changes to utility billing systems are frequently started over a year in advance of launch date, as opposed to the three months in advance that CALSSA proposes. As such, the utilities would have to plan well in advance of the three-month notice.

2. <u>The Utilities Offer a Proposal for Transitioning to the Reform Tariff Which Provides an Expedited Transition To Minimize Cost Shift</u>

Several parties (CALSSA and SEIA/Vote Solar) state that the utilities have no proposal for transitioning from the current NEM tariff to the Reform Tariff,[237] which is not the case, as described in our Opening Testimony. The Joint Utilities recognize that a transition "buffer" period is necessary between the Final Decision and ending NEM 2.0 enrollment to allow time for the market to adapt.[238]

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[237] CALSSA Opening Testimony, page 46; SEIA Vote Solar Opening Testimony, page 76.

[238] Joint IOU Opening Testimony, page 182.

However, due to the significant cost shift — approximately $935 million over a 20-year period — that is locked in for each additional month that Utilities' customers take service on NEM 2.0,[239] this transitional buffer period must be as short as possible. SEIA/Vote Solar's proposal for a 14-month buffer is too long and would lock in significant continued cost shift that will be borne by non-participating customers, untenably exacerbating equity and affordability concerns. SEIA's proposal assumes that a Tier 3 Advice Filing will be required for the utilities to update their applicable tariffs and that market adaptation can only begin once the tariff is completely finalized and approved. CALSSA proposes an 8-month period between the end of NEM 2.0 enrollment and customers taking service on their proposed reform tariff.

To implement the Utilities' Reform Tariff, we propose an approach below that would facilitate quicker market adaptation to end NEM 2.0 enrollment and control the cost shift sooner. Within 30 days of the final decision, the utilities would file an information-only Tier 1 Advice Letter to provide details of the Reform Tariff as directed in the Final Decision. This Tier 1 Information-only advice letter will summarize our interpretation of how the NEM tariff will be structured and provide indicative levels of price components. This will include information regarding pricing for the underlying net billing tariff as well as the export compensation rate. The level of information provided in the Tier 1 Information-only Advice Letter should be sufficient to allow customers and solar providers to plan for and adjust to the Reform Tariff. A supplemental Advice Letter to the Tier 1 Information-only Advice Letter will be filed within 60 days of the final decision containing rate factors based on the applicable revenue requirements and associated tariff sheets. To the extent the start date of the Reform Tariff is scheduled for later in the year or in the following year, the Utilities will withhold the Reform Tariff Rate Schedules and Tariff language from their respective online tariff books until the Reform Tariff goes into effect.

This "Indicative Reform Tariff Structure and Pricing" advice letter and buffer process would be enabled by a Final Decision that has a high degree of clarity on the revised tariff regarding the

[239] Joint IOU Opening Testimony, page 182.

rate structure and eligibility. We urge the Commission to provide a detailed directive in its Final Decision regarding specific aspects of the adopted reform tariff. Elements such as netting, export compensation, GBC structure and composition, eligibility and legacy treatment need to be clearly described to avoid delay in further rounds of Commission review and approval. The deleterious proposal put forth by SEIA/VS will extend the proceeding through a Tier 3 Advice Filing, which is essentially a formal application. The Utilities' proposal would instead provide clarity to the proceeding through steps that ensure a continuation of service on solar and storage tariff options while also limiting the inequity that comes from a continuation of the existing NEM structure. To facilitate a speedy transition, vendors must also plan in advance so they can begin updating customer-facing materials and tools immediately, based on the Final Decision and the supporting Indicative Reform Tariff Structure and Pricing utility filing.

An additional consideration is that customers who are in the contracting process near or right after the Final Decision should be provided sufficient time to submit a valid interconnection application.[240] We recommend a buffer period of three months (90 days) from the Final Decision for residential customers and five months (150 days) from the Final Decision for non-residential customers, after which no new customers would take service on the current NEM 2.0 tariff. Customers who interconnect after the deadline for ending NEM 2.0 eligibility would take service and be billed on NEM 2.0 temporarily, and then be transitioned to the Reform Tariff once the Reform Tariff is operationalized, as described in the Utilities' Opening Testimony. As an additional measure to control the cost shift, the Utilities propose that customers who apply for interconnection during the buffer period receive reduced NEM 2.0 legacy treatment, long enough that a typical customer is able to receive a reasonable payback for their systems (3-7 years depending on the utility).[241] Customers who will submit a valid interconnection application on the cusp of the end of this buffer period must be given sufficient and accurate information to enable an informed decision at the time they commit to their installation.

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[240] A valid interconnection application includes an accurate single-line diagram and any additional supporting documentation for any specialty programs, such as NEM-Aggregation or Virtual Net Metering.

[241] Per Table II-2 in Joint Utilities' Opening Testimony, page 31.

Customers submitting interconnection applications after this period will be temporarily billed under NEM 2.0 while the Reform Tariff is being implemented.

Filing of Reform Tariff updates and implementation plans, stakeholder review, and Commission approval on details of the Reform Tariff would be required for customers to take service on the Reform Tariff before customers are transitioned to the Reform Tariff once it is operationalized in utility billing systems, which we anticipate would happen 12-24 months from the Final Decision.

Tariff updates for NEM 2.0 were accomplished through Tier 2 filings, which the utilities propose would be appropriate for the Reform Tariff, as long as the Final Decision provides sufficient clarity on the revised tariff. The utilities should be able to file separate Tier 2 implementation plans within 90 days of the Final Decision.

3. Annual True-ups in April Conflict with Utility Proposals and Create an Undue Burden on Utilities

CALSSA, Silicon Valley Leadership Group, and Aurora Solar recommend that all true-up cycles for successor tariff customers begin either at the end of March or in the April billing month[242], which may result in partial year true-ups. An Annual True-up only serves to confuse customers, and an Annual True-up at the same time for all customers would create operational challenges, including potential delays in bill calculations as well a large volume of customer calls. Utility systems would need to retrieve a large volume of interval data for the prior year to calculate the true-up, which could impede the ability to calculate all customer bills for that month. Essentially, having customers all true-up in the same month would create an operational process that is currently spread throughout the year and turn it into a single annual process that may create bill processing and customer service problems. The Commission should select the Reform Tariff proposal because it does not have these implementation issues in that, at least in part, it eliminates the need for an annual true-up.

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[242] CALSSA Opening Testimony, page 56; SVLG Opening Testimony, page 6; Direct Testimony of Aurora Solar, page 21.

4. Day-Ahead Hourly CAISO Market Prices Would Complicate Bill Calculations and Lead to Customer Confusion

TURN proposes to leverage day-ahead hourly CAISO market prices on customer bills. Hourly prices would require additional bill calculations that would greatly lengthen bill processing time and potentially delay bills. In addition to the more difficult bill calculation process, customers would not have visibility to the detailed calculations of their bill, as we currently don't provide hourly bill details on their billing statement. In order to provide transparency and show the detailed rates, customers would need to be communicated to in advance of the rates, and a bill would need to contain a line item for each time period, which for a monthly bill would be over 700 line items. This would lead to customer confusion and does not support the Guiding Principle F that states that the tariff should be transparent and understandable for all customers.

5. CALSSA's proposed data portal is duplicative and unnecessary

In their testimony, CALSSA proposes that utilities should "construct a portal to enable approved solar providers to upload a customer authorization form and download a file with customer interval data".[243] We concur with CALSSA's assertion that enabling solar contractors to reasonably access customer interval data is an important enabler of accurate NEM bill savings estimates. However, we do not share CALSSA's approach of assessing the constraints imposed by existing methods as only a source of difficulty and costs. Utility customers can have solar vendors access their own usage information in multiple ways as CALSSA states in the four cases mentioned, and these methods each are designed to protect customer privacy and allow customers to be an active decision-maker in the data-sharing process. In the case of Green Button options, both have been developed in accordance with national standards for providing customer data in a secure manner.[244] The existing data access methods of the Joint Utilities prioritize the associated high degree of data privacy protection of the individual

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[243] CALSSA Opening Testimony, page 57.

[244] https://www.energy.gov/data/green-button

methods, and this important aspect is unfortunately lost in CALSSA's focus on a proposed portal that should work for all customers and all companies.

CALSSA states that a data portal will "ensure timely access to customer usage data,"[245] but a data portal would still require manual review of the CISR uploaded to ensure that privacy standards are upheld and would offer no difference in timing than the third option that CALSSA presents of obtaining written authorization by the customer and requesting the data via email. Such a platform would be costly to implement and would be duplicative of services we currently provide that support customer-authorized data access.

C. Low Income Considerations

1. Low-income Proposals Should Compensate Generation Fairly; and Should Be Transitional and Transparent

In developing our NEM proposal for income-qualified customers,246 the Joint Utilities considered a variety of sometimes competing factors to develop a proposal that encourages behind-the-meter renewable adoption by income-qualified customers with little to no unintended consequences. In this chapter, we review those considerations and assess the income-qualified proposals submitted by other parties.

The factors that we considered in developing our proposal in opening testimony include the following:

1. **Balance incentives for income-qualified customers with impact on all customers, including non-participating income-qualified customers.**
2. **Equal pay for same generation.**

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[245] CALSSA Opening Testimony, page 57.

[246] In our Opening Testimony, we proposed both an Income-Qualified Discount (IQD) for CARE and FERA NEM customers and a storage subsidy called the Savings Through Ongoing Renewable Energy (STORE) pilot. In Table V-36 of our Opening Testimony we provided an overview of these programs including cost estimates and potential number of benefitting customers. Subsequently, we found an error in the number of benefitting customers from the IQD: it should read 74,404 customers instead of 166,577. This does not impact program cost estimates. We plan to correct this table in the version of Opening Testimony that will be submitted in advance of hearings.

3. Programs should complement existing programs and not be duplicative.

Several parties explicitly or implicitly applied similar principles in developing their low-income proposals. For example, TURN, NRDC, and CalPA all propose funding from existing non-CARE NEM 1.0 and NEM 2.0 customers to support low-income adoption, consistent with our principle of balancing incentives for income-qualified customers with impacts on non-participating customers. Several parties also discuss and support equal pay for the same generation, including Grid Alternatives, Vote Solar, Sierra Club, and CALSSA. Parties also support transparency in subsidization: TURN, NRDC, and CalPA all support a version of transparent subsidies to encourage solar adoption among low-income customers.

a) Grid Alternatives, Vote Solar, and Sierra Club

Grid Alternatives, Vote Solar and Sierra Club propose to set export compensation at a time-varying rate equal to the current default TOU rate offered by the utility in 2021 for customers with incomes at or below 80% of area median income (AMI). These parties state that the intent of this proposal is to rectify the current unintended consequence of a retail-rate based compensation structure that compensates CARE and FERA customers at lower amounts than customers not on an income-qualified discount program. The Joint Utilities share the goal of Grid Alternatives, Vote Solar, and Sierra Club of providing income-qualified customers with access to behind-the-meter renewables and ensuring that these customers receive equal pay for the same generation, as described in our Opening Testimony. However, we do not believe this approach is the correct approach to achieve those objectives.

First, we do not support setting export compensation at the 2021 TOU retail rate. As noted in our Opening Testimony, NEM customers receive export compensation that is 8 times the value that we could procure the same power in the market.[247] Setting the compensation at the retail rate would overcompensate for generation, creating significant cost shift for non-participants including other low-income customers. As demonstrated in the "Net Energy Metering 2.0 Lookback Study," most low-

[247] Joint Utilities Opening Testimony. P. 67.

income customers do not benefit from the NEM program subsidies.[248] It is important to strike a balance between providing a subsidy and minimizing the impact on customers: compensating generation at 8 times its value does not strike that balance.

Second, although this program purports to address the illogical difference in compensation for the same generation between customer groups, we prefer programs that provide subsidies in a more transparent way and do not violate the principle of equal pay for the same generation.

Third, the Grid Alternatives, Vote Solar, and Sierra Club proposal would lock in not only the 2021 rates but the TOU periods as well. This would likely result in mismatches between some customers' underlying rates and the export compensation rates which would be confusing for customers.

Additionally, we oppose the Grid Alternatives, Vote Solar, and Sierra Club proposal to increase eligibility for receiving their proposed low-income discount to anyone at or below 80 percent AMI. This is not the proceeding to modify the eligibility for income qualified programs.

We also believe that adopting a different definition of income-qualified for NEM but not for rates generally would create customer confusion. The CARE/FERA eligibility requirements are standardized across a given utility's service area. Having different requirements based on local median income to establish eligibility for NEM income qualified treatment could be confusing for customers. A customer could be in a situation where they may qualify for the special NEM Tariff treatment and not for CARE, or vice versa, and have to navigate understanding the differences in eligibility requirements to understand their billing.

b) California Solar and Storage Association (CALSSA)

CALSSA proposes various exceptions to its NEM revisions; all of these should be rejected. CALSSA proposes to maintain NEM 2.0 for low-income customers in single family homes and apartment buildings in low- and moderate-income census tracts; and properties eligible for the MASH

[248] Verdant Associates. 2021. "Net Energy Metering 2.0 Lookback Study." P. 33.

and SOMAH programs. CALSSA also proposes that credits for exports for CARE and FERA NEM customers be set at the undiscounted retail rate.[249] This suite of proposals shares common elements with the Grid Alternatives, Vote Solar, and Sierra Club proposals described above including compensation that exceeds both its value to the grid and compensation for the same generation from non-income-qualified NEM facilities and expansion of eligibility beyond the CPUC's existing low-income designations. We oppose this suite of proposals for the same reasons described above.

CALSSA also proposes that projects "owned by the community" be allowed to retain NEM 2.0. Specifically, any system "owned by a California cooperative corporation, as defined by the California Corporations Code, a nonprofit organization, or certain public entities: the state, a county, a city, or a California community college district" would retain current NEM 2.0 rules.[250] While this is purported to provide additional opportunities for low income customers, the proposal has nothing in it to ensure that this program benefits low income customers. Rather, this proposal is likely to create unintended incentives for ownership of solar installations to be held by entities still eligible for NEM 2.0 rules. For example, it seems possible that a home-owners association, which are often established as non-profits, would be an eligible organization under CALSSA's proposal. The utilities will address the legal issues with this proposal further in briefing.

c) TURN, NRDC, and CalPA

TURN, NRDC, and CalPA each propose surcharges on existing NEM 1.0 and 2.0 customers to fund programs to encourage solar adoption among low-income customers. Our discussion of these proposals is in Section A of this chapter.

2. Low-income Program Evaluation Should Consider How Third-Party Ownership Models Benefit or Do Not Benefit Low-income Customers

In their Opening Testimony, CalPA presents data on the cost savings realized by NEM customers who purchase their system outright and NEM customers who use a third-party ownership

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[249] CALSSA. P. 22.

[250] CALSSA, p. 28.

model for their system. CalPA also notes that low-income customers are 65% more likely to use a third-party ownership model when installing rooftop solar, meaning that the low-income customers who do install rooftop solar tend to realize less bill savings and increases in property values compared to customers who are not on CARE. We share CalPA's concerns about the reduced benefits realized by low-income customers. For example, during the pandemic the state extended a moratorium on disconnections for customers who were unable to pay their bills. Low-income customers who use third party ownership models have lease or PPA payment obligations, but the moratorium did not extend to those customers.

We propose that the CPUC track and consider ownership in its evaluation of any adopted low-income proposals.

VI.

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

This final chapter addresses a number of other issues raised in the opening testimonies of intervenors. First, the chapter addresses the types of reforms that are needed in the current virtual net metering programs and in the NEM program for agricultural customers, and the proposals to authorize a new form of unbundled service (as recommended by CCSA), to allow for community solar (as proposed by CALSSA), and to put in place a NVEM capacity limit (as recommended by Ivy).

Second, the chapter explains why the Commission should not be distracted by irrelevant arguments advanced by parties not supporting meaningful reform of the NEM 2.0 tariff. These issues include the SEIA/VS's use of the 2020 ACC; the false choice presented by SEIA/VS with regard to rooftop solar versus utility-scale solar; the overstated societal benefits of NEM systems; the cost of transmission in retail rates; the utility's financial interest in reforming NEM 2.0; and the inappropriate representations that NEM DG systems are like RPS resources, or energy efficiency, or electric-vehicle charging.

A. Virtual Net Metering

1. All Virtual Tariffs Should Appropriately Be Included In NEM Reform

Some parties argue that virtual tariffs must maintain NEM 2.0 provisions because there is no record to support modification.[251] They argue that because the NEM 2.0 Lookback Study did not analyze virtual tariffs that the CPUC is somehow prohibited from modifying those tariffs. This reasoning is flawed. There is ample record to support reform of virtual arrangements without relying on specific findings of the Lookback Study regarding virtual tariffs.

Virtual net metering arrangements have well-known similarities to single account NEM, and those similarities were included in the Lookback Study. Primarily, both NEM and VNEM currently

[251] EWA Opening Testimony, p.3, and Ivy Energy, p. 5.

credit customers for exports to the grid at retail rates, less certain NBCs. As the Lookback Study established, and confirmed further by E3's Comparative Analysis using the 2021 ACC, the avoided cost of any energy produced is far less than the credit received by participating customers – whether NEM or VNEM.

In addition, virtual arrangements have some key differences from single account NEM, also well-known and well understood. First, a VNEM arrangement will support a larger generator, as it is based on more than one account. This means that virtual NEM generators can benefit from economies of scale and cost less per kW installed than a NEM generator benefiting a single account. Consequently, the payback period for a virtual arrangement, all things equal, would be less and NEM reform could be better tolerated by the market.

Ivy Energy presents data demonstrating that, under certain conditions, nearly all generation from a virtual NEM system could physically supply the load of benefiting meters, without any of it being exported to the grid.[252] While this may be true in the cases that Ivy Energy identifies, it does not appear this is true for virtual NEM customers in general. As seen below, only 31% of benefiting meters under PG&E virtual NEM arrangements are located behind the same service transformer. That said, even if all virtual NEM arrangements were configured such that they physically exported less energy beyond the service transformer than standard NEM, it would not impact the need for change. Per the 2021 ACC, the average value of a kWh from a solar profile in PG&E's service territory is $0.046, far less than any retail rate credit. Of this, $0.0017 and $0.00207 are categorized as being from distribution capacity and T&D losses, respectively. The utility proposal still provides these values in our virtual crediting successor tariff, even though they may not be justified for many virtual NEM configurations. Improving equity for Californians living in multifamily homes is best achieved by reforming the NEM tariffs as proposed by the utilities and other parties, not continuing or expanding virtual NEM tariffs that will only directly benefit a fraction of them.

[252] Ivy Energy Opening Testimony, p.3-4.

Figure VI-11
Percent of PG&E Virtual NEM Benefiting Meters on Same Delivery Infrastructure as the Generating Meter

Virtual NEM Type	% of Benefiting Meters on Same Feeder, weighted by allocated generator size	% of Benefiting Meters on Same Transformer, weighted by allocated generator size
All Virtual NEM	80%	31%
NEMA	84%	31%
NEMV	94%	71%
NEMV-MASH/SOMAH	97%	50%

2. <u>NEMA Customers Are Also Appropriately Subject To NEM Reform</u>

AECA/CFBF appear to acknowledge that full retail rate compensation should not continue for NEMA, but only propose general principles for a revised NEMA tariff.[253] Most of their testimony attempts to diminish the need for significant change by making inaccurate claims.

First, AECA/CFBF state that NEMA customers pay full transmission, distribution and non-bypassable charges and that, as a result, "there are no material cross subsidies from other ratepayers to NEMA customers."[254] While it is true that agricultural rate include demand charges, not all NEMA arrangements are composed of *only* agricultural accounts. Further, even with a demand charge, not all transmission and distribution costs are included in that demand charge. All of PG&E's currently available agricultural tariffs recover a portion of distribution and all transmission and non-bypassable costs through volumetric rates, and are therefore avoidable via NEMA credits.[255] As seen below in Figure VI-12, the bill savings of currently available PG&E agricultural rates exceed the avoided cost as calculated by the 2021 ACC by a significant margin, meaning agricultural NEM-A customers do shift costs to other customers. While this table is based on near term avoided costs, using a long term levelized average, as requested by AECA/CFBF, would not meaningfully impact the result.

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[253] AECA/CFBF Opening Testimony, p. 6.

[254] AECA/CFBF Opening Testimony, p. 2.

[255] While NEMA customers cannot avoid some NBCs under NEM 2.0, others are still billed on net usage.

Figure VI-12
Cost Shift of Currently Available PG&E Agricultural Rates

Rate	Bill Savings ($/kWh)	Avoided Cost ($/kWh)	Cost Shift ($/kWh)
AG-A1	$0.22	$0.05	$0.18
AG-A2	$0.17	$0.05	$0.12
AG-B	$0.21	$0.05	$0.17
AC-C	$0.16	$0.05	$0.11

Second, AECA/CFBF cite analysis other than the ACC to argue that NEMA customers' investments benefited other customers through avoided generation, transmission, and distribution investments .[256] All of these benefits have been included and quantified in the 2021 ACC values shown above, and are much less than the compensation NEMA customers currently receive. This is not the appropriate venue to relitigate the merits of avoided cost methodologies.

Third, AECA/CFBF notes that the Commission "recognized that non-residential NEM and NEMA customers do not impose a burden on non-NEM customers and could even be providing a large benefit" when supporting SB594, the initial legislation that established the NEMA tariff.[257] However, AECA/CFBF does not note that this support was conditional on the very different circumstances in 2012, and is not a reason for other customers (including non-participating agricultural customers) to continue to subsidize NEM for participating agricultural customers. In fact, in SB594 the Legislature ordered the CPUC to ensure that NEMA would "not result in an increase in the expected revenue obligations of customers who are not eligible customer-generators." Resolution E-4610, which implemented the provisions of SB594 to implement NEMA, found that NEMA would not increase the overall cost shift of the NEM program largely because NEM was capped. At the time, the logic was that any increased non-residential adoption from NEMA would displace residential adoption under the cap, which would potentially reduce the overall cost shift of the program. The NEM cap has been lifted for

[256] AECA/CFBF Opening Testimony, p. 8-16.

[257] AECA/CFBF Opening Testimony, p. 7.

several years, and it is reasonable for the Commission to implement a successor tariff that ensures this statutory requirement that non-participants are indifferent is met.

3. The Commission Should Reject CCSA's Proposal to Create a New Form of Unbundled Service

The Coalition for Community Solar Access (CCSA) proposes that solar developers could build solar installations between 1 to 5 MW and contract with customers to pay subscription fees, who would in turn receive credits based on a combination of CAISO day-ahead market prices and a 25-year levelized average value from the Commission's avoided costs calculator. They also propose that installations located in disadvantaged communities with at least 50% of facility capacity subscribed by low-income participants should instead get credits near the full retail rate.[258] First, we acknowledge and appreciate that CCSA recognizes that, at least for the general market, compensation should be based on value. However, this proposal amounts to creating a new form of unbundled generation service similar to but with fewer obligations than Direct Access and should be rejected for that reason alone. The utilities will address the legal issues with this proposal further in briefing.

That said, the proposal has other serious issues. While this purports to be a distributed generation program, the terms proposed by CCSA risk unintended outcomes: it proposes systems can be no larger than 5 MW but proposes no restrictions on the geographic proximity of other eligible generators. One could reasonably expect that savvy developers would co-locate many 1-5 MW eligible solar facilities to gain the cost savings of utility scale solar, while receiving premium compensation meant for distributed solar. They also appear to propose that eligible installations interconnect at secondary voltage. This is inappropriate in the context of requesting compensation as though it were a behind the meter resource, as such a large facility would likely have a dedicated transformer through which all production would be exported. The proposal also partially bases compensation on a 25-year average of avoided costs, which is inappropriate for reasons discussed in Chapter 4. The low-income

[258] CCSA, B. Smithwood, Opening Testimony, p. 33-34. While CCSA presents a table showing illustrative EJ adder rates, all their workpapers were based on the 2020 ACC, and therefore overstate the compensation provided in their general market proposal, and understate the magnitude of their EJ adder.

proposal results in excessively high compensation for quasi-utility scale solar installations, and would likely result in developers capturing much of the margin between the cost of these resources and retail rates. CCSA admits developers will capture much of this margin, only proposing "that at least half of the adder value be required to be conveyed to the participant to ensure these enhanced savings are realized."[259] That only 50% of participants in this sub-program meant to promote equity are required to be low income is another concern – to the extent equity concerns justify additional subsidies, those subsidies should be directed to low income customers. Instead, the CSSA proposal would only require 25% of those subsidies to be directed to low income customers.

In addition, the commission has already authorized a community solar structure through R.14-07-002 with the creation of the Disadvantaged Communities Community Solar Green Tariff Program. Unlike CCSA's proposal, this program contains a minimum requirement for low-income customers, and it offers an easy-to-understand discount for the customer. CCSA fails to explain why their proposal is superior to the existing program. Having an additional community solar offering would only serve to complicate the market for customers and cannibalize the current program and projects.

If the CPUC does approve a tariff based on CCSA's proposal, it must make at least the following changes: (1) Align the credit calculation methodology with the utility proposal for calculating the export compensation rates, with further adjustment to account for the voltage at which the generator delivers electricity onto the grid, (2) impose restrictions against clustering, (3) impose a cap on the program, with a reevaluation triggered upon reaching half of the MW target, and (4) reject the low-income adder proposal. If the CPUC wishes to provide compensation higher than avoided cost to virtual crediting customers, they should do so via a transparent adder based on a calculation of the amount needed to achieve a targeted bill savings, not by maintaining retail crediting.

4. <u>Any Virtual Arrangement Intended to Address Equity Should Do So.</u>

Some parties justify a proposal to continue or expand virtual net metering based on equity reasons. Aurora Solar explains that virtual net metering is effective at bringing benefits of solar to

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[259] CCSA, B. Smithwood, Opening Testimony, p.38.

everyone "especially working class and disadvantaged communities."[260] CALSSA proposed continuing the existing virtual net metering tariff for multifamily rental properties located in census tracts with median income below 100% of the AMI.[261] Both parties justified their proposals with discussions of the benefits for low-income customers, but neither restricted their proposal to CARE and FERA customers. As was demonstrated by PG&E in the NEM 2.0 proceeding, the primary reason there are lower adoption rates in DACs is that there are higher concentrations of low-income customers in DACs, while non-low income customers in DACs had similar adoption rates to non-low-income customers in the rest of the state. [262] Continuing a program or tariff in the name of equity without actually ensuring that program promotes equity will just result in the same inequitable outcomes. As further described in Chapter 5, any equity programs should be carefully targeted and provide transparent incentives; simply extending NEM 2.0 virtual NEM rules does neither.

5. VNEM Capacity Limit Proposal unduly delays action on the Cost Shift

Ivy Energy (8:1-4) recommends maintaining current VNEM until VNEM reaches a 10,000 MW trigger. We do not agree with this recommendation. The Legislature was clear that a NEM transition tariff was required once NEM reached the cap established in PUC Section 2827 – 5,256 MW total for the three IOUs. NEM 2.0 does not meet the requirements for that successor tariff and there is nothing in the record to support the CPUC extending any existing tariff. The statutory cap for a noncompliant tariff was reached over three years ago and the CPUC is diligently addressing the need for a compliant successor tariff in this proceeding. It is unclear that a 10,000 MW VNEM cap would ever be reached, and amounts to a request to delay reform indefinitely.

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[260] Aurora Solar Opening Testimony, p 23.

[261] CALSSA Opening Testimony, pp. 24-25.

[262] D.18-06-027, p. 18.

B. The Commission Should Not Be Persuaded By Distracting Arguments or By Irrelevant Matters Advanced by Parties Not Supporting Meaningful Reform

1. Parties Representing the Solar Industry Downplay the Cost Shift and Overstate the Benefits of Rooftop Solar to the System

In sometimes large and sometimes small or subtle ways, the solar parties' testimony attempts to minimize the size and adverse consequences of the cost shift, and in so doing, leave the impression that it would be inadvisable for the Commission to introduce significant and structural reforms to NEM 2.0. These potential distractions include: SEIA/VS's use of the 2020 ACC; the false choice presented by SEIA/VS with regard to rooftop solar versus utility-scale solar; the overstated societal benefits of NEM systems; the overall cost of transmission; the utility's financial interest in reforming NEM 2.0; and the inappropriate representations that NEM DG systems are like RPS resources, or energy efficiency, or electric-vehicle charging.

This section of the Joint Utilities' Rebuttal Testimony highlights ways that the Commission should discount the solar parties' testimony.

a) Parties Representing the Solar Industry Did Not Adhere to the Administrative Law Judge's Encouragement Regarding Use of the 2021 ACC and Consequently Undermine the Ability of the Commission to Make Apples-to-Apples Comparisons of the Proposals

SEIA/VS open their testimony (through Mr. Beach) with a summary of their positions, including highlighting their use of the 2020 ACC to calculate benefits of customer-sited generation and to set the level of compensation for excess output into the grid.[263] At the time that SEIA/VS submitted their Opening Testimony, there were strong indications that the 2021 ACC should be used in this proceeding.[264] Nonetheless, SEIA/VS used the 2020 ACC in their analysis. SEIA/VS's

[263] SEIA/VS Beach Testimony, pages ii and iii.

[264] Email message of ALJ Kelly A. Hymes, R.20-08-020 Procedural Email Providing Guidance on Party Testimony (email 1 of 3), May 21, 2021, with the ALJ's discussion of the ACC and the issue of cost-effectiveness, and its reference to the ACC proposed in draft resolution E-5150 and the consideration of that resolution at the Commission's June 24th meeting.

decision to use the 2020 ACC is unhelpful and hinders the Commission's ability to compare the proposals. As explained above in Chapter 4 of this Rebuttal Testimony, the newer, updated 2021 ACC includes lower estimates of avoided costs, and it would not be surprising if SEIA/VS chose to rely on 2020 ACC because of its higher avoided-cost values.

The Commission has now approved the 2021 ACC[265] and the Commission should rely on it in assessing various tariff proposals and to calculate benefits of customer-sited generation and the value of (and compensation for) excess output into the grid. To that end, the Commission should require an updated set of information from the solar parties, using the 2021 ACC.

b) <u>Parties Representing the Rooftop Solar Industry Create a False Choice Between Rooftop and Utility-Scale Solar Projects</u>

The Solar Parties present the Commission with discussions that tend to depict a false all-or-nothing choice between rooftop and utility-scale solar. SEIA/Vote Solar's witness Mr. Beach observes, for example, that California "would commit a serious error to rely only on utility-scale renewables."[266] CALSSA paints a similarly dire picture of what could happen if the Commission were to implement significant NEM reforms: "If the state relies on utility-scale renewables and allows the distributed solar and storage market to wither, and is then unable to site transmission lines, there is a high likelihood that California will abandon its commitments to addressing climate change."[267]

This proceeding is hardly about whether California should follow a path of reliance on utility-scale solar to the exclusion of customer-sited distributed generation. The two are not mutually exclusive. The Commission should not be distracted by concerns that NEM reform will eliminate the ability to tap into the solar resource through DG facilities.

Indeed, both rooftop solar and utility-scale solar will be needed to help California meet its climate goals, even if it is not clear today how much of each will be deployed during different periods of time. For example: Will California and neighboring states add new transmission capacity to

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[265] 2021 ACC was approved in Resolution E-5150.

[266] SEIA/VS, T. Beach, 7:31-32.

[267] CALSSA, B. Smithwood, Opening Testimony, page 88:4-6.

expand their ability to share and depend on each other's resources to meet demand and carbon-reduction goals? How fast will electrification of buildings and vehicles occur over the next two decades? How much will California rely on incremental solar and battery storage resources to meet needs for zero-carbon electric resources in the future, and will other resources (e.g., zero-carbon firm generation) enter the market and lessen the overall capacity additions that would be required in a system with high reliance on solar power? These many uncertainties about the pace and character of California's paths to a carbon-neutral economy make it far too soon to conclude that the Commission should reform NEM 2.0 only on a gradual basis.

Solar parties have raised the concern (in their false "either/or" premise about NEM reforms equating to a utility-scale-only future for solar power) that land use constraints in a utility-scale-only pathway will limit the ability of California to reach its climate targets.[268] To be sure, some decarbonization pathways will face greater land pressures than others but such tradeoffs are not before the Commission. The studies that examine the cost, reliability, land-use, and other aspects of different resource portfolios indicate that inevitably there will be trade-offs among them.

The Nature Conservancy's study, called "The Power of Place," pays particular attention to the issue of how various zero-carbon pathways lead to "natural and working land impacts and how land constraints on energy availability affect infrastructure planning and the choices between technologies"[269] in California. The study relied on modeling of scenarios that varied by such things as: the amount of land with legal, administrative or other constraints on its use for renewable development; the ability to access renewable resources in other states in the Western Interconnection; the cost of DERs; and other variables. The study highlights the trade-offs associated with land constraints and development of renewable resources, with the largest impact on portfolio mix stemming from the ability of California to meet some of its resource needs from renewables located outside of California. Relying

[268] SEIA/VS Beach Testimony, 9:6-15 and Attachment A. The Joint Utilities' technical analysis of SEIA/VS Attachment A is in Chapter 3 of this Rebuttal Testimony.

[269] Wu, G.C.; Leslie, E.; Allen, D.; Sawyerr, O.; Cameron, D.; Brand, E.; Cohen, B.; Ochoa, M.; Olson, A. Power of Place: Land Conservation and Clean Energy Pathways for California, 2019, page 2.

only on new in-state resources would have the effect of raising costs for California's system as well as requiring more DERs (including rooftop and utility-scale solar as well as storage) to be added in California, which would put development pressure on land in California.

Either way, the study identifies the need for substantial deployment of rooftop and utility-scale solar capacity in California. In fact, the recent study by Long *et al*.[270] makes the point that the greatest pressure on land use from the future power system's configuration will come from having California being overly dependent on solar and other renewable capacity to the exclusion of other forms of generation. The study examines many issues (e.g., cost, reliability, land implications) and concludes that a diverse resource portfolio including "clean firm power alongside solar and wind in a 100% carbon-free electric system would require between 625 and 2,500 square miles dedicated to utility-scale solar and wind. Without clean firm power, more than 6,250 square miles of land would be required—bigger than the combined size of Connecticut and Rhode Island...."[271]

c) Parties Representing the Solar Industry Overstate the Societal Benefits of the NEM Program

One reason why renewable energy is viewed so favorably by the public is because of societal benefits like reducing or avoiding the emissions that contribute to climate change.[272] Clearly,

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[270] Jane C.S Long, Ejeong Baik, Jesse D. Jenkins, Clea Kolster, Kiran Chawla, Arne Olson, Armond Cohen, Michael Colvin, Sally M. Benson, Robert B. Jackson, David G. Victor, Steven P. Hamburg, "Clean Firm Energy is the Key to California's Clean Energy Future," *Issues in Science and Technology* (March 24, 2021), (hereafter "Long et al."), at https://issues.org/california-decarbonizing-power-wind-solar-nuclear-gas/#:~:text=Clean%20Firm%20Power%20is%20the%20Key%20to%20California's%20Carbon%2DFree%20Energy%20Future&text=California's%20plan%20to%20make%20all,2045%20will%20double%20electricity%20demand.&text=A%202018%20law%20mandated%20that,derive%20from%20carbon%2Dfree%20sources.

[271] Long et al, p. 2.

[272] Sarah Mills, Barry Rabe, and Christopher Borick, "Widespread Public Support for Renewable Energy Mandate Despite Proposal Rollbacks," Issues in Energy and Environmental Policy, June 2015, ieep-nsee-2015-renewable-portfolio-standards.pdf (umich.edu); Alec Tyson and Brian Kennedy, "Two-Thirds of American Think Government Should Do More on Climate," Pew Research Center, June 23, 2020, https://www.pewresearch.org/science/2020/06/23/two-thirds-of-americans-think-government-should-do-more-on-climate/; Brian Kennedy and Alison Spencer, "Most Americans supporting expanding solar and wind energy, but Republican support has dropped," Pew Research Center, June 8, 2021, https://www.pewresearch.org/fact-tank/2021/06/08/most-americans-support-expanding-solar-and-wind-energy-but-republican-support-has-dropped/.].

such societal benefits are important, with some incorporated (e.g., avoided GHG emissions) into the ACC adopted by the Commission.[273] Many of the benefits of DG that are mentioned by the solar parties — e.g., resiliency, societal importance of supporting the growth and continued cost reductions of PV — are overstated or speculative (despite the attempts of some of these parties to quantify/monetize them).[274] In Chapter 3, there is a detailed technical discussion of the potential benefits offered by these parties.

As SEIA/VS admit, many of these societal benefits can be achieved with any type of renewable generation, not just small-scale distributed generation.[275] But SEIA/VS's quantitative discussion fails to take such comparability into account. Any societal benefits of DG should be compared to other renewable generation options to determine whether there are incremental benefits of DG. This is the reason the Commission declined to adopt a societal cost test (SCT) for use in demand-side proceedings, and instead ordered further study of a three-part SCT for informational purposes in the Integrated Resources Planning (IRP) proceeding[276], which is the proper venue to perform an apples-to-apples analysis of different resource options.

Finally, even if there were unique and incremental benefits that accrue to society from DG,[277] it is not appropriate to have a subset of society (i.e., non-solar customers of the Joint Utilities) to continue to underwrite those benefits through higher utility bills. Instead, such broad-based

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[273] D.20-04-010.

[274] SEIA/VS Beach Testimony, pages 5:19-21 and 20:1 through 27:10; CSSA Testimony, pages 81:4 through 90:8; Prepared Testimony of Tyson Siegele on Behalf of Protect Our Communities Foundation, page 2:25-27; Environmental Working Group, generally.

[275] See SEIA Opening Testimony, Attachment RTB-3, p. 1: "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."

[276] See D.19-05-019, at p. 32: "A defining feature of integrated resource planning is the fair and unbiased consideration of both demand and supply side resources as potential solutions for meeting system or societal needs."

[277] SEIA/VS Beach Testimony, page iv.

societal benefits should be supported through broad-based public support (e.g., taxes) (as discussed in Chapter 2 of the Joint Utilities' Opening Testimony).

It is worth noting in this context that President Biden has proposed a 2022 federal budget that is grounded in part on his proposed American Jobs Plan which includes a "ten-year extension and phase down of an expanded direct-pay investment tax credit and production tax credit for clean energy generation and storage."[278] This proposal is designed to provide the type of publicly supported financial assistance that might be helpful to encourage further investments in solar projects, storage projects and other eligible clean-energy projects needed to address societal objectives such as those that "would reduce carbon and other kinds of air pollution, bolster domestic clean energy industries and supply chains, create high-quality jobs, and align the country with international climate initiatives such as the Paris Climate Agreement."[279] If adopted, these proposed or other federal tax-incentive extensions for clean energy investments would help to address the societal values called for by the solar parties.

d) <u>Transmission Costs Are an Irrelevant Red Herring</u>

Several of the solar advocates point to the high portion of the Joint Utilities' electricity rates that is tied to recovery of transmission-related costs, and in so doing, try to minimize the size of the cost shift.[280]

This is a distraction in this NEM reform proceeding. A fundamental difference between recovery of transmission investment, operations, and maintenance, on the one hand, and the cost shift, on the other hand, is that the former costs are incurred to support the reliable and efficient operation of the Joint Utilities' transmission system for the benefit of their wholesale and retail customers. Those costs are recovered from all benefitting customers and, unlike the cost shift, are not a

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[278] https://www.whitehouse.gov/briefing-room/statements-releases/2021/03/31/fact-sheet-the-american-jobs-plan/.

[279] U.S. Department of the Treasury, "General Explanations of the Administration's Fiscal Year 2022 Revenue Proposals," May 2021, p. 39, https://home.treasury.gov/system/files/131/General-Explanations-FY2022.pdf

[280] SEIA/VS Beach Testimony, page 8:15-17 and footnote 3; CALSSA Testimony, page 4:11-21; Environmental Working Group Testimony, page 6:12-17.

subsidy that requires a transfer of wealth from one set of customers that do not install rooftop solar to those that do.

In addition, solar parties ignore the fact that the ACC includes a value for avoided transmission expense. This value was extensively discussed and litigated in the Distribution Resources Planning and Integrated Distributed Energy Resources proceedings and resulted in a consistent methodology across IOUs to capture the avoided transmission benefits of DERs.[281] Further, the explicitly rejected arguments that the ACC underestimates this value. In doing so the Commission noted comments from the CAISO refuting these arguments and found they are based on a "factual misrepresentation".[282]

e) <u>Contrary to the Position of Some Parties, the Joint Utilities Do Not Have a Corporate Financial Stake in NEM Reform In Light of the Cost-of-Service Rate-Regulated Business Model</u>

The Environmental Working Group (EWG) argues that the Commission should "consider the incentives that utilities have to make solar less financially attractive to consumers and preserve their monopoly."[283] In support of this recommendation, EWG references a 2013 paper sponsored by the Edison Electric Institute that identifies adoption of rooftop solar and other distributed energy resources (DERs) as creating "disruptive challenges" for utilities and their investors.[284]

While it is true that many in the electric utility industry (including both publicly owned[285] and investor-owned utilities) began to raise concerns about the impact of DERs on the revenue

[281] D.20-04-010, pp. 56-61.

[282] D.20-04-010, pp. 76-77.

[283] Prepared Direct Testimony of Ken Cook on Behalf of the Environmental Working Group, page iii.

[284] EWG Testimony, 8:8-10.

[285] See, for example, the report sponsored by the American Public Power Association (the trade association of municipally owned and other public power utilities) in 2016 that made similar points to those in the EEI study cited by EWG: "Distributed Energy Resources (DER), especially rooftop solar photovoltaic (PV) systems, are significantly changing the way customers use energy and, as a result, having a noticeable impact on electricity sales. Customer-sited generation in particular creates a unique challenge for utilities. Customers not only generate a portion of their electric power needs, but they are also able to supply excess power to the grid.

(*Continued*)

recovery starting a decade ago, that is not the same as concluding that an investor-owned utility has a financial interest in making solar less financially attractive so as to preserve its role as the sole provider of local distribution service. First, the Joint Utilities themselves do not have an incentive to invest in utility-scale solar at this time because they already have procured enough renewable resources to exceed their current RPS obligations.[286] Second, the EWG position fails to recognize the fundamental nature of the cost-of-service business model for publicly and investor-owned distribution utilities in California (and elsewhere). Utilities are under an obligation to serve their customers who pay for the service they receive from the utility. Under California's decoupled policy, utilities do not earn more by selling more electricity. Rates are designed to recover the cost of service. If some customers are not paying their fair share of the utility's revenue requirement, rates have to be adjusted so that other customers pick up the cost.

To recover the costs of service, publicly owned and investor-owned utilities, as well as those who regulate them, are faced with that basic choice. As noted in the 2021 Future of Electric Power Study published by the National Academies of Sciences, Medicine and Engineering: "Retail electricity prices, including rate designs, need to reflect the changing cost structure of the electric grid, which will rely increasingly on resources (distribution resources, transmission resources, storage, on-site and central-station resources) that are capital-intensive with low variable costs. More innovation is needed in rate design, more creative and tailored service offerings that take lessons from other

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Under most utility tariffs, this excess supply is netted against the customer's consumption, lowering a customer's monthly electricity bill. This arrangement, known as net energy metering (NEM), not only impacts utility revenues, but it often creates a cost shift to non-net metered customers who must make up the shortfall if the utility is to fully cover costs. These changes have spurred utilities to explore and implement new rate designs to more equitably recover costs from customers....Obviously, the utility cannot continue to operate with persistent revenue shortfalls, so if sales are expected to remain at the lower level, rates will have to be adjusted upward to enable recovery of fixed and variable costs." Paul Zummo and James Cater, "Rate Design Options for Distributed Energy Resources," prepared for the American Public Power Association, November 2016, pages 3 and 5. https://www.publicpower.org/system/files/documents/ppf_rate_design_options_for_der.pdf.

[286] California Public Utilities Commission, "2020 California Renewables Portfolio Standard: Annual Report," November 2020, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_Electricity_and_Natural_Gas/2020%20RPS%20Annual%20Report.pdf.

industries that have evolved from high-reliance on usage-based rates to ones that allow for diverse options for consumers and for revenue recovery for service providers."[287]

The introduction of distributed generators necessitates changes in residential rate designs in the electric industry. Rates that traditionally recover many if not most fixed costs through volumetric rate elements will need to be adjusted to ones that use customer charges, minimum bills, demand charges, grid charges, or other approaches to ensure that customers pay their fair share of the costs to provide them with service.

f) Parties Representing the Solar Rooftop Industry Make an Inappropriate Analogy Between Rooftop and Resources Eligible for the Renewables Portfolio Standard

Likewise, SEIA/VS offer a false equivalence between NEM and the RPS program. California's RPS program sets forth a statutory mandate to meet certain renewable energy content requirements for load-serving entities' supplies of power. Electricity supplied via the grid is required to depend upon increasing supplies of renewable energy. Even though the NEM program supports a renewable resource (i.e., solar power), the NEM program neither technically nor practically advances the ability of the state to satisfy its RPS requirements. SEIA/VS are making an apples-to-oranges comparison for several reasons.

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[287] National Academies of Sciences, Engineering and Medicine, *The Future of Electric Power in the United States*, Washington, DC: The National Academies Press, 2021, https://doi.org/10.17226/25968. See, for example, the following findings and recommendations of this report of the Future of Electric Power Committee (of which I was a member): "Much more innovation in retail market design is needed in conjunction with significant adoption of DER and changes in power flows on the local grid. Attention to and discussion of such markets for services provided by DER are still in their infancy in most states. New retail market structures are needed, with underlying pricing signals that are not only dynamic but also location-specific across time. The development of such markets will not be easy but will be important if states seek to rely on an electric grid that is not only based on deep penetration of centralized and decentralized variable resources but also key to lowering carbon emissions in buildings and transportation to meet climate-change goals. Recommendation 3.5: The decentralization of supply and other transformations of the electric power system could have large impacts on access, costs, benefits, and other qualities of grid service. For this reason, local regulatory bodies—organized by the National Association of Regulatory Utility Commissioners (NARUC) in partnership with DOE—should accelerate and deepen their evaluations of new rate structures and other policies with an eye to how a transforming grid will affect issues of equity.... For decision makers at publicly owned utilities, APPA and NRECA should also provide assistance in accelerating such evaluations." page 140.

First, California's electric utilities are not permitted to treat NEM exports as RPS-eligible supply, except for the small amount of net surplus calculated at the end of customers' 12-month billing cycle. Thus, the vast majority of NEM exports to the grid receive zero RPS credit.

Second, in arguing that NEM facilities have reduced historic RPS obligations by having reduced total retail sales, SEIA/VS overstate the load-reduction benefits associated with NEM customers' on-site generation for RPS purposes. That argument lacks merit for the same reasons that SEIA/VS's EE and EV arguments lack merit (as explained further below). Moreover, SEIA/VS would assign too much value to NEM on-site generation by giving it a one-to-one accounting for RPS credit (rather than giving it only the percentage associated with RPS requirements in any year).[288]

Third, utility procurements of RPS resources do not involve a shift of costs from one group of customers to others, especially in the form of a cross subsidy from those who are more financially burden with energy costs to those who have more economic means. The costs of RPS procurement are born by and socialized among all customers through generation and Power Charge Indifference Adjustment (PCIA) rates.

Finally, although early RPS contracts ended up having above-market costs, that is no longer the case. As costs of utility-scale renewables have declined and as competition for the right to enter into an RPS contract with a utility have changed over time, the prices paid to renewables that qualify for RPS have also declined over time. The same cannot be said of NEM 1.0 and 2.0, with the price paid for exports has increased over time as retail prices have increased.

g) <u>NEM Systems are Not Analogous to Energy Efficiency Measures</u>

SEIA/VS and Silicon Valley Leadership Group (SVLG), in their Opening Testimonies (and in prior comments on the Lookback Study), suggest a false equivalence between energy efficiency (EE) upgrades and the installation of DG facilities on NEM customers' premises.[289] The faulty premise of the SEIA/VS and SVLG position is that both EE upgrades and facilities covered

[288] SEIA/VS, T. Beach, p. 22.

[289] Opening Comments of the Solar Energy Industries Association and Vote Solar on the Net Energy Metering 2.0 Lookback Study, p. 8.

by the NEM tariffs are a form of load reduction and should be treated similarly in terms of taking any cost-shift into account.

The two programs are not analogous in the relevant context of this proceeding for several reasons. All of these reasons demonstrate that NEM, unlike EE measures, creates a persistent, regressive transfer of wealth from middle class and lower income customers to wealthier customers.

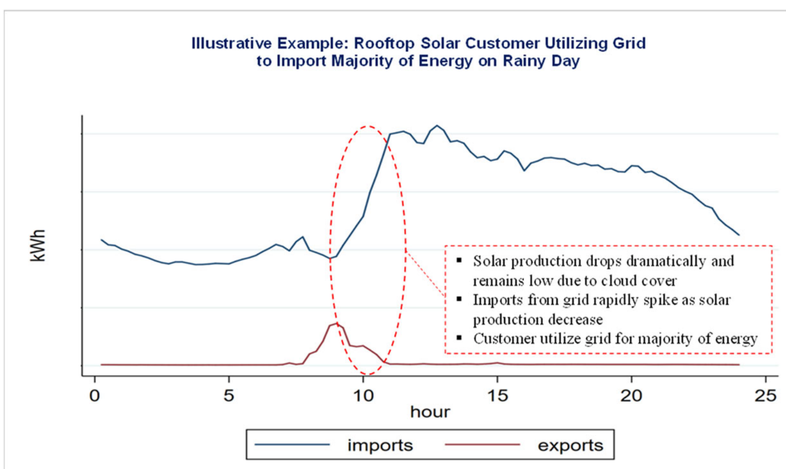
NEM customers reduce the amount of electric energy they use from the utility in highly irregular ways, even though they still rely on generating and delivery capacity with fixed costs. Currently, retail rates for residential customers (including those on the NEM 2.0 tariff) recover a significant share of fixed costs through volumetric electric energy rates. By serving a portion of their own energy requirements, NEM customers avoid paying for and shift their share of the cost of service to nonparticipating customers, resulting unfairly in having nonparticipating customers cover NEM customers' share of critical costs, such as wildfire costs. Also, NEM customers' exports of excess energy to the grid are compensated at the retail rate, which bears no resemblance to the value of NEM customers' intermittent exports. Stated differently, compensation for NEM excess energy exports is not cost effective for the utility's customers, as discussed in Chapter 4 of this Rebuttal Testimony and in Chapter 3 of the Joint Utilities' Opening Testimony.

While on-site solar generation reduces consumers' electric energy use in ways that can create some average changes in the patterns and profiles of load requirements, under actual system operating conditions such reductions are intermittent and depend on external factors such as cloud cover and weather patterns and on-site energy consumption. By contrast, EE measures result in a dependable reduction in energy use, with different EE measures leading to reductions with different load profiles. To illustrate the point: Assume that a customer installs a more energy-efficient appliance or adds better insulation or more-efficient windows. Such measures dependably and reliably reduce the customer's load during the hours when the relevant end-use equipment would otherwise be using energy. By contrast, NEM customers do not dependably reduce their load by relying on on-site solar generation due to the intermittency of solar resources. For NEM customers, the utility must therefore continue to procure enough utility-scale resources to serve NEM customers' load at any time their on-site generation is unavailable.

In the figure below, the illustrative load profile shows a NEM customer's usage of the grid during a day which starts out sunny but then turns cloudy. In that illustration, the NEM customer has had to rely almost entirely on imported energy from the grid for household consumption because generation from the rooftop solar PV panels ended up being extremely low. NEM customers rely on the grid when there is an imbalance between their on-site energy use and the output from onsite generation. On cloudy days, NEM customers' load profiles are similar to non-NEM customers' load profiles. On sunny days when no one is at home at a NEM customer's premise, the customer injects a lot of energy into the grid.

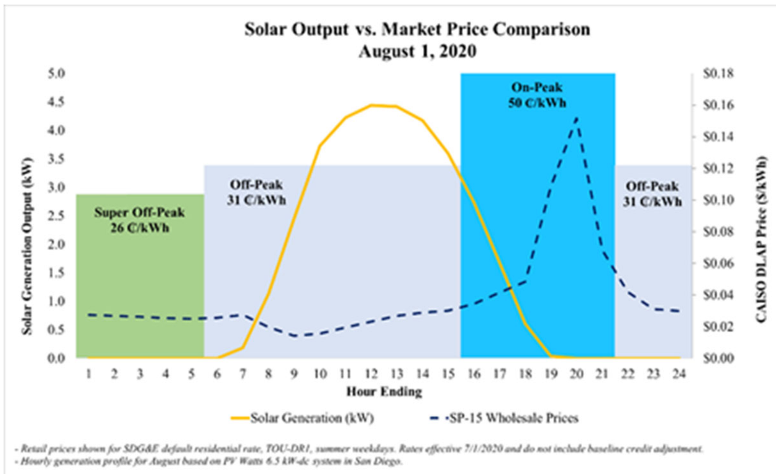
The upshot of this situation from the point of view of the electric system is that the distribution utility must invest in infrastructure that can provide these customers with the energy they need under any and all conditions.

Figure VI-13
Illustrative Example of Intermittent Rooftop Solar



EE upgrades, by contrast, dependably reduce energy use and dependence upon the grid. EE appliances and lightbulbs do not rely on the distribution system to export energy; rather, they tend to reduce demand for investments in and use of the electric grid. EE can contribute to lower overall system peak demand during ramping and high-cost periods. This differs from the load profiles of standalone solar customers whose energy generation and usage patterns contribute to the need for additional ramping and peak resources as onsite generation wanes during the high-cost periods.

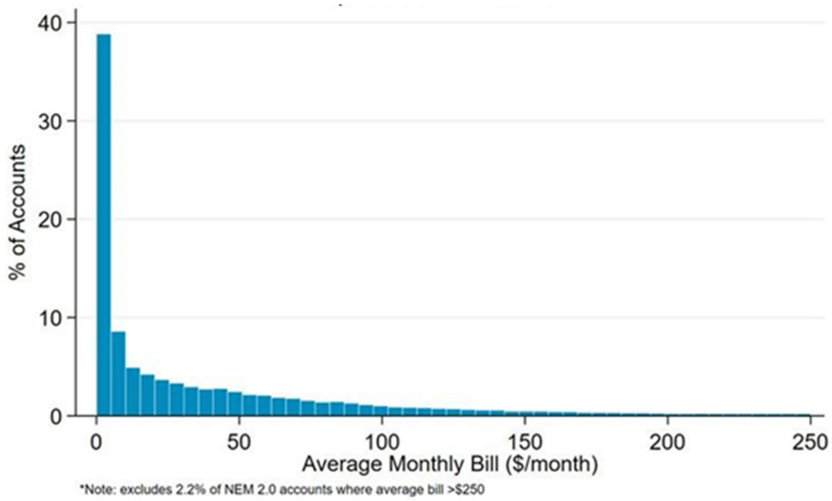
Figure VI-14
Solar Output vs. Market Price Comparison
August 1, 2020



Similarly, customers that adopt EE measures do not typically end up avoiding large portions of their bill. This is different from the reality through which some NEM customers are able to eliminate much if not most of their electric bills through the net metering of all new generation produced on site and netted from the monthly electric bill.[290] (See Figure VI-15 below.) Additionally, EE customers do not bank export credits that are used against charges at future unrelated dates and times.

[290] See, for example, the recent blogpost from Severin Borenstein, "Is Rooftop Solar Just Like Energy Efficiency?" Energy Institute Blog, UC Berkeley, July 12, 2021, https://energyathaas.wordpress.com/2021/07/12/is-rooftop-solar-just-like-energy-efficiency/.

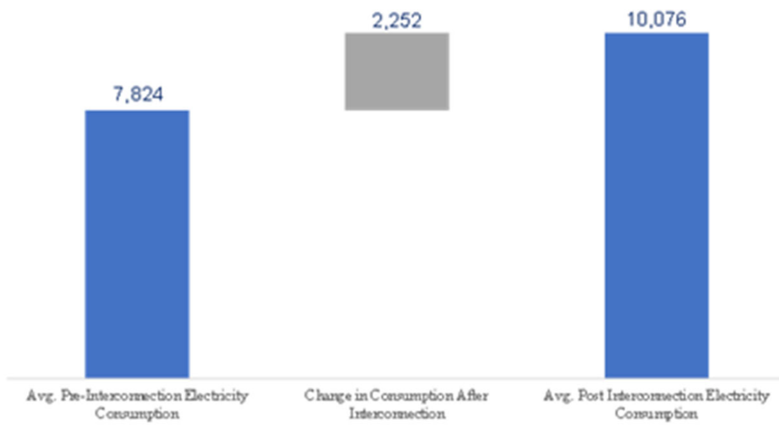
Figure VI-15
Residential NEM 2.0 Average Monthly Payments
SDG&E
April 2020 – March 2021



Because NEM customers must be able to export their excess generation to the grid and import energy when their on-site generation provides less than their instantaneous demand at any point in time, NEM systems do not reduce the utility's obligation to ensure a reliable and adequate electric grid. Nonetheless, the current tariffs allow NEM customers to offset the majority of their bill and thereby avoid paying their fair share of fixed transmission and distribution costs. As highlighted in the Lookback Study, on average after they install solar generating equipment, NEM 2.0 customers' net consumption may tend to decrease but, as shown in Figure VI-16 below, these customers' total electricity consumption (net load plus generation) on average increases with impacts on the availability and use of grid services.[291]

[291] *See* also California Solar Initiative (CSI) Final Impact Evaluation, Chapter 7, pp. 158-159, which shows for residential PG&E NEM 1.0 customers an average increase in monthly consumption and evening peak consumption following PV system installation.

Figure VI-16
Verdant NEM 2.0 Lookback Study
Change in Energy Consumption Post NEM 2.0 Interconnection (kWh)



The Commission established I D.19-05-019 that the TRC test would be the primary cost-effectiveness test, in most cases, for distributed energy resources, including EE.[292] This decision has led to the adoption of EE measures that are valuable to the system.

By contrast, the NEM program is not currently subject to any cost-effectiveness requirement or test and, in fact, credible analyses provided by various parties show that NEM 2.0 fails cost-effectiveness tests for the system and for non-participants (as explained in the Opening Testimony of the Joint Utilities, CalPA and TURN, and further discussed above in this Rebuttal Testimony). Thus, non-participating customers receive value for their investment in EE portfolios[293] but receive little to no value for their investment in NEM. Indeed, the IRP proceeding found that while EE is one of the least costly ways to meet resource needs, rooftop solar is the most expensive way to meet those same needs.[294] Thus, from the point of view of establishing a successor to the NEM 2.0 tariff that provides value to the other customers and the electric system more generally, comparing EE and NEM is like comparing apples to oranges.

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[292] D. 19-05-019, p. 2.

[293] D.21-05-031, Ordering Paragraph 3 (requiring that resource acquisition segments of EE portfolios pass the TRC test).

[294] D.18-02-018, p. 40.

Another way in which NEM programs differ from EE programs is that the latter are generally available to and financially accessible to a broader cross section of customers than NEM. The Lookback Study confirms that the NEM program creates inequities because wealthier customers are more likely to adopt rooftop solar than lower income customers.[295]

The barriers to participation in residential EE programs are lower (as compared to NEM program/facility adoption) because EE programs generally target replacing devices that customers already have in their homes or include promoting behavioral and operational changes that may be implemented with little or no investment by the customer. Rooftop solar systems, by contrast, tend to be options available to a subset of the customer mix — generally single-family homeowners.

Among the Joint Utilities' residential customers, only ~10% participate in the NEM program.[296] By contrast, EE programs have a much higher participation rate. The participant population changes every year, with most customers participating at some point, whether they know it or not.[297] In the single year of 2020 alone, 86,466 low-income PG&E customers participated in the Energy Savings Assistance (ESA) program;[298] this represents 5% of all CARE customers in that year. By contrast, only 73,000 PG&E CARE customers have participated in NEM 1.0 or 2.0 programs since their inception decades ago.

h) <u>NEM Systems Are Not Analogous to Electric Vehicle Charging</u>

To diminish the influence of the RIM test in evaluating reform tariff proposals, SEIA/VS argue 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".[299] To support this position, SEIA/VS advance another false equivalence between customers with EV charging and solar adopters, arguing that EV adopters are not required to keep gasoline consumers whole because of EV's significant

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[295] NEM Lookback Study, p. 39.

[296] Joint Proposal of PG&E, SDG&E and SCE, R. 20-08-020, Attachment A, Fig 4, p. 34.

[297] For example, with upstream programs, customers might purchase energy efficient lightbulbs (for example) without knowing the price is lower due to an incentive to the vendor.

[298] Annual Report of PG&E on the Results of its ESA and CARE Programs, p. 3.

[299] SEIA/VS, R. Thomas Beach, p.48.

reduction on gasoline consumption with the associated reduction of payment to oil and gas companies. SEIA/VS, however, miss the point by focusing on the reduced revenues experienced by oil and gas companies instead of on infrastructure (i.e., roads, bridges, highways, etc.) that is shared by gasoline-powered vehicles and EVs.

Road improvements are often funded through gasoline tax revenues. By not purchasing gasoline, EV drivers can avoid paying this tax and thus avoid contributing to the ongoing maintenance and improvement of transportation infrastructure, passing the burden of paying for infrastructure on a shrinking group of drivers who still use gas powered vehicles. This scenario, if left unremedied, is analogous to the cost shift created by NEM.

But this scenario does not exist in California where the Legislature recognized and repaired the inequity, just as we are asking the Commission to correct the inequities created by NEM in this proceeding.

California considered the impact on non-participants and concluded that the expected trajectory was unsustainable. Accordingly, in 2017 the California Legislature enacted The Road Repair and Accountability Act of 2017 (SB1) to ensure the cost of road infrastructure would be borne by those who use the road system and benefit from its improvements. As of July 1, 2020, California assesses a road improvement fee of $100 for non-exempt zero-emission vehicles of model year 2020 or later.[300] SB1 also directed the University of California Davis (UC Davis) to conduct a study of fees, taxes, and incentives "that ensure the purchase and ownership of zero- low-emission vehicles are properly incentivized to assist in meeting state clean air and climate targets, while also ensuring appropriate levels of funding for roads and transportation."[301]

The Commission should reject SEIA/VS's arguments regarding the level of influence afforded the RIM test and look to the example of the Road Repair and Accountability Act of 2017 as guidance for taking into consideration the impact of specific technology adoptions on non-

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[300] California Vehicle Code Section 9250.6.

[301] The Road Repair and Accountability Act of 2017 (SB1), SEC 48.

participants and ensuring costs for programs and infrastructure are paid for by those who use and benefit from the infrastructure.

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF JORGE CHACON

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

A. My name is Jorge Chacon, and my business address is 3 Innovation Way, Pomona, California 91768.

Q. By whom are you employed?

A. I am employed by Southern California Edison Company (SCE).

Q. Briefly describe your present responsibilities at SCE.

A. I am the manager of the Generation Interconnection Planning Group in SCE's Transmission and Distribution Business Unit. In that capacity, I am responsible for, among other things, managing the planning of high voltage transmission systems for SCE, including the Tehachapi Renewable Transmission Project (TRTP).

Q. Briefly describe your educational and professional background.

A. I obtained my Bachelor of Science degree in Electrical Engineering, from California State Polytechnic University, Pomona, in 1997. I have over twenty years of experience in SCE's Transmission and Distribution Planning departments where I have developed a solid technical knowledge base and understanding of the electric power system including planning, permitting, construction, and operation of transmission and distribution facilities. Over my career, I have ample experience performing the actual planning studies for addressing both load growth and new generation interconnections, sponsoring new transmission projects, supporting project execution including licensing support, and managing various study groups that perform both load studies and generation interconnection studies.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Section IV.C.2 of the *Joint Rebuttal Testimony of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) on Issues 2-6 of Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SAN DIEGO GAS & ELECTRIC COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF GREGORY SMITH

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

A. My name is Gregory Smith, and my business address is 8690 Balboa Avenue San Diego, CA 92123.

Q. By whom are you employed?

A. I am employed by San Diego Gas & Electric Company (SDG&E).

Q. Briefly describe your present responsibilities at SDG&E.

A. I am a Technology Strategy Architect at SDG&E. My primary responsibilities include establishing and reviewing systems integration and communication solutions for distribution-level grid management solutions and supporting regulatory processes where these topics are discussed.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Management Science from the University of California, San Diego in 1981. Upon receiving my degree, I have been employed in a variety of industries including aerospace and defense, telecommunications, software, and system integration services. I joined San Diego Gas and Electric in 2006 and have been employed in a variety of technical positions supporting the information technology, smart grid and advanced technology organizations.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of the *Joint Rebuttal Testimony of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) on Issues 2-6 of Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles*, as identified in the Table of Contents thereto.

I have not previously testified before the California Public Utilities Commission.

Appendix B

Selected Data Request Responses

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

California Solar & Storage Association Response to
The Joint IOUs Data Request-04

General Statement

The California Solar & Storage Association ("CALSSA") hereby objects and responds to the information requests ("Requests") to CALSSA from Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas and Electric Company (collectively, the "Joint IOUs") on June 22, 2021 in R.20-08-020. CALSSA expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses, including objections not listed below. Notwithstanding any of the following objections, and without waiving these objections, CALSSA responds in good faith to the Requests after a diligent search and reasonable inquiry. Further, in responding to the Requests, CALSSA hereby reserves:

- Its rights to produce and provide additional documentary evidence based on information, evidence, or analysis hereafter obtained or evaluated; and

- The right to update and/or supplement the responses provided herein if and when additional evidence, which is responsive to the applicable Requests, becomes available and, at any time, if it appears that inadvertent errors or omissions have been made.

Pursuant to the Instructions in the Requests, these responses have been transmitted via email to the following recipients: Rebecca Meiers-De Pastino (Rebecca.Meiers.DePastino@sce.com), Andre Ramirez (Andre.Ramirez@sce.com), Steven Frank (Steven.Frank@pge.com), Jane Oliveira (jop1@pge.com), Greg Barnes (Gbarnes@sdge.com), and William Fuller (Wfuller@sdge.com).

CALSSA
Rulemaking 20-08-020
Data Response

To:	CALSSA
From:	Joint IOUs
Witness:	Brad Heavner
Request Date:	June 22, 2021
Due Date:	July 7, 2021

Q1: If the Commission adopts the 2021 ACC update, confirm or deny if CALSSA will then supplement its Successor Tariff Proposal and Opening Testimony to reflect the 2021 ACC.

A1: CALSSA will not update its NEM-3 proposal based on the 2021 ACC. However, we recognize that the 2021 ACC is one of many things that the Commission will take into account in developing its decision.

CALSSA
Rulemaking 20-08-020
Data Response

To:	CALSSA
From:	Joint IOUs
Witness:	Brad Heavner
Request Date:	June 22, 2021
Due Date:	July 7, 2021

Q2: Provide all documents currently in your possession, custody and control reflecting all analyses of your Successor Tariff Proposal using the 2021 ACC update.

A2: CALSSA is currently developing analysis of cost recovery periods using the 2021 ACC update and intends to include it in rebuttal testimony.

CALSSA
Rulemaking 20-08-020
Data Response

To:	CALSSA
From:	Joint IOUs
Witness:	Brad Heavner
Request Date:	June 22, 2021
Due Date:	July 7, 2021

Q3: Provide an updated version of all CALSSA's workpapers with 2020 ACC values replaced with 2021 ACC values.

Specific Objections: CALSSA objects to this question because it is unduly burdensome, requiring CALSSA to perform a calculation it has not already performed.

CALSSA also objects to this question on the basis of it seeking documents or information to which the requesting party has equal access because the documents or information are already in the Joint IOUs' possession or already publicly available. The Joint IOUs can perform this analysis with data already in the Joint IOUs' possession or that is publicly available.

Notwithstanding this objection, and without waiving it, CALSSA responds as follows:

A3: Please see the answer to Q02. CALSSA can provide workpapers to their rebuttal testimony if requested.

CALSSA
Rulemaking 20-08-020
Data Response

To:	CALSSA
From:	Joint IOUs
Witness:	Brad Heavner
Request Date:	June 22, 2021
Due Date:	July 7, 2021

Q4: Please explain in detail all the ways, if any, the 2021 ACC alters any of the conclusions made in your Opening Testimony. If the 2021 ACC update does alter your testimony in any way, produce a redlined version of your Opening Testimony demonstrating what has changed.

A4: The 2021 ACC does not alter CALSSA's conclusions.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

California Solar & Storage Association Response to
The Joint IOUs Data Request-05

General Statement

The California Solar & Storage Association ("CALSSA") hereby objects and responds to the information requests ("Requests") to CALSSA from Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas and Electric Company (collectively, the "Joint IOUs") on June 24, 2021 in R.20-08-020. CALSSA expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses, including objections not listed below. Notwithstanding any of the following objections, and without waiving these objections, CALSSA responds in good faith to the Requests after a diligent search and reasonable inquiry. Further, in responding to the Requests, CALSSA hereby reserves:

- Its rights to produce and provide additional documentary evidence based on information, evidence, or analysis hereafter obtained or evaluated; and

- The right to update and/or supplement the responses provided herein if and when additional evidence, which is responsive to the applicable Requests, becomes available and, at any time, if it appears that inadvertent errors or omissions have been made.

Pursuant to the Instructions in the Requests, these responses have been transmitted via email to the following recipients: Rebecca Meiers-De Pastino (Rebecca.Meiers.DePastino@sce.com), Andre Ramirez (Andre.Ramirez@sce.com), Steven Frank (Steven.Frank@pge.com), Jane Oliveira (jop1@pge.com), Greg Barnes (Gbarnes@sdge.com), and William Fuller (Wfuller@sdge.com).

CALSSA
Rulemaking 20-08-020
Data Response

To:	CALSSA
From:	Joint IOUs
Witness:	Brad Heavner
Request Date:	June 24, 2021
Due Date:	July 9, 2021

Q4: On pg. 110 CALSSA says "It is CALSSA's expectation that the utilities will soon file applications with residential fixed charges that include customer outreach plans sufficient to satisfy the Commission's rate design principles." If the utilities file such an application, will CALSSA support this application?

A4: CALSSA would not oppose fixed charges that comply with Public Utilities Code Section 739.9.

CALSSA
Rulemaking 20-08-020
Data Response

To:	CALSSA
From:	Joint IOUs
Witness:	Brad Heavner
Request Date:	June 24, 2021
Due Date:	July 9, 2021

Q5: If future rate changes impacting all customers cause a reduction in solar bill savings for NEM 1 and 2 customers, will CALSSA refrain from requesting legacy treatment for NEM 1 and 2 customers?

A5: CALSSA would not seek legacy treatment for NEM-1 and NEM-2 customers to exempt them from fixed charges that are approved for all residential customers and comply with Public Utilities Code Section 739.9.

The Solar Energy Industries Association and Vote Solar Response to Joint IOUs Fourth Set of Discovery Requests in R.20-08-020

1. If the Commission adopts the 2021 ACC update, confirm or deny if SEIA/VS will supplement its Successor Tariff proposal and Opening Testimony to reflect the 2021 ACC.

   Response: It is the intent of SEIA and Vote Solar to address the 2021 ACC in their rebuttal testimony to be submitted on July 16, 2021.

2. Provide all documents presently in your custody, possession and control reflecting any and all analyses of your Successor Tariff Proposal using the 2021 ACC update.

   Response: As of the date of the response to this data request, SEIA and Vote Solar have not undertaken an analysis of their Successor Tariff Proposal using the 2021 ACC update.

3. Provide an updated version of all of SEIA/VS's workpapers with 2020 ACC values replaced with 2021 ACC values.

   Response: In Response to Data Request SDG&E 1, SEIA and Vote Solar provided the Joint IOUs the workpapers supporting their proposal for a successor tariff as presented in their June 18, 2021, testimony. SEIA and Vote Solar have not updated their workpapers to replace the 2020 ACC values with the 2021 ACC values and, pursuant to the rules of discovery, are not obligated to undertake that exercise.

4. Please explain in detail all the ways, if any, the 2021 ACC alters any of the conclusions made in your Opening Testimony. If it does alter your testimony in any way, produce a redlined version of your Opening Testimony demonstrating what has changed.

   Response: See response to Question 1.

5. Does your testimony propose any changes to your March 15 filed proposal? If your response is yes, please provide a list of changes and a redline of your March 15 proposal.

   Response: The only substantive change to SEIA and Vote Solar proposal reflected in their June 18 testimony in comparison to their March 15 proposal is the addition of the recommendation that the Commission allow all NEM customers to access critical peak pricing (CPP) rates. See Prepared Direct Testimony of R. Thomas Beach at pp. 74-76.

Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison (Joint IOUs)
Net Energy Metering Successor Tariff proceeding
R. 20-08-020
Data Request

To:	Solar Energy Industries Association-VoteSolar (SEIA-VS)		
Recipient Name:			
PG&E Data Request No.:	JointIOUs_SEIA-VS_005		
PG&E File Name:	NetEnergyMetering_DR_JointIOUs_SEIA-VS_005		
Request Date:	June 23, 2021	PG&E	Jane Oliveira
Due Date:	July 8, 2021		

Question: The following questions pertain to the testimony of Thomas Beach

As an initial matter please note that the testimony of R. Thomas Beach was submitted on behalf of the Solar Energy Industries Association and Vote Solar. Accordingly, we assume that all references to SEIA in the below questions are references to SEIA and Vote Solar.

Q 1: On page 6, SEIA notes a customer should be allowed to oversize and net surplus should be compensated at value set in 2020 ACC. Does SEIA propose that Net Surplus Compensation in 2023 should be based on the 2020 ACC, or whatever the most recent approved ACC is at the time?

Response: Page 40 of the SEIA-Vote Solar proposal makes clear that we are proposing "a reform of the rate for net surplus compensation so that it is set equal to current avoided costs for DERs." Current avoided costs for DERs would be the most recently approved ACC. Consistent with this proposal, our March 15 proposal calculated NSC rates using the 2020 ACC.

Q 2: Does SEIA agree that its proposal would raise rates for non-participating customers?

Response: Yes, the SEIA/ Vote Solar proposal would raise rates for non-participants for several years. This rate impact will decline over time due to the use of electrification rates with lower off-peak rates, the adoption of more valuable solar-plus-storage systems, and the decline in export rates that SEIA/Vote Solar have proposed. It is important to place these rate impacts into the context of (1) the larger societal benefits of solar and solar-plus-storage systems, (2) the fact that a similar level of above-market costs would have resulted if utility-scale solar had been developed instead of distributed solar, (3) the growing customer demand for resilient solar-plus-storage systems, (4) the fact that other distributed energy resources (DERs) that reduce or shift electric usage, such as energy efficiency and demand response, also raise rates for non-participants, and (5) the fact that non-participant impacts will present less of an equity issue if the Commission expands programs that work to provide equitable access to DERs for all ratepayers. SEIA and Vote Solar strongly support such programs, such as the Vote Solar / GRID Alternative / Sierra Club proposal in this case.

Q 3: Is the witness aware of the TOU legacy rate provisions approved in the Peak Electricity Usage Patterns OIR (R.15-12-012)? Please elaborate on what engagement, if any, the witness had in this proceeding.

Response: Yes. Mr. Beach as the technical consultant that advised SEIA on its position and participation in R. 15-12-012.

Q 4: Please explain your understanding of whether or not PG&E's updated non-residential TOU rates (B1/6/10/19/20) are now, or have been, mandatory for customers not subject to solar legacy treatment.

Response: It is SEIA's and Vote Solar's understanding that PG&E's updated non-residential TOU rates (the B-series rates, B1/6/10/19/20) are now mandatory for customers who are not subject to solar legacy treatment. There was a period of time after the approval of these rates in D. 18-08-013 when these rates were optional; for most schedules this optional period ended in March 2021.

Q 5: On page iv, Mr. Beach states "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." Please provide all arguments, reports and analysis, supporting that statement

Response: The arguments, reports and analysis supporting this statement are presented in Mr. Beach's testimony at page 22, line 6, to page 23, line 14. In general, if California has not developed 10 GW of distributed solar, it would have had to procure a comparable amount of utility-scale renewables in order to meet both the state's RPS requirements and California's long-term goals to reduce greenhouse gas emissions.

Q 6: page 5: ", 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." Please admit or deny that electrification is beyond the scope of this OIR, that it is not a requirement of AB 327, and that it is not a principle listed by the CPUC in D.21-02-007

Response: Deny. Electrification is an overarching policy goal of the state and is a key strategy for meeting the state's goals to reduce greenhouse gas emissions. There are a number of CPUC proceedings, including this one, that will determine the technologies that customers will adopt in order to electrify the state's economy. As a result, how the outcome of this case contributes to the state's electrification efforts is a central issue in this case. One of the principles listed by the CPUC in D.21-02-007 is that a successor to the net energy metering tariff should be coordinated with the Commission's and California's energy policies – which include electrification.

Q 7: page 14: "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". Is it your testimony that the TRC is the appropriate test to evaluate different NEM program designs for compliance with 2827.1(b)(4)?

Response: It is not Mr. Beach's testimony that the TRC test is the only appropriate test to evaluate different NEM program designs for compliance with 2827.1(b)(4). It can be one of the tests, along with the Participant test and the RIM test.

Q 8: p. 45: "costs and benefits for non-participants are in alignment by 2027." Is it your testimony that if export compensation were 50% of retail rate for PG&E and SDG&E and 75% of retail rate for SCE that bill savings would equal avoided costs? What is the assumed retail rate for each IOU and the assumed avoided cost in 2027?

Response: Yes, it is Mr. Beach's opening testimony that, if export compensation were 50% of retail rate for PG&E and SDG&E and 75% of retail rate for SCE, bill savings would equal avoided costs in 2027. The assumed retail rate is the January 1, 2021 retail rate escalated at 3.4% per year to 2027. The assumed avoided cost is the 2020 ACC avoided cost for 2027, applied to representative solar and solar-plus-storage output profiles.

Q 9: p. 47: "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)." Do all customers have "reasonable access" to energy efficiency programs? What is your definition of "reasonable access"? What percentage of residential non-CARE and CARE customers respectively does SEIA expect will be participating in a DG program in 2030?

Response: "Reasonable access" to a DER means that a customer can acquire, use, pay for, and realize lifecycle benefits from the DER based on the information, knowledge, capital, and cash flow available to the customer. SEIA and Vote Solar are aware that approximately 5% of CARE customers and 10% of non-CARE customers have adopted solar today (see Table IV of the Vote Solar / Sierra Club / Grid Alternatives proposal). We would like to grow and to equalize these percentages over time – for example, to reach a goal of 20% of both CARE and non-CARE customers having adopted solar or solar-plus-storage by 2030.

Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison (Joint IOUs)
Net Energy Metering Successor Tariff proceeding
R. 20-08-020
Data Request

To:	Solar Energy Industries Association-VoteSolar (SEIA-VS)		
Recipient Name:			
PG&E Data Request No.:	JointIOUs_SEIA-VS_007		
PG&E File Name:	NetEnergyMetering_DR_JointIOUs_SEIA-VS_007		
Request Date:	June 24, 2021	PG&E	Jane Oliveira
Due Date:	July 9, 2021		

As an initial matter please note that the testimony of R. Thomas Beach was submitted on behalf of the Solar Energy Industries Association and Vote Solar. Accordingly, we assume that all references to SEIA in the below questions are references to SEIA and Vote Solar

1: On pg.6 of appendix RTB-4, SEIA argues that bill savings realized by existing solar customers will be lower in the future, as “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.”

A. Does SEIA support eliminating tiered rates?

Response: SEIA and Vote Solar are not taking a position regarding the elimination of tiered rates in this proceeding. We note that Public Utilities Code Section §739 requires a tiered residential rate with a baseline tier for a certain quantity of electricity. Thus, absent a statutory change, tiered rates cannot be eliminated.

B. Does SEIA support requiring all customers to take service on a rate such as PG&E’s EV2 or E-ELEC?

Response: SEIA and Vote Solar assume that the question is referring to residential customers as commercial and industrial customers are not eligible to take service under PG&E’s EV2 or E-ELEC. SEIA and Vote Solar are not taking a position in this proceeding as to whether all of PG&E’s residential customers should be required to take service on PG&E’s EV2 or E-ELEC Rate. SEIA has supported evolving residential default rates toward electrification rates, at a pace more rapid than PG&E or PAO have proposed – see SEIA’s position on residential rate design in A. 19-11-019, the PG&E GRC Phase 2 case.

C. Regardless of SEIA’s support for this change to rate design, in what year does SEIA expect this transition to an “electrification rate” to occur?

Response: The referenced sentence from Appendix RTB-4 is addressing NEM 1.0 and NEM 2.0 customers. SEIA and Vote Solar are not attesting that the transition of all NEM 1.0 and 2.0 customers to an electrification rate will occur in one specific year. We expect that this transition will occur gradually, as NEM 1.0 and 2.0 customers choose electrification rates (as discussed on pages 38-39 and 61-62 of the SEIA/Vote Solar testimony), and as default TOU rates evolve to more closely resemble electrification rates – for example, with high peak-to-off-peak (POP) rate differences.

D. If the utilities proposed that a rate design resembling E-ELEC or EV2 be mandatory for all residential customers, would SEIA support this proposal?

Response: SEIA and Vote Solar are not taking a position in this proceeding as to whether a rate design resembling E-ELEC or EV2 should be mandatory for all residential customers.

2. On pg.6 of appendix RTB-4, SEIA claims it expects 25% of existing NEM 1.0 and 2.0 customers will install storage. When does SEIA expect this adoption rate to be achieved? If available, please provide an annual forecast of storage adoption by existing NEM 1.0 and 2.0 customers.

   Response: The adoption rate would be achieved over time, possibly by 2030, with a more rapid adoption rate if there are significant incentives for these customers to adopt storage in conjunction with electrification rates.

3. The provided workpaper “NEM 1-2 Cost Shifts Going Forward.xlsx” links to a file with the path " Z:\Solar Alliance\Net Metering 3 point 0\RTB Workpapers Mar-21\Bill Savings and Avoided Costs - Summary and Analysis.xlsx”, which does not appear to be included in the provided workpapers. Please provide this file or indicate which previously provided file this refers to. In addition, the “Cost Shifts Going Forward” file has hardcoded avoided cost estimates. When updating this workpaper to use the approved 2021 ACC, please retain the reference to the workpaper in which this avoided cost estimate was calculated.

   Response: The cited file is part of the workpapers for the SEIA – Vote Solar March 15, 2021 proposal, which have already been provided to the Joint IOUs. In preparing the SEIA / Vote Solar opening testimony, we did not update this workpaper to use the 2021 ACC, and we have not done so to date.

4. Is it your contention that there are no societal costs from rooftop solar? If that is not your contention, what societal costs did you not include in your analysis?

   Response: There could be societal costs from rooftop solar, as discussed on page 24 of the SEIA – Vote Solar testimony.

5. Has SEIA estimated the annual value of the property tax exemption given to solar energy systems in California? If so, please provide this estimate along with any supporting calculations and data.

   Response: SEIA and Vote Solar have not done such an estimate. SEIA and Vote Solar observe that the revenues lost to the state from the property tax exemption are offset by additional tax revenues and user fees associated with the economic activity resulting from California’s transition to clean energy and its place as a national leader in solar deployment and the home to many solar companies that are active in markets outside of California. We also observe that the property tax exemption for residential solar only applies in the initial years after solar is added to a property. Once the property is sold and re-assessed for property tax purposes, the re-assessment will capture the higher value of the property associated with the solar addition, and property taxes will begin to be collected on the solar installation. Given that the average U.S. home is sold every 13 years (see https://www.nar.realtor/blogs/economists-outlook/how-long-do-homeowners-stay-in-their-homes), this indicates that the property tax exemption applies, on average, only for the first 6.5 years of a system's life.

Attached is a study that SEIA prepared for Kern County that show the tax and user fee revenues for that county associated with utility-scale solar development in Kern County. The tax and user fee revenues associated with distributed solar will be different than for utility-scale projects, but they also will be significant for jurisdictions with substantial levels of solar deployment.

6. #65 - Assuming the cost shift is the difference between bill savings and avoided costs, is it your testimony that the cost shift is reduced 40% simply by switching PG&E NEM customers from E-TOUC to EV2?

   Response: That reference was to the impact of both PG&E and SDG&E NEM 3.0 residential customers using electrification rates; it was not specific to PG&E.

7. #71 – On p. 37 you state "Overall, electric use will be expanding, so in the end the growth of all types of DERs will benefit ratepayers". Please provide quantitative evidence or analysis to support the statement that as load grows all types of DERs are beneficial to all ratepayers.

   Response: Some DERs will grow loads (EVs, heat pumps); other DERs will shift loads placed on the grid out of more costly TOU periods (storage); some DERs will reduce loads on the grid (EE, DR, and solar). If the overall impact of all DERs is to grow loads, all ratepayers will benefit from the incremental revenues. It is critical not just to adopt DERs that build loads, for these reasons: (1) it remains important to use energy efficiently, (2) distributed generation provides substantial societal benefits and is important as a hedge against complete reliance on utility-scale generation delivered by high-voltage transmission, (3) there is significant customer demand to be able to produce a portion of their electricity on-site, as an alternative to grid power, and (4) distributed solar is necessary to charge on-site storage to provide resilient electric service.

8. #72 – On p. 40 you state "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." Is it SEIA's contention that the state should discourage energy efficiency as a means to make rooftop solar systems more economic for participants?

   Response: No, SEIA and Vote Solar are not making such a contention. California should continue to pursue energy efficiency programs whose benefits exceed program costs. The referenced testimony is addressing a means to advance the state policy of electrification by incenting customers, for example, to purchase electric cars and residential heat pumps that displace fossil fuels (gasoline and natural gas). Customers will be more likely to purchase such DERs if they can produce economically a portion of the off-peak power needed to fuel these DERs from their own on-site solar.

9. #73 – On p. 42 SEIA contends it is "critical…to focus on growth of solar + storage systems", including "assessing the economics of these systems for participants". Does SEIA agree that the only element of its proposal meant to encourage storage adoption is the electrification rate? Does SEIA agree that its proposal shows a longer economic payback for solar plus storage?

   Response: No, we do not agree that the only element of our proposal meant to encourage storage adoption is the electrification rate. Other elements of our proposal that support storage adoption include: (1) recognizing and quantifying the resiliency benefits of solar plus storage systems, (2) the proposed gradual decline in the export rate, which encourages the use of storage to increase on-site use of the solar output, (3) our assumption of and support for a continuing SGIP incentive for storage.

   SEIA and Vote Solar agree that, due to the higher capital cost of solar plus storage systems, our proposal shows a longer payback for solar plus storage systems compared to solar systems. That said, our proposed paybacks for solar plus storage are far shorter than those proposed by the Joint IOUs, as shown in Figure 13 of our testimony.

10. #75 – On p. 71 SEIA indicates the Utilities have no data on how much power is actually generated behind the meter, and therefore the GBC would overestimate this charge. Has SEIA approached its member organizations or would SEIA be willing to in order to provide this data to utilities for accurate measurement of BTM generation? If so, please provide such data.

    Response: SEIA has not approached its member organizations nor would it be willing to approach its member organizations for data regarding customer generation behind the meter. SEIA as a member organization must be mindful of antitrust laws. It does not collect competitively sensitive information from its member organizations. SEIA also observes that solar companies generally do not have access to generation data from customer-owned systems. Finally, the meters that record customer generation may not be revenue-grade meters in terms of their accuracy.

11. Provide all calculations and support for SEIA's proposal to allow new solar customers to oversize their systems by 50% (page 40, lines 3-5). Provide all estimates of increased consumption as a result of household electrification by household appliance.

    Response: The 50% oversizing contemplates a scenario where a typical residential customer using 7,500 kWh per year plans to add an EV that consumes 3,750 kWh per year. A system that is 50% oversized would allow the customer to supply 11,250 kWh per year, which is enough to cover both the household use and the EV.

SEIA has not studied in detail the incremental consumption from the use of heat pumps for space or water heating, but is aware that these DERs also can add thousands of kWhs per year to a home's electric consumption, displacing natural gas. The 50% oversizing would allow a solar customer to oversize their system to handle adding one of these DERs in the future (i.e. one EV, one heat pump water heater, or one heat pump HVAC sysem), but probably no more. SEIA's and Vote Solar's proposal that any annual net surplus generation from an oversized system would be priced at current avoided costs means that non-participating ratepayers will be indifferent to the oversizing.

DATE: **June 25, 2021**

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Request No: SDG&E Data Request 8 (JOINT-IOU-SEIA-VS-08) **Due Date: July 12, 2021**

SDG&E is providing this data request on behalf of the Joint-IOUs. Please provide the following information as it becomes available but no later than the due date. If you are unable to provide the information by this date, please provide a written or verbal explanation why the response date cannot be met and your best estimate of when the information can be provided. Please electronic mail all responses that can be transmitted electronically. If attachments cannot be electronically transmitted, please notify myself (gbarnes@sdge.com) and Will Fuller (wfuller@sdge.com) via e-mail or phone and arrangements will be made for the transmittal of said attachments.

As an initial matter please note that the testimony of R. Thomas Beach was submitted on behalf of the Solar Energy Industries Association and Vote Solar. Accordingly, we assume that all references to SEIA in the below questions are references to SEIA and Vote Solar

REQUEST:

1. On page 18 of the Opening Testimony of Witness Beach, SEIA states "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." Please explain how an individual residential customer's solar plus storage installation maintains essential electric service to the benefit of all customers.

   Response: The solar plus storage installation of a residential customer can maintain electric service during a prolonged grid outage. This will benefit other neighboring customers, who can use their neighbor's available power for essential services like charging cell phones or using the refrigerator to store perishable medications. The neighbor with power also will be a source of up-to-date information that may not be accessible to neighbors whose internet routers lack power. The extreme weather, wildfire, or natural disaster situations that cause prolonged grid outages are situations in which people lend a helping hand to their neighbors.

2. Is it SEIA's contention that, during an outage, an individual residential customer with solar plus storage on one circuit that does not export power provides benefits to customers on different circuits?

   Response: By definition, if the grid is out, a solar-plus-storage customer will not be exporting power. As discussed above, a customer with a solar-plus-storage system will benefit neighboring customers. Those customers are likely to be on the same circuit but could be on a different circuit that also is out, depending on the geometry of the circuits in that neighborhood.

3. On page 68 of the Opening Testimony of Witness Beach, SEIA states, "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." Please provide evidence to show that NEM customers do not use the utility grid.

   Response: The only time when a NEM customer uses the grid is when their meter is running forward. NEM customers are not using the grid at times when they are not taking power from the grid. In other words, the evidence that a NEM customer is not using the grid is the fact that a NEM customer's meter is not running forward. As discussed in Mr. Beach's testimony, at page 69, when a NEM customer exports power, the NEM customer is not using the grid: "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. 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."

4. On page 69 of the Opening Testimony of Witness Beach, SEIA states, "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." Please provide evidence that NEM customers are paying the full cost of service.

   Response: Whether solar customers are paying the full cost of service will depend on the cost that they pay for the service that they receive from the utility, as measured by the imported power delivered by the utility, not by the solar customer's net usage (i.e. imports minus exports). NEM customers pay the same rates as non-NEM customers for the service that they receive from the utility. So long as NEM customers have load profiles and cost characteristics for imported power that are within the range of the customers of the class as a whole, they can be assumed to pay their full cost of service. Not every customer contributes exactly 100% of the cost of service.

5. On page 10 (Witness Beach), SEIA states "Customer-owned solar generation can supply 100%, or more, of a customer's electric use with on-site renewable generation." Please clarify whether SEIA means that customers self-supply 24 hours a day, 7 days a week, 365 days a year, or if they still rely on the grid to

export excess generation and import power when they are not self-generating. If SEIA means solar generation can supply 100% of gross usage, please provide supporting workpapers and analysis.

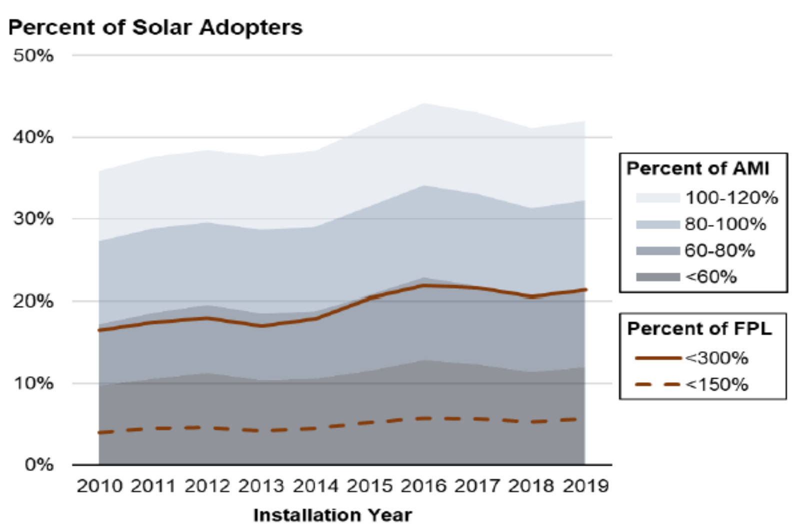
Response: SEIA means that customers rely on the grid to import power when their self-generation is not adequate to serve 100% of their on-site load.

6. The cost shift calculated by the utilities represent utility bills not paid by NEM customers that other customers pay for, regardless of any alleged societal benefits. Is it SEIA's contention that it is appropriate for non-participating customers to pay, for example, $245 more per year in SDG&E's service territory than they would without the NEM program?

   Response: The question is unclear on the exact circumstances assumed in the statement that non-participating customers are paying "$245 more per year in SDG&E's service territory than they would without the NEM program." SEIA and Vote Solar have made clear that they believe that the Joint IOU cost shift calculations are exaggerated and that the Joint IOUs would have incurred similar above-market costs even in the absence of rooftop solar. See the SEIA / Vote Solar testimony, at pages 62-63 and Attachment RTB-4. Moreover, SEIA and Vote Solar agree that the NEM program needs to change, and that a successor tariff should be adopted that reduces the impacts of rooftop solar adoption on non-participating ratepayers.

7. On p. iii of Witness Beach's testimony, SEIA states 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)." Please provide all analysis and workpapers that support this statement.

   Response: See the Lawrence Berkeley National Lab data below, showing that about 40% of solar adopters have incomes below 120% of the Area Median Income (AMI). From LBNL, *Residential Solar-Adopter Income and Demographic Trends: 2021 Update* (April 2021), at Slide 17. Available at https://emp.lbl.gov/publications/residential-solar-adopter-income-and.



Solar Adoption Trends by Income (LBNL)[vi]

Also see Figure 3-8 of the NEM 2.0 Lookback study, reproduced below, which shows that more than 50% of new rooftop solar systems are being installed by middle- and low-income households (incomes up to $99,000). The median household income in California in 2015-2019 was $75,235, in 2019$. See https://www.census.gov/quickfacts/fact/table/CA/INC110219. 120% of this median is about $90,000.

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FIGURE 3-8: PERCENT OF SYSTEMS INSTALLED BY MEDIAN INCOME BRACKET BY YEAR

California-specific deployment numbers are available from LBNL at https://emp.lbl.gov/solar-demographics-tool . Select "Percent of AMI" as the metric, choose 120% of AMI and then click on CA.