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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

R.20-08-020
(Filed August 27, 2020)

JOINT REPLY BRIEF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39-E),
SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), AND
SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

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<u>Citation to the record transcript:</u> [witness surname, if applicable], T. [page number(s)]: [line number(s)] (date). *E.g.*, Tierney, T. 210:22-211:2 (July 27, 2021).

<u>Citations to Prepared Testimony</u> identified as exhibits in this case shall use the party initials and exhibit numbers assigned by the ALJ. Cite as follows: Ex. [party abbreviation] [exhibit number] ([witness surname]) [page:line number(s) and/or footnote number]. *E.g.*, Ex. IOU-2 (Morien) 47:17-21 and n. 136. Note that the cited page numbers omit any associated initials. Citation to witness panels will show only the lead witness surname, followed by "et al."

<u>Citation to Other Record Exhibits</u>: other items identified as exhibits will use the party initials and exhibit number assigned by the ALJ. *E.g.*, Ex. [party abbreviation] [exhibit number], [exhibit title, if referenced ([date], if any)] [page number(s) if applicable]. *E.g.,* PCF-15, Net-Energy Metering 2.0 Lookback Study ("Lookback Study") (Jan. 21, 2021), pp. 32-33.

<u>Citation to Opening Briefs:</u> [Party Abbreviation] Brief p. (or pp.) __. *E.g.,* IOU Brief p. 5.

SUMMARY OF RECOMMENDATIONS

Pursuant to Commission Rule of Practice and Procedure 13.12, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (collectively, the Joint Utilities) provide the following summary of their recommendations in this proceeding.

- Reject the solar parties' proposals for the reasons discussed in Section II of this reply brief, which include the fact that these other proposals do not meaningfully address the cost shift that is harming non-participating customers.
- Reject parties' criticism of the Joint Utilities' proposal for the reasons discussed in Section III of this reply brief, which include that the Joint Utilities' proposal is the most effective at addressing the requirements of Federal and State Law and addressing the Commission's Guiding Principles for this proceeding.
- Adopt some, but not all, of the joint recommendations of the Independent Parties as discussed in Section IV of this reply brief and as summarized below:
  - With respect to export compensation rates, the Commission should:
    - compensate exports based on the avoided cost calculator, preferably using an amount updated annually or, in the alternative, using a rolling-two-year average updated annually.
    - not set export compensation rates based on a day-ahead or real-time rate; and
    - not lock-in export compensation rates for 10 years following interconnection.
  - With respect to the Grid Benefits Charge, the Commission should adopt a Grid Benefits Charge at the high end of the range recommended by the Independent Parties.
  - With respect to the equity provisions proposed by some, but not all, of the Independent Parties, the Commission should reject that aspect of the parties' proposal.
  - With respect to the interim tariff recommended by the Independent Parties, the Commission should reject it for being impractical, furthering the cost shift and distracting the marketplace from the more important matter of getting a replacement tariff in place as soon as possible.

* * *

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I. INTRODUCTION AND OVERVIEW OF THIS REPLY

Pursuant to Commission Rule of Practice and Procedure 13.12, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (collectively the "Joint Utilities") provide this joint reply brief responding to the opening briefs that were filed in the above-captioned matter on or about August 31, 2021.

This reply focuses on the ultimate issue in this proceeding, which is addressed in Scoping Issue 5: "*Which of the Analyzed Proposals Should the Commission Adopt as a Successor to the Current Net Energy Metering Tariff and Why?*" Accordingly, our reply is organized as follows:

First, in Section II, we address the various proposals that the Commission should summarily reject. Those proposals are unsupported by law and fact. Many of them misrepresent or minimize the cost shift, and therefore fail to mitigate it. Others would draw out the cost shift for years in the name of "gradualism." Many of these proposals also are premised on purported benefits of customer-sited distributed generation that either (a) are already accounted for in the Commission's avoided cost calculator, or (b) do not exist.

Next, in Section III, we explain why the Commission should adopt our proposed Reform Tariff. The criticisms leveled by other parties against our proposal are unsupported by the record evidence. Rather, the evidence reflects that our proposal is necessary to, and best at, ensuring just and reasonable rates.

Finally, in Section IV, we respond to the Joint Recommendations offered by the "Independent Parties."[1] The Joint Utilities were not invited to, and had no part in, the negotiation or preparation of the Independent Parties' recommendations. The Joint Utilities respond to these recommendations here for the first time. The Independent Parties' recommendations are referred to herein as the "Independent Recommendations."

In summary, the Commission should adopt the Joint Utilities' proposed Reform Tariff. It remains the best proposal on the record to satisfy the requirements of Federal and State law, as well as the Commission's Guiding Principles for this proceeding. While the Independent Recommendations are also a laudable effort at reform and a step in the right direction, the Joint Utilities' proposal is more effective in meeting the objectives for reform that will serve all customers' interests.

II. ISSUE 5: THE COMMISSION SHOULD REJECT THE SOLAR PARTIES' PROPOSALS BECAUSE THEY DO NOT COMPORT WITH LAW AND ARE UNSUPPORTED BY THE EVIDENTIARY RECORD

A. Proposals that Fail to Address the Cost Shift Do Not Comport with AB 327's Requirements

The Commission's decision on the principles that will guide its determination in this proceeding clearly holds that AB 327 addresses cost shifts.[2] Likewise, Guiding Principle B requires all consumers to pay a fair share for the grid services they use. Except with respect to some arguments regarding non-residential commercial customers (see Section II.A.3 below), parties agree that the cost shift is real. The only true controversy before the Commission is thus one of degree.[3] Proposals that fail to effectively mitigate the cost shift, including, for example,

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[1] The "Independent Parties" comprise Cal Advocates, CalWEA, CUE, IEP, NRDC, and TURN.

[2] D. 21-02-007, p. 39, Findings of Fact (FOF) 32.

[3] *See, e.g.,* SEIA/VS Brief, p. 8 ("[SEIA/VS] agree that the Study illustrates the need for reform of the current NEM structure in the residential market. There seems to be little debate on this point among parties to this proceeding. There also does not appear to be any debate that reduction of the impact of solar adoption on non-participating ratepayers should be addressed through the successor tariff. The controversy among the parties lies with the scope and degree of the necessary change and how fast these changes should be implemented.")

those made by SEIA/VS, CALSSA, PCF, Foundation Windpower and Ivy Energy therefore should be rejected.

1. CALSSA and SEIA/VS's Gradualist Proposals Amplify and Perpetuate the Cost Shift

As the Joint Utilities explained in the Legal Framework section of our Opening Brief,[4] California's implementation of NEM allows NEM customers to avoid non-generation related charges and receive excess compensation for their exports. The utilities must collect from other customers the delta between what NEM customers owe and what they actually pay. In that regard, the utilities' revenue recovery is not directly affected by NEM. The Joint Utilities' interest in this proceeding is to promote affordable rates for all customers by proposing to end the unfair and unreasonable electric rates customers pay because of the NEM subsidy. Affordability is likewise a driving concern for a diverse group of parties, including Cal Advocates, NRDC, TURN and others, because, at least in part, affordability plays a critical role in advancing the state's energy and environmental goals. Without reforms, increasing rate pressure is expected to amount to over $500 per year for most non-participating non-CARE customers by 2030.[5]

As established in our Opening Brief, parties representing the corporate interests of the solar industry, including publicly held companies like Sunrun and Tesla, benefit from perpetuating the NEM subsidy. These parties make no attempt to propose a successor tariff that addresses the cost shift, much less mitigates, or eliminates it. Similarly, their proposals fail to meaningfully further any of AB 327's requirements or the state's equity or energy and environmental policy objectives. Instead, their proposals, at their core, promote delay.

California created the NEM program in 1996 and it has not been meaningfully altered or reformed for 25 years. Four years after AB 327's deadline for meaningful reform, SEIA/VS still

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[4] IOU Brief p. 10.

[5] Ex. IOU-01 (Pierce et al.) 70, Table III-8 (reflecting non-CARE customer impact) and 73, Table III-9 (reflecting CARE customer impact).

ask the Commission for another 13-year delay before fully implementing so-called reform that would still have non-participating customers paying significantly more for NEM exports than they are worth.[6] To make matters worse, SEIA/VS propose to multiply the problem by providing a 20-year legacy treatment for each export compensation step.[7]

Nothing in the record or law supports departing from the clear legal requirements of AB 327 or ignoring its statutory mandates for another 13 years. SEIA/VS and CALSSA's gradualism is not a plan to avoid abrupt or overnight change. They have had a 25-year glide path. The time for reform has long passed. The Commission should reject these parties' request that the Commission perpetuate the inequity caused by the current NEM program.

2. PCF's Analysis of the Magnitude of the Cost Shift is Incorrect

PCF claims that the Joint Utilities' cost shift analysis wrongly "focus[es] … on bill savings that NEM customers receive as a result of consuming energy from their on-site systems" and concludes that "customer bill savings reflect nothing more than lost utility revenue from customers' decreased use of grid-supplied energy."[8] PCF misses the fundamental cause of the cost shift -- it is not bill savings from energy consumption, but the fact that such savings consist of far more than the cost of energy.[9] The cost shift from participating to non-participating

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[6] The overpayment is based upon the estimated export value proposed by SEIA/VS and the Commission-approved ACC values. *See, e.g.*, SEIA/VS Brief p. 19, Figure 2.

[7] SEIA/VS Brief pp. 109-110.

[8] PCF Brief p. 8.

[9] While the Lookback Study (Ex. PCF-15) does not attempt to analyze the components of the cost shift it identifies, the Commission's affordability report sums the fundamentals of the cost shift well:

> At a high level and in the specific context of the NEM program, NEM creates costs shifts because the bill savings, or compensation, that NEM customers receive for their behind-the-meter generation exceeds the value that the solar generation provides to the system. In addition, the export compensation structure of NEM, coupled with the volumetric pricing structure of residential rates, allows NEM customers to avoid both fixed and variable costs incurred by the utility to serve them. Both the overcompensation for exported excess generation and the costs that NEM customers avoid are recovered via higher electricity rates from non-participating customers, including lower-income customers.

customers is the result of two key components of the NEM tariff design: non-participating customers overcompensate NEM customers for their exports,[10] and non-participants pay for the infrastructure and public policy costs that NEM customers avoid.[11]

As for PCF's characterization of the Lookback Study as finding a $500 million cost shift, PCF apparently sums each utility's post-NEM bill payments minus cost of service from the Lookback Study.[12] However, a deeper analysis of the Lookback Study finds a cost shift of $1 billion, based on customer impact.[13] The source of PCF's cost shift number arises from several limits in the Lookback Study.

First, the Lookback Study looks only at NEM 2.0 customers prior to 2020, while the Joint Utilities' $3.4 billion cost shift estimate includes all customers who have adopted through mid-2021, providing a more accurate picture of the pace of adoption and the urgent need for reform.[14] Stated another way, the Joint Utilities' calculation includes all NEM customers, not just NEM 2.0 customers. PCF obscures the magnitude of the cost shift when stating, "By comparing costs of service to aggregate customer payments, the Lookback Study finds that, in 2019, the cost of serving NEM customers exceeded their bill payments by $500 million."[15] PCF fails to

California Public Utilities Commission, "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), pp. 27-28*; see also*, for instance, December 6, 2012 Residential Rate Principles, stating: "Rates should be based on cost causation."

10 Export compensation is tied to retail electricity rates, meaning NEM customers are overcompensated for the value their resource provides to the grid – a situation that will worsen due to anticipated future increases in retail rates over time. Ex. IOU-01 (Pierce et al.) 66:3-6, 66:12-67:5.

11 Residential NEM customers can bypass payment of infrastructure and other costs incurred to serve them, because such costs are embedded in volumetric rates and avoided by NEM customers, requiring other customers to make up the difference. Ex. IOU-01 (Pierce et al.) 66:7-11, 67:6-68:4.

12 Ex. PCF-15, Lookback Study, Table 5-10.

13 The Lookback Study states: "The NPV of RIM costs exceed the RIM benefits by approximately $13,000 m." Ex. PCF-15, p. 79. Translated to an annual impact, this would be over $1 Billion in cost shifting per year, consistent with our estimate for NEM 2.0 installations of the same vintage. Ex IOU-01 (Pierce et al.) 81, n. 128.

14 Ex. IOU-01 (Pierce et al.) 64:3-66:11.

15 PCF Brief p. 8.

acknowledge the important limitation that the Lookback Study's calculation applies only to NEM 2.0 customers and only goes through 2019, and therefore, accounts for only a fraction of total NEM customers.

Second, PCF focuses on the Lookback Study's comparison of adopting customers' bills to a hypothetical "cost of service" calculation. While the results are directionally the same for residential customers, this comparison is distinct from the Joint Utilities' calculation, which is based on total bill savings. Cost of service can be informative, but, in this context, it does not provide the full picture of the actual cost shift. Accounting for total NEM customer bill savings is important because those bill savings are what drive increases to rates from NEM.

Third, the Lookback Study uses the 2020 ACC, while Joint Utilities use the more current 2021 ACC.

With respect to the limits in the study's cost of service analysis, PG&E's recent GRC Phase 2[16] showed that NEM customers typically have a different (and higher) cost of service.[17] The Lookback Study's analysis does not account for this higher cost of service, and only compares their average customer class "cost of service" calculation to post-adoption customer bills. While customer rates are *based* on cost-causation and cost of service, actual retail rates can differ from cost of service for policy reasons.[18] Even if NEM customers actually paid an approximation of their cost of service, they still would shift costs to non-participating customers due to their bill savings. Therefore, using a cost of service analysis to estimate the NEM cost shift does not provide a complete picture; a more complete way to estimate the cost shift is to compare total customer bill savings (NEM) vs. no bill savings (no NEM). The Joint Utilities' cost shift calculation does just this.

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16 A.19-11-009.

17 Ex. IOU-01 (Kerrigan) 112:7-12.

18 Such policies include, *e.g.*, having the commercial customer class pay a higher proportion of cost of service than residential customers through equal-cent-kWh allocation of costs deemed to be in the public good.

3. Assertions Regarding the Lack of a Cost Shift Created by Non-Residential Customers Are Unsupported by the Record

ACEA/Farm Bureau, Foundation Windpower, SEIA/VS, and Walmart argue non-residential customers are not causing a cost shift based on the Lookback Study's finding that non-residential customers pay their cost of service.[19] The Lookback Study's cost of service calculations capture rate design and revenue allocation policy choices, but they do not indicate that there is no cost shift attributable to all NEM customers.[20]

In addition, Foundation Windpower's position that wind customers produce no cost shift and therefore should remain on NEM 2.0 is also misguided. Its conclusion is based upon its expert's modeling of a single scenario of a subset of customers using the outdated 2020, not current 2021, ACC.[21] Despite Foundation Windpower's claims, neither the Lookback Study nor E3's findings support such an assertion. CALSSA similarly asserts that the E3 Whitepaper stands for the proposition that the successor tariff should be the same as the NEM 2.0 tariff for commercial and agricultural customers,[22] but this is not supported by the E3 Whitepaper. Rather, as the Joint Utilities' witness Kerrigan testified, *all current rates result in cost shifting according to the 2021 ACC.*[23]

Accordingly, these parties provide the Commission with no foundation upon which to grant a request to maintain NEM 2.0 for all non-residential customers.

B. Proposals that Rely on the TRC Test and the 2020 ACC to Assess Cost Effectiveness Fail to Account for the Cost Shift as Required by AB 327

The Commission's Guiding Principles decision noted that under D.19-05-019, the Total Resource Cost (TRC) test is the primary cost-effectiveness test but that the Commission would also review the results of the RIM and PCT tests to assess the cost effectiveness of party

[19] AECA Brief p. 2; FWP Brief p. 8; SEIA/VS Brief p. 10; WAL Brief pp. 6-8.

[20] The Joint Utilities' rebuttal testimony, Ex. IOU-02, addresses other arguments made by these parties that large customers should remain on NEM 2.0. Ex. IOU-02 (Kerrigan) 85:1-92:11.

[21] FWP Brief p. 6.

[22] CALSSA Brief p.103.

[23] Kerrigan, T. 290:4-8 (July 27, 2021).

proposals.[24] As the Joint Utilities have consistently explained, the TRC test has little, if any, value here.[25] The TRC test does not consider the cost to non-participants, i.e., the cost shift, which is what AB 327 requires the Commission to address as a matter of law.[26] It is not the case, as SEIA/VS assert, that "[t]he 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."[27] Instead, the TRC ignores the cost-effectiveness of a DER from the perspective of a non-participating customer and merely allows for the comparison of the cost of NEM facilities to utility-scale solar.

The better measures to use in evaluating the proposals in this proceeding are the RIM test and the PCT. The RIM test looks at the cost-effectiveness of a program from the non-participating customer perspective, and the PCT test looks at the cost-effectiveness of a customer program from the participating customer perspective. AB 327's focus on the cost shift requires the Commission to use both the RIM and PCT tests and balance their outcomes in a way that favors the customer-sited renewable generating facility industry sustaining its own viability.

SEIA/VS criticize E3's RIM test results but fail to recognize that the E3 inputs and assumptions are applied uniformly to all party proposals. In that regard, E3 and the Commission have created a level playing field in which any infirmities affect all parties, which is why no party's proposals pass the RIM test, but better proposals score higher.

SEIA/VS continue to not only advocate for the TRC test, but also the TRC test using the outdated 2020 ACC values. The Commission has adopted the 2021 ACC. It is therefore the ACC

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24 D.21-02-007, p. 36.

25 The TRC test, when applied to all party proposals, produces the exact same score for all proposals, despite the diversity of proposals, with no proposal passing or even outperforming others. That outcome indicates that the TRC is not equipped to accurately assess the cost effectiveness of a program like NEM, which requires an assessment of costs to non-participants and participants.

26 D.21-02-007, p. 39, FOF 31; p. 32 ("AB 327 addresses cost shifts.").

27 SEIA/VS Brief p. 12, n. 20.

applicable to this proceeding.[28] SEIA/VS and CALSSA have testified that they are not making a collateral attack on the Commission's 2021 ACC decision[29] but that is precisely what they are doing when they refuse to discuss their proposal in the context of the currently applicable ACC.[30] CALSSA and Windpower's proposals suffer from the same infirmity. By refusing to provide a cost effectiveness analysis using the current and applicable 2021 ACC, their experts' testimony is incomplete, and not comparable to the evidence proffered by virtually all other parties to support their proposals. The Commission should thus evaluate all proposals on a level playing field using the cost effectiveness tests that satisfy AB 327's requirements -- the RIM and PCT tests -- with the 2021 ACC values.

C. Proposals that Rely on Inaccurate Assessments of the Benefits of NEM Systems Conflict with AB 327's Requirements and Should Be Rejected

The Commission should reject SEIA/VS's argument that "distributed solar and solar + storage systems provide important additional benefits for the ratepayers and citizens in the IOU service territories that are not included in the avoided costs used in many of the [Standard Practice Manual] tests."[31] The Commission similarly should reject SEIA/VS and CALSSA's contention that the ACC does not capture all the benefits of NEM systems to customers and the electrical system.[32]

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[28] Even if the Commission felt it could abandon its current ACC in favor of a stale version, the 2020 ACC was a flawed and anomalous outlier, while the 2021 ACC is more accurate and consistent with past ACCs. *See* Ex. NRD-02 (Chhabra) 8:7-13 (describing errors in the 2020 ACC); Chait, T. 1659:8-19 (Aug. 6, 2021).

[29] *See, e.g.*, Ex. SVS-04 (Beach), 13:19-21 ("That said, Vote Solar and SEIA recognize that the Commission has made its decision, and this case is not the venue for challenging the Resolution E-5150 or for litigating ACC issues.")

[30] SEIA/VS Brief, p. 12 (advocating for their proposal using 2020 ACC by stating that "Through analysis presented in its opening testimony, SEIA and Vote Solar demonstrated, using 2020 ACC values, that both solar and solar + storage pass the TRC test, with an average TRC ratio of benefits to costs over the period 2022 to 2030 of 1.30 for solar and 1.23 for solar + storage."); p. 19 (analyzing their proposed export compensation stepdown using the 2020 ACC).

[31] SEIA/VS Brief p. 11.

[32] SEIA/VS Brief p. 7.

Neither SEIA/VS nor CALSSA's testimony[33] attempt to quantify these purportedly overlooked benefits or offer a principled basis for calculating a value for such adders. Instead, CALSSA asks the Commission to "consider any TRC and RIM score above 0.9 to be cost-effective" based on these unquantified benefits. That request is the practical equivalent of CALSSA asking the Commission to assign any value to these benefits that will manufacture cost effectiveness where none otherwise exists. If the Commission were to grant SEIA/VS and CALSSA's request, the Commission would be engaging in arbitrary and capricious decision making that could threaten the viability of the final decision.

The purported benefits that SEIA/VS and CALSSA contend the SPM tests and ACC omit do not exist and thus provide no cognizable benefit to the system or non-participating customers. For instance, as discussed in the Joint Utilities' Opening Brief, the Commission and the CAISO, respectively, already rejected the purported resiliency and transmission deferral benefits that continue to be promoted by SEIA/VS and CALSSA.[34] Therefore, proposals such as SEIA/VS and CALSSA's that rely on such non-existent benefits to support their cost-effectiveness should be rejected.

1. The Evidence Does Not Show that the NEM Subsidy Promotes Conservation, Electrification, Land Use, and Energy Efficiency

The Commission should reject SEIA/VS's contention that the Lookback Study finds that the NEM subsidy promotes conservation behavior, electrification, land use, and energy efficiency.[35]

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33 Ex. CSA-01 (Heavner, et al.) 82:6-10 ("Key elements are missing from the TRC and RIM tests that the Commission should include as benefits. DERs provide benefits for land conservation, avoidance of uncalculated future transmission needs, and community resilience. These are concrete impacts but are difficult to measure. Also missing from the Commission's cost-benefit analysis are the impacts of electrification on "lost" utility revenues from DER energy production. Because of these factors, the Commission should consider any TRC and RIM score above 0.9 to be cost-effective.")

34 Ex. IOU-07, R.14-08-013, et al., Reply Comments of the … [CAISO] (Aug. 23, 2019), pp. 3-5.

35 SEIA/VS Brief pp. 10, 104-105.

a. **The Record Does Not Show that NEM Promotes Conservation**

As SEIA/VS describe, "the Lookback Study shows that, on average, the residential NEM 2.0 solar customers in PG&E's and SDG&E's service areas increased their electric usage by about 30% after adding solar."[36] Increasing usage after installing solar panels, however, does not show that NEM customers are engaging in conservation as some parties contend.

b. **The Record Does Not Show that NEM Promotes Electrification**

The record shows that without reform the NEM program will actually frustrate, not promote, electrification because of the upward pressure NEM puts on rates and the affordability of electricity.[37] Notably, other than to contest E3's 4% rate escalation figure, SEIA/VS virtually ignore affordability concerns for non-participating customers. Like SEIA/VS, CALSSA avoids addressing how the NEM cost shift affects affordability and how affordability in turn affects electrification. CALSSA's affordability discussion focuses on the cost of transmission and distribution (T&D) investments without acknowledging the impact of NEM on rate design.[38] Similarly, when CALSSA discusses low-income customers, its focus is on the ability to adopt solar, not the burdens of affordability for those who cannot or will not adopt solar. CALSSA also attempts to divorce electrification from affordability and the NEM cost shift with the assertion that the "Commission should reject arguments that there is a conflict between electrification and NEM-supported solar adoption for lower-income customers."[39] The record evidence, however, does not support separating the issue of electrification from the NEM subsidy.

In fact, the opposite is true. Indeed, this is the reason Sierra Club supports measures that reduce operational costs [rates] of electric appliances and vehicles compared to fossil-fueled alternatives[40] — something that should be considered for all customers.

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36 *Id*.

37 Ex. IOU-01 (Tierney) 1:4-20, 15:8-31, 56:4-13, 60:7-13; Ex. IOU-02 (Tierney) 4:5-5:10, 12:4-13:20, 19:3-13 (explaining why the cost shift harms California's electrification agenda by keeping electricity prices higher than they would otherwise be absent the NEM subsidy).

38 CALSSA Brief pp. 4-5, 51.

39 CALSSA Brief p. 79.

40 Sierra Club Brief p. 4.

c. The Record Evidence Does Not Show that NEM Reduces Land Use for Utility-Scale Resources

As for land use, CalWEA's witness, Dr. Dariush Shirmohammadi, provided data demonstrating that NEM actually increases the need for utility scale resources and land use.[41] Although the proposition may sound counterintuitive, it is supported by factual analysis and data.[42]

No party, including CALSSA, SEIA/VS, or PCF, has come forward with evidence that is sufficient to rebut CalWEA's findings. The Commission should therefore adopt CalWEA's analysis and reject the notion that NEM promotes land use conservation.

d. The Commission Should Reject Comparisons to Purported Benefits of NEM and Energy Efficiency

The Joint Utilities' witness, Susan Tierney, testified at length in opening and rebuttal testimony about why NEM does not confer the same or even similar benefits as energy efficiency.[43] SEIA/VS offer only a collateral argument against Dr. Tierney's testimony, arguing that because the RIM test is not applied to energy efficiency upgrades there is no way to test, and no basis for, Dr. Tierney's assertion that "NEM, unlike EE measures, creates a persistent, regressive transfer of wealth from middle and lower-income customers to wealthier customers."[44] For the reasons detailed in Dr. Tierney's rebuttal testimony, there is no cost shift associated with the installation of *permanent load reducing* energy efficiency fixtures,[45] which is why the TRC, not the RIM, test is used to assess the cost effectiveness of energy efficiency upgrades. Dr. Tierney's expert testimony discusses other distinctions between the costs and

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41 CalWEA Brief pp. 4-5.

42 *Id*.

43 Ex. IOU-02 (Tierney) 124:21-130:16 (explaining all the reasons why NEM does not provide benefits like EE and that any comparison between the two is without merit.)

44 SEIA/VS Brief p. 25 (complaining that EE is not subject to the RIM test to assess the merit of Ms. Tierney's assertions).

45 Ex. IOU-02 (Tierney) 124:21-130:16 (explaining all the reasons why any analogizing NEM to EE is without merit.)

benefits of energy efficiency and NEM.[46] The Commission, therefore, should reject these arguments attempting to make comparisons where none exist.

2. Resiliency Benefits Are Not Substantiated for Cost Effectiveness Analysis

As discussed in the Joint Utilities' Opening Brief, the Commission already rejected SEIA/VS's resiliency arguments in the Integrated Distributed Energy Resource (IDER) proceeding. SEIA/VS attempt to distinguish their resiliency argument here stating: "SEIA and Vote Solar are not contending that the resiliency benefit is an avoided cost to the utility that should be included in the ACC – which was the issue before the Commission in the IDER proceeding."[47] The Commission should reject this distinction without a difference.

SEIA/VS are asking the Commission to create a resiliency benefit adder for the purpose of assessing cost-effectiveness. This is the precise role of the ACC. SEIA/VS assert that they are not asking for NEM customers to be compensated for this benefit; rather, they ask the Commission to take this benefit into account in adopting SEIA/VS's gradualist proposal.[48] That is, include resiliency in the cost/benefit balancing test that cost effectiveness is designed to measure.

The Commission's decision adopting the 2021 ACC accounts for all discernable benefits the Commission deems reasonable to incorporate into the cost effectiveness analysis. No additional, unquantified benefits should be added, much less ones the Commission already has rejected.

3. The Record Evidence Does Not Support a Finding that NEM Defers Transmission Upgrades, Reducing Customer Costs

CALSSA and PCF argue that the CAISO has found that distributed generation has deferred transmission, and that the value of this deferral is a benefit of NEM that should be

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46 *Id*.

47 SEIA/VS Brief pp. 25-26.

48 SEIA/VS Brief p. 29.

applied as an offset against the cost shift.[49] PCF also uses the most expensive transmission line in the state's history as an example, to assert a value for deferred transmission.[50] Both premises supporting this transmission benefits argument are unproven.

While the CAISO study cited by CALSSA and PCF acknowledges that distributed generation can affect system peak,[51] it does not support assigning any value to transmission as an offsetting NEM tariff benefit. Both parties cite the planning study for the proposition that the cancellation of certain sub-transmission projects in PG&E's service area was driven by the growth of distributed generation.[52] Responding to an almost identical solar industry characterization of the subject study in another Commission proceeding, the CAISO set the record straight:

> Although the review focused on projects that were primarily load driven, SEIA erroneously attributes project cancellations only to recent decreases in load forecasts, which it in turn erroneously assumes to be solely driven by growth in DERs. However, the impact of DERs is more nuanced, and the transmission project cancellations were driven by a number of factors. For example, the growth in DERs, particularly behind-the-meter solar, have a pronounced impact on the transmission grid as flow patterns change from traditional patterns and frequency throughout each day. In other words, the effects of solar behind-the-meter generation tend to have a one-time effect of pushing demand down in the middle of the afternoon and moving the daily peak load to later in the day, when additional solar generation no longer reduces demand. Further, although some of the changes in flow patterns led to declining gross peak loads, loads remain high after sunset and the increasing load variability results in more widely varying voltage profiles. This causes an increased need for reactive control

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[49] CALSSA Brief p. 48; PCF Brief p. 16-21.

[50] PCF Brief pp. 16-21.

[51] PCF Brief, pp 18-20, *citing*, Ex. PCF-04, CAISO, 2017-2018 ISO Transmission Plan (March 22, 2018) pp. 3-4, 17 n. 11. Note that PCF-04 was not admitted for the truth of the matter asserted, but only as it relates to cross examination within the transcripts. ALJ Hymes, T. 1138:20-1139:3 (August 3, 2021). Therefore, it is improper to cite the exhibit for the truth of the matter asserted, as PCF does in its brief, especially without acknowledging the limited purpose for which Judge Hymes admitted the document.

[52] PCF Brief pp. 18-20; CALSSA Brief, p. 48, *citing* Ex. PCF-01 (Siegele) 4:5-8, which in turn cites the CAISO planning study subsequently identified as PCF-04.

> devices to maintain acceptable system voltages. Other reasons for project cancellation include Commission siting decisions and the availability of more effective and economic solutions. Lastly, as the CAISO noted in previous comments, energy efficiency and load-modifying DERs are already embedded in the California Energy Commission forecast which the CAISO uses in the transmission planning process.[53]

In sum, the CAISO did not find that PG&E cancelled certain sub-transmission projects due to the growth of rooftop solar. Indeed, the CAISO points to the "increasing load variability" from DER growth causing an "increased need for reactive control devices" – *i.e.*, a need for *increased* grid investment. In any event, "load-modifying DERs are already embedded" in the CAISO planning, so the subject transmission cancellation cannot be attributed to DER growth. For these reasons, the Commission should disregard the suggestion that any transmission cost savings from the cited cancellation should be attributed to DER.[54]

PCF cites SDG&E's Sunrise Powerlink 500 kV transmission line to provide an illustrative calculation of the value of distributed generation in deferring specific transmission projects, claiming that, if this project had been replaced by distributed generation, each distributed 6 kW NEM system would have avoided over $1,000 per year in transmission costs.[55] The record proves the illustration both disingenuous and inapposite. PCF's position ignores that the Sunrise Powerlink was approved as a reliability project – that is, to keep the lights on, and

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[53] Ex. IOU-07, R.14-08-013, *et al., Reply Comments of the … [CAISO]* (August 23, 2019), pp. 3-4 (citations omitted). On cross-examination, CALSSA's witness was shown Ex. IOU-07, and did not dispute the authenticity of the document or the accuracy of the CAISO's reply. Heavner, T. 1189:8-1192:28 (August 3, 2021).

[54] PCF, at p. 13 of its Opening Brief, claims that these cancelled projects translate to annual transmission savings of over $600 per year per each distributed generation system in PG&E's service territory, *citing* Ex. PCF-24 (Powers) 37.

[55] PCF Brief pp. 13 and 20, *citing* Ex. PCF-24 (Powers) 40 Table 8. It is noteworthy that PCF's witness Powers testified in SDG&E's application to the Commission for approval of the Sunrise Powerlink (A.06-08-010), and proposed customer-funded 2,040 MW of rooftop solar PV as an alternative to the project. See D.08-12-058, pp. 38-39. Is this a reprise of Mr. Powers' rejected proposal of thirteen years ago?

not based on access to renewables.[56] And, PCF selects for its illustrative calculation the most expensive transmission project in the state's history.[57]

The Commission should reject these efforts to offer a value for transmission allegedly displaced by rooftop solar alone. The record does not support a finding of such displacement. Moreover, there is a value for transmission and distribution in the ACC, and the Joint Utilities' proposal uses the ACC for export compensation. The ACC values have been recently and robustly litigated on this precise point, and the ACC is adjusted annually. This proceeding is not the place to relitigate those values.

4. The RPS Procurement Benefits Do Not Comport with the NEM Legal Framework

SEIA/VS's comparisons of NEM to RPS are a red herring.[58] For the reasons explained in the Joint Utilities' Opening Brief,[59] NEM exports generally cannot be treated as energy or capacity supplied to the grid or to reduce RPS obligations. Only net surplus compensation eligible exports at the end of the annual period qualify for RPS and, even then, the utility cannot know in advance how much surplus energy the NEM customer will provide. NEM customers therefore do not supply capacity to the Joint Utilities and are not legally required to deliver any

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[56] D.08-12-058, p. 290, Conclusions of Law (COL) 4: "Sunrise is the best solution to meeting SDG&E's current and future resource and reliability needs." PCF conceded on cross that Sunrise was not approved for the purpose of access to renewable energy. Siegele, T. 975:4-9 (Aug. 2, 2021). Nonetheless, it is true that Sunrise imports substantial quantities of renewable generation. See, Ex. PCF-01 (Siegele) 5:11-12 (Sunrise imports over 1000 MW of renewable energy). While PCF's illustrative calculation is inapposite, if it had been honest, it would have offset its asserted DER value with the value of the more efficient large-scale renewables that Sunrise imports. *See* Ex. IOU-01 (Tierney) 36:10-37:3. Indeed, statewide, the export compensation NEM customers receive is eight times the price utilities could procure the same power in the market. Ex. IOU-01 (Pierce et al.) 67:3-5 and n. 111.

[57] D.08-12-058, p. 290, FOF 44: "Sunrise is one of the largest and most complicated transmission projects in California's history." The Commission can take official notice that 500 kV transmission is the most expensive in terms of cost per mile, and that it comprises a small percentage of the states' transmission mileage – transmission constituting lines of 60 kV and above.

[58] SEIA/VS Brief pp. 97-98.

[59] IOU Brief pp. 6-18, 97.

energy to the utilities. As such, the record does not and cannot support the proposition that NEM has saved non-participating customers from incurring any above-market RPS costs.

D. The AB 327 "Sustainably Grows" Requirement Does Not Justify Proposals that Continue a Subsidy Paid for by Non-Participating Customers

SEIA/VS attempt to create the impression that the NEM subsidy is necessary to sustain the growth of DERs. This impression should be rejected, and for the same reason, their proposal should be rejected as well. SEIA/VS consistently conflate the niche NEM-eligible facilities and DERs as one and the same.[60]

SEIA/VS characterize the Joint Utilities' rebuttal testimony as going "to great lengths to minimize the societal benefits of *distributed resources*."[61] This is a mischaracterization. The Joint Utilities' rebuttal testimony is narrowly tailored to rebut the exaggerated benefits of *NEM-eligible resources* claimed by parties representing the solar industry. This proceeding is not evaluating the benefits of all DERs.

The Commission can take official notice of the existence of numerous other proceedings that are directing the procurement of DERs and developing customer programs to promote their adoption. Those proceedings have resulted in an array of policy directives to support the adoption of solar, storage, DERs, and electrification.[62]

In addition to the Commission's proceedings, and as discussed in our Opening Brief,[63] the CEC's Title 24 mandates support the solar and paired storage industry such that it is neither necessary nor reasonable to perpetuate the massive wealth transfer to ensure self-sustaining growth of customer-sited renewables.

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60 *See, e.g.*, SEIA/VS Brief pp. 14-16 (discussing the societal benefits of DERs as though NEM facilities and DERs are one in the same).

61 SEIA/VS Brief p. 30 (emphasis added).

62 Ex. IOU-01 (Peterman), 4:6-23, 10:8-13:20, 30.

63 IOU Brief p. 66.

CALSSA and SEIA/VS speculate that the Title 24 mandates will be eliminated if the CPUC adopts a proposal that is not cost effective.[64] That speculation is without merit.[65] First, CALSSA and SEIA/VS ask the Commission to adopt their proposal, which, if analyzed using the current 2021 ACC, does not have a TRC or RIM score greater than 1.0. Presumably these scores would not be "too narrow a margin upon which the CEC can predicate its Title 24 mandate."[66] Yet if the Commission adopts other proposals that similarly score less than 1.0, CALSSA and SEIA/VS assert the mandate is threatened. These parties cannot have it both ways.

Second, the citation upon which SEIA/VS rely for their assertion does not support their hypothesis. The CEC explained that even compensating exports at avoided cost would maintain cost effectiveness.[67] The full quotation is as follows:

> Question 10: The Energy Commission used only the current net energy metering, known as NEM2, rules to determine cost effectiveness for the onsite PV systems. NEM2 will be up for review by the California Public Utilities Commission (CPUC) in 2019. Did the Energy Commission consider alternatives to the current NEM2 policy?
>
> Answer: Yes, the Energy Commission examined three net energy metering scenarios: (1) the current NEM 2.0 systems; (2) ***an alternative that significantly reduces bill savings for PV hourly exports to the grid (avoided cost instead of retail cost)***; and (3) a case where all generation is credited only with avoided costs – a highly unlikely scenario. Under the first two scenarios, all systems were cost effective by large margins. Under the third scenario, PV

64 See, e.g., SEIA/VS Brief pp. 106-107.

65 Indeed, based on Sunrun's representations to its investors that a PV system has a 35-year useful life, homebuyers will find the solar systems on Title 24 homes to be attractive. *See* Sunrun, Inc., *Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934*, (February 25, 2021) p.27. The typical residential mortgage is 30 years, so the solar system will be financed as part of the home purchase, and its useful life will continue after the mortgage is paid off.

66 Heavner, T. 1084:13-1085:2 (Aug. 3, 2021).

67 Ex. SVS-05, 2019 Building Energy Efficiency Standards FAQs, p. 7, Question and Answer 10, available at: https://www.energy.ca.gov/sites/default/files/2020-06/Title24_2019_Standards_detailed_faq_ada.pdf (emphasis added). (accessed Sept. 11, 2021)

> passed the cost test in 5 of 16 climate zones and narrowly failed in the others.[68]

As detailed in the legal framework section of the Joint Utilities' Opening Brief, the plain language of the statute requires the Commission to adopt a successor tariff that addresses the cost shift, ensures benefits to the system and all customers, and requires the solar rooftop market to sustain its own viability.[69] No party has posited any plausible standard under which the CEC will terminate the Title 24 mandates. These mandates will help the solar and solar + storage industry to sustain its own viability without a continued inequitable cost shift.

In addition to rejecting conjecture about the future of the Title 24 mandates, for the reasons explained in the Joint Utilities' Opening Brief, the Commission should also reject SEIA/VS's interpretation of AB 327's "grow sustainably" requirement that relies on legislative history, as opposed to the unambiguous language of the statute.[70]

The Commission should adopt the Joint Utilities' construction of the "grow sustainably" requirement because it complies with the rules of statutory interpretation, is in accord with the overall reform objectives of the entire statute, maintains harmony with the internal subparts of Section 2827.1, and is consistent with the English language and rules of grammar. The Commission should therefore find that its legal obligation is to ensure that the continuing growth of the solar industry is self-sustaining.

As SEIA/VS's Opening Brief concedes, the goal of its proposal is not to satisfy all of Section 2827.1's requirements, but rather "is tailored to promote the continued growth of the residential market for renewable DG."[71] Elsewhere throughout the brief, SEIA/VS discuss NEM in the context of sustaining the solar industry, *i.e.*, providing the sustenance for the industry's

68 *Id.*

69 IOU Brief pp. 19-20.

70 SEIA/VS Brief pp. 74-76.

71 SEIA/VS Brief p. 76.

survival.[72] It advances that goal by disguising a proposal to maintain the status quo as one for gradual change that even when concluded still overcharges non-participating customers by 50% for NEM energy exports. That is not what AB 327 contemplates or authorizes. The solar industry has already enjoyed a 25-year glidepath. The time for reform is now.

1. NEM Reform in Hawaii Did Not Cause the Industry to Crash

SEIA/VS cite other states that have reformed their NEM programs to argue that reform will cause the industry to crash in California. However, the representations SEIA/VS make about those states are inaccurate. For instance, SEIA/VS claim that other states that have shifted their NEM policy to reduce or eliminate inequitable cost shifts, such as Hawaii, have dramatically negatively impacted the solar market.[73] The assertions about Hawaii are contradicted by SEIA/VS's own witness, Mr. Guise. Figure 12 in his direct testimony shows year-on-year growth in solar capacity in Hawaii since 2015.[74]

Indeed, Hawaii's Public Utilities Commission fully considered what they were doing when they reformed NEM and explained their sound and well-reasoned decision making, stating:

> [T]he commission believes it is unrealistic to expect that the high growth in distributed solar PV capacity additions experienced in 2010-2013 time period can be sustained, in the same technical, economy and policy manner in which it occurred….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 hopefully becomes a key

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72 *See, e.g.*, SEIA/VS Brief p. 82 ("Installations of 150 MW per year will not sustain the California solar market.")

73 SEIA/VS Brief pp. 76-77.

74 For a detailed discussion on Hawaii, see Ex. IOU-02 (Tierney), 38:13-41:20.

> contributor to Hawaii's grid modernization, and most importantly as a consequence, customers are compensated by the utility for the grid value created."[75]

The Commission should arrive at the same conclusion here.[76]

2. SEIA/VS and CALSSA's Gradualist Approach to Reducing Export Compensation Will Not Promote the Paired Storage Market

SEIA/VS claim the Commission must not create economic barriers to paired storage systems because the Commission cannot achieve equilibrium between the AB 327 mandates without incentivizing paired storage.[77] As SEIA/VS assert, the only way to satisfy AB 327's mandate is "if the successor tariff allows the industry to move away from one primarily reliant on standalone solar installations to one primarily reliant on solar + storage."[78]

Solar industry witnesses Heavner and Beach concede reducing export compensation incentivizes paired storage.[79] The fact that the 2021 ACC results in what CALSSA describes as a massive reduction in export compensation[80] is evidence that the compensation NEM customers receive for exports today far exceeds its actual value – a problem AB 327 requires the Commission to address. Yet, SEIA/VS and CALSSA's gradualist proposals do not reduce export compensation enough to provide a meaningful incentive for customers to install paired systems.

AB 327 does not require the Commission to continue any subsidy or cost shift. However, to the extent one is continued, it should incentivize paired storage systems. The Joint Utilities'

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[75] Ex. IOU-02 (Tierney), 39:1-41:20 (quoting a Hawaii Public Utilities Commission decision).

[76] Ex. IOU-02 (Tierney), 15:17-19:13 (discussing affordability concerns); 41:3-20 (discussing why California needs more aggressive reform and the proposed Reform Tariff structure, which includes a GBC); see also Ex. IOU-02 (Peterman) 3:1-4:14 (discussing affordability); Ex. IOU-01 (Tierney), 41:3-42:16 (same).

[77] SEIA/VS Brief pp. 2-3.

[78] SEIA/VS Brief p. 2.

[79] Ex. IOU-02 Appendix B on page B-16, SEIA/VS Witness Beach Response to Data Request Question 9 (stating that "the proposed gradual decline in the export rate, which encourages the use of storage to increase on-site use of the solar output."); Ex. CSA-02 (Heavner et al.) 2:10-12, (stating that "all proposals that reduce export compensation encourage energy storage.")

[80] CALSSA Brief p. 107 (noting that the 2021 ACC "export compensation rates would be reduced from current levels by 81% (PG&E), 68% (SCE), and 84% (SDG&E), respectively for residential solar customers.")

proposal does that: it incentivizes paired storage by reducing export compensation to be more consistent with avoided costs. SEIA/VS and CALSSA's gradualist approach fails to address the over-valuing of exports and fails to incentivize storage. Their proposals should be rejected.

E. The Commission Should Reject Community Solar and VNEM Proposals that Are Unlawful and Perpetuate an Unlawful Cost Shift

The community solar and VNEM proposals presented to the Commission are not viable. GRID Alternatives[81] proposes community solar arrangements that implicitly allow for the communal generation be to be oversized – that is, the proposals permit generation to have an output larger than the customer load.[82] They also would maintain NEM 2.0 for qualifying customers. CCSA's community solar proposal would permit customer subscription to any qualifying projects in a utility service area. It also sets a specific eligibility limit that could allow substantial oversizing by relying on individual subscribers' up-front estimates or evidence of 12 months of historic usage with no provision for ongoing monitoring of customer load.[83] Ivy Energy explicitly proposes to maintain the current VNEM compensation structure and the attendant cost shift implications.[84]

These proposals have the following common elements – they each: (1) propose to permit (implicitly or explicitly) generation to be oversized in violation of state and federal law as detailed in our Opening Brief;[85] (2) do not require the generation to be sited near, or directly

[81] GRID Alternatives, Vote Solar and Sierra Club filed a joint brief. For brevity, we refer herein to the joint brief as the GRID Brief. Note that, pertinent to the following discussion, SEIA/VS essentially adopts the GRID Proposal B for community solar. Note that Sierra Club also submitted a separate brief, which is not referenced here.

[82] GRID Brief pp. 19, 28-31; SEIA/VS Brief pp. 92-93, endorsing the GRID proposal. Both proposals are limited to defined disadvantaged communities.

[83] CCSA's Opening Brief did not set forth the particulars of its proposal, but instead referred the reader to its opening testimony. CCSA Brief p. 8. CCSA's proposal is subscription-based, with eligibility extended to all customers in a utility service territory. Fifty percent of subscribers must be residential or small commercial customers, and subscription size is limited to "12 months of historic usage," or, if that information is unavailable, an estimate of load. See Ex. CCS-01 (Smithwood) 19:20-22:11.

[84] IOU Brief (pp. 120-121) anticipated and addressed Ivy's specific criticisms of Joint Utilities' VNEM proposals.

[85] *See* IOU Brief pp. 10-14 (explaining the net consumer requirement and limitation on oversizing).

connected to, load;[86] and (3) propose customer compensation that would exacerbate the cost shift.[87] As a result, these proposals do not qualify for NEM treatment and would violate AB 327 by increasing -- rather than mitigating -- the cost shift.

1. Federal and State Law Require Net Billing Systems to Be Onsite and Sized to Load

The Joint Utilities' Opening Brief details the pertinent law, and we will not repeat that explanation here.[88] In sum, the statutes and implementing Commission decisions establish:

- NEM reform must abide by federal law and Commission decisions requiring that NEM customers be net energy consumers to avoid implicating federal jurisdiction. That is, the generation serving the customer must be sized to avoid net exports after customer consumption.[89]
- California's NEM implementation in effect overcompensates customers as compared to what would be allowed under federal law, reflecting areas ripe for reform.[90]
- AB 327, the Ratepayer Reform Act, provides policy directives that require elimination of the cost shift.[91]

The community proposals made by GRID and CCSA would violate the law. Under NEM 2.0, sizing generation to exceed customer load increases net surplus compensation (NSC) and the resultant cost shift in proportion to the excess generation, thereby violating AB 327. With respect to generation sizing, the GRID Proposal B, which would retain NEM 2.0 customer compensation, is silent as to size of the generation; it merely refers to a "clean DG project" … "owned and controlled by the community."[92] Proposal B contains no siting, or participating

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86 IOU Brief pp. 116, n. 342.

87 IOU Brief pp. 18-21.

88 IOU Brief, pp. 5-21.

89 IOU Brief pp. 6-18.

90 IOU Brief pp. 9-10.

91 IOU Brief pp. 18-21.

92 GRID Brief pp. 29-31.

customer eligibility requirements (other than location in an ESJ community, along with implied residence in the community). It has no controls over generating unit proximity to customers, or any relation between generator output and customer demand.[93] Failing to specify such requirements leaves the proposal non-compliant with the siting and colocation requirements for NEM. The CCSA proposal would also violate the law by allowing a host customer to oversize their generator and sell the excess to other customers potentially hundreds of miles away at levels near the retail rates.[94]

2. Continuing NEM 2.0 for VNEM Violates AB 327

The Joint Utilities propose to continue to make VNEM available to appropriate customers, while revising the VNEM tariff to be consistent with the Reform Tariff proposal to mitigate the cost shift.[95] In contrast, other parties' explicit and implicit VNEM proposals in this proceeding would exacerbate the cost shift in violation of AB 327. As the Lookback Study established, and as 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.[96]

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[93] As discussed in our Opening Brief, based on the testimony of witness Campbell at the hearing, GRID's proposal would allow a project *anywhere* in the utilities' service to retain NEM 2.0, apparently requiring no proximity to the benefitting accounts. IOU Brief pp. 80-81 (citing Campbell, T. 1016:3-1017:22 and 1024:26-1025:3 (Aug. 2, 2021).

[94] Similarly, the CCSA proposal makes no attempt to link the project size (1 to 5 MW) to load, or even to a customer site. *See* CCS-01 (Smithwood) 19:20-22:11. As discussed in our Opening Brief, CSSA's netting proposal is also troubling, and does not avoid the legal issue attending net exports. IOU Brief p. 101 n. 314. Reinforcing the developer-centric nature of the CCSA "equity-focused" subsidy proposal is the fact that only one quarter of the subsidy goes to low-income participants: CCSA proposes that only 50% of the subscriptions for EJ adder-eligible projects be required to be low to moderate income, and developers are required to convey only 50% of the EJ adder to participants. That results in 25 cents on the dollar of that subsidy to low-income participants. Ex. IOU-02 (Kerrigan) 112:24-113:8. *See also*, Smithwood, T. 1700:7-1701:3, 1712:24-1714:1 (Aug. 6, 2021).

[95] Ex. IOU-01 (Kerrigan) 157:10-162:14.

[96] Ex. IOU-02 (Kerrigan) 108:24-109:4. *See* IOU Brief p. 119.

CCSA's proposal would appear to imply a VNEM arrangement[97] with customers, and would provide compensation near or at NEM 2.0 levels for qualifying customers, as Ivy Energy also proposes be maintained for VNEM generally. While our Opening Brief addressed the criticisms of their VNEM reform proposals,[98] it is worth reinforcing here that to maintain the existing NEM system for VNEM will exacerbate the cost shift, and the status quo thereby violates AB 327.[99] Such proposals therefore must be rejected.

III. ISSUE 5 (CONT.): THE COMMISSION SHOULD ADOPT THE JOINT UTILITIES' REFORM TARIFF

A. The Record Does Not Support Assertions Opposing the Joint Utilities' Proposal

Solar parties oppose the Joint Utilities' proposal, because it "will not only act as a barrier for sustainable growth in the solar industry in California but will inflict economic harm on those who do attempt to participate in the market."[100] We show below that these assertions are not true.

1. Customer-Sited Distributed Generation Will Continue to Grow Sustainably if the Joint Utilities' Proposal Is Adopted

Solar parties allege that adoption of the Joint Utilities' Reform Tariff will "act as a barrier for sustainable growth."[101] The Joint Utilities' brief shows that, based on robust experience from other states that have reformed NEM and industry trends confirmed by the solar industry, rooftop

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[97] Strictly speaking, D.20-08-007 (pp. 1, 2 n. 1, and 9, emphasis added) defines VNEM as providing for "for netting of energy from a single eligible renewable generation facility among … multiple customers or accounts behind multiple service delivery points and on multiple *contiguous* parcels (whether tax /assessor or legal) …." While the CCSA proposal does not explicitly identify VNEM or acknowledge the current contiguity requirement in the VNEM tariff, its proposal necessarily implies for implementation "netting from an eligible renewable generation facility among multiple customers or accounts behind multiple service delivery points and on multiple parcels."

[98] IOU Brief pp. 119-121.

[99] CCSA would adopt the ACC for NSC, but would add to that an explicit subsidy – the "EJ adder" - to customer compensation. Ex. CCS-01 (Smithwood) 31:5-38:7. This substantial adder to the NSC would, of course, exacerbate the cost shift. *See*, Smithwood, T. 1706:21-26 (CCSA's proposed "value stack" and possibly its "EJ aadder" will be paid for by nonparticipating ratepayers).

[100] SEIA/VS Brief p. 7. *See also* CALSSA Brief p. 4.

[101] SEIA/VS Brief pp. 55-56.

solar will continue to grow if the Reform Tariff is adopted.[102] We reply here to the solar parties' contention in their opening briefs that the payback periods[103] inherent in the Reform Tariff will stifle solar adoption.

In particular, CALSSA, focusing on the importance of payback, relies heavily on an adaptation of a solar adoption curve in a NREL study for the proposition that a seven-year payback is necessary to sustain the industry.[104] CALSSA asserts:

> [W]hile other factors may support customers investing in distributed energy systems, payback is by far the most important indicator of customers' willingness to invest and, therefore, the best indicator of whether a party's proposal will ensure 'customer-sited renewable distributed generation continues to grow sustainably'.[105]

But the cited NREL study does not support this conclusion.[106] CALSSA focuses on one aspect of the NREL study -- payback period. In fact, the NREL study indicates that monthly bill savings are the most important economic factor in households' decisions whether to adopt. See the following table from the NREL study (p. 6), which was not included in CALSSA's testimony or brief:

Table 3: Economic metrics used to evaluate solar investment

	Buyers	Leasers	Non-Adopters
Monthly bill savings	40.3%	60.5%	43.4%
Payback time	29.5%	16.1%	41.8%
Rate of return	17.1%	9.8%	6.3%
Net present value	2.2%	1.6%	3.5%
I would not estimate economics	3.0%	4.6%	3.7%
Other	7.8%	7.2%	1.4%

102 IOU Brief, pp. 31-39 (experiences in other states) and pp. 39-51 (industry trends).

103 Cal Advocates confirmed a useful definition for payback period, which represents "the time it takes for a customer to recoup the total installation costs of their PV system through their cumulative total annual bill savings." Gutierrez, T. 922:6-10 (August 2, 2021).

104 CALSSA Brief pp. 22-23. SEIA/VS Brief at 55-56 also cites this NREL study for this proposition.

105 CALSSA Brief p. 23.

106 Note that this NREL study was published in 2013 for a January 2014 conference. The data precedes AB 327 and reflects a much different market than today.

The NREL study's abstract says (p. 1):

> To better understand how the next wave of solar diffusion could occur, we explore the range of economic thresholds that households without PV would require to consider solar adoption, finding that these households require more attractive payback times by 1-3 years to achieve comparable market share as current adopters. In contrast, non-adopters indicate they would be satisfied with equal or lower returns when the benefits of solar are expressed in terms of their monthly bill savings—as is the case for third-party owned systems.

In examining the maturation of the solar market, the NREL study's abstract (*id.*) also states:

> Environmental concern, once a preeminent reason for adopting is decreasing in relative importance, whereas lowering total electricity costs and protecting one's household from future increases in prices are now the two more important reasons.

Finally, with respect to California, the study (p. 6) states:

> Concerns over high electricity bills, in addition to concern about future rate changes is [sic] often highlighted as a motivation for adopting solar—supported by our results, particularly in California which has some of the highest retail rates of the nation.

The record reinforces the primacy of customer bill savings as motivation to go solar. Cal Advocates endorsed an NREL study showing that 72% of solar adopters used monthly or annual electric bill savings as their motivating metric, while only 13.3% used the payback period.[107] Mr. Gutierrez observed:

> That 72% of solar adopters use monthly or annual electric bill savings shows that customers overwhelmingly do not use complicated metrics like payback period or internal rates of return to estimate the economic benefits of adopting solar – meaning they are not comparing solar to other forms of investment – but rather they are driven by a much simpler economic motivation to realize electric bill savings. Measurement of discounted payback periods, therefore, are overly complex and do not reflect customers' economic motivations for adopting solar.[108]

[107] Ex. PAO-02 (Gutierrez) 3-16:21-3-17:5. This NREL study from 2017 is more recent than the one relied on by CALSSA cited above. Ex. PAO-02 (Gutierrez) 3-17 n. 73.

[108] *Id.*, 3-15:5-11.

In sum, the Commission should disregard CALSSA's assertion that payback period is the customer's principal concern.[109]

2. The Estimated Payback Periods under the Joint Utilities' Proposal Are Reasonable

Notwithstanding that customers are more interested in the bill savings they will receive after installing solar, the payback periods estimated under the Joint Utilities' proposal are reasonable. Those that criticize the payback periods[110] ignore not only the bill savings that customers will continue to receive under our proposal, but also the estimated 35-year useful that a major solar manufacturer—Sunrun—represents for its solar systems.[111] The longest payback period under the Joint Utilities proposal is approximately half this useful life, and even less considering storage.[112] Given the useful life Sunrun reports, the payback periods under the Joint Utilities' proposal allow customers to recoup their investments long before their solar systems' useful life ends. Moreover, the increasing useful life that Sunrun reports, combined with the decreasing technology costs,[113] creates a double-win for customers.

[109] There is another reason to disregard CALSSA's assertions concerning the payback period, which it asserts are based on "the collective experience of its members," citing only to its prepared testimony. CALSSA Brief p. 20 n. 94, *citing* Ex. CSA-01 (Heavner et al.) 60:15-61:23. These same witnesses testified at hearings that they had no knowledge of CALSSA members' public representations concerning useful life of a PV system. Heavner, T. 1205:10-23 (August 3, 2021). Equipment service life is an important fact in this proceeding relating to sustainability, payback and appropriate cost horizons. See Sunrun, Inc., *Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934*, (February 25, 2021) p.27 (useful life of rooftop solar equipment is 35 years). It is not credible for a witness to testify to "collective experience" of CALSSA member companies with respect to customer expectations, but then to disclaim knowledge of the members' expectations or public representations for the useful service life for PV equipment. Accordingly, the Commission should disregard CALSSA's testimony and briefing relating to customer expectations related to payback periods.

[110] *See e.g.*, SEIA/VS Brief pp. 33-34; CALSSA Brief p. x.

[111] Sunrun, Inc., *Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934*, dated February 25, 2021 (Sunrun Form 10-K), p. 27 of which official notice was taken by the August 30, 2021 ALJ ruling

[112] Ex. IOU-01 (Morien) 105, Table IV-14.

[113] Ex. IOU-01 (Tierney) 36:8-43:2.

3. Use of the ACC to Set the ECR as Proposed by the Joint Utilities Is More Appropriate Than Measures Using Longer Forecasts

Solar parties propose the 25-year levelized value of exported energy from the ACC as a guide to set NEM export compensation as a percentage of rates. They argue that solar energy systems are a 25-year resource and, therefore, the correct levelization period in the ACC is 25 years.[114]

The Joint Utilities' proposal to use the most current ACC for export compensation comports with Section 2827.1: (3) and (4), helping to "[e]nsure that the standard tariff made available to eligible customer-generators is based on the costs and benefits of the renewable facility, and that the total benefits of the standard tariff to all customers and the system are approximately equal to the total costs." The proposal's reliance on one-year forward time-differentiated avoided costs, updated annually (rather than long-term avoided costs), as the basis for compensating exports, more closely aligns with a reasonable approximation of (a) the value of exports to the system over the course of a day and a season, and (b) the character of system benefits as they change from one year to the next.[115]

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."[116] We agree. Indeed, the change in the forecasted value of solar even between the 2020 and 2021 versions of the ACC illustrates the folly of basing compensation on long-term forecasts. 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

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114 CALSSA Brief p. 93; SEIA/VS Brief p. 20.

115 Ex. IOU-01 (Kerrigan) 125:8-11 and 129:12-14, 20-23.

116 Ex. CUE-01 (Earle) 14:10-12. TURN, Cal Advocates, NRDC and Sierra Club also 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. Ex. TRN-01 (Chait) 9:6-8, 45:20-22; Ex. PAO-01 (Gutierrez, et al.) 3-17:4-7; Ex. NRD-01 (Chhabra) 15:10-16:12; Ex. SCL-01 (Vespa) 27:1-2.

annual update cadence -- ensures that future solar customers will be appropriately compensated. This is not so for the solar industry proposals.

First, the solar parties even now do not update their proposals to account for the 2021 ACC. If they were consistent with the 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 more accurate, their proposal would prevent participating customers from being compensated accordingly.[117]

Further, basing compensation on a 25-year forecast is 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 (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.[118]

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[117] Ex. IOU-02 (Kerrigan) 52:3-17.

[118] Ex. IOU-02 (Kerrigan) 52:18-53:4. Further, use of a 25-year forecast to determine compensation is also inconsistent with Commission 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. Ex. IOU-02 (Kerrigan) 53:5-13.

4. The Joint Utilities' Proposed Netting Intervals and True-Up Periods Provide More Accurate Price Signals and Have Greater Potential to Incentivize Load Shifting

The Joint Utilities' proposal for netting and true-ups provides a balance of price signal granularity and ease of customer understanding. Cal Advocates also proposes "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."[119] 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. Under hourly export compensation, to support Guiding Principle F (tariffs should be both transparent and understandable), the customer bill would need to be modified to show costs for each hour. This would greatly lengthen the bill and make it harder to find key details. In contrast, our proposal for TOU period based compensation will help participating customers understand the temporal value of their onsite generation while still maintaining a reasonable level of simplicity and an accessible tariff.[120]

a. Current Netting Policy Is Complicated and Unnecessary

SEIA/VS propose to maintain the current netting intervals, but provide no rationale for this proposal, other than to state that "[o]ne hour is the established metered interval for residential customers" and "[g]enerally, the data that the utility provides to residential customers on its website shows hourly data that has been netted over that metered interval."[121] 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.[122] 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

[119] Ex. PAO-01 (Gutierrez) 3-6:6-3-7:7.

[120] Ex. IOU-02 (Morien) 55:1-15.

[121] SEIA/VS Brief p. 71; Ex. SVS-03 (Beach) 64:7-8.

[122] Ex. IOU-02 (Morien) 55:3-9.

the details of the billing concept of "netting." That 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.[123]

CALSSA also proposes to maintain the current netting policy, stating that the Joint Utilities' proposal would be unfair to [solar] customers. However, the Commission must consider what is fair to all customers, including those who are non-participants. CALSSA's argument for maintaining the current policy is that the Joint Utilities' and Cal Advocates' proposals would be too complicated to implement.[124] However, the Joint Utilities' and Cal Advocates' proposals are much less complicated than CALSSA states. As explained by Cal Advocates, "[t]he IOUs' meters automatically perform instantaneous netting of customers' exports and consumption and do not require any modifications to implement this practice under net billing."[125]

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 export compensation rate (ECR) as proposed by the Joint Utilities. 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.[126]

b. Annual True-Ups Have No Cost Basis, Do Not Sufficiently Encourage Load Shifting or Paired Storage, and Are Difficult for Customers

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

[123] Ex. IOU-02 (Morien) 55:16-56:4.

[124] CALSSA Brief, p. 150.

[125] Ex. PAO-01 (Gutierrez) 3-6:6-7.

[126] Ex. IOU-02 (Morien) 56:5-17.

reduce the value proposition for the customer.[127] However, SEIA/VS offer no evidence that the value of the energy in one month equals that in 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 up policy, stating that "solar conditions have a natural annual cycle."[128] SEIA/VS and CALSSA appear to view netting and true-up policy through a single lens, from the new participating-customer's perspective.

The Commission should consider the value that 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. 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.[129] 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. To true 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 greater load shifting. Customers will not have credits from high production months carried over to offset charges during times of grid stress.[130]

SEIA/VS also would change the annual true-up date for all new residential and small commercial customers to April, but offer little explanation for this proposal.[131] It is likely that

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127 SEIA/VS Brief pp. 40-41, 69-71.

128 Ex. CSA-01 (Heavner, et al.) 117:19-25.

129 Ex. IOU-01 (Morien) 131:18-22, 133:2-8.

130 Ex. IOU-02 (Morien) 57:10-14.

131 SEIA/VS Brief pp. 70-71.

this billing arrangement would only benefit the customer, not the grid, by allowing the customer to offset any remaining charges with excess generation accumulated in March and April.[132]

Our proposal will 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 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.[133]

Moreover, as mentioned in the Joint Utilities' testimony, customers have found the annual true-up confusing and difficult to manage.[134] Frequently they are left with large bills that require a payment plan. The Joint Utilities' proposal provides more transparency and decreases the risk of this occurring.

5. Solar Party Arguments Against the Grid Benefits Charge (GBC) Are Flawed

Parties opposing the Joint Utilities' proposal assert that the proposed GBC is discriminatory, and therefore unlawful, and that the costs it would collect are fixed for all customers, not just NEM customers.[135] Both arguments lack merit.

a. The GBC, Which Is Essential to Rectifying the Cost Shift, Is Not Discriminatory Under Federal or State Law

SEIA/VS and CALSSA argue that the GBC may violate PURPA requirements in that utilities' rates for sales to QFs selling under PURPA should be comparable to non-NEM

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[132] It also must be noted that requiring the Joint Utilities to bill charges on a monthly basis but carryover credits for 12 months for an annual true-up as SEIA/VS proposes is as expensive to bill as the current billing system, creating costs that must be borne by customers.

[133] Ex. IOU-02 (Morien) 57:3-58:2.

[134] Ex. IOU-01 (McCutchen) 194:1-195:1.

[135] See CALSSA Brief p. viii; SEIA/VS Brief p. 7, 58-62.

customers with similar characteristics.[136] They erroneously claim that the legality of such charges is already under scrutiny at FERC.[137] In truth, FERC refused to hear the case.[138] The facts are that NEM customers, by their very nature, have different usage and load profiles than non-NEM customers in their customer class.[139] SEIA/VS and CALSSA cite no evidence that there is *any* set of customers that has exactly the same usage and load profile for sales from the utility as do other, non-NEM customers. Rather, SEIA/VS make only a theoretical claim that *if* any such non-NEM customers had the same patterns, then the GBC would be contrary to PURPA.[140] This is unsupported conjecture.

CALSSA incorrectly argues that grid charges are discriminatory under a California statute enacted in the 1970s.[141] That statute has now been superseded by the Legislature's 2013 enactment of AB 327.

CALSSA also argues that such charges are discriminatory under federal law, citing another inapposite FERC decision. That FERC decision applies to QF net sellers, not NEM net

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[136] SEIA/VS Brief p. 62; CALSSA Brief p. 138 (citing FERC Order No. 69, Docket No. RM79-55, Small Power Production and Cogeneration Facilities, Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12,214, 12,228 (February 25, 1980)) available at: https://www.ferc.gov/sites/default/files/2020-04/order-69-and-erratum.pdf (accessed Sept. 11, 2021).

[137] *Id.* The *very* case they cite shows that FERC decided not to involve itself and *refused* to "scrutinize" the issue. *James H. Bankston, Jr. v. APSC*, 175 FERC ¶ 61,181 (2021). FERC instead chose to allow the relevant parties to debate the issue in federal court. Dennis Pillion, *Fight against Alabama Power solar fee heads to federal court,* al.com (Jul. 13, 2021) located at: https://www.al.com/news/2021/07/fight-against-alabama-power-solar-fee-heads-to-federal-court.html. (accessed Sept. 11, 2021).

[138] *Id.*

[139] Ex. PCF-15, Lookback Study, pp. 3-4, Table 1-1.

[140] SEIA/VS Brief p. 62.

[141] CALSSA Brief p. 136 (citing Cal. Pub. Util. Code § 2801).

consumers, and was decided in ***1980, three years before the nation's first net metering law was even passed***.[142]

CALSSA next argues that the Joint Utilities' Reform Tariff constitutes a back door buy-all-sell-all (BASA) tariff that violates QFs' non-existent right to self-serve.[143] This is not true. The Joint Utilities' proposal does not stop NEM customers from serving their onsite load and is not tantamount to a BASA tariff. Regardless, CALSSA's arguments lack merit for at least four reasons. First, no court has found BASA arrangements unlawful. Second, federal law does not require states to offer NEM. Third, AB 327 does not require the Commission to continue to authorize a NEM program. Fourth, there is no authority for the proposition that maintaining just and reasonable rates for non-participating customers by mandating specific rates and charges for customers electing to take service on a subsidy program is discriminatory.[144]

The GBC actually *remedies* undue discrimination among customers with NEM and those without NEM by preventing cross-subsidization.[145] There are costs that are incurred, many mandated by this Commission, that should be paid by *all* loads that the Joint Utilities serve. In sum, none of the decisions or the statutes CALSSA and SEIA/VS cite have application here.

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142 CALSSA Brief p. 138 (citing FERC Order No. 69, Docket No. RM79-55, Small Power Production and Cogeneration Facilities, Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12,214, 12,228 (February 25, 1980)) available at: https://www.ferc.gov/sites/default/files/2020-04/order-69-and-erratum.pdf (accessed Sept. 11, 2021).

143 CALSSA Brief p. 124.

144 CALSSA is also incorrect that the Joint Utilities propose to impose standby charges on standalone storage customers. Standalone storage is not a NEM-eligible resource and thus falls outside the scope of this proceeding. The Joint Utilities' proposal is to terminate the standby charge exemption for **non-NEM solar generators** sized 1MW and below. Ex. IOU-01 (Kerrigan) 152:4-23.

145 As explained in our Opening Brief at p. 70: "When NEM customers avoid paying volumetric rates, they not only avoid paying the generation component of the bill, but also avoid paying all other aspects of the bill, such as grid services (transmission, distribution, and cost allocation mechanism), policy mandates (CARE, program subsidies for energy efficiency programs, public purpose programs, the Wildfire Fund, Nuclear Decommissioning, etc.), and the costs of utility-provided customer services."

b. **The GBC Appropriately Recovers Costs NEM Customers Incur**

While it is true that there are fixed costs to serve all customers, NEM customers are able to avoid payment of these costs. As a result, NEM customers are not paying their fair share of fixed costs. Fixed costs are currently recovered in residential volumetric kWh rates, which was a practical approach at a time when one-way grid imports were the default supply option for most residential customers. Today, in a system of imports and exports that both use the grid, an approach to recover fixed system costs through volumetric cost recovery based on imports alone is insufficient.

Despite this obvious shortcoming with the historic approach to recovery of these fixed costs, the solar parties rely on several unfounded claims to dispute the need for a grid benefits charge. These claims are addressed below.[146]

(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."[147] However, CALSSA fails to provide any support for its claim that minimum bills are sufficient to cover grid costs. Furthermore, minimum bill charges imposed on all customers, not just those avoiding the fixed costs, perpetuate the cost shift.

The Joint Utilities calculate applicable distribution customer access costs to be significantly higher than the current minimum bill, and these costs are not the only grid and policy costs that current NEM customers unfairly avoid. NEM customers also are able to avoid paying for upstream distribution costs, transmission charges, fixed costs of generation, and

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[146] The Commission should note that other states have adopted GBCs for their NEM programs. Ex. IOU-02 (Tierney) 66:6-67:5.

[147] Ex. CSA-01 (Heavner et al.) 99:15-16. *See also* CALSSA Brief pp. 126-127 n. 652.

others. Further, the 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.[148]

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

Solar parties object to the GBC, asserting behind-the-meter generation and customer consumption do not impose costs on the grid.[149] Unlike energy efficiency measures that sustainably reduce load in a way that the utility can respond to over a long-term investment planning cycle, NEM self-consumption 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 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 in an oversupplied market and as a GHG-displacing resource.[150]

Solar customers still impose costs on grid operations. Solar customers who use electricity at night or when it is cloudy (when the sun's rays do not shine through) use the distribution and transmission grid like a non-solar customer. Solar customers also benefit from the same public policy programs, wildfire mitigation, local reliability, and other functions as non-solar customers.[151]

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

[148] Ex. PCF-15, Verdant NEM 2.0 Lookback Study, Figure 1-3, at 11; Ex. IOU-02 (Morien) 62:1-14.

[149] SEIA/VS Brief p. 59-61; CALSSA Brief p. viii.

[150] Ex. IOU-02 (Morien) 62:15-63:4.

[151] Ex. IOU-02 (Morien) 63:5-9.

non-NEM residential customers. The coincident peak period is 4PM – 9PM, a time when the sun is in the process of setting or not shining at all.[152] NEM customers' higher demand is partially due to the fact they were, on average, customers with higher electricity demands to begin with. However, that does not change the fact that on average, NEM customers are higher cost-of-service customers and place more demand on the grid. 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 (Ex. IOU-02 (Morien) 64:1)

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

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

CALSSA argues that AB 327 does not require customer indifference for NEM and that the Commission has previously exempted NEM customers from standby charges.[153] However, AB 327 explicitly states that fixed charges that are specific to NEM customers are allowable.[154] D.16-01-044 included the addition of NBCs when it reformed NEM 1.0. In any event, previously providing an exemption from a charge does not bind the Commission to maintain that exemption in future decisions.

(4) Solar Argument 4: NEM Customers Benefit from the Grid Only When They Import Energy

SEIA/VS assert that customers only use and benefit from the grid when they import energy, 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:

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[152] Ex. IOU-02 (Morien) 63:10-19.

[153] Ex. CSA-01 (Heavner, et al) 102:4-103:2.

[154] AB 327 Public Utilities Code § 739.9 (e).

> [T]he 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.[155]

This statement would only be true if NEM customers were compensated at wholesale rates, like wholesale generators are. In the NEM context, customer-generators use the grid like a giant battery, taking their generation when they do not want it and providing different generation back when they do.

It is not surprising that SEIA/VS fail to present facts 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. In reality, NEM places demands on the grid by creating a two-way flow of energy, which creates additional operational complexities such as transformer loading and voltage management on the distribution grid.[156]

Their argument confirms the Joint 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. Together 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.[157]

(5) Solar Argument 5: The GBC Calculation Is Imprecise

SEIA/VS argue that the Joint Utilities' GBC would be too imprecise and that the utilities have no idea how much a customer generates.[158] However, when asked if SEIA/VS would be willing to share data or ask their members to share data to enhance the precision of such a

155 Ex. SVS-03 (Beach) 69:9-13.

156 Ex. IOU-02 (Morien) 65:1-8.

157 Ex. IOU-02 (Morien) 65:9-15.

158 Ex. SVS-03 (Beach) 71:6-24.

charge, SEIA/VS stated that they would not be willing to approach member organizations for data regarding customer generation behind the meter.[159] SEIA/VS should not be able to have it both ways.

The Joint 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.[160] The Joint Utilities' VODE proposal would extend the same optional metering arrangement to all behind the meter solar customers, including residential. The Joint Utilities' proposal balances customer understanding, precision, and implementation considerations. We will update the estimate of onsite consumption annually by customer class to ensure that on average, customers pay the correct amount. This is consistent with ratemaking principles, where rates are designed based on the customer class's average cost of service.[161]

c. Other States Have Adopted GBCs for Their Reformed NEM Tariffs

The Commission should weigh the fact that other jurisdictions have allowed utilities to introduce GBCs as part of successor tariff structures to NEM.[162] Table II-3 in our Opening Testimony provides information about these rate-design elements for selected investor-owned and publicly owned utilities.[163] Here are a few examples:

- Recently, on May 19, 2021, the South Carolina Public Service Commission approved a settlement proposal between Duke Energy, and various groups

[159] Ex. IOU-02 (Morien) 65:19-21, *citing*, Appendix B: SEIA/VS Response to Joint Utility DR-007.

[160] Ex. IOU-02 (Morien) 65:16-24.

[161] Ex. IOU-02 (Morien) 66:1-5.

[162] Ex. IOU-02 (Tierney) 66:6-67:5.

[163] Ex. IOU-01 (Tierney) 33, Table II-3.

representing solar and environmental interests (including Vote Solar).[164] 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.[165]
- 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.[166]
- In 2016, 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, up to a maximum fee of $37.00 per month.[167]

In sum, the above examples demonstrate that the attacks on the inclusion of a GBC in the Joint Utilities' proposal should be ignored. A GBC is an appropriate and necessary element of any successor tariff that will mitigate the cost shift.

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164 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 (accessed Sept. 11, 2021).

165 Ex. IOU-01, Appendix B, p. B-28.

166 Ex. IOU-01, Appendix B, pp. B-7 and B-8.

167 "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." DistributedGenerationFee INSERT 3-16.pdf (peoplesenergy.coop) (accessed Sept. 11, 2021).

B. The Evidence Shows that the Joint Utilities' Proposal Is Necessary to Ensure Just and Reasonable Rates

Our proposal is the most effective at mitigating the current inequities of the NEM tariff. There is broad consensus among the parties that the successor tariff should require cost-based TOU rates, set export compensation according to the latest ACC, and include a grid benefits charge.

Each element should be incorporated for the reasons discussed below.

Cost-based TOU rates (aka "Electrification Rates"): Such rates better align price signals with grid needs, maximize benefits to all customers, and further the state's electrification and GHG reduction goals.[168] These rates include modest fixed charges that result in lower overall volumetric rates, having the potential to encourage electrification since the average price per kWh is lower. Indeed, SEIA/VS do not oppose such fixed charges, as witness Beach stated: "I do not oppose the use of fixed charges in these rates, provided they are consistent with the Commission's rate design policies, including cost causation principles, and are generally available to residential customers who install a broad range of DERs." [169] 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 on cost-causation principles.[170]

ECR based on the most recently adopted ACC: In addition to the Joint Utilities, diverse parties including Cal Advocates, CCSA, NRDC, Sierra Club and TURN all support use of the

168 Ex. IOU-02 (Morien) 44:12-14; Ex. NRD-01 (Chhabra) 16:16-17:2; Ex. SCL-01 (Vespa) 2:6-9, 5:16-6:7; Ex. SVS-03 (Beach) 36:3-6, 41:11-22.

169 Ex. SVS-03 (Beach) 67:11-14. Sierra Club also agrees that fixed charges folded into electrification rates are beneficial. Ex. SCL-01 (Vespa) 23:13-27.

170 Ex. IOU-02 (Morien) 44:19-23.

most recent ACC to inform export compensation.[171] Even the solar parties recognize the importance of the ACC in their proposed step-down of the ECR to ultimately align with avoided costs.[172] The ECR should be based on a short-term forecast of the ACC, as many parties also agree, and compensation should be based on actual exports as measured by the utility meter.[173] Finally, our proposal -- weighting ACC outputs by an export profile to determine export rates in a given time period -- ensures that Reform Tariff customers will be accurately compensated as their export profiles evolve over time.[174]

GBC: As discussed above, and again below concerning the Independent Recommendations, a GBC is entirely appropriate and should be included as part of the successor tariff. 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 non-participant indifference is achieved.[175]

In addition to these essential components, netting of a customer's consumption and exports should be on an instantaneous basis during TOU periods to provide more accurate price signals to customers.[176] Likewise, for the reasons set forth above and detailed in our testimony, true-ups should be on a monthly, not annual, basis.[177] These elements, as a whole, support a balance between continued customer adoption of rooftop solar and ensuring just and reasonable rates for all the Joint Utilities' electricity customers.

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171 Ex. TRN-01 (Chait) 45:12-46:2; Ex. NRD-01 (Chhabra) 15:10-16:15; PAO-01 (Gutierrez, et al.) 3-16:9-3-17:14; SCL-01 (Vespa) 26:24-27:6; CCS-01 (Smithwood) 13:16-19, 44:9-17, 45:13-46:1.

172 Ex. CSA-01 (Heavner, et al.) 13:13-14 ("CALSSA designed its export compensation proposal to approach the 25-year levelized value of exported energy from the Avoided Cost Calculator using all default inputs"); Ex. SVS-03 (Beach) Executive Summary, p. ii.

173 *See* Ex. TRN-01 (Chait) 9:6-8, 45:20-22; Ex. PAO-01 (Gutierrez, et al.) 3-17:4-7; Ex. NRD-01 (Chhabra) 15:10-16:12; Ex. CUE-01 (Earle) 14:8-13; Ex. SCL-01 (Vespa) 27:1-2.

174 Ex. IOU-02 (Kerrigan) 50:12-20.

175 Ex. IOU-01 (Morien) 135:10-138:5; Ex. IOU-02 (Morien) 58:3-61:8.

176 Ex. IOU-02 (Morien) 55:4-15.

177 Ex. IOU-01 (Morien) 134:13-135:9, (McCutchan) 194:1-18; Ex. IOU-02 (Morien) 56:20-57:2, (Molnar) 101:13-23.

IV. ISSUE 5 (CONT.): THE COMMISSION SHOULD ADOPT SOME, BUT NOT ALL, OF THE INDEPENDENT RECOMMENDATIONS

While the Independent Parties' recommendations are very good overall, ultimately, they are not strong enough. As explained below, in many respects, the Independent Recommendations are a strong step forward, and away, from the status quo. In other respects, the Independent Recommendations fall short. Most notably, the Independent Recommendations fail to sufficiently address the future cost shift and they present a variety of implementation issues.

A. The Independent Recommendations, In Many Respects, Are Laudable and Should Be Supported

The Joint Utilities agree with, and designed our Reform Tariff to meet, many of the same fundamental policies described in the Independent Recommendations. Those policies are to: fairly compensate successor tariff customers, require successor tariff customers to pay their fair share of the grid, and support the needs of lower-income customers.[178] Therefore, we also agree conceptually with some of the key components of the Independent Recommendations. Namely, we agree that the successor tariff should: (1) compensate exports based on the avoided cost, divorced from the retail rate; and (2) include a GBC.

Based on the broad consensus of consumer advocates, environmentalists, labor and industry -- not to mention the major utilities -- these elements should be incorporated in the reform tariff.

B. The Independent Recommendations Do Not Do Enough to Mitigate the Future Cost Shift

Despite the many positive aspects of the Independent Recommendations, they do not go far enough to reform the current NEM tariff. That is, while the Independent Parties and Joint Utilities are in alignment concerning compensation of exports based on avoided cost and the need for a GBC, the specific methodologies proposed by the Independent Parties for calculating

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[178] Cal Advocates Brief, Appendix A, p. A-1. The Independent Recommendations also list "transitioning existing NEM 1.0 and 2.0 non-California Alternate Rates for Energy (CARE) and non-Family Electric Rate Assistance (FERA) customers…" as a fundamental policy of the recommendation. *Id.* While the Joint Utilities have not proposed transitioning NEM 1.0 and NEM 2.0 customers, the Joint Utilities are not opposing the recommendations for these customers.

these components are less effective than those of the Joint Utilities at reducing the cost shift. Additionally, while we agree with the goal of supporting lower income customers, the equity provision proposed in the Independent Recommendations misses the mark.

1. The ECR Should Be Based on the ACC, But Should Not Be Locked-In for 10 Years

The Independent Recommendations propose to compensate exports based on the two most recent Commission-adopted ACC versions, updated annually.[179] The export rate would be based on either (i) the ACC or (ii) all avoided cost values except avoided energy costs, the latter based on the day-ahead or real-time market prices. Exports would be subject to instantaneous netting (or, if not possible, then hourly netting). The Independent Recommendations also would allow the initial ECR to be locked in for up to 10 years.

The Joint Utilities agree that the ECR should be based on the ACC and that exports should be netted instantaneously.[180] The ACC is an appropriate tool for valuing exports because, at least under the Joint Utilities' proposal, it will ensure that compensation provided to new solar customers for exported energy will match the value of that energy to the grid.[181]

The Joint Utilities' proposal would set the ECR based on only one year of the ACC (the most recently adopted version), updated annually,[182] whereas the Independent Recommendations would use the two most recent years of the ACC. We prefer our ECR proposal. However, if the Commission is concerned about fluctuations in the ACC from year to year, the Joint Utilities can support two-year averaging of the ACC for setting the ECR as long as the ECR is updated annually for all participating customers.

We diverge from the Independent Parties' ECR proposal in (i) the option to use day-ahead or real-time market prices for avoided energy costs and (ii) the 10-year lock-in of the

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[179] Cal Advocates Brief, Appendix A, p. A-2.

[180] Ex. IOU-01 (Morien) 98:4-8, 130:16-131:6. *See also* Ex. IOU-02 (Morien) 55:5-8.

[181] Ex. IOU-01 (Kerrigan) 125:8-11. Even the solar parties agree that export compensation should be different (i.e., lower) than the rate charged to customers for imports. SEIA/VS Brief p. 4.

[182] Ex. IOU-01 (Kerrigan) 123:3-7, 125:8-10, 129:11-14; Ex. IOU-02 (Thomas) 82:1-3.

ECR. These elements would serve to preserve some aspect of the cost shift and create additional problems.

a. The Option to Use Day-Ahead or Real-Time Pricing Is Not Practical or Customer Friendly

We understand that use of day-ahead pricing for the energy component of the ECR has conceptual merit because it would ensure that compensation is tied to the exact market value of the generation. However, at this time, this proposal is not practical to implement. The first problem is that we do not currently have a low-cost or automated capability to give customers day-ahead notice of prices. Customer bills are rendered and presented after usage. Therefore, the effectiveness of a day-ahead price signal is severely diminished.[183]

In addition, we currently do not provide hourly details in customer billing statements. To provide the best transparency and show the detailed rates, we would need to communicate with customers in advance of the rates, and our bill would need to contain a line item for each time period, resulting in a monthly bill with over 700 line items.[184] This likely would lead to customer confusion, contrary to the requirement of Guiding Principle F that the successor tariff be transparent and understandable for customers. Moreover, use of day-ahead pricing would significantly add to the cost and time needed for implementation, as the Joint Utilities do not calculate bills based on wholesale market prices.

In contrast to this aspect of the Independent Parties' approach, the Joint Utilities' proposal uses ECRs that are set and adjusted on a similar frequency to all other rates on a customer's bill.[185] We use the one-year levelized ACC avoided costs as the basis for the ECR. The Reform Tariff ECRs 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 ECRs far in advance and use them to plan an initial purchase or develop new behavioral patterns that

[183] Ex. IOU-02 (Thomas) 81:1-16.

[184] Ex. IOU-02 (Molnar) 102:4-9.

[185] Ex. IOU-02 (Thomas) 81:8-14.

provide consistent load reductions or shifts.[186] Our proposed ECR therefore provides better transparency and potential for an improved customer experience.

b. The 10-year Lock-in of Export Rates Will Render those Values Out-of-Date

The Independent Recommendations' proposal to lock-in export rates for 10 years would reduce the effectiveness of using the ACC as the basis for the ECR. Locking in the ACC values over a 10-year period will render those values untimely,[187] and unfairly shifts forecasting risk to non-participants.[188] In contrast, the Joint Utilities' proposal to use an ECR that is based on a weighted one-year ACC avoided costs, updated annually, would ensure more accurate and timely alignment of costs and benefits related to export compensation.[189]

Additionally, vintaging of the ECR—meaning the use of different ECR values depending on their interconnection dates for the same types of customers—as proposed under the Independent Recommendations, would complicate the billing process and cause customer confusion.[190] If the Commission is concerned about fluctuations in the ACC and the resulting impact on the ECR, a better solution is to use a two-year ACC average, updated annually, as discussed above. A rolling two-year average to smooth out variation in the rate is a much fairer and more practical alternative than locking-in the ECR for ten years.

2. The GBC Should Fall at the Higher End Proposed by the Independent Recommendations to Accurately Reflect Use of the Grid and Ensure that Solar Customers Pay Their Fair Share of Costs

For the reasons discussed above, there should be no question concerning the necessity and propriety of a GBC. Numerous parties have come to recognize that a GBC serves a distinct

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186 *Id. See also* Ex. IOU-02 (Kerrigan) 50:12-20.

187 *See* Ex. IOU-02 (Kerrigan) 52:5-7.

188 *See* Kerrigan, T. 761:17-26 (July 30, 2021) (testifying regarding forecasting risk and "that the utility proposal is that [] that risk should not be borne by non-participating customers").

189 Ex. IOU-02 (Thomas) 81:25-82:8.

190 *Id*.

purpose that cannot be achieved through other rate elements and should be adopted as part of the Commission's decision.[191] Without a GBC, a cost shift will remain.[192]

Therefore, contrary to arguments made by other parties (e.g., CALSSA),[193] adopting a GBC would not be discriminatory to solar customers. Rather, failing to adopt a GBC would discriminate against non-solar customers who, in the absence of a GBC, have to pay the costs that solar customers should be paying. Likewise, without a GBC, the rates charged to non-solar customers may well violate the mandate set forth in Public Utilities Code Section 451 that such charges must be just and reasonable.

a. The GBC Should Be Based on System Size, Not Other Factors

The Independent Recommendations propose that the GBC should be based on (a) customer's system size, (b) energy production, or (c) portion of production consumed onsite.[194] Of these alternatives, options (b) and (c) are impractical. Customers would need to have a second meter installed to measure system generation to have the data to calculate the GBC based on energy production or the portion of production consumed onsite.[195] While TURN proposes that production consumed on-site could be estimated "based on engineering estimates that account for system capacity, location, orientation and other relevant factors,"[196] doing so creates complexity and expense. Thus, for practical reasons, the GBC should be based upon customers' system size (i.e., installed solar capacity) and calculated as described in detail in the

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191 As reflected in Appendix A to the Cal Advocates Brief, all six of the parties supporting the Joint Recommendation support a GBC. Cal Advocates Brief, Appendix A, p. i. The Joint Utilities also support a GBC.

192 Ex. IOU-01 (Morien) 135:12-138:5; Ex. IOU-02 (Morien) 59:5-61:8; Ex. NRD-02 (Chhabra) 13:4-28.

193 CALSSA Brief p. viii.

194 Cal Advocates Brief, Appendix A, p. A-5.

195 Ex. IOU-02 (Morien) 65:17-24.

196 TURN Brief p. 83.

Joint Utilities' opening testimony.[197] The calculation yields a GBC for residential solar customers ranging from $10.24/kW to $14.13/kW, depending on the utility.[198]

b. The GBC Should Justifiably Be Set at the High End of the Range Proposed by the Independent Parties

As for the costs to be included in the GBC, we agree with the Independent Parties that it should include: transmission and distribution costs of service, as well as all NBCs described in the Independent Recommendations.[199] While the Independent Recommendations' GBC proposal is a positive step forward, the low range GBC they propose would stymie mitigation of the cost shift. Therefore, the Joint Utilities' GBC proposal is the better approach.

The Joint Utilities' proposal sets the GBC based on the value of the generation produced and consumed onsite, and by its inclusion of generation cost recovery.[200] Specifically, generation capacity costs for ramp and peak energy costs are generally not avoided by standalone solar systems. Thus, inclusion of the full generation energy and capacity costs in the GBC appropriately recovers the cost for services provided.[201]

For this reason, the Commission should adopt the high end range of the GBC reflected in the Independent Recommendations, consistent with that proposed by the Joint Utilities.[202]

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197 Ex. IOU-01 (Morien) 135:15-17, 141:4-142:4.

198 Ex. IOU-01 (Morien) 143, Table IV-28.

199 Cal Advocates Brief, Appendix A, pp. A-5 – A-6.

200 Ex. IOU-01 (Morien) 140:24-141:2; Ex. IOU-02 (Morien) 80:8-16.

201 Ex. IOU-02 (Morien) 80:8-16.

202 Cal Advocates Brief, Appendix A, p. A-5. The GBC range recommended by the Joint Utilities assumes that the Commission adopts the proposed cost-based rates with associated fixed customer charges described in our Opening Testimony. Ex. IOU-01 (Morien) 106:2-3. If the Commission decided not to adopt fixed customer charges as a component of the default rate, the GBC would need to increase commensurately to ensure equitable cost responsibility from Reform Tariff customers. Ex. IOU-01 (Morien) 117:25-118:5.

c. The Joint Utilities Support the Independent Parties' Approach for Non-Residential Customers, Virtual NEM, and NEM Aggregation

The Joint Utilities agree with the Independent Parties that the GBC should apply to non-residential customers and should recover NBCs just as it would for residential customers.[203] However, to the extent that non-residential rates do not include demand charges covering transmission and distribution costs of service, or fixed generation costs, such costs also should be recovered through the non-residential GBC.[204]

Finally, assuming virtual NEM and NEM Aggregation continue to treat all energy generated as exports and benefiting accounts pay for all energy imports, the Joint Utilities agree that the GBC would not apply to such systems. The exception, as identified in the Independent Recommendations, would be NEM-A residential accounts with the generation behind the meter—such customers would be subject to the GBC.

3. The Equity Provisions in the Independent Recommendations, While Well-Intentioned, Are Problematic

Like the Independent Parties, we agree that the NEM successor tariff should include provisions to ensure equity. However, the Joint Utilities recommend that the equity provisions we propose -- using the same ECR for all customers (regardless of CARE/FERA status), the income-qualified discount on the GBC, and the STORE program -- be adopted over the equity provisions set forth in the Independent Recommendations.[205]

The Independent Recommendations propose two equity provisions: (1) exempting CARE/FERA successor tariff customers from the GBC indefinitely; and (2) a monthly equity charge applied to existing non-CARE/FERA NEM 1.0 and 2.0 customers, and which also would be applied to new residential customers beginning 10 years after system interconnection. While

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[203] Cal Advocates Brief, Appendix, p. A-6.

[204] Ex. IOU-01 (Morien) 145:10-24; Ex. IOU-02 (Kerrigan) 68:1-5. Because demand charges associated with some non-residential rates recover a portion of grid and generation capacity costs, the non-residential GBC would be adjusted to avoid double recovery of the same costs through two different rate components. Ex. IOU-01 (Morien) 145:10-24.

[205] Notably, three of the Independent Parties – CUE, CalWEA and TURN – do not join in the equity provisions. Cal Advocates Brief, Appendix A, p. i.

the Independent Recommendations do not set forth a specific use for the funds collected through the equity charge, the Independent Parties offer examples of how those funds could be used.[206] The Joint Utilities' concerns regarding the equity provisions proposed by the Independent Recommendations are twofold.

First, the equity provisions should balance incentives for low-income customers with the impact of those incentives on all customers, including other low-income customers that are not participating. Completely exempting CARE/FERA customers from the GBC for an indefinite period of time, as the Independent Recommendations propose, will continue the cost-shift and harm those low-income customers who are unable to install solar. As CUE described in its Opening Brief:

> Under every scenario, there will be vastly more people who are less wealthy or live in disadvantaged communities who do not have solar than who do. This unfortunate majority would have an even more onerous burden if they also have to subsidize both the rich and a few lucky low-income customers who benefit from an excessive NEM subsidy.[207]

A discount on the GBC, as the Joint Utilities propose, is a better approach than that set forth in the Independent Recommendations. Moreover, the Joint Utilities' proposal that the discount be available for enrollment during the first three years of implementation of the successor tariff, and subject to Commission review and determination thereafter, is more appropriate than an exemption on which customers could be enrolled indefinitely.

Second, the equity charge is poor policy. Initially, California's early NEM adopters -- NEM 1.0 and 2.0 customers -- would be singled out to pay the charge. While those customers have received the benefits of the NEM program, the earliest of those adopters did so in a very different context than today, when solar technology was newer, novel and more expensive.[208]

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206 Cal Advocates Brief, Appendix A, p. A-7.

207 CUE Brief p. 3.

208 Ex. IOU-01 (Tierney) 22:18-19, 23:12-19.

Additionally, the equity charge creates a new subsidy to ameliorate the subsidization of solar that is driving the cost-shift. In other words, it creates a new subsidy to undo an existing subsidy.

That said, if the Commission is inclined to incorporate the equity charge as proposed in the Independent Recommendations (i.e., \$3.41-\$3.81/kW) the charge is unlikely to have a significant impact on existing customers' payback period. 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. If the Commission were to adopt this aspect of the Independent Recommendations, we recommend the Equity Fund be allocated to existing program budgets, to complement existing programs, not duplicate them.

C. The Commission Should Consider Whether Changes to Legacy Treatment Are Appropriate

The Independent Recommendations propose transitioning existing customers to the successor tariff and include a storage rebate for NEM 2.0 customers that voluntarily switch after January 1, 2023 until December 31, 2027.[209] The Joint Utilities agree that NEM 1.0 and 2.0 customers represent most of the cost shift for the foreseeable future and that transitioning them will help mitigate that cost shift.[210] As stated in our prepared testimony, the Joint Utilities have not proposed changes to NEM 1.0 and 2.0 legacy treatment and do not do so here.

In deciding whether to adopt the Independent Parties' proposal for transitioning NEM 1.0 and 2.0 customers, the Commission should consider the following:

- *Whether the costs of a storage incentive as compared to the reduction in the cost shift by transitioning customers to the successor tariff justify such an incentive.* If, under the terms of a new tariff, current NEM customers are still able to shift costs to non-participating customers, a new storage incentive for these customers may not be justified. In such circumstances, these customers would have benefitted from both the NEM cost shift to date and the storage incentive.

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209 Cal Advocates Brief, Appendix A, pp. A-8 – A-10.

210 Ex. IOU-01 (Pierce, et al.) 76:1-83:6.

- *Switching existing non-CARE/FERA NEM 1.0 and 2.0 customers to new non-tiered underlying TOU rates, with a large TOU differential and fixed charge.*[211] Such an incremental change may be reasonable because it would allow legacy customers to maintain the NEM structure, only altering the underlying rate on which they take service. This would reduce the cost shift from these customers and could support the State's electrification goals. This approach also is supported by Sierra Club.[212] Application of the GBC to existing customers would reduce the cost shift even more.

In sum, if the Commission decides to transition legacy customers, it should consider the above-listed principles and aim to reduce the overall NEM cost shift in doing so. However, for the reasons discussed below, the January 1, 2023 timing proposed by the Independent Parties to begin these transitions may not be viable for each of the Joint Utilities. Changes to NEM 1.0 and 2.0 customers' tariff treatment would require time to implement the more cost-based tariff (for utilities that do not have an appropriate tariff available at this time), and other billing system changes necessary to enable transitions for these customers.

D. The Independent Parties' Interim Tariff Recommendations Create Real Implementation Problems

The Independent Recommendations acknowledge that implementation of the successor "end-state" tariff may take time. The Independent Parties therefore propose an interim tariff to be implemented on an aggressive schedule -- within 90 days of the Commission's final decision -- while the utilities also work to implement the final tariff ordered in this proceeding. More specifically, the proposed interim tariff would: (i) require new residential solar customers to take service on an electrification rate, (ii) set export compensation at a set percentage of the net retail rate (net of the four NBCs recognized under NEM 2.0 and the PCIA), and (iii) set the netting period to be instantaneous if practicable and, if not, then hourly. Additionally, customers signed

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211 As stated in the Joint Recommendation, for PG&E, this would be EV2 or E-ELEC, for SCE it would be TOU-D-PRIME, and for SDG&E, until an applicable rate is adopted, customers would transition to DR-SES or EV-TOU/EV-TOU2.

212 Sierra Club Brief pp. 40, 42.

on to the interim tariff would be allowed to remain on it for 10-15 years (depending on the utility).[213] The Joint Utilities oppose implementation of the interim tariff for the reasons explained below.

The Joint Utilities are just as anxious to end the cost shift as the Independent Parties. However, the interim tariff is not the right answer to resolving the cost shift. The interim tariff would perpetuate a cost shift for customers taking service under it and would do so for another 10-15 years.[214]

The interim tariff also poses real practical problems. It will not be possible for any of the Joint Utilities to implement a tariff in 90 days given the necessity to change billing systems and processes. Whatever time it takes will distract from, and delay, utility efforts to implement the final tariff ordered in this proceeding. As TURN stated in its Opening Brief: "TURN recognizes that utility billing system limitations may affect the overall implementation timeline."[215] The interim tariff's proposed ECR, set at a percentage of the retail rate, is a structural change that would require far more time than 90 days to implement.[216] In fact, it would be no easier to implement than the proposed ECR for the final successor tariff.

Furthermore, the utilities will also incur additional expenses for an interim solution (to be sought in rates) in billing system changes, maintaining and tracking information and record-keeping for an extra set of customers, i.e., those on the interim tariff.

The most effective way to end the cost shift is to close NEM 2.0 eligibility as we proposed.[217] Shortening the legacy period for customers that take service on NEM 2.0 during the 3- to 5-month buffer period following the final decision (as described in our testimony), will also

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213 Cal Advocates Brief, Appendix, p. A-11 – A-12.

214 Cal Advocates Brief, Appendix A, tables on pp. A-14 and A-15.

215 TURN Brief p. 131.

216 *See* Ex. IOU-02 (Molnar) 97:4-9, 98:4-6; Molnar, T. 650:1-8 (July 29, 2021).

217 Ex. IOU-01 (McCutchan, et al.) 182:1-14; 184:9-185:3.

mitigate the cost shift.[218] Solar customers interconnecting after the final decision (and after the buffer period), would take service on NEM 2.0, but only temporarily. As soon as the new tariff is operationalized, such customers would be billed under the new tariff.[219] This proposal provides a natural glidepath for transition, but without locking in a cost shift for 10-15 years as would occur under the Independent Recommendations.

V. CONCLUSION

For the reasons discussed in the Joint Utilities' Opening Brief and in this Reply Brief, the Commission should adopt the Joint Utilities' proposal as the one put forward that most effectively satisfies Federal and State law, as well as the Commission's Guiding Principles adopted in D.21-02-007. Alternatively, the Joint Utilities recommend that the Commission adopt the joint recommendations of the Independent Parties, modified and strengthened as discussed above in this Reply Brief.

Respectfully Submitted,

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[218] Ex. IOU-01 (McCutchan, et al.) 183:23-184:6; Ex. IOU-02 (Molnar) 100:12-22.

[219] Ex. IOU-01 (McCutchan, et al.) 185:5-186:1; Ex. IOU-02 (Molnar) 100:12-101:2.

APPENDIX OF ACRONYMS

Acronym	Description
AB	Assembly Bill
ACC	Avoided cost calculator
AECA	Agricultural Energy Consumers Association
ALJ	Administrative Law Judge
AMI	Area median income
APS	Arizona Public Service
BTM	Behind the meter
CAISO	California Independent System Operator
Cal Advocates	The Public Advocates Office at the CPUC (also CalPA or PAO)
CalWEA	California Wind Energy Association
CALSSA	California Solar and Storage Association
CARE	California Alternate Energy Rates
CCSA	Coalition for Community Solar Access
CEC	California Energy Commission
CFBF	California Farm Bureau Foundation
CPUC	California Public Utilities Commission
CGS	Customer-grid supply
CSIP	Common Smart Inverter Profile
CSI	California Solar Initiative
CSLB	California State Licensing Board
CSS	Customer-self supply
CUE	California Utility Employees
DAC	Disadvantaged Communities
DFPI	Department of Financial Protection and Innovation
DG	Distributed Generation
DLAP	Default Load Aggregation Price
DER	Distributed energy resources
E3	Energy and Environmental Economics, Inc.
ECR	Export compensation rate
ESJ	Environmental and social justice
FERA	Family Electric Rate Assistance
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GBC	Grid Benefits Charge
GHG	Greenhouse gas
GRC	General Rate Case
GT	Green tariff
GW	Gigawatt
HECO	Hawaii Electric Companies
HFRA	High Fire Risk Areas
HFTD	High Fire Threat Districts
IEEE	Institute of Electrical and Electronics Engineers

APPENDIX OF ACRONYMS
(continued)

Acronym	Description
IDER	Integrated Distributed Energy Resources
IOU	Investor Owned Utilities
IQD	Income qualified discount
IRP	Integrated Resource Plan
kWh	Kilowatthour
kW	Kilowatt
LADWP	Los Angeles Department of Water and Power
MASH	Multifamily Affordable Solar Housing program
ME&O	Marketing, Education and Outreach
MIT	Massachusetts Institute of Technology
MTC	Market Transition Credit
MW	Megawatt
MWhs	Megawatthours
NBC	Non-bypassable charges
NCCETC	North Carolina Clean Energy Technology Center
NEM	Net Energy Metering
NEMA	Net Energy Metering Aggregation
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
NSC	Net Surplus Compensation
NSHP	New Solar Homes Partnership
NUS	Non-bypassable, unavoidable, and shared
NV	Nevada
NY	New York
PAC	Program Administrator Cost
PCF	Protect our Communities Foundation
PCT	Participant cost test
PG&E	Pacific Gas and Electric Company
PPA	Power Purchase Agreement
PSPS	Public Safety Power Shutoff
PTO	Permission to operate
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
QF	Qualifying Facility
REC	Renewable Energy Credit
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
SASH	Single Family Solar Homes
SOMAH	Solar on Multifamily Affordable Housing
SB	Senate Bill
SCE	Southern California Edison Company
SCT	Societal Cost Test

APPENDIX OF ACRONYMS
(continued)

Acronym	Description
SDG&E	San Diego Gas & Electric Company
SEIA	Solar Energy Industry Association
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SPM	Standard Practice Manual
SOMAH	Solar on Multifamily Affordable Housing
STORE	Savings Through Ongoing Renewable Energy
T&D	Transmission and distribution
TOE	Time of export
TOU	Time of use
TRC	Total Resource Cost
TURN	The Utility Reform Network
UC	University of California
VNEM	Virtual Net Energy Metering
VODE	Value of Distributed Energy
VS	Vote Solar