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

OPENING BRIEF OF THE CALIFORNIA SOLAR & STORAGE ASSOCIATION

Tim Lindl
Julia Kantor
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (510) 314-8385
Email: tlindl@keyesfox.com
jkantor@keyesfox.com

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On behalf of the California Solar & Storage Association

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SUMMARY OF RECOMMENDATIONS

CALSSA's Proposal

CALSSA proposes a NEM-3 tariff that focuses on reducing the export compensation rate, with a reasonable glidepath to step the rates down based on the achievement of adoption targets. NEM is a tariff that credits customers for energy exported to the grid. Changes to NEM should be focused on changes to export compensation value. A NEM successor tariff framework must not nullify a customer's right to self-generate behind the meter by imposing solar fees unrelated to energy exported to the grid. These issues are discussed in Sections III.C.2-5 below.

CALSSA proposes that NEM credits be based on a percentage of retail rates, with the relative pace of reduction between the IOUs informed by the Avoided Cost Calculator ("ACC"). The depth of change is based on the amount that CALSSA believes the market can bear. As an alternative, CALSSA encourages the Commission to consider export compensation step-down based on the structure of a glidepath. The Commission would only need to determine a methodology for translating ACC outputs into export compensation and decide how many steps there should be. The structure is self-calibrating as the ACC is updated over time. These issues are discussed in Sections III.C.2-4 below.

CALSSA's proposal includes a suite of income-qualified provisions. Low-income customers, Virtual Net Energy Metering ("VNEM") customers in low- and moderate-income locations, and community-owned projects should receive net metering credits in the same structure as NEM-2. California Alternate Rates for Energy ("CARE") and Family Electric Rates Assistance ("FERA") customers should receive export credits at the non-CARE/FERA rates. The VNEM tariff should improve CARE eligibility requirements, allow new tenants to begin receiving credits when they move in, and pool the generation credits from multiple solar arrays on a single property. These issues are discussed in Sections III.C.1 and III.E below.

The proposal also includes customer experience provisions that seek to reduce unexpected end-of-year bills and increase the accuracy of savings estimates while reducing project costs. These proposals are discussed in Sections III.C.9-10. The overall superiority of CALSSA's proposal is discussed throughout the Brief, with a summary of why it should be adopted provided in Section III.D.1.

The Pro-Transmission Parties' Proposals

The Joint IOUs,[1] Natural Resource Defense Council ("NRDC"), The Utility Reform Network ("TURN"), and the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates") are collectively referred to herein as the "Pro-Transmission Parties" because they oppose customer solar in favor of renewable energy generated outside of communities and delivered via increased grid infrastructure. The proposals of the Pro-Transmission Parties should be rejected because of the following fatal flaws:

1. **Fixed Solar Fees Violate State and Federal Law and Are Bad Policy**: Solar fees represent an about-face on decades of conservation-focused energy policy in California. The deceptively labeled "grid benefits charges" are solar fees that (i) reach behind the meter to treat self-supply like retail sales, charging customers for services they have not received and denying customers the ability to realize the benefits of their investments; (ii) increase charges for customers that no party has shown cause higher utility costs compared to other customers with similar load profiles in the same rate class; (iii) unjustifiably treat one group of customers differently than another; (iv) violate at least half of the Commission's ratemaking principles for residential customers; and (v) give customers the unappetizing choice between inaccurate consumption estimates that are not based on usage and utility monitoring of private consumption data. These issues are explored in depth throughout Section III.C.5 of this Brief.

2. **The Pro-Transmission Parties' Combination of Fixed Solar Fees and Rate Requirements Are Unprecedented**: The combination of (i) the large solar fees proposed by the Pro-Transmission Parties and (ii) the requirement to take service under rates with high fixed charges is unprecedented in the United States. Proposals by TURN, Cal Advocates and NRDC would launch California's IOUs to the top of the list in terms of the highest unavoidable charges for solar customers in the nation, while the Joint IOUs' proposal, which totals just under $100/month in SDG&E's service territory for a 5 kW

[1] Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E").

system, would be nearly *double* the next highest investor-owned utility in the nation. These issues are explored in depth in Section III.C.5.i of this Brief.

3. **Impair the Ability to Install Solar and Storage, Contrary to State Law**: Fixed charges and dispatch obligations dampen all other price signals and discourage the installation of distributed energy resources ("DERs"), especially in disadvantaged communities. These issues are discussed in Sections III.C.1.c, III.C.5.e and III.C.11 of this Brief.

4. **Create Significant Consumer Protection Concerns**: To one degree or another, all of the Pro-Transmission Parties proposals for export compensation and/or solar fees include adjustment mechanisms that will revise solar customers' costs over the course of the lifetime of the system. Because the methodologies to calculate these elements are complex, and cannot be reasonably forecasted, they create substantial consumer protection concerns by both (i) limiting installers' ability to provide reasonable savings estimates and (ii) making administrative oversight of the successor tariff labor-intensive and unwieldy. These issues are discussed in Sections III.C.2, III.C.3 and III.C.5.g.

5. **No Transition Period, Long Implementation Timelines, and Never-Ending Litigation**: The lack of *any* transition period in the Pro-Transmission Parties' proposals demonstrates either an indifference to the fate of the workers and small companies within the DER industry, a significant lack of knowledge regarding the time it takes to translate new regulatory frameworks into marketable products, an interest in killing off the competition, an unwarranted dismissal of the experiences of other states that abruptly ended a NEM program, or some combination of these factors. Their proposals would be difficult and time-consuming to implement, and in the case of NRDC and TURN, would require at least a year of further litigation prior to implementation. NRDC's less-than-half-based "proposal," which is not supported by substantial evidence, will also require on-going litigation to update market transition credits. These issues are discussed in detail in Sections III.C.4, III.D.2, and III.D.3.

6. **<u>Reverse Progress in Equity</u>**: Rather than proposing increased access to solar for renters and multifamily properties, the restrictions in the Pro-Transmission Parties' proposals would hit low-income customers the hardest. Low-income customers are least likely to have the means to bear the cost of large fixed fees. Retroactive changes to existing tariffs are out of scope, violate California law and undermine relationships important to the ability of the State to use DERs to meet its SB 100 goals. These Issues are discussed in Sections III.C.1, III.C.5.h, III.E and IV.

7. **<u>Unreasonable Cost Recovery Periods and Reliance on Modeling With Significant Analytical Gaps</u>**: Under various analyses, including their own, the Pro-Transmission Parties payback periods are awful, severely restricting customers' ability to invest in distributed generation by requiring paybacks up to three decades long. Both the Pro-Transmission Parties and E3 substantially under-estimate the actual costs customers face to install DERs when calculating paybacks and anticipated solar adoption rates. Cal Advocates' eligibility period is shorter than its payback period, even with their faulty modeling in this case. The modeling conducted by TURN's witness in rebuttal misinterprets CALSSA's proposal, undermining much of her rebuttal testimony. These Issues are discussed in Sections III.B.1 and III.B.3, along with the elements leading to poor paybacks discussed in Sections III.C.2-3, III.C.5, III.C.6-III.C.8 and III.C.12.

8. **<u>Fail to Understand the Realities of the Energy Storage Market</u>**: Proposals like Cal Advocates' proposal to end NEM-1 and NEM-2 tariffs prematurely require a near-term, ready availability of battery storage systems that does not exist. TURN and the Joint IOUs' proposals to restrict a customer's ability to determine when and how those systems are dispatched would depress or eliminate customers' motivation to install storage in the first place. These issues are discussed in Sections III.C.1, III.C.4 and III.C.11.

For the myriad legal and policy reasons discussed in detail in this Brief, CALSSA urges the Commission to adopt CALSSA's proposal and reject the Pro-Transmission Parties' Proposals. While this Opening Brief does not address every party's proposal, components of other parties' proposals align with those of the Pro-Transmission Parties. CALSSA does not agree with those components, which suffer from the same shortcomings as those proposed by the Pro-Transmission Parties, and CALSSA likewise urges the Commission to reject them for the reasons stated herein.

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OPENING BRIEF OF THE CALIFORNIA SOLAR & STORAGE ASSOCIATION

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Commissioner Guzman Aceves's November 19, 2020 Scoping Ruling ("Scoping Ruling"),[2] Administrative Law Judge ("ALJ") Hymes's April, 8, 2021 ruling revising the schedule of this proceeding,[3] and the extension to the deadline for Opening Briefs granted by ALJ Hymes at hearing on August 3, 2021,[4] the California Solar & Storage Association ("CALSSA") hereby submits this opening brief.

I. ELECTRIFICATION AND CALIFORNIA'S SB 100 GOALS

After decades of relatively flat statewide electricity consumption, electrification will soon push California back into electric load growth. One day in the near future, California will have vehicle chargers in most homes and nearly every commercial area. It is essential that the Commission preserves a pathway for much of that new load to be served by local solar and storage to avoid ballooning costs that have not been measured accurately.

[2] R.20-08-020, *Joint Assigned Commissioner's Scoping Memo and ALJ Ruling Directing Comments on Proposed Guiding Principles*, pp. 2-4 (November 19, 2020) ("Scoping Ruling").

[3] R.20-08-020, *Email Ruling Noticing April 22, 2021 Workshop and Revising Procedural Schedul*e (April 22, 2021).

[4] 7 Tr. 1057:26-1058:5.

CALSSA's NEM-3 proposal is aimed at maintaining the average pace of adoption of customer solar from recent years, which produces approximately 1.9 terawatt-hours (TWh) of electricity per year.[5] By maintaining this pace through the end of 2030, total utility load reduction would be approximately 17 TWh.[6] For comparison, the Commission estimates that vehicle and building electrification will add 15 TWh to state load in 2030 in a reference scenario and 33 TWh in 2030 under a High Electrification scenario.[7] That is, CALSSA's proposal would barely cover the increase in load from electrification that the Commission assumes in its reference case and only half of the increased load in the High Electrification scenario.

By transitioning net metering credits to much lower mid-day value, the Commission can encourage the proliferation of customer-sited energy storage.[8] That transition is necessary to meet time-dependent customer energy needs as we continue to wean ourselves from gas-fired power plants. Punitive solar fees proposed by other parties would undermine that objective.[9]

Distributed energy storage systems will come on the back of the solar market.[10] The solar industry's network of contractors, engineers, suppliers, workforce development centers, and related participants provides the workforce that will install those resources.[11] If the market crashes before energy storage becomes a mainstream product, expertise and efficiencies will be lost.[12] Limited battery availability and high soft costs for storage projects remain barriers to full-

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5 Exh. CSA-01 at 3:9-12.

6 Exh. CSA-01 at 3:12-14.

7 Exh. CSA-01 at 2:19-21.

8 Exh. CSA-01 at 2:12.

9 *See* Section III.B.1.

10 Exh. CSA-01 at 6:10.

11 Exh. CSA-01 at 6:10-12.

12 Exh. CSA-01 at 6:12-14.

scale storage deployment.[13] The Commission must allow time for the distributed energy storage market to mature.[14]

Other parties have different visions. The utilities, and their employees, have a financial motivation to maintain a system that is heavily reliant on transmission and distribution infrastructure;[15] and the utilities' extreme proposal is clearly intended to reduce adoption of customer solar.[16] The Natural Resources Defense Council's ("NRDC") less-than-half-baked proposal will slow the installation of customer-sited solar and storage at a time when climate change is raging, wildfires are ravaging the natural environment, and Californians and their communities are at risk.[17] The Public Advocates Office at the California Public Utilities Commission ("Cal Advocates") and The Utility Reform Network's ("TURN") proposals and advocacy in this case pit one group of ratepayers against another, rather than aiming to give the same access to solar technology to all customers.[18] The wind industry prefers a generation scenario with less solar and batteries,[19] eyeing a plan to back up large-scale wind farms with natural gas peaker plants,[20] and build much more transmission to accommodate increased wind capacity.[21]

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13 *See* Section III.C.4.

14 *See* Section III.C.4.

15 *See* Exh. CSA-01 at Attachment 10.

16 *See* Section III.B.1.

17 *See* Sections III.B.1 and III.C.2.

18 *See* Section III.C.1.

19 Exh. CWA-01 at 9:9-12.

20 Exh. CWA-01 at 9:4-9.

21 Exh. CSA-28 at 6; 9 Tr. 1495:7-1499:6. (CWA – Shirmohammadi).

Most parties fighting against rooftop solar in this proceeding make claims that their proposals will lead to continued rooftop solar adoption, but they base that conclusion on an idealized solar cost that is far out of line with the documented cost of installed solar; [22] and even with that bad assumption, the customer value propositions under their proposals are far worse than the value underlying current adoption levels—some expecting customers to wait two to three decades to recover the cost of their investments.[23] The record clearly shows that proposals with solar fees violate State and Federal law and would result in greatly reduced adoption of customer solar.[24]

The Joint IOUs,[25] NRDC, TURN, and Cal Advocates are collectively referred to herein as the "Pro-Transmission Parties" because they oppose customer solar in favor of renewable energy generated outside of communities and delivered via increased grid infrastructure.

The State has not adequately studied the cost of transmission that will be needed to reach 100% renewables. The joint agency report published in March 2021 on strategies to meet SB 100 goals includes a simplified grid model to compare the costs of different portfolios of large-scale resources,[26] but does not include a transmission price tag for comparison to incremental customer-sited resources.[27] Given that the costs of transmission are unknown but certain to be astronomical, the State should not push them even higher by pursuing electrification powered exclusively by generating facilities far away from consumption. The Commission's paper,

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[22] *See* Section III.B.1.c.

[23] *See* Section III.B.1.

[24] *See* Sections III.C.5 and III.B.1.

[25] Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E").

[26] 9 Tr. 1493:21-22 and 1495:2-6 (CSA – Shirmohammadi).

[27] Exh. CSA-01 at Attachment 9.

Utility Costs and Affordability of the Grid of the Future, finds that runaway spending on transmission is the State's largest upward pressure on rates. The combined annual transmission spending of the investor-owned utilities ("IOUs") has increased to $4.3 billion in 2021, and the transmission rate base has soared to $19.2 billion.[28] Add to that $11 billion the IOUs spend each year on the distribution system.[29] All of this investment has occurred during a decade *with declining sales*.

California's commitment to decarbonization is at risk if we assume all of our clean energy can come from remote locations. Under current modeling of state goals for 100% renewable energy, the rate of large-scale solar development will need to nearly triple and remain at that elevated level every year for the next 25 years.[30] If distributed solar is reduced below current projections, the build rate of large-scale renewables would need to be even higher. The Commission should be cautious about betting that it can site transmission lines without decades of delay and can overcome obstacles to developing industrial facilities on sensitive lands. If we reduce the pace of customer solar adoption, we may not be able to make up for it with large-scale generating facilities given the realities of siting, land-use concerns, engineering challenges, and financing availability. The decision on NEM today is, in part, a decision on our long-term climate commitments,[31] and one potential outcome is that California simply fails to achieve its greenhouse gas reduction objectives.[32]

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[28] Exh. CSA-01 at 4:11-14.

[29] Exh. CSA-02 at 55 n. 153.

[30] Exh. CSA-01 at 82:19-24.

[31] Exh. CSA-01 at 87:3-7.

[32] Exh. CSA-01 at 87:3-7.

California, and the Commission in particular, should take pride in the vibrant solar industry it has helped foster. Just as the California Air Resources Board has pushed a revolution in vehicle design through decades of low emission vehicle standards, and the California Energy Commission has caused manufacturers around the world to change product design through strong energy performance standards, the California Public Utilities Commission has overseen remarkable growth in customer solar and is poised to show the world the benefits of electric grid management that is built around distributed energy storage powered locally with clean generation.

II. LEGAL STANDARD APPLICABLE TO ALL ISSUES

The successor tariff must comply with a number of different state and federal laws and regulations, including both the California Public Utilities Code and the Public Utility Regulatory Policy Act of 1978.

A. Section 2827.1 of the Public Utilities Code

Public Utilities Code Section 2827.1 requires that, in developing the successor tariff, the Commission must do all of the following:

1. Ensure that the tariff "ensures that customer-sited renewable distributed generation continues to grow sustainably";[33]
2. Ensure that the tariff "include[s] specific alternatives designed for growth among residential customers in disadvantaged communities";[34]
3. "Establish terms of service and billing rules for eligible customer-generators";[35]

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[33] Cal. Pub. Util. Code § 2827.1(b)(1).

[34] Cal. Pub. Util. Code § 2827.1(b)(1).

[35] Cal. Pub. Util. Code § 2827.1(b)(2).

4. Ensure that the tariff "is based on the costs and benefits of the renewable electrical generation facility";[36] and
5. "Ensure that the total benefits of the . . . tariff to all customers and the electrical system are approximately equal to the total costs."[37]

The Commission is tasked with adhering to and balancing these statutory requirements in its development of a successor tariff. It must also determine the appropriate statutory interpretation of any statutory language that is the subject of dispute among parties.

1. Grow Sustainably

Public Utilities Code Section 2827.1(b)(1) directs the Commission to design a successor tariff that ensures that behind-the-meter distributed generation continues to grow sustainably. To interpret the meaning of the statutory term "grow sustainably," the Commission must first look to the plain meaning of the statute; only if the Commission determines the statute's language is ambiguous must it then examine other sources of information to determine the legislative intent underlying the statute. As articulated by the California Supreme Court:

> As in any case involving statutory interpretation, our fundamental task is to determine the Legislature's intent so as to effectuate the law's purpose." . . . Statutory interpretation begins with an analysis of the statutory language . . . "If the statute's text evinces an unmistakable plain meaning, we need go no further." . . . If the statute's language is ambiguous, we examine additional sources of information to determine the Legislature's intent in drafting the statute.[38]

The plain meaning of "grow sustainably" is evident from the statute: the term clearly pertains to the continued growth of the customer-sited renewable distributed generation industry

36 Cal. Pub. Util. Code § 2827.1(b)(3).

37 Cal. Pub. Util. Code § 2827.1(b)(4).

38 *Olson v. Automobile Club of Southern California*, 42 Cal. 4th 1142, 1147 (2008).

in the State. The California Supreme Court has explained that, "[w]hen attempting to ascertain the ordinary, usual meaning of a word, courts appropriately refer to the dictionary definition of that word."[39] To "grow" means "to increase in size or amount, or to become more advanced or developed."[40] "Sustainably" means "in a way that can continue over a period of time."[41] Therefore, the plain meaning of a tariff that "ensures that customer-sited renewable distributed generation continues to grow sustainably" is a tariff that ensures the continued increase of customer-sited distributed generation in the State in a manner that can continue over a period of time. This interpretation of the plain meaning of statute is also consistent with the Commission's prior interpretation of this term in D.16-01-044, in which the Commission highlighted that its "responsibility under Section 2827.1 is to see to the continued growth of customer-sited renewable DG."[42]

If the Commission nonetheless determines that the meaning of this term under statute is ambiguous in light of the various statutory interpretations advanced by parties to this proceeding,[43] the law requires the Commission to examine "additional sources of information to determine the Legislature's intent in drafting the statute."[44] In particular, "[b]oth the legislative history of the statute and the wider historical circumstances of its enactment may be considered in ascertaining the legislative intent."[45] The Legislature's intent regarding this language is

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39 *Wasatch Property Management v. Degrate*, 35 Cal. 4th 1111, 1121-1122 (2005).

40 *See Cambridge Dictionary*, https://dictionary.cambridge.org/us/dictionary/english/grow.

41 *See Cambridge Dictionary*, https://dictionary.cambridge.org/us/dictionary/english/sustainably.

42 D.16-01-044, p. 58.

43 *See* R.20-08-020, *Proposed Decision Adopting Guiding Principles for the Development of the Successor to the Current Net Energy Metering Tariff*, pp. 8-10 (January 5, 2021).

44 *Olson v. Automobile Club of Southern California*, 42 Cal. 4th 1142, 1147 (2008).

45 *Dyna-Med, Inc. v. Fair Employment & Housing Com.*, 43 Cal. 3d 1379, 1387 (1987).

evident in the AB 327 bill analysis that informed legislators when they voted to approve this language.[46] In discussing "sustainable growth," this bill analysis refers to "whether the changes to NEM will impact the *sustained growth of the industry*."[47] It notes several matters that impact "sustainable growth" in addition to NEM, such as federal tax credits, treatment of depreciation, and customer credits for greenhouse gas reduction.[48] All of these items impact the customer economics of investing in distributed energy resources, and therefore the ability of the industry to continue to grow. This source of legislative history clearly demonstrates that in enacting AB 327, legislators understood the concept of "sustainable growth" to mean *sustained industry growth*. Further bolstering this interpretation is the fact that the Legislature approved this language in 2013, which was a period of rapid year-over-year growth of the solar market.[49] "Sustainable growth" in that context clearly meant a continuation of this market growth.

In addition, statutory provisions should be read with reference to the whole statute, as statutory interpretation is a holistic endeavor.[50] Here, the statutory context of the term "grow sustainably" informs its meaning. Until AB 327, the State's NEM program was capped.[51] As caps were reached, litigated before the Commission, or revised by the Legislature, the industry would grow in fits and starts, making it difficult for companies to craft long-term business plans to the benefit of many, including the State's economy and clean energy workforce. The

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46 Exh. CSA-01 at Attachment 11.

47 Exh. CSA-01 at Attachment 11 (emphasis added).

48 Exh. CSA-01 at Attachment 11.

49 R.20-08-020, *Reply Comments of the California Solar & Storage Association on Guiding Principles*, p. 7 n. 30 (December 11, 2020).

50 *John Hancock Mut. Life Ins. Co. v. Harris Trust & Sav. Bank*, 510 U.S. 86, 94-95 (1993) ("we examine first the language of the governing statute, guided not by 'a single sentence or member of a sentence, but looking to the provisions of the whole law, and to its object and policy.'").

51 *See* Cal. Pub. Util. Code § 2827(c)(1).

language "grow sustainably" was included in AB 327 within the context of removing the program caps, balancing the ability for onsite generation to "grow sustainably" with the ability of the Commission to "revise the standard contract or tariff as appropriate…"[52] In this context, the term "grow sustainably" represents the Legislature's desire for the program to avoid the fits and starts that the previous capped program placed on the industry's growth.

Both the plain meaning of the term "grow sustainably" and AB 327's legislative history, historical context, and statutory context confirm that the language refers to sustained industry growth. In line with this statutory directive, the Commission must therefore design a successor tariff that ensures the continued growth of the distributed generation industry in the State.

2. Approximately Equal Benefits and Costs

The statutory requirement that the Commission ensure that the total benefits of the successor tariff are approximately equal to the total costs also requires Commission interpretation. To assess cost-effectiveness, the Commission has already determined that it must use the approved tests laid out in the Commission's Standard Practice Manual, "designat[ing] the Total Resource Cost test as the primary test for analyzing the cost effectiveness of successors to the net energy metering tariff but . . . also review[ing] the Ratepayer Impact Measure and Participant Cost Test as part of the analysis."[53]

Ascertaining the meaning of the term "approximately equal" is a matter of statutory interpretation. Again, this process "begins with an analysis of the statutory language . . . 'If the statute's text evinces an unmistakable plain meaning, we need go no further.'"[54] Using a

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[52] Cal. Pub. Util. Code § 2827.1(b) and (b)(1).

[53] D.21-02-007, p. 36. *See also id.,* Finding of Fact 4, Conclusion of Law 2.

[54] *Olson v. Automobile Club of Southern California*, 42 Cal. 4th 1142, 1147 (2008).

standard dictionary definition[55] of "approximately", the plain meaning of "approximately equal" is "close to . . .[equal] although not exactly [equal]."[56] Thus, in assessing cost-effectiveness, the Commission must ensure that the total benefits and the total costs of the tariff are close to equal, although not exactly equal.

If the Commission finds ambiguity in this term, it must then examine "additional sources of information to determine the Legislature's intent in drafting the statute."[57] In particular, if a court determines a statute is ambiguous, it can consider the legislative history of the statute to inform its view of the legislative intent.[58] The legislative history of AB 327 makes clear that the Legislature was concerned with the balancing of costs and benefits to all customers, but specifically rejected the concept of ratepayer indifference in this statute. During consideration of AB 327, the Legislature deliberately stripped language from the bill that directed the Commission to "preserve nonparticipant ratepayer indifference."[59] The September 3, 2013 bill amendments replaced that language with the current language in Public Utilities Code Section 2827.1(b) on sustainable growth, disadvantaged communities, and the requirement that the benefits to all customers be approximately equal to the costs.[60] This revision to the bill's language reflects a clear legislative intent to remove the concept of ratepayer indifference from the statute in favor of a set of requirements that aims to strike a reasonable balance between cost-effectiveness concerns and other key statutory goals.

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55 *Wasatch Property Management v. Degrate*, 35 Cal. 4th 1111, 1121-1122 (2005).

56 *See Cambridge Dictionary*, https://dictionary.cambridge.org/us/dictionary/english/approximately (defining "approximately" as "close to a particular number or time although not exactly that number or time.").

57 *Olson v. Automobile Club of Southern California*, 42 Cal. 4th 1142, 1147 (2008).

58 *Dyna-Med, Inc. v. Fair Employment & Housing Com.*, 43 Cal. 3d 1379, 1387 (1987).

59 *See* Exh. CSA-01 at Attachment 8.

60 *See* Exh. CSA-01 at Attachment 8.

Indeed, in D.16-01-044, the Commission recognized this legislative history and the elimination of all references to “nonparticipants” in the statutory language, concluding that a standard focused on evaluating proposals for a successor in terms of their impact on nonparticipants would “not fully reflect the actual legislative requirement.”[61] In removing both the requirement that the tariff preserve nonparticipant ratepayer indifference, and the language requiring that the Commission ensure that the tariff is based on the costs and benefits *received by nonparticipating customers*, the “Legislature deliberately expanded the scope of statutory concern from ‘nonparticipating customers’ to ‘all customers and the electrical system.’”[62]

“Ratepayer indifference” is the concept that non-participating ratepayers should be entirely indifferent as to the participation of other ratepayers in a policy or program—they should be left unaffected by the policy, with zero cost shifts. This concept of ratepayer indifference—which is distinct from the concept of “approximately equal” costs and benefits—is well established in California. The Legislature has required “ratepayer indifference” in several policies related to distributed generation. For instance:

- In 2009, the Legislature passed SB 32, which created the renewable market adjusting tariff feed-in tariff. The bill required: “The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff.”[63]

61 D.16-01-044, pp. 54-55.

62 D.16-01-044, p. 55.

63 SB 32 (2009) (amending Cal. Pub. Util. Code § 399.20(d)(3)).

- Also in 2009, the Legislature passed AB 920 to provide compensation to net metered customers with annual net surplus generation. The bill required: "The net surplus electricity compensation valuation shall be established so as to provide the net surplus customer-generator just and reasonable compensation for the value of net surplus electricity, while leaving other ratepayers unaffected."[64]
- In 2013, the same year that the Legislature passed AB 327, it passed SB 43, which created the Green Tariff Shared Renewables program. The bill required: "The commission shall ensure that charges and credits associated with a participating utility's green tariff shared renewables program are set in a manner that ensures nonparticipant ratepayer indifference for the remaining bundled service, direct access, and community choice aggregation customers and ensures that no costs are shifted from participating customers to nonparticipating ratepayers."[65]

The Legislature that deliberated over AB 327 was aware of this concept of "ratepayer indifference," but deliberately chose <u>not</u> to include such a requirement in the statute. This context further supports the interpretation that this provision requires the total benefits and the total costs of the tariff to be reasonably balanced, although not necessarily exactly equal. This provision does not disallow cost shifting among customer groups, but rather requires an attention to the cost-effectiveness of the tariff, with a goal of costs and benefits being reasonably balanced.

B. Just and Reasonable and Non-Discriminatory

Pursuant to Public Utilities Code Section 451:

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished

64 AB 920 (2009) (amending Cal. Pub. Util. Code § 2827(h)(4)(A)).

65 SB 43 (2013) (adding Cal. Pub. Util. Code § 2833(p)).

> or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.[66]

This foundational statutory requirement is applicable to all rates and charges, including those established by the successor tariff. The Legislature reemphasized the importance of ensuring just and reasonable rates for NEM customers in Public Utilities Code Section 2827.1, requiring that "[t]he commission . . . ensure customer generators are provided electric service at rates that are just and reasonable."[67]

The Commission has recognized that, "[h]istorically, the determination of just and reasonable has emphasized cost-causation."[68] Customers should be responsible for the costs they cause the utility to incur. Cost responsibility and the fair allocation of costs among different groups of ratepayers should be determined by cost-of-service studies.[69]

The Public Utilities Code also requires rates to be non-discriminatory. Public utilities are prohibited from establishing "any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[70] Any distinct rate structure to be imposed upon a group of ratepayers must be scrutinized to ensure it is

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66 Cal. Pub. Util. Code § 451.

67 Cal. Pub. Util. Code § 2827.1(b)(7).

68 D.15-07-001, p. 2 (citing *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982) ("[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity."); *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973) (recognizing the desirability of each group's bearing its fair share of the cost of service, as such share is measured by the cost of service study); *In the Matter of the Application of PacifiCorp*, D.10-09-010 (2010)). The decision further notes: "For this reason a cost of service study is part of each general rate case for establishing electricity rates." D.15-07-001, pp. 2-3 n. 3.

69 D.15-07-001, p. 2 (citing *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973)).

70 Cal. Pub. Util. Code § 453(c).

reasonable, non-discriminatory, and well designed to recover costs caused by that group. Therefore, proponents of fees or charges that would be imposed only on one customer group—in this instance, NEM customers—must demonstrate that the cost of serving that targeted customer group is significantly different from the cost of serving other non-NEM customers, and that the fees or charges are proportionate to that cost-of-service difference.

C. Section 1757 of the Public Utilities Code

The Scoping Ruling categorized this proceeding as ratesetting.[71] The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting,[72] establishing the following standards:

- The Commission must act within "its powers or jurisdiction";
- The Commission must proceed "in the manner required by law";
- The final decision must be "supported by the findings," and those findings must be "supported by substantial evidence in light of the whole record," *i.e.*, they are based on the record or inferences reasonably drawn from the record;[73]
- The final order or decision must not be "procured by fraud" or constitute "an abuse of discretion"; and
- The final order or decision must not violate an interested person or party's rights "under the Constitution of the United States or the California Constitution."

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71 Scoping Ruling, p. 8.

72 Cal. Pub. Util. Code § 1757; *see, e.g.,* D.20-05-027, pp. 5-6 (Order Denying Rehearing of D.18-06-027, stating "As an initial matter, SDG&E cites to the wrong statute, because Public Utilities Code section 1757.1 does not set forth the applicable standards for a ratesetting proceeding like this one. Rather, section 1757 provides the appropriate standard and requires a finding as to whether the Commission's findings are not supported by substantial evidence in light of the whole record.").

73 *See, e.g.*, D.20-05-027, p. 6.

The Commission's decision and orders in this proceeding must meet these standards.

D. Protections Afforded to Customer-Generators Under PURPA.

NEM-eligible behind-the-meter solar facilities of 1 MW or less constitute Qualifying Facilities ("QFs") under the Public Utility Regulatory Policies Act ("PURPA"). QF status automatically applies to on-site solar generators up to 1 MW, including those on net metering tariffs.[74] Order No. 732 exempts QFs up to 1 MW from the filing requirement to self-certify as a QF via Form 556; as a consequence of this exemption, solar facilities up to 1 MW possess the rights and protections afforded to all QFs under PURPA.[75]

In particular, among the other rights and protections for QFs under the statute, PURPA provides that:

- Electric utilities have an obligation to purchase any energy and capacity which is made available from a QF,[76] at rates that are just and reasonable and non-discriminatory;[77]
- Electric utilities have an obligation to sell to any QF energy and capacity requested by the QF,[78] and "[r]ates for sales . . . [s]hall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility";[79]

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74 18 C.F.R. §§ 292.203(d), 292.204(b); FERC Order No. 732, 130 FERC ¶ 61,214, 2010 FERC LEXIS 507 (2010).

75 FERC Order No. 732, 130 FERC ¶ 61,214, 2010 FERC LEXIS 507, *31 (March 19, 2010). *See also Sun Edison LLC*, 129 FERC ¶ 61,146 (November 19, 2009) (recognizing onsite generators that participate in net metering as eligible for QF status even if they make no net sale of electricity to a utility).

76 18 C.F.R. § 292.303(a).

77 18 C.F.R. § 292.304(a).

78 18 C.F.R. § 292.303(b).

79 18 C.F.R. § 292.305(a)(1)(ii).

- Electric utilities have an obligation to interconnect any QF as may be necessary to accomplish these purchases or sales;[80] and
- Each electric utility must offer to operate in parallel with a QF, provided that the QF complies with certain applicable standards.[81]

The Commission's decision in this proceeding must be consistent with the rights and protections afforded to QFs under PURPA.

III. SCOPING RULING ISSUES

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

The Lookback Study has very limited value in this case because it analyzes the NEM-2 program, and few, if any, parties have proposed keeping that structure for general market residential customers moving forward. CALSSA did find the Lookback Study to be useful for its commercial cost of service analysis and its provision of customer load profiles for a variety of customer types.[82] Much of the economic modeling of distributed energy resources is dependent on the load profiles used, and it is useful for all parties to use a standard set of profiles.[83]

However, the Commission should give minimal weight to a backward facing analysis containing many key assumptions that are different, if not incomparable, to future tariff elements, grid conditions, and ratemaking structures.[84] Moreover, despite the Commission

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80 18 C.F.R. § 292.303(c).

81 18 C.F.R. § 292.303(e).

82 Exh. CSA-02 at 3:5-10. It should be noted that the profiles are bland and do not capture the diversity of customers in the real world.

83 Exh. CSA-02 at 3:5-10.

84 *See generally* R.20-08-020, *Comments of the California Solar & Storage Association on the NEM-2 Lookback Study* (February 4, 2021).

making available some of Verdant's workpapers, a number of the Study's assumptions are or appear flawed, and the source code necessary to investigate or replicate the Study's main conclusions is not provided.[85] Similar to its treatment of the Commission's E3 consultants in this proceeding,[86] the Commission did not make the Verdant analysts available for discovery or cross-examination, and re-running of Verdant's model would have been time-consuming,[87] meaning there was no opportunity to investigate or address these shortcomings on the record.

CALSSA urges the Commission to look forward, give the Lookback Study the weight such uncorroborated evidence is due, and studiously consider documented factual information that differs from the findings of the Lookback Study.

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

The legal standards for the successor tariff inform the methodologies the Commission should use to analyze parties' proposals and their resulting program elements, while ensuring the proposals comply with the guiding principles. To address the requirement that the tariff "ensures that customer-sited renewable distributed generation continues to grow sustainably,"[88] parties mostly have relied on modeling addressing the cost recovery or "payback" period of the proposals to ascertain how a proposal will affect customer adoption. Parties and the Commission have used the Commission's Standard Practice Manual tests to address the requirement that the tariff ensure the total benefits of the tariff "to all customers and the electrical system are

[85] R.20-08-020, *Reply Comments of the California Solar & Storage Association on the NEM-2 Lookback Study*, p. 1 (February 16, 2021).

[86] Exh. CSA-01 at 80:3-81:2.

[87] R.20-08-020, *Reply Comments of the California Solar & Storage Association on the NEM-2 Lookback Study*, p. 1 (February 16, 2021).

[88] Cal. Pub. Util. Code § 2827.1(b)(1).

approximately equal to the total costs."[89] The requirement that the tariff be "based on the costs and benefits of the renewable electrical generation facility" informs both of these cost-effectiveness and cost recovery analyses.[90]

While parties largely agree on the types of methodologies to be utilized, parties disagree on both the correct way to execute those methodologies and the assumptions used therein. Much of the modeling completed by the Pro-Transmission Parties is faulty and cannot be relied upon by the Commission in this case. Further, it is critical for the Commission to analyze parties' proposals and their various components in the context of electrification and the SB 100 goals, recognizing the short-coming of modeling done to date to reach those goals. The advantages of CALSSA's modeling approach and the various shortcomings in the Pro-Transmission Parties' approaches are discussed in the following sections.

1. Sustainable Growth, Cost Recovery Periods and Parties' Modeling

a. Cost Recovery Periods Are Critical to Sustainable Growth.

The best measure of whether growth in distributed generation can be steady is the consistency of the cost recovery period that is motivating to customers.[91] Often referred to as the payback period, this is the time it takes for a system owner to recover the cost of installing a solar energy system.[92] As the Joint IOUs' witnesses Tierney and Morien both noted, paybacks are important since economics are the principal reason customers go solar. [93]

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89 Cal. Pub. Util. Code § 2827.1(b)(4).

90 Cal. Pub. Util. Code § 2827.1(b)(3).

91 Exh. CSA-01 at 60:15-61:23.

92 Exh. CSA-01 at 60:15-61:23.

93 Exh. IOU-01 at 43:7-11; 3 Tr. 438:11-14 (IOU – Morien).

CALSSA's targeted cost recovery period is seven years and is based on the collective experience of its members.[94] Regardless of the size or type of the contractor, a seven-year cost recovery is the "sweet spot" for customers to sign up for a solar energy system.[95] The E3 whitepaper agrees with this focus on customer economics as the key to ensuring continued customer interest in solar, and includes a target cost recovery period of 7.5 years.[96]

It is important to keep in mind that during the cost recovery period customers are at a financial loss.[97] In the first few years past the cost recovery period the project is net positive but still may have been a poor investment considering risk/reward and other opportunities.[98] Customers do not invest their own capital in projects if the only expectation is to get their money back over time.[99] Seven years with a negative return is the upward bound of what should be considered acceptable for residential customers.[100]

For most commercial customers, a much shorter cost recovery is needed to motivate a financial decision.[101] Commercial customers nearly always have competing financial opportunities, so the decision is about the best way to use available capital to increase revenue, and there are normally other options with a timeframe of 2-3 years.[102] CALSSA is not

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[94] Exh. CSA-01 at 60:15-61:23.

[95] Exh. CSA-01 at 60:15-61:23.

[96] Exh. CSA-01 at 60:15-61:23 (citing to *See Alternative Ratemaking Mechanisms for Distributed Energy Resources in California*, California Public Utilities Commission, pp. 29-32 (January 28, 2021) ("E3 White Paper")).

[97] Exh. CSA-01 at 60:15-61:23.

[98] Exh. CSA-01 at 60:15-61:23.

[99] Exh. CSA-01 at 60:15-61:23.

[100] Exh. CSA-01 at 60:15-61:23.

[101] Exh. CSA-01 at 60:15-61:23.

[102] Exh. CSA-01 at 60:15-61:23.

suggesting that commercial customers should be guaranteed a three-year cost recovery period, but the Commission should be mindful that commercial customer investment decisions are evaluated in that context.[103]

Many customers finance the installation of solar and storage systems through loans, leases, and power purchase agreements.[104] This has opened up the market to customers that do not have enough capital to effectively purchase years of electricity in advance by buying a system outright.[105] Cal Advocates seems to take issue with the fact that paybacks for financed systems are longer, somehow concluding the increased access to solar these arrangements provide to low and middle-income customers is an equity issue.[106] However, all these longer paybacks reflect is that financing adds to the total cost, the same as securing a loan for a car or paying a mortgage on a house.[107] Cal Advocates fails to acknowledge that proposals like theirs that substantially increase cost recovery periods will only harm the same customers they are claiming to help.

Consumer Interest in Solar Drops Precipitously as the Cost Recovery Period Increases.

The National Renewable Energy Laboratory dGen model assesses market demand for residential solar under different policy assumptions.[108] In developing the model, NREL found that the portion of the eligible market base that is willing to adopt solar drops precipitously as the

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[103] Exh. CSA-01 at 60:15-61:23.

[104] Exh. CSA-01 at 60:15-61:23.

[105] Exh. CSA-01 at 60:15-61:23.

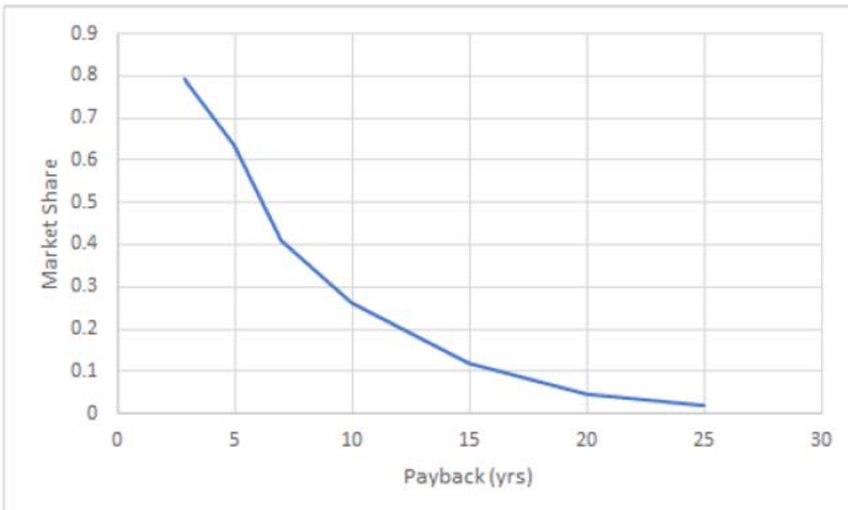
[106] Exh. PAO 2-33:5-2-35:12.

[107] Exh. CSA-01 at 60:15-61:23.

[108] Exh. CSA-01 at 61:24-62:3 (citing to *Distributed Generation Market Demand Model*, NREL, https://www.nrel.gov/analysis/dgen).

cost recovery period moves from five to ten years.[109] With a seven-year cost recovery period solar can reach 40% of the market, while at 15 years only 12% of the market will adopt solar, as shown below in Figure 14 from CALSSA's Direct Testimony:[110]

Figure 14. NREL Adoption Curve in dGen Model



Other sources reach similar conclusions that customer interest drops precipitously as the cost recovery period increases:

- A San Diego-specific NREL survey found that increasing the cost recovery period from 7 to 10 years would cut the market by about half, and market interest continues to decline at cost recovery periods beyond ten years.[111]
- Ahmad Faruqui's latest article finds: "A one-year increase in the payback period drops solar installations by 6 percent. Thus, a 10-year increase in the payback period, such as that being proposed by the utilities, would drop solar installations by more than half."[112]

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109 Exh. CSA-01 at 61:24-62:3 (citing to Ben Sigrin, National Renewable Energy Laboratory, *Diffusion into new markets: Economic returns required by households to adopt rooftop photovoltaics* (January 2014), https://www.researchgate.net/publication/282888559_Diffusion_into_new_markets_Economic_returns_required_by_households_to_adopt_rooftop_photovoltaics).

110 Exh. CSA-01 at 62, Fig. 14.

111 Exh. CSA-01 at 62:4-63:1 and p. 63, Fig. 15.

112 Exh. CSA-02 at 11:14-12:7 (citing to Ahmad Faruqui, Agustin J. Ros and Gordon E. Kaiser, *The Battles Over Net Energy Metering,* Energy Regulation Quarterly 9-2 (July 2021), *available at* https://energyregulationquarterly.ca/articles/the-battles-over-net-energy-metering).

Thus, while 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."[113]

b. Cost Recovery Period Results

Numerous Analyses – Including Their Own – Show the Pro-Transmission Parties' Proposals Will Devastate Customers' Ability to Go Solar.

CALSSA analysis of the Pro-Transmission Parties' payback period results shows those proposals would significantly diminish the number of customers willing to invest in solar. This disaster can also be seen from those parties' *own analyses* as well as the analysis E3 conducted, all of which are deeply flawed themselves, as will be discussed in the next section. Even viewed in the best light possible, *none* of the Pro-Transmission Parties' proposals can satisfy the statutory requirement that customer-sited resources will continue to grow sustainably.[114]

Proposals like those from Cal Advocates and NRDC that rely on export compensation rates tied directly to the Avoided Cost Calculator significantly increase payback periods, without even taking into consideration the large solar fees these parties would levy on customers or the fixed charge these customers would be required to pay.[115] As can be seen in the excerpts from Tables 1 and 2 below in CALSSA's Rebuttal Testimony, which uses the solar costs in Table 7 of CALSSA's Direct Testimony, changing export compensation rates to be based on the 2021 Avoided Cost Calculator results in discounted cost recovery periods of 9-18 years for standalone

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[113] Cal. Pub. Util. Code § 2827.1(b)(1).

[114] Cal. Pub. Util. Code § 2827.1(b)(1).

[115] NRDC's "proposal" would have the Commission work to set a market transition credit to make most payback periods ten years. The fatal flaws with this suggestion, which could not be completed accurately by E3, are discussed in Section III.C.4.d.

solar and 10-22 years for solar plus storage systems.[116] Given how extreme these impacts are from reducing export compensation, the Commission cannot even consider solar fees in addition to export compensation reduction without severely violating the statutory requirement for sustainable growth.

Table 1. Cost Recovery Periods for Residential Solar (Years)

		Simple			Discounted		
		PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Non-Levelized 2021 ACC	2022	9.8	10.3	8.0	12.0	12.7	9.5
	2024	12.9	13.6	10.3	16.7	18.0	12.8
	2026	12.6	12.4	9.6	15.3	16.1	11.8
	2028	12.4	11.1	8.8	13.5	14.0	10.5
	2030	12.2	10.6	8.2	12.8	13.2	9.8

Table 2. Cost Recovery Periods for Residential Solar Plus Storage (Years)

		Simple			Discounted		
		PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Non-Levelized 2021 ACC	2022	13.4	12.9	10.2	17.6	16.8	12.6
	2024	15.9	15.3	12.0	22.1	21.1	15.3
	2026	13.8	13.1	10.4	18.4	17.2	12.9
	2028	12.2	11.5	9.2	15.7	14.5	11.2
	2030	11.2	10.4	8.4	14.1	13.0	10.0

Incorporating rate requirements, solar fees, and changes to netting and true-up would obviously make cost recovery worse than the values in the tables above that evaluate the impacts of export compensation reduction alone.[117] E3's analysis of the Cal Advocates proposal, for example, shows simple paybacks of 9-16 years.[118] This uses the unrealistic solar cost of $2.34

116 Exh. CSA-02 at 9-10, Tables 1 and 2.

117 Exh. CSA-02 at 8:1-12:7.

118 Exh. CCS-01 at Attachment, E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020*, p. 34 (May 28, 2021) (listing paybacks in 2023 for Non-CARE customers between 9 and 17 years for Cal Advocates proposal for standalone solar).

per watt, and the same analysis with a real solar price would yield much longer cost recovery periods.

PG&E's own bill savings analysis shows the simple cost recovery period from their proposal to be greater than 30 years. PG&E's testimony workpapers show that a residential customer installing a 6.6 kW solar system would achieve a bill reduction of $546 in the first year,[119] which translates to a simple cost recovery period of 20.9 years using the unrealistic assumption of an installed price of $2.34 per watt.[120] A real solar price of $3.55 per watt for 2022 results in simple cost recovery of 31.8 years.[121] Both examples assume the 2022 level of the federal Investment Tax Credit of 26%, which will not be in place in 2024 and beyond according to current law. [122]

The cost recovery periods in the Joint IOUs' own testimony (which also use the unrealistic solar cost of $2.34 per watt)[123] are terrible, as seen in Table IV-14 from their Direct Testimony.[124] These payback periods also include rate escalation for future years without applying a discount rate to those future years, which makes them shorter than simple payback.[125]

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119 Exh. CSA-02 at 4:13-5:7.

120 Exh. CSA-02 at 4:13-5:7.

121 Exh. CSA-02 at 4:13-5:7.

122 Exh. CSA-02 at 4:13-5:7.

123 Exh. CSA-02 at 4:21.

124 Exh. IOU-01 at 105, Table IV-14.

125 Exh. CSA-02 at 4 n. 14.

Table IV-14
Joint Utilities Proposal -- Illustrative Estimated Payback Periods of Participating DG-ST Customers

Utility	Estimated Payback (Standalone Solar)	Estimated Payback (Solar+Storage)
PG&E	19 years	14 years
SCE	18 years	12 years
SDG&E	15 years	11-years

As noted above in the discussion of PG&E workpapers for this table, using a real solar price would push simple paybacks beyond 30 years. As Joint IOU Witness Morien admitted, the IOUs have no documentation, and did not conduct any research, showing payback periods from 11-19 years would result in customers investing in solar,[126] let alone those that approach 30 years.

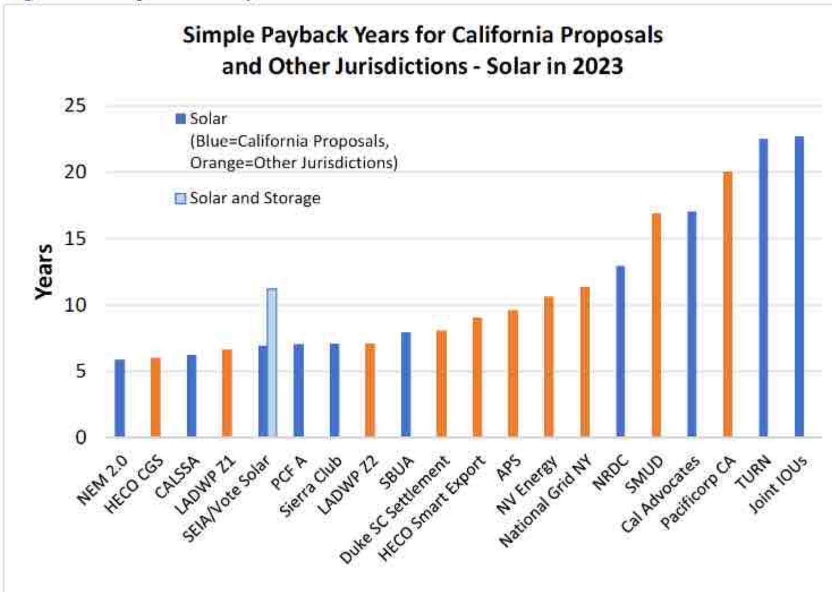
An IOU response to a CALSSA data request also failed to cite any documentation, although it did point to the North Carolina State study attached to the IOUs' direct testimony.[127] However, the "comparable" payback periods that the IOUs calculated for those states' reforms are incorrect, as shown clearly in Figure 14 from Solar Energy Industries Association ("SEIA")/Vote Solar Witness Beach's Direct Testimony, which shows a revised, more reasonably calculated version of Figure 3 in the Joint IOUs' Proposal:[128]

126 3 Tr. 440:16-23 (IOU – Morien).

127 Exh. CSA-09.

128 Exh. SVS-01 at 55, Fig. 14 and 53:5-55:7.

Figure 14: *Simple Solar Paybacks in 2023*



By its own admission, TURN's proposal is worse. Without a market transition credit, which TURN would prohibit for non-CARE standalone solar customers and only encourage for solar + storage customers,[129] simple payback periods range between *20 and 35 years*, and discounted payback periods are all well beyond 20 years. To quote TURN's own direct testimony: "[I]n the absence of a MTC incentive, TURN's Successor Tariff proposal is not expected to be economic for participants."[130]

CALSSA's Proposal Maintains the Solar Value Proposition

In contrast, CALSSA's proposal keeps the cost recovery in the "sweet spot" of right around seven years for standalone residential storage and between 7-10 years for solar plus storage systems, also shown below in excerpts from Tables 1 and 2 in CALSSA's Rebuttal Testimony:[131]

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129 Exh. TRN-01 at 54:4-5; Exh. TRN-03 at 70:14-19.

130 Exh. TRN-01 at 67:14-15.

131 Exh. CSA-02 at pp. 9-10, Tables 1 and 2.

Table 1. Cost Recovery Periods for Residential Solar (Years)

		Simple			Discounted		
		PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
CALSSA Proposal	2022	6.3	7.3	5.3	7.2	8.6	6.0
	2024	8.2	9.2	6.8	9.7	11.2	7.9
	2026	8.0	8.7	6.6	9.4	10.5	7.7
	2028	7.8	8.2	6.3	9.2	9.8	7.2
	2030	7.7	7.7	6.5	9.0	9.1	7.5

Table 2. Cost Recovery Periods for Residential Solar Plus Storage (Years)

		Simple			Discounted		
		PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
CALSSA Proposal	2022	8.7	10.1	7.6	10.5	12.5	8.9
	2024	10.2	11.5	8.8	12.5	14.6	10.5
	2026	9.0	10.0	7.7	10.9	12.3	9.1
	2028	8.3	8.9	7.2	9.9	10.8	8.4
	2030	7.6	8.0	6.7	8.9	9.5	7.7

The cost recovery periods for solar with storage in Table 2 form CALSSA's Rebuttal Testimony above include aggressive assumptions for the reduction in storage costs, and the periods are still longer for solar with storage than solar without storage.[132] The Commission should approve a smaller reduction in export compensation for systems that contain energy storage, as proposed by CALSSA.[133] Even the reductions in installed costs used in this analysis are far from certain, especially in the short term, as explained in more detail in Section III.C.4 of this Opening Brief, discussing Glidepaths.

Cal Advocates' rebuttal testimony includes a criticism of the assumptions used in CALSSA's payback analyses, erroneously suggesting CALSSA assumed a 0.8 percent decline in

132 Exh. CSA-02 at 11:1-13.

133 Exh. CSA-01 at 7, Table 1.

solar PV costs from 2019-2020.[134] As demonstrated during the cross examination of the Cal Advocates witness sponsoring that testimony, and in light of Exhibit CSA-20, CALSSA's workpapers actually demonstrate that it assumed a 5% decline in PV costs from 2019-2020.[135] Cal Advocates' error undermines its critique.

c. Short-Comings in the Pro-Transmission Parties' Modeling

Modeling Using an Idealized Cost of Residential Solar That Does Not Reflect Real-World Pricing Results in Under-Estimates of Cost-Recovery Periods, Especially for Small Companies.

It is essential to have an understanding of the customer cost of solar to get a reasonable estimate of a typical cost recovery period.[136] Estimated cost recovery is not meaningful if it is based on a cost that is not available to customers.[137] That is the case with the estimates in the E3 Comparative Analysis and in the proposals of the Joint IOUs, NRDC, and TURN,[138] all of which use a $2.34 per watt cost of solar derived from the NREL Annual Technology Baseline.[139]

The Annual Technology Baseline is an ongoing study of the costs of energy generation technologies.[140] It is a bottom-up analysis, adding up the costs of components and estimated labor costs, rather than an analysis of actual market prices.[141] It is a *baseline* of the cost to go

[134] Exh. PAO-02 at 3-11:7-8.

[135] Exh. CSA-20; 6 Tr. 935:11 to 940:10 (PAO – Gutierrez).

[136] Exh. CSA-01 at 63:7-67:10.

[137] Exh. CSA-01 at 63:7-67:10.

[138] Exh. CSA-01 at 63:7-67:10.

[139] 3 Tr. 441:17-442:20, 442:12-16, and 442:21-26 (IOU – Morien); 9 Tr. 1546:25-1547:1 (TRN – Chait); Exh. CSA-1; Exh. CSA-01 at 63:7-67:10.

[140] Exh. CSA-01 at 63:7-67:10.

[141] Exh. CSA-01 at 63:7-67:10.

solar, *i.e.*, a starting point, meaning it misses a lot of real world costs; it is an *ideal* cost rather than an *actual* cost.[142]

NREL itself recognizes that there are costs that lie between the ideal costs and the true costs.[143] Its most recent annual report states, "Our benchmarking method includes bottom-up accounting for all *necessary* system and project development costs incurred when installing U.S. residential PV systems."[144]

As IOU Witness Morien acknowledged during hearing, if costs are higher than those used in a party's modeling, the payback periods will be longer than those suggested in testimony or analyses.[145] Costs that are left out of the Annual Technology Baseline estimate include main panel upgrades, permitting and interconnection delays, and financing costs.[146] The Annual Technology Baseline is based on a cash purchase, *i.e.*, it does not include the costs of financing a system for standalone solar.[147] Thus, the cost recovery periods calculated by the IOUs, E3, Cal Advocates, and TURN will be shorter than those for systems that used financing.[148]

In the IOUs' direct testimony, IOU witness Tierney states that smaller solar companies rely on customer adoption and ownership, with loans provided by banks and credit unions.[149] Thus, the costs excluded from the IOUs' assumptions mean cost recovery periods are likely to be

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142 Exh. CSA-01 at 63:7-67:10.

143 Exh. CSA-01 at 63:7-67:10.

144 Exh. CSA-01 at 63:7-67:10 (citing to *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020*, pp. 24-25, NREL, *available at* https://www.nrel.gov/docs/fy21osti/77324.pdf) (emphasis added).

145 3 Tr. 442:27-443:7; 447:23-448:2 (IOU – Morien).

146 Exh. CSA-01 at 63:7-67:10.

147 3 Tr. 444:12-18 (IOU – Morien); Exh. CSA-07.

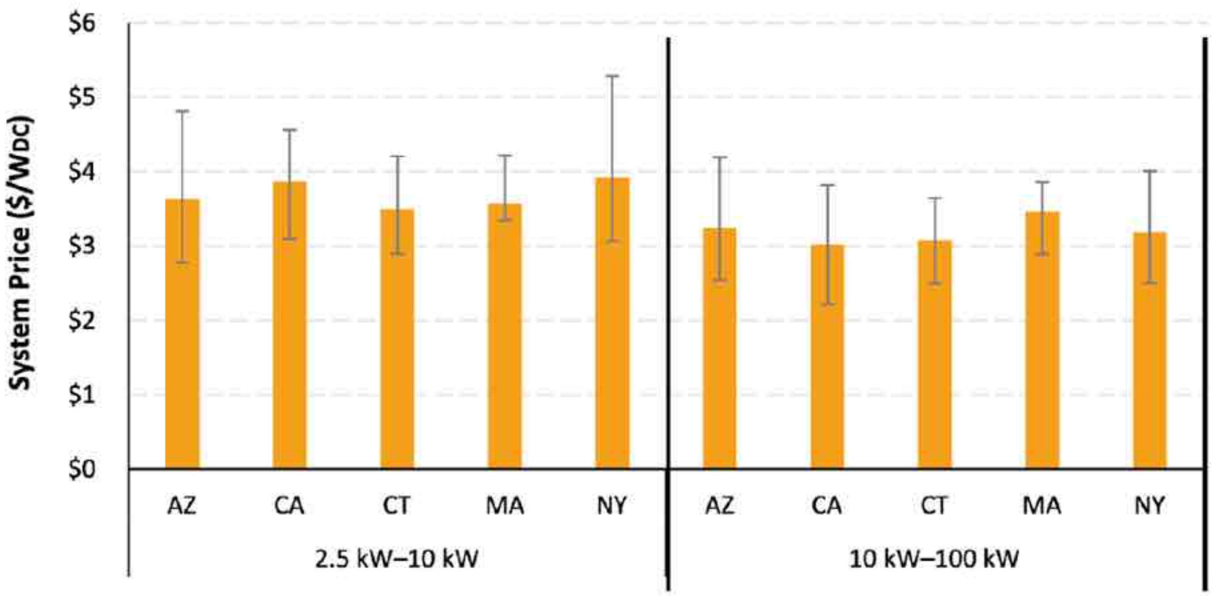
148 3 Tr. 444:19-25 (IOU – Morien).

149 Exh. IOU-01 at 49-1-2.

longer than the IOUs' assume, especially for customers using loans to purchase distributed energy systems from small companies.

There are other, more realistic sources for the actual cost of solar to be used in modeling cost recovery periods. The National Renewable Energy Laboratory itself released an update on the actual customer cost of solar in California on July 12, 2021.[150] NREL found costs of slightly less than $4 per Watt for residential customers.[151] That true market price is far above the theoretical residential price of $2.34/W used by the Pro-Transmission Parties and E3 in their payback modeling, as seen in Figure 1 of CALSSA's Rebuttal Testimony:[152]

Figure 1. Average Solar Pricing from NREL 2021 Update



In addition, Lawrence Berkeley National Laboratory publishes an annual study that is more aligned with the needs of this proceeding because it is based on the actual costs that

150 Exh. CSA-02 at 6:6-7:2.

151 Exh. CSA-02 at 6:6-7:2.

152 Exh. CSA-02 at 6, Fig. 1.

customers pay.[153] As opposed to the theoretical bottom-up analysis from NREL's Annual Technology Baseline, the annual "Tracking the Sun" report analyzes and summarizes actual installed prices.[154] It is now in its 13th edition.[155] The most recent version, published in December 2020, shows that the average cost of solar to residential customers in California was $3.80 per Watt in 2019.[156] Cal Advocates appropriately calculated its payback modeling with figures from Lawrence Berkeley National Laboratory,[157] but its analysis suffers from numerous other flaws discussed later in this section.

The one source of actual reported solar system cost data in California is the California Distributed Generation Statistics database, which is maintained under contract with the Commission.[158] That true California data shows residential solar declined very slightly from $4.28/W in January 2019 to $4.03/W in February 2021.[159] As shown in Figure 2 from CALSSA's Rebuttal Testimony, costs increased dramatically in the most recent two months of data, which may be short-term impacts of global supply chain disruptions: [160]

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153 Exh. CSA-01 at 63:7-67:10.

154 Exh. CSA-01 at 63:7-67:10.

155 Exh. CSA-01 at 63:7-67:10.

156 Exh. CSA-01 at 63:7-67:10.

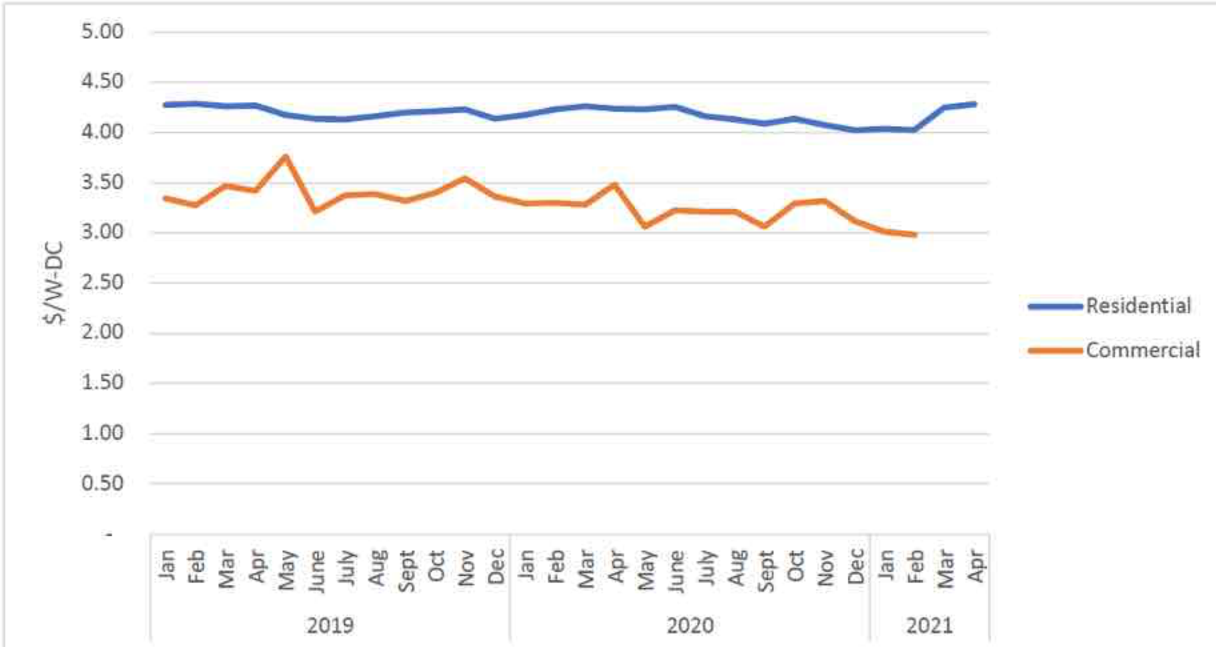
157 12 Tr. 2093:28 to 2094:24 (PAO – Buchholz).

158 Exh. CSA-02 at 6:14-7:2.

159 Exh. CSA-02 at 6:14-7:2.

160 Exh. CSA-02 at 6:14-7:2 and p. 6, Fig. 2 (with n. 17 explaining: "California Distributed Generation Statistics, *available at* californiadgstats.ca.gov. This analysis only includes solar systems without storage and does not include records with prices higher than $9/W or lower than $1/W under the presumption that data entry for such records was inaccurate.").

Figure 2. Monthly Average Solar Price in Interconnection Data[17]



All of these sources show the Commission's consultant and the Pro-Transmission Parties are under-estimating the cost recovery periods.

The IOUs' Storage Modeling Also Fails to Reflect Real-World Pricing.

Similar to the shortcomings in their modeling for the cost of standalone solar, the IOUs modeling of the cost of residential storage systems excludes costs that extend the payback periods for those technologies. The IOUs simply went to Tesla's website to obtain the cost of storage systems of $740/kWh that were used to calculate the IOUs' solar plus storage payback periods.[161] However, as the IOUs' admitted, those costs not only exclude financing, they also exclude the costs of "additional upgrades", such as upgrades to the "electrical main panel" and the costs of "hidden conduit."[162]

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161 3 Tr. 446:7-447:3 (IOU – Morien); Exh. CSA-10.

162 3 Tr. 447:22 (IOU – Morien); Exh. CSA-07.

Additional Costs in Other Party Proposals

Beyond low-balling the cost of solar and solar plus storage installations that residential customers face, the payback periods TURN and the Joint IOUs calculated also exclude other costs contained in their own proposals. TURN's payback estimates do not include the $900 cost of installing a production meter for either standalone or storage-paired solar PV resources, despite requiring the meter on storage-paired resources.[163] TURN also excludes the as-yet-unknown cost of providing access to real-time wholesale market price information that is part of its export compensation regime.[164] Elongating the cost recovery periods in the Joint IOUs' proposal are hidden costs tied to the new obligations in the Joint IOUs' Proposal of active cyber-security monitoring ($50-$150/year over the lifetime of the system plus costs to secure router and wireless network devices), inverter compliance with the IEEE 2030.5 networking standards ($200 plus any network-related costs), and commissioning tests to validate new communications technologies (costs currently unknown).[165] All of these costs would be customers' responsibility under these parties' proposals but are not included in their estimated payback periods.

The Cost of Solar for Commercial Customers

The NREL Annual Technology Baseline values for commercial solar systems are unrealistic for the same reasons as the residential values.[166] The 2020 capital cost for

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163 9 Tr. 1524:17-1525:21 (TRN – Chait).

164 Exh. CSA-01 at 75-77, Table 11 (citing to various parties' proposals and discovery requests attached to Exh. CSA-01).

165 Exh. CSA-01 at 75-77, Table 11 (citing to various parties' proposals and discovery requests attached to Exh. CSA-01).

166 Exh. CSA-01 at 67:11-71:3.

commercial solar systems is $1.74/W.[167] For its analysis of NEM-3 proposals, E3 uses the 2023 value of $1.53/W.[168] However, the actual costs are much higher, approaching $2.62/W in 2020, which was the median price among 270 projects quoted by Belvedere partners – a prominent solar financing entity that reviews recent trends in solar costs – as shown in Figure 19 from CALSSA's Direct Testimony:[169]

Figure 19. Belvedere Finance Distribution of Project Costs for Commercial Rooftop Solar in 2020

The experience from Belvedere Finance is consistent with data from LBNL's Tracking the Sun report.[170] The most recent version of that report found that the average cost of solar in California was $3.20/W for small commercial customers and $2.50/W for large commercial customers in 2019.[171] Thus, E3 and other parties to this proceeding are underestimating the costs

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167 Exh. CSA-01 at 67:11-71:3.

168 Exh. CSA-01 at 67:11-71:3.

169 Exh. CSA-01 at 70, Fig. 19.

170 Exh. CSA-01 at 67:11-71:3.

171 Exh. CSA-01 at 67:11-71:3.

of installing solar on commercial systems, undermining the results of the payback analyses they present.

The Commission Should Not Rely Upon Cal Advocates Payback Modeling

There are numerous problems with the modeling Cal Advocates did to calculate payback periods. First, generally speaking, the workpapers supporting Cal Advocates analyses are a mess. During hearings, Cal Advocates admitted that various portions of its workpapers were "outdated",[172] "incorrect",[173] or irrelevant to its proposal.[174]

Second, Cal Advocates correctly used LBNL 2019 solar costs as a starting point, but applied an annual decline rate of 5.8% in the cost of solar PV from 2019-2022 based on NREL numbers.[175] However, the actual California residential solar prices, as documented by LBNL, show a very different trend, with only a 3.6% annual decline between 2014-2019.[176] Witness Gutierrez admitted that Cal Advocates does not have any evidence that the annual rate of decline in solar costs has increased in the past two years and will continue to increase.[177] Thus, Cal Advocates' assumption for a 2022 solar cost is unrealistic.

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[172] 6 Tr. 946:3-7 (PAO – Gutierrez) ("The formula in this tab is a little outdated in that O&M costs are not subtracted from the savings on this tab, rather added in as a one-time cost to the upfront cost of the system.").

[173] 6 Tr. 947:5-10 (PAO – Gutierrez).

[174] Exh. CSA-14; 11 Tr. 1938:16 to 1939:10 (PAO – Gutierrez and Chau).

[175] 6 Tr. 942:21 to 943:16 (PAO – Gutierrez).

[176] *See* Exh. CSA-21; 6 Tr. 943:17-28 (PAO – Gutierrez).

[177] 6 Tr. 944:22-27 (PAO – Gutierrez).

Third, Cal Advocates includes rate escalation in its payback estimates,[178] but it does not include a discount rate in those estimates.[179] These estimates are shorter than a simple payback calculation and should not be considered as such.[180]

Lastly, Cal Advocates' calculations of annual bill savings are extremely (and unnecessarily) complicated. Witness Gutierrez agreed that a "common method" of calculating customer annual bill savings as part of a payback period estimate would be to model a sample customer's bill before and after installation, and then include sensitivities.[181] However, Cal Advocates did not use this common method.[182] Instead, Cal Advocates relied on an incredibly complex methodology to calculate annual bill savings per kilowatt for all residential customers as a whole using Cal Advocates' cost burden model.[183] This involves estimating total reduction in utility collections for each individual component of each rate separately,[184] using a projection from the IOUs of the total solar capacity and generation of each customer class,[185] and adjusting it according to a separate IOU estimate of the portion of generation that is exported to the grid.[186] Comparing utility revenue reduction to total solar capacity yields a value for customer savings per kW, which can then be compared to solar system cost per kW to produce a payback period.

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178 6 Tr. 949:6-9 (PAO – Gutierrez).

179 6 Tr. 949:18-21 (PAO – Gutierrez).

180 6 Tr. 949:10-14 (PAO – Gutierrez).

181 11 Tr. 1946:16 to 1947:6 (PAO – Gutierrez and Chau).

182 11 Tr. 1939:16-20 and 1946:2-15 (PAO – Gutierrez and Chau).

183 11 Tr. 1939:16 to 1943:25 (PAO – Gutierrez and Chau); Exh. PAO-01 at 2-41:1-19.

184 11 Tr. 1940:11-14 (PAO – Gutierrez and Chau).

185 11 Tr. 1943:2-8 (PAO – Gutierrez and Chau).

186 11 Tr. 1940:22-27 (PAO – Gutierrez and Chau).

This unbelievably complicated methodology is prone to error and involves assumptions that are unnecessary when it is possible to simply measure a customer's bill before and after installing solar to determine bill savings and payback periods. The Commission should not rely on Cal Advocates' creative approach to estimating cost recovery periods in reaching its decision in this proceeding.

d. Cal Advocates' Faulty dGen Modeling

Beyond its payback modeling, Cal Advocates' testimony includes projections of solar market growth under its proposal using the dGen model from the National Renewable Energy Laboratory, presented in Figure 5-3 of direct testimony.[187] This modeling does not model Cal Advocates' proposal accurately.[188] At the outset, one clear flaw is that Cal Advocates uses the theoretical and unrealistic solar price data from the NREL Annual Technology Baseline in its dGen modeling rather than any data source of real market pricing.[189] That approach is also inconsistent, as Witness Buchholz confirmed, with their use of solar cost derived from LBNL data to estimate payback periods.[190]

Beyond using the wrong cost of solar, Cal Advocates staff did not run the model themselves for testimony or sufficiently review inputs and outputs of the dGen modeling. Instead, Witness Buchholz confirmed Cal Advocates relied on NREL to perform the dGen modeling[191] and deferred to NREL's selection of certain inputs to its modeling.[192] In fact, on

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187 Exh. PAO-3 at 5-11:3-12.

188 Exh. CSA-02 at 15:17-16:3.

189 Exh. CSA-02 at 15:17-16:3.

190 12 Tr. 2093:28 to 2094:24 (PAO – Buchholz).

191 Exh. CSA-02 at Attachment 13; 12 Tr. 2093:16-27 (PAO – Buchholz).

192 12 Tr. 2094:20-26 (PAO – Buchholz).

redirect examination, Cal Advocates' attorney asked witness Buchholz to confirm that he did not "oversee" NREL's efforts, but "merely provide[d] them with guidance[] for the modeling that [he] needed them to do."[193] Witness Buchholz further admitted that he did not even obtain the raw output files of this modeling in order to thoroughly review and verify them before presenting this modeling in his testimony.[194] He said he did not receive the raw output files from NREL at all,[195] but then stated that he produced raw output files on his own and compared them to the NREL raw output files, which he had just admitted he never received.[196] The Commission should conclude that Cal Advocates' dGen modeling was not properly validated.

Even though a "common approach" would be to run the model under historic conditions to make sure it produces results that have been observed historically, Witness Buchholz was "not sure if they did exactly that here in this case."[197] Therefore, by using market data external to dGen for the historical portion of Figure 5-3, and dGen modeling with a faulty solar cost assumption for the post-2020 portion of the figure, the analysis effectively assumes a price reduction from the 2020 actual market price of $3.77 per watt[198] to a 2022 theoretical price of approximately $2.34 per watt. This unrealistic reduction explains how the figure can show strong market activity under the Cal Advocates proposal despite a sharp reduction in customer bill savings.[199] It is essentially cooking the numbers to achieve a desired result.

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193 12 Tr. 2115: 1-9 (PAO – Buchholz).

194 12 Tr. 2097:20 to 2098:3 (PAO – Buchholz).

195 12 Tr. 2096:13-16 (PAO – Buchholz).

196 12 Tr. 2096:22-28 (PAO – Buchholz).

197 12 Tr. 2107:8-28 (PAO – Buchholz).

198 Exh. CSA-01 at 67, Table 7.

199 12 Tr. 2104:24-26; 2100:17-2102:4 (PAO – Buchholz).

Due to the lack of close review by the sponsoring witness, and the poor modeling approach, the data in Cal Advocates' Figure 5.3 should be given no weight.

e. The CEC Mandate is Not a "Guarantee" of Anything.

Cal Advocates, NRDC and others make the specious claims that the Title 24 New Home Solar Mandate will "guarantee" growth in solar.[200] These claims are incorrect and ignore the context in which the mandate was approved.

Public Resources Code section 25402(b)(3) contains the following requirement:

> The standards adopted or revised pursuant to subdivision (a) and this subdivision <u>shall be cost-effective when taken in their entirety and when amortized over the economic life of the structure compared with historic practice</u>. When determining cost-effectiveness, the commission shall consider the value of the water or energy saved, impact on product efficacy for the consumer, and the life-cycle cost of complying with the standard.[201]

In order to adopt the building standard, the California Energy Commission ("CEC") had to demonstrate that it was cost effective for homebuyers.[202]

The CEC hired E3 to perform the mandated cost effectiveness analysis.[203] As CALSSA Witness Heavner explained during cross examination, E3 analyzed two potential NEM reforms, one of which was an extreme scenario where both exports and self-generation were valued at avoided costs.[204] This scenario is similar to the Pro-Transmission Parties' proposals when the solar fee is taken into account.[205] E3 found that the mandate would *not* be cost effective for

200 Exh. PAO-3 at 5-10:11-14; Exh. NRD-01 at 9:16-18.

201 Cal. Pub. Resources Code § 25402(b)(3) (emphasis added).

202 Exh. CSA-02 at 14:10-15:16.

203 Exh. CSA-02 at 14:10-15:16.

204 7 Tr. 1081:22-1082:2 (CSA – Heavner and Plaisted); Exh. CSA-02 at 14:10-15:16.

205 7 Tr. 1082:11-13 (CSA – Heavner and Plaisted).

participants in all climate zones in that scenario,[206] and, for the other climate zones, the results were at or near 1.0, representing "extremely marginal cost-effectiveness."[207] Moreover, the value E3 used for avoided costs in its study was not disclosed, but since it was done by E3 in 2017, we can presume it is a higher value than the 2021 Avoided Cost Calculator.[208] Further, as noted by Witness Plaisted, it is unlikely E3 would have included rates with the high fixed charges currently being proposed by NRDC and the IOUs.[209] The results in 2017 are likely much better than they would be today.

Even if a new analysis arrived at the same results as the 2017 analysis, it is very unlikely the California Energy Commission would vote to continue a mandate on *all* customers based on such "extremely marginal cost effectiveness."[210] The values are too tight for such a universal mandate; [211] there needs to be a comfortable margin to demonstrate that nearly all customers would not be harmed by the mandate.[212] For example, the CEC approved the mandate when NEM-2 was the predominant tariff and carried a resulting cost-benefit ratio for participants of 2.0 across all climate zones.[213]

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206 *Building Energy Efficiency Measure Proposal to the California Energy Commission for the 2019 Update to the Title 24 Part 6 Building Energy Efficiency Standards, Rooftop Solar PV System*, p. 46, Table 20, Energy and Environmental Economics, Inc. (September 2017), *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=221366&DocumentContentId=27228.

207 7 Tr. 1084:20-24 (CSA – Heavner and Plaisted).

208 7 Tr. 1081:22-1082:2; 1085:14-16 (CSA – Heavner and Plaisted).

209 *See* 7 Tr. 1085:17-21 (CSA – Heavner and Plaisted).

210 7 Tr. 1084:20-24 (CSA – Heavner and Plaisted).

211 7 Tr. 1084:20-24 (CSA – Heavner and Plaisted).

212 7 Tr. 1084:28-1085:2 (CSA – Heavner and Plaisted).

213 7 Tr. 1087:9-12; 7 Tr. 1118:9-17 (CSA – Heavner and Plaisted).

The New Home Solar Mandate will therefore be in danger if any of the Pro-Transmission Parties' proposals are adopted.[214] The argument that the New Solar Homes Mandate is a guarantee of continued solar growth is overly simplistic; a much more likely result is that the CEC would cancel the New Home Solar Mandate if the Commission adopts the changes to net metering proposed by the Pro-Transmission Parties because of the anemic cost recovery periods resulting from those proposals.

2. Cost-Effectiveness and Cost-Shift Analyses

Public Utilities Code Section 2827.1(b)(4) requires that the Commission "[e]nsure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs."[215] As discussed above, this provision does not disallow cost shifting among customer groups, but rather requires an attention to the cost-effectiveness of the tariff, with a goal of costs and benefits being reasonably balanced.

Further, the Commission has determined that "the [Total Resource Cost ('TRC') test is] the primary test for evaluating the cost-effectiveness of distributed energy resources, except where prohibited by statute or Commission decision."[216] While the Commission has made clear that future DER proceedings should generally also include a review and consideration of all the cost-effectiveness tests,[217] the Commission has emphasized that "RIM and [Program

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214 Exh. CSA-02 at 14:10-15:16.

215 Cal. Pub. Util. Code § 2827.1(b)(4).

216 D.19-05-019, Conclusion of Law 2.

217 *Id.*, Conclusion of Law 3. *See also id.*, p. 24 ("we require the review and consideration of the RIM and PAC tests results during deliberation of all distributed energy resources proceedings and advice letters where cost-effectiveness analyses are required, including distributed energy resources reporting and evaluation requirements. The record indicates each of the tests have value. *However, RIM and PAC test results should only be considered supplemental to the TRC test results*") (emphasis added).

Administrator Cost ('PAC')] test results should only be considered supplemental to the TRC test results."[218]

The Commission's Standard Practice Manual, which serves as the foundation of cost-effectiveness analysis for all demand-side resources, also reinforces this principle that these tests should not be used in isolation. It provides that, with regard to the different cost-effectiveness tests, "[t]he tests set forth in this manual are not intended to be used individually or in isolation . . . This multi-perspective approach will require program administrators and state agencies to consider tradeoffs between the various tests."[219] Thus, the cost-effectiveness tests must be viewed in concert with each other, with the TRC test leading the way.

a. Shortcomings in SB 100 Modeling.

Avoiding spending on transmission and distribution infrastructure should be a primary consideration of the Commission in developing net metering policy and considering the cost-effectiveness of that policy.[220] Utility-scale renewables development will require new transmission capacity at a time when siting and paying for additional transmission appears more challenging than ever.[221]

The Joint Agency SB 100 report models scenarios for achieving California's 100% renewable goal, but barely begins to describe the amount of transmission that will be needed.[222]

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218 *Id.*, p. 24.

219 *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, p. 6, California Public Utilities Commission (October 2001), *available at* https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf ("Standard Practice Manual").

220 Exh. CSA-02 at 3:14-4:12.

221 Exh. CSA-01 at 84:4-87:7.

222 Exh. CSA-01at Attachment 9.

As noted by SCE, SDG&E, the California Independent System Operator ("CAISO"), the California Wind Energy Association ("CalWEA"), and NRDC in comments on the draft SB 100 report, increased transmission needs were not studied sufficiently in SB 100 modeling.[223] CALSSA's Direct Testimony includes important statements from these parties that: "Until that modeling is performed, the transmission costs associated with the delivery of power that would be needed to support the resource mix will be understated"; "modeling results *imply* a significant need for new transmission"; and "Experience with RESOLVE, in particular, shows that many important policy considerations are not readily quantifiable and therefore are either ignored or require manual workarounds to capture."[224] CalWEA states in comments to the CEC: "Because the Draft Report pays scant attention to the value of resource diversity, it is not surprising that it does not call attention to the actions that must be taken in the near term … including workforce training and development of the state's *transmission* and ports infrastructure."[225]

Of particular note are CAISO's comments that replacing gas-fired generation that is located close to load with renewable generation that is far from load is not an equal trade in terms of transmission needs.[226] The fact is long-term transmission needs, beyond the ten-year CAISO planning horizon, have not been studied sufficiently and are almost certain to be vast even with a continuation of DER adoption.[227]

[223] Exh. CSA-01 at 84:4-87:7; Exh. CSA-28 at 6.

[224] Exh. CSA-01 at 84:9-85:16.

[225] Exh. CSA-28 at 6.

[226] Exh. CSA-01 at 84:4-87:7.

[227] Exh. CSA-02 at 3:14-4:12.

Closer Scrutiny of CalWEA's Rebuttal Testimony Demonstrates the Insufficiency of Transmission Modeling Done to Date.

One of the parties criticizing the SB 100 Report was CalWEA, who recognized that much more transmission would be needed to accommodate increased wind capacity.[228] Despite such statements, and despite not filing either a legitimate proposal or direct testimony in this case, CalWEA filed rebuttal testimony asserting that such study has been completed. However, admissions from CalWEA's witness during cross examination confirm CALSSA's positions rather than support CalWEA's.

There are three key inputs to the SB 100 Report, the first two of which inform CAISO's transmission planning process:

- The Generator Interconnection and Deliverability Allocation Procedures ("GIDAP"), which is the "primary source of information for transmission capability estimation."[229]
- CAISO transmission plans;[230] and
- E3's RESOLVE Model[231]

CalWEA's witness admitted a number of the shortcomings to each of these inputs on the stand. First, the GIDAP includes a high volume of projects that will never be built, some of which have been in the queue for 10-15 years,[232] undermining its credibility as a source to rely on for transmission upgrades. Second, the CAISO Transmission Plan only has a 10-year planning

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[228] Exh. CSA-28 at 6; 9 Tr. 1495:7-1499:6. (CWA – Shirmohammadi). The Report was not revised in response to CalWEA's comments. 9 Tr. 1498:21-23.

[229] Exh. CSA-26 at 4, 7 (emphasis added).

[230] Exh. CSA-26 at 7.

[231] 9 Tr. 1493:7-15 (CWA – Shirmohammadi).

[232] 9 Tr. 1487:22-1488:3 (CWA – Shirmohammadi).

horizon,[233] meaning one key source for the needed transmission upgrades to meet SB 100's 2040 goals did not look past 2030.

The results of the third source, the RESOLVE model, are problematic because its conclusions on where projects can ideally be sited on the transmission system do not reflect reality. First, RESOLVE only uses a simplified version of the CAISO transmission system – it does not include all of the details of that system.[234] Further, when RESOLVE selects capacity for a particular preferred location on the transmission system, it only analyzes the location-specific cost of developing a project at the level of the Competitive Renewable Energy Zone – it does not do a site-specific analysis of such costs.[235]

In contrast, generators enter the GIDAP with a set size and location, with the latter typically chosen based on costs related to environmental and land issues.[236] While recently developers have hired transmission consultants to assess transmission capacity availability,[237] Witness Shirmohammadi admitted that a project has no knowledge of *deliverability* to load until the CAISO performs a study of that project in relation to all other projects currently in the queue.[238] Deliverability is what matters for a project to provide resource adequacy capacity,[239] a feature that nearly all load-serving entities require of generators today due to the need to meet resource adequacy obligations.[240] Thus, when RESOLVE chooses a site for a project to be built,

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233 9 Tr. 1493:2-6 (CWA – Shirmohammadi).

234 9 Tr. 1493:16-24 (CWA – Shirmohammadi).

235 9 Tr. 1493:25-1495:6 (CWA – Shirmohammadi).

236 9 Tr. 1488:20-1490:3 (CWA – Shirmohammadi).

237 9 Tr. 1488:20-1490:3 (CWA – Shirmohammadi).

238 9 Tr. 1490:3-1491:14 (CWA – Shirmohammadi).

239 9 Tr. 1490:3-1491:14 (CWA – Shirmohammadi).

240 9 Tr. 1491:15-1492:16 (CWA – Shirmohammadi).

it does not take into account the feasibility or real-world costs of developing a project in a particular site, especially the project's ability to achieve deliverability. The modeling CalWEA's witness describes in his testimony is clearly insufficient to establish the amount of transmission capacity that must be built to accommodate the amount or cost of large-scale generation necessary to meet SB 100's goals.

Distributed Energy Resources Avoid Transmission Costs.

While the Joint IOUs were surprisingly dismissive of the ability of DERs to reduce the need for transmission and distribution system expansion,[241] the IOUs acknowledge that the addition of large-scale renewables in California will require expansion of transmission capacity. The Joint IOU direct testimony states, "There are a variety of non-demand driven reasons why transmission projects are built, including supporting public policy requirements or goals (e.g. Renewable Portfolio Standard Requirements), building facilities to reduce local capacity requirements (LCR) or reduce congestion, building facilities necessary for safety, grid control, visibility, and measurement enhancements, as well as fire hardening and aging infrastructure replacement."[242] Renewable Portfolio Standard Requirements means construction of large-scale renewables, and congestion happens when increased load is served by generation that is not in proximity to the load.[243] Thus, those costs are a direct result of commitments to reduce greenhouse gas emissions.

Because the transmission needs to achieve a completely decarbonized grid in California have not been studied sufficiently, it is critical that the Commission consider the impact of

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241 Exh. IOU-01 at 140:4-5.

242 *Id.* at 140:17-22.

243 Exh. CSA-02 at 3:14-4:12.

distributed energy resources in reducing those needs. While it is difficult for the ACC to accurately incorporate those long-term costs or the ability to avoid them,[244] the Commission acknowledged in D.20-04-010, "distributed energy resources avoid transmission costs but, at this time, the record in this proceeding provides no reasonable alternate method of determining unspecified avoided transmission costs."[245] The ACC does include reduced transmission needs with increased customer solar, but assigning a value is challenging.[246] As an example, CAISO identified the unexpected growth in NEM as a primary reason why it cancelled $2.6 billion in transmission projects in PG&E's service territory in 2018, yet looking forward it is difficult to know if avoidable projects have the same size and scope.[247]

b. Cost-Effectiveness of CALSSA's Proposal.

The cost-benefit results CALSSA calculated for its proposal are listed below in Table 12 from CALSSA's Direct Testimony:[248]

Table 12. Cost-Benefit Results

	TRC					RIM	
	2022	2024	2026	2028	2030	NEM-2	Step 5
PG&E	0.82	0.72	0.82	0.93	1.04	0.40	1.05
SCE	1.01	0.89	1.03	1.16	1.29	0.59	0.98
SDG&E	0.82	0.73	0.84	0.95	1.07	0.40	1.05

CALSSA has been upfront that these RIM values are based on exports to the grid.[249] As CALSSA Witness Heavner explained during cross examination, CALSSA believes that the

244 Exh. CSA-02 at 3:14-4:12.

245 D.20-04-010 at 60.

246 Exh. CSA-02 at 3:14-4:12.

247 Exh. PCF-01 at 4:3-8.

248 Exh. CSA-01 at 79, Table 12.

249 Exh. CSA-01 at 1-12.

Commission should consider both an all-generation RIM and an export-only RIM in its deliberations in this proceeding,[250] similar to what it did in the NEM-2 proceeding.[251]

Other parties in the proceeding, as well as E3, calculate RIM in a way that includes self-generation.[252] However, net metering is a tariff that gives credits for exports to the grid and should be measured as such.[253] Customers do not have an obligation to obtain their electricity through purchases from the utility.[254]

Moreover, calculating RIM to include self-generation also captures generation to supply new load.[255] If a customer purchases an electric vehicle and installs solar and storage to fuel the vehicle, it is not replacing utility sales that previously occurred.[256] This makes the all-generation approach to RIM inaccurate even if the objective is to count utility lost revenue as a cost to non-participating customers.[257] Thus, it makes sense for the Commission to consider a RIM test from both perspectives, *i.e.*, one that measures the program from the perspective of all generation, and one that considers NEM for what it is: a program to compensate net exports.

It should also be pointed out that these numbers are based on the 2020 Avoided Cost Calculator. For the reasons stated in CALSSA's direct testimony, the 2021 Avoided Cost Calculator contained significant flaws that led CALSSA to believe it would not be approved as

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[250] 7 Tr. 1073:24-1074:5 and 1161:24-1162:3 (CSA – Heavner and Plaisted).

[251] 7 Tr. 1162:4-17 (CSA – Heavner and Plaisted).

[252] Exh. CSA-01 at 1-12.

[253] Exh. CSA-01 at 1-12.

[254] Exh. CSA-01 at 1-12.

[255] Exh. CSA-01 at 1-12.

[256] Exh. CSA-01 at 1-12.

[257] Exh. CSA-01 at 1-12.

proposed in Draft Resolution 5150,[258] which was adopted after the deadline for direct testimony in this proceeding. After those changes were adopted, in recognition that the 2021 ACC values are much lower than the 2020 ACC values, CALSSA developed the alternative glidepath in Figure 11 of Rebuttal Testimony.[259] With this approach, the Commission can adopt a Step 5 end point different from CALSSA's core proposal in Table 1 of Direct Testimony.[260] A five-step glidepath will ensure that the NEM tariff approaches cost neutrality as measured by the ACC without causing excessive disruption to customer adoption of clean generating facilities.

Cost-Effectiveness Scores Will Improve in the Near Future.

In addition, CALSSA believes the Commission should consider other factors, such as the values for avoided transmission and distribution, that are likely to increase the corresponding values beyond both the 2020 Avoided Cost Calculator and the 2021 Avoided Cost Calculator. [261] Such consideration makes sense on account of the fact that implementation of the successor tariff is likely to last well beyond the 2022 update, as discussed in Section III.D.2 below on implementation timelines.

As discussed extensively in CALSSA's Opening Testimony and summarized in the bullets below,[262] key elements are missing from the TRC and RIM tests that the Commission should include as benefits. DERs provide benefits for:

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258 Exh. CSA-01 at 81:3-19.

259 Exh. CSA-02 at 48.

260 Exh. CSA-01 at 7.

261 Exh. CSA-02 at 45:5-6.

262 Exh. CSA-01 at 82:4-89:8.

- **Land Conservation:**[263] Modeling for implementation of SB 100 indicates a need to nearly triple the amount of utility-scale solar built every year through 2045. This will be an enormous challenge and will put pressure on land availability, requiring development of more than one million acres of land (that is equivalent to *one-sixth of all current land development*). These projections assume the installation of approximately 1 GW of distributed solar each year through at least 2030. If less distributed clean energy is built, even more utility-scale renewables will be needed.
- **Avoided Future Transmission Needs That Remain Uncalculated:**[264] The Commission's recent paper on electric rates, *Utility Costs and Affordability of the Grid of the Future*, made clear that transmission spending is the biggest upward pressure on rates. The report finds that utility transmission revenue requirements and rate base increased by ***<u>38 percent</u>*** from 2016 to 2021. Because transmission costs are amortized over many years, transmission spending can lock in rate increases for decades. Every reduction in the need for new transmission is a long-term cost savings. The paper states: "Conservative assumptions indicate that every dollar put into transmission rate base costs ratepayers in excess of $3.50 over the life of a transmission asset."[265] As discussed above, comments on the SB 100 draft report suggest that policy-related transmission costs will

263 Exh. CSA-01 at 82:11-84:2.

264 Exh. CSA-01 at 84:3-87:7 (citing to *Utility Costs and Affordability of the Grid of the Future*, p. 36).

265 Exh. CSA-01 at 84:3-87:7.

increase even further in the future. The Commission should not exacerbate that problem by failing to enable distributed solar.

- **Community Resilience**:[266] Recent wildfires and grid failures have caused a vibrant public debate about community energy resilience. The vulnerability of customers with special medical needs is a cause of great concern. The Commission has steered the majority of energy storage incentive dollars to support customer resiliency. Communities will benefit from backup power sources at both public and private locations. Solar and storage DERs are the *only* non-fossil fuel options customers currently have to keep their lights on during Public Safety Power Shut-offs. In addition, aggregating fleets of dispatchable resources into virtual power plants should be a major grid reliability strategy of the future. One of the important steps to getting to that endpoint is having a large enough concentration of resources to make a difference. NEM can pave the way for resource growth that is harnessed for grid benefit when the rules and price signals become available.

These are concrete impacts but are difficult to measure.[267] Because of these factors, CALSSA believes the Commission should consider TRC and RIM scores well below 1.0 to be cost-effective.

c. Cost-Effectiveness of Other Parties' Proposals

The change in cost-effectiveness scores between those measured under the 2020 Avoided Cost Calculator and the 2021 Avoided Cost Calculator underscore the sensitivity of that tool to

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266 Exh. CSA-01 at 87:8-89:8 (citing to D.19-09-027, Conclusions of Law 9 and 35).

267 Exh. CSA-01 at 82:4-89:8.

changes in existing inputs. It also serves as evidence of the electric industry's ever-evolving understanding of how to leverage and value different capabilities of distributed energy resource assets as fundamental transformations take place in the electric sector, especially in light of the high-DER scenarios the Commission envisions.[268] In fact, after the Commission updated the Avoided Cost Calculator, the only proposal to come close to satisfying the RIM test in E3's Comparative Analysis was from CARE.[269] That is, one supposedly minor update to the Avoided Cost Calculator negated most parties' claims of cost-effectiveness. This calls into question E3's methodologies.

NRDC and the Coalition of California Utility Employees' ("CUE") direct testimony highlight the impacts of this change on the strident positions those parties had taken on cost-effectiveness. For example, NRDC's tariff does not meet its own definition of "sustainably". NRDC drew a line in the sand in its direct testimony stating that "a tariff that burdens those who cannot access it is not sustainable."[270] Given that NRDC's proposal scored between 0.22 and 0.47 in the RIM test,[271] it would, at least according to E3, burden those who cannot access it.

CUE does not have a proposal in this case, other than to vehemently express its almost cartoonish disapproval for net metering, as well as to convey its dislike for rooftop solar as a technology, companies and employees that comprise the solar industry, and the customers that install solar. It simply is not possible to tell which of the myriad Pro-Transmission Parties'

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268 *See, e.g., R.21-06-017, Order Instituting to Modernize the Electric Grid for a High Distributed Energy Resources Future*, pp. 7-10, 12-24 (July 2, 2021).

269 Exh. CCS-01 at Attachment, E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020*, pp. 4 and 34-35 (May 28, 2021).

270 Exh. NRD-01 at 9:9-10; 9:23-10:2.

271 Exh. CCS-01 at Attachment, E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020*, p. 34 (May 28, 2021) (listing paybacks in 2023 for Non-CARE customers between 9 and 17 years for Cal Advocates proposal for standalone solar).

positions CUE says it supports in its direct and rebuttal testimony would be cobbled together to form a CUE "proposal." However, its direct testimony does make clear that "any NEM tariff that results in a RIM value of far less than one is therefore not just and reasonable."[272] Since none of the Pro-Transmission Parties' proposals meet this standard and CUE does not have a proposal, it appears that CUE does not see any way to comply with all statutory requirements.

3. TURN's Error Undermines Its Analysis of CALSSA's Proposal.

TURN's witness admitted during cross examination that *all* of the analysis she had conducted on CALSSA's direct testimony—including over half of the tables in TURN's rebuttal testimony, *i.e.*, Tables 2, 3, 5, 10 and 13-20—excluded a key element of CALSSA's proposal.[273] TURN's modeling assumed CALSSA's proposal would compensate customers at the full retail rate without subtracting out nonbypassable charges.[274] However, as Witness Chait admitted on the stand, CALSSA's testimony states "each step is a percentage of the current export rate (*i.e.*, reducing the retail rate by a percentage and then subtracting out non-bypassable charges)."[275] Thus, TURN's absurd conclusion that CALSSA's proposal would be *more* lucrative than NEM-2 in the near-term for customers in SCE's service territory must be dismissed as untrue.[276] More importantly, the results from various cost-effectiveness tests, payback periods, internal rates of return, and first year cost shifts in TURN's testimony are inaccurate,[277] and, therefore, the

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[272] Exh. CUE-01 at 12:19-20.

[273] 9 Tr. 1510:15-1513:21 (TRN – Chait).

[274] Exh. TRN-03 at 18:5-11; 9 Tr. 1511:80-22 (TRN – Chait). *See also* Exh. TRN-03 at p. 18, n. 17 (stating erroneously that "CalSSA does not state in its proposal that the full retail rate used to calculate export compensation excludes nonbypassable charges.").

[275] Exh. CSA-01 at 39:6-7; 9 Tr. 1513:7-9 (TRN – Chait).

[276] Exh. TRN-03 at 18:5-11.

[277] 9 Tr. 1510:15-21; 1512:1-12 (TRN – Chait).

CALSSA-specific conclusions in that testimony cannot be relied upon in the Commission's decision in this case.

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

1. Low- and Moderate-Income Residential Customers and Equity Considerations

Public Utilities Code Section 2827.1(b)(1) requires the NEM tariff to "include specific alternatives designed for growth among residential customers in disadvantaged communities." This language demonstrates the Legislature's intent for customers in disadvantaged communities ("DACs"), including low-income customers, to participate in renewable distributed generation.[278] That is, the tariff must increase adoption of solar and other distributed generation by these customers.

The Commission's Environmental and Social Justice ("ESJ") Action Plan, released in February 2019, demonstrates a similar interest in expanding clean energy resources in ESJ communities, recognizing that investment in these resources improves local air quality and public health.[279] ESJ communities include disadvantaged communities and low-income households and census tracts, whether within or outside disadvantaged communities.[280]

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[278] Disadvantaged communities are identified using indicators that include socio-economic burdens as well as environmental and health burdens. Exh. CSA-35 at 11. DACs have greater numbers of low-income residents than other communities do. Exh. PAO-03 at 2-30, fn. 129 (citing CalEnviroScreen 3.0 Manual, https://oehha.ca.gov/media/downloads/calenviroscreen/report/ces3report.pdf).

[279] Exh. CSA-35 at 6-7.

[280] Exh. CSA-35 at 9-10.

a. Progress and Policy Support for Equity in Solar Adoption

Existing net metering policies have played an important role in increasing solar adoption among equity communities—despite numerous socioeconomic obstacles—and access has been expanding under current policies.[281] The Commission should aim to continue those trends.

The expansion of solar into lower-income and disadvantaged communities is heartening. Studies that focus on income level percentages demonstrate a gradual broadening and deepening of solar adoption to lower-income households.[282] Looking at growth over time is even more revealing. As shown in Table 3 from CALSSA's direct testimony, these trends in solar adoption have benefited lower-income customers dramatically, with tenfold growth in solar adoption among California single-family households with incomes below $50,000.[283]

Figure 4 from CALSSA's rebuttal testimony similarly shows nearly tenfold growth in solar adoption among low- and moderate-income single-family households, as measured by area median income ("AMI").[284] Annual adoption numbers increased from 6,664 adopters in 2010 to 60,057 in 2019.[285]

281 Exh. CSA-02 at 22:8-13.

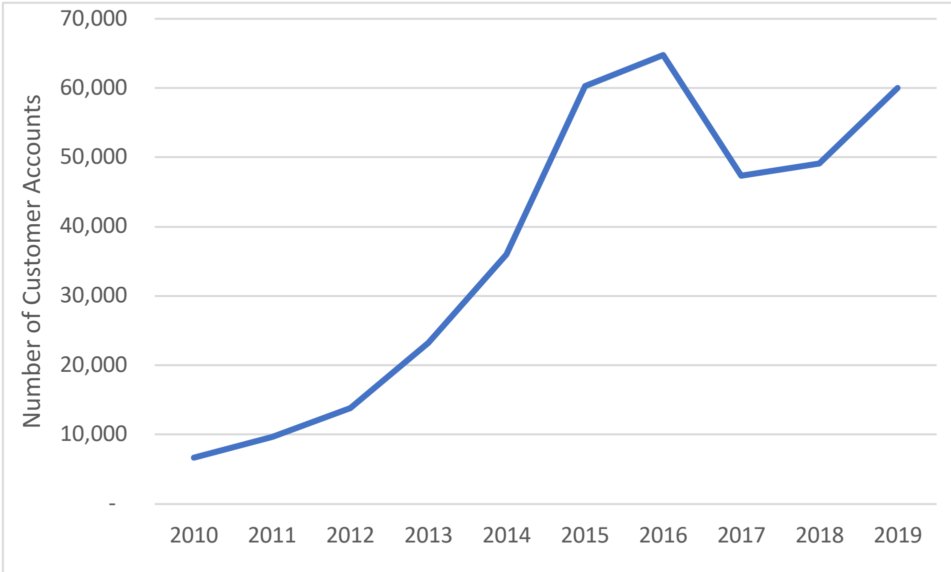
282 Exh. IOU-02 at Appendix B, p. B-20 (showing increasing solar adoption trends from 2010 to 2019 and noting about 40% of solar adopters had incomes below 120% of the area median income in 2019; *see also id.* at p. B-21 (increasing trends in percent of systems installed by customers with incomes to $74,000 in the same time frame, 2010 to 2019).

283 Exh. CSA-01 at 21:6-11 and Table 3 (source: *Solar Demographics Tool*, Lawrence Berkeley National Laboratory, Electricity Markets and Policy, https://emp.lbl.gov/solar-demographics-tool); *see* Exh. CSA-02 at 23, fn. 74 (citing Barbose, Galen, et al., *Residential Solar-Adopter Income and Demographic Trends: 2021 Update*, p. 41, Lawrence Berkeley National Laboratory (April 2021), *available at* https://eta-publications.lbl.gov/sites/default/files/solar-adopter_income_trends_final.pdf ("With the exception of the multi- versus single-family comparison, all other elements of the analysis are based only on single-family adopters.")).

284 Exh. CSA-02 at 22, Fig. 4 (source: *Solar Demographics Tool*, Lawrence Berkeley National Laboratory, Electricity Markets and Policy, https://emp.lbl.gov/solar-demographics-tool).

285 Exh. CSA-02 at 22:12-13 & fn. 70.

Figure 4: Single-Family Solar Adopters with Incomes Up to 120% of Area Median Income, 2010-2019



Solar adoption, including among lower-income customers, is sensitive to policy changes that affect the financial benefits of a solar system. The trends shown in Figure 4 showed the greatest uptake among low-income customers under NEM-1, which provided favorable market conditions allowing solar adoption to accelerate significantly between 2010 and 2016.[286]

The shift from NEM-1 to NEM-2, which took effect between June 2016 and July 2017, and which included a decrease in the export rate of 2 ¢/kWh in addition to mandatory TOU rates, led to a marked drop in new NEM systems installed between 2016 and 2017.[287] This held true for lower-income adopters: among adopters with incomes up to 120% of AMI, there was a 27% drop-off in the one year from 2016 to 2017, and the market has not yet reached the same level as it had during the period before the transition from NEM-1 to NEM-2.[288]

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[286] Exh. CSA-02 at 22:14.

[287] Exh. CSA-01 at 22:4-6 (citing NEM 2.0 Lookback Study, p. 24 (Fig. 3-1)).

[288] Exh. CSA-02 at 22, Fig. 4 & fn. 20 (noting that the values represented in Figure 4 are as follows: 2010—6,664; 2011—9,666; 2012—13,863; 2013—23,259; 2014—35,965; 2015—60,333; 2016—64,774; 2017—47,383; 2018—49,095; 2019—60,057).

Despite the significant negative pressure on solar adoption among lower-income customers from the relatively small change from NEM-1 to NEM-2, several proposals in this proceeding seek much greater decreases in the value of solar exports. If the Commission adopts a successor tariff that approaches the level of change contemplated by these proposals, it would likely reverse positive trends in solar adoption among lower-income customers and disadvantaged communities. Such a change in direction would be contrary to equity goals, the guiding principles, and the mandate to design tariff policies to encourage growth among disadvantaged communities. It is for this reason that CALSSA has proposed the most protective set of policies for lower-income customers and disadvantaged communities.

b. CALSSA's Suite of Proposals for Low- and Moderate-Income Customers

CALSSA proposes to address equity and access goals by maintaining policies that encourage solar adoption among low-income customers and in lower-income census tracts, by fostering greater participation by customers taking service under the CARE and FERA programs, and by addressing obstacles that have hindered solar growth for renters.[289] Four relatively simple provisions achieve these ends:

1. Allow low-income customers in single-family homes to be eligible for a tariff that is equivalent to NEM-2: NEM credits at full retail rates minus non-bypassable charges ("NBCs");
2. Credit exports from CARE and FERA NEM customers at the undiscounted otherwise applicable retail rate minus NBCs;

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289 Exh. CSA-01 at 22:13 to 23:3.

3. Allow apartment buildings in low- and moderate-income census tracts and properties that would be eligible for the MASH and SOMAH programs to be eligible for a virtual net metering tariff that is equivalent to the structure under NEM-2; and

4. Extend eligibility for the NEM-2 structure of export credits to community-owned solar projects.[290]

First, CALSSA proposes to continue building momentum in DER adoption by single-family residential customers with income below 80% of AMI, including CARE and FERA customers. Specifically, eligible customers will receive NEM credits at full retail rates minus NBCs, as under the NEM-2 tariff. Maintaining NEM-2 tariff eligibility for single-family residential customers with income below 80% of AMI will strengthen the inroads the industry has made in recent years in serving these customers, as discussed above.[291]

Second, customers on CARE and FERA rates will receive NEM credits for exports according to the non-discounted rates of their otherwise applicable rate schedule. CALSSA disagrees with the overly simplistic conclusions suggesting that CARE and FERA customers have been left out of NEM altogether.[292] For example, NEM adoption rates for CARE customers are 4%-8% of customers, depending on the utility, while general market adoption rates are near

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[290] *See* Section III.C.1.h.

[291] Exh. CSA-01 at 23:6-11. *See also* NEM 2.0 Lookback Study, p. 34 (stating: "ZIP codes with lower median incomes have seen an increase in the proportion of solar PV installations in somewhat recent years as shown in Figure 3-8 . . . This study found that solar adoption has been gradually migrating toward lower income ranges over time, reflecting both a broadening and a deepening of U.S. solar markets.").

[292] Exh. CSA-01 at 23:13-16; *see, e.g.*, California Public Utilities Commission, *Utility Costs and Affordability of the Grid of the Future*, pp. 28-29 (February 2021) ("*Utility Costs and Affordability of the Grid of the Future*").

11%.[293] Given the higher proportion of CARE customers that are renters, the lower value of NEM credits for CARE customers, the Commission's prior rejection of "CleanCARE" and similar programs,[294] and the lack of functional community solar programs in the state, a difference in participation rates is not surprising. The fact that 4%-8% of CARE customers have adopted solar despite obstacles like these is impressive.[295]

Third, CALSSA proposes a continuation of the current virtual net metering ("VNEM") credit value for multifamily rental properties in census tracts with median income below 100% of AMI, and for properties that would meet the eligibility requirements for the Multifamily Affordable Solar Housing ("MASH") program or the Solar on Multifamily Affordable Housing ("SOMAH") program. These residential customers would receive NEM credits at retail rates minus NBCs, as under the NEM-2 tariff, and as proposed for low-income single-family households.[296]

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293 Exh. CSA-01 at 23:16-18 (citing *Utility Costs and Affordability of the Grid of the Future,* pp. 28-29; California Distributed Generation Statistics, *available at* www.californiadgstats.ca.gov).

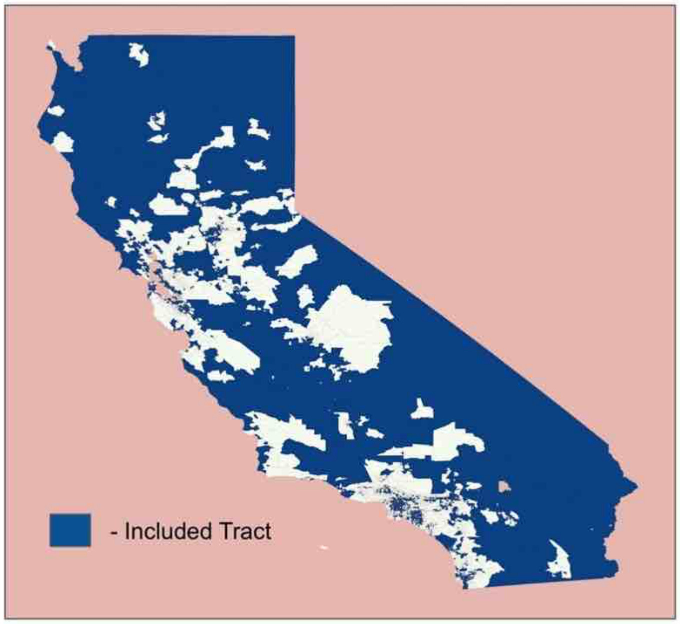
294 *See* R.14-07-002, *Proposal for Alternative for Growth in Disadvantaged Communities of the Interstate Renewable Energy Council, Inc.*, p. 3 (August 3, 2015) ("CleanCARE would allow customers eligible for the CARE program to choose to redirect the funds associated with their CARE rate discounts toward purchasing renewable generation from a third-party developer, selected by the utility through a competitive bid process. CARE customers electing the CleanCARE option would move to the standard rate for their rate class and, through participation in the CleanCARE program, would offset a portion of their monthly bills through kilowatt-hour (kWh) bill credits. As a result, a CleanCARE customer would receive the equivalent or a lower bill than the customer would have seen under the standard CARE program rates. In this way, the CleanCARE option would increase opportunities for low-income households to participate in renewable energy programs while guaranteeing at least the bill discount available under the current CARE program.").

295 Exh. CSA-01 at 23:18 to 24:2.

296 Exh. CSA-01 at 24:19 to 25:2. It is important to define eligibility as equivalent to the eligibility requirements in the MASH or SOMAH programs rather than requiring participation in those programs, as this provision of net metering may outlast those programs.

Including census tracts below 100% of AMI, as shown in Figure 5 of CALSSA's direct testimony, will allow for expansion of solar among lower-income multifamily rental residents.[297]

Figure 5. Census Tracts with Median Income Below 100% of AMI



This threshold for census tract eligibility is intended to be consistent with the "moderate income" category while striking a balance that excludes areas with significant numbers of higher-income rental residents.[298] MASH and SOMAH are generally intended for properties that are regulated under federal housing subsidy programs for the lowest income group, and it is important to include eligibility for other renters who are not in regulated affordable housing but are still low- and moderate-income apartment tenants. Additionally, extending the proposal to properties that would be eligible for the MASH or SOMAH program ensures that low-income

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297 CSA-01 at 25:3-4 & Fig. 5.

298 Qualifying census tracts can be identified each year based on the American Community Survey, a product of the U.S. Census Bureau that is commonly used in program planning and implementation. *About the American Community Survey*, U.S. Census Bureau, https://www.census.gov/programs-surveys/acs/about.html. *See* Exh. CSA-01 at 25, fn. 25; *id.* at 25:8-11.

properties in other census tracts can continue to use a NEM structure that enables participation in those programs.[299]

This proposal addresses one of the biggest reasons there has been less solar adoption in low-income communities: that many low-income families live in apartments, and solar on apartment buildings has been harder to develop than solar on single-family homes.[300] It is imperative not to add further obstacles that will discourage rental property owners from installing distributed generation going forward. Continuing the current treatment of VNEM systems for lower-income rental properties and properties that would be eligible for the MASH and SOMAH programs will help support this market segment. It is also a crucial foundation for the success of incentive programs like MASH and SOMAH.[301]

The Commission can implement this proposal through two VNEM tariffs, in contrast with the three separate tariffs currently.[302] One will provide a continuation of NEM-2 tariff rules, applicable to customers that either are located in eligible census tracts or meet eligibility requirements for the MASH or SOMAH program. A second VNEM tariff would apply to all other customers.

CALSSA's suite of proposals will accelerate the positive trends in adoption of distributed generation among low-income customers and customers in disadvantaged communities. These proposals comport with the equity goals expressed in guiding principle (b) and with the statutory

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299 Exh. CSA-01 at 25:11-13.

300 Exh. CSA-01 at 24:10-11. Approximately 70% of Californians who live in multifamily buildings—90% of whom are renters—have incomes below the AMI. Exh. CSA-02 at 24:1-3, 15-16.

301 *See* Exh. GRD-02 at 5:1-5, 16:6-13.

302 Exh. CSA-01 at 26:1-6.

mandates for sustainable growth in distributed generation and specifically for alternatives designed for growth in disadvantaged communities.[303]

c. Pro-Transmission Parties' Tariffs Harm Low-Income Access

While CALSSA's proposal moves decisively in the right direction on equity goals in solar access, several parties' proposals would instead greatly increase barriers and cause a downturn in solar adoption in low-income and disadvantaged communities. The overall thrust of these proposals is directly contrary to equity goals.

The faulty premise at the heart of the Pro-Transmission Parties' proposals is that low-income solar adopters and those who live in DACs should immediately be subject to greatly reduced export compensation and—for some or all low-income customers—new monthly fees as well.[304] These parties assert that fee exemptions or subsidies for the lowest-income customers will avoid the great damage that this new tariff structure will cause, but those assertions merely mask the combined negative impact of the proposals.[305]

If changes to the NEM tariff rules reduce the level of compensation for distributed solar generation exported to the grid, that will impose new barriers for low-income customers, as the California Energy Commission has recognized in its study of barriers to low-income residents' participation in California's clean energy transformation.[306] Joint IOU witness Wright

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[303] Cal. Pub. Util. Code § 2827.1(b)(1).

[304] Exh. CSA-01 at 33:1-2; Exh. IOU-01 at 123:3-5; Exh. PAO-03 at 1-6:8-9; Exh. NRD-01 at 15:10-11; Exh. TRN-01 at 5:6-8.

[305] Exh. CSA-01 at 33:2-5; Exh. GRD-02 at 13:22-26; *see* Exh. IOU-01 at 19:23-35 (proposal "encourages adoption of rooftop solar and storage by income-qualified customers"); Exh. TRN-01 at 53:6-8 (proposal for CARE customers allowing costs to be recovered in 10 years "represents a reasonable horizon for recovering the costs of an initial investment"); Exh. PAO-03 at 3-54:19-21 & 3-56:15-17 (fee exemption and upfront incentive for CARE customers will achieve "equity in payback periods").

[306] Exh. CSA-02 at 21:19-22 (citing *Commission Final Report for the SB 350 Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers*

acknowledged that such a reduction in export compensation would not help solar adoption by low- and moderate-income customers.[307] Instead, export compensation rates based on avoided cost measures would reduce access to solar for low-income customers and customers in DACs by reducing bill savings and increasing the time to recover an upfront solar investment.[308]

In addition to large reductions to export values, the Pro-Transmission Parties would add new monthly fees on NEM customers based on installed capacity or self-consumption.[309] Such fees go beyond net metering to reduce savings associated with self-generation, significantly discouraging solar adoption.[310] While the Joint IOUs, NRDC, and Cal Advocates exempt certain low-income customers from these fees, or would apply a reduced fee to them, those exclusions are limited and fail to protect many lower-income customers from the added burdens of the new fees.

At the greatest extreme, the Joint IOUs would temporarily charge some CARE and FERA customers a lower monthly fee (through what they call the "Income-Qualified Discount").[311] This "transitional discount" is only for customers who receive permission to operate within the first three years of the successor tariff's implementation.[312] It is also only available for about 10 years, after which customers who previously received the discount would be subject to the same

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and Small Business Contracting Opportunities in Disadvantaged Communities, p. 54, California Energy Commission (Dec. 2016)).

307 11 Tr. 1896:5 to 1896:4 (IOU – Wright).

308 Exh. CSA-02 at 20:12-14.

309 Exh. CSA-01 at 90:16 to 92:8 & 91-92, Table 14 (mechanics of Pro-Transmission Parties' proposed residential solar fees); Exh. CSA-02 at 53:4 to 55:1 & 53, Table 9 (increase in IOUs' proposed residential solar fees); CSA-01 at 33:7-13. *See* Section III.C.5 for further discussion of solar fees.

310 Exh. CSA-01 at 90:18 to 91:2.

311 Exh. IOU-01 at 169:2-12.

312 Exh. CSA-02 at 19:5-8; Exh. IOU-01 at 169:2.

high fees as other customers.[313] Even for the period when the discount applied, the eligible recipients would still face a new charge that does not currently exist.[314] This fee is in addition to new monthly fixed charges in the underlying rates that new distributed generation customers would be required to take service on.[315] There is no provision to reduce those charges for any low-income customers.[316]

When asked which aspect of the Joint IOUs' proposal would best show that the proposal would increase low- and moderate-income customers' solar adoption rates, the Joint IOUs' witness pointed only to existing incentive programs and one element of their proposal, a pilot storage incentive program for 25,000 customers.[317] This amounts to an admission that the IOUs' tariff proposal will harm, not help, low-income customers. Combined with reduced export compensation, the new solar fee with only a temporary reduction for CARE and FERA customers will shut many low-income customers out of the market for distributed generation, contrary to equity principles and statutory goals.[318]

The other Pro-Transmission Parties' proposals also include new solar fees with insufficient protections for low-income customers.[319] Cal Advocates would exempt CARE and FERA customers from their new solar fee, while NRDC would exempt only CARE customers.[320] TURN would not exempt any customers from their new monthly fees, but CARE customers

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313 Exh. CSA-02 at 19:21-26; Exh. IOU-01 at 169:25 to 170:3.

314 11 Tr. 1893:10-16 (IOU – Wright).

315 Exh. CSA-01 at 107:11-16 & Table 16 (showing illustrative monthly customer charges of $20.66, $24.10, and $12.02 respectively for PG&E, SDG&E, and SCE).

316 Exh. GRD-02 at 14:17-18 & fn. 28.

317 11 Tr. 1896:17 to 1897:12 (IOU – Wright).

318 Cal. Pub. Util. Code § 2827.1(b)(1); Exh. GRD-2 at 15:11-22.

319 Exh. CSA-01 at 91-92, Table 14.

320 Exh. PAO-03 at 3-53:6-7; Exh. NRD-01 at 18:8-10.

would be eligible for an upfront subsidy of part of the price of a solar system.[321] All of these proposals would represent an erosion of bill savings and the economic benefit of installing a solar system compared to the present tariff terms.[322]

These proposed fee discounts, fee exemptions, and subsidies are not only inadequate to protect eligible customers from the harms of these solar fees, as discussed above. They also do nothing for the many lower-income customers who would not be eligible. This issue is discussed in Section III.C.1.e below. Those customers will immediately be subject to full monthly fees with no relief.[323]

Taken together with avoided-cost-based export compensation, these new fees add significantly to the cost of adopting solar and create powerful disincentives that would dramatically reduce the participation of low-income families in net metering.[324] Given the imperative to increase equity in the clean-energy transition, these proposals are not just or reasonable.[325]

Increasing the time that it takes to recover costs makes it more difficult for most customers to adopt solar, but this is especially so for customers with lower incomes, who have less discretionary income.[326] Keeping cost recovery periods short is key to ensuring that low-income customers can continue to adopt distributed generation.[327]

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321 Exh. TRN-01 at 5:28 to 6:2.

322 Exh. CSA-02 at 20:15-16, 20:23 to 21:2; Exh. CSA-01 at 33:10-13, 35:10-17.

323 Exh. CSA-02 at 19:17-20.

324 Exh. CSA-01 at 34:6-11.

325 Cal. Pub. Util. Code §§ 451, 2827.1(b)(7).

326 Exh. CSA-01 at 34:15-18, 60:6-11.

327 Exh. GRD-02 at 8:21-22.

Beyond a seven-year cost recovery period, it is much harder for a customer to install solar, and periods over 10 years limit solar to customers with disposable income and environmental motivations.[328] This means that if the Commission approves a new NEM tariff with a cost recovery period exceeding 10 years, CARE customers and low-income non-CARE customers will be shut out.[329] This would be the result of the Pro-Transmission Parties' proposals: using realistic solar cost values, many of the CARE cost recovery periods for these proposals are greater than 10 years, and most exceed 15 years.[330]

TURN and NRDC both propose upfront payments to change the effective cost recovery period to 10 years—NRDC's proposal is for all customers, while TURN's, which would provide for a 10-year discounted payback, is limited to CARE customers.[331] It would be very difficult for the Commission to determine a subsidy resulting in a 10-year payback, as discussed in detail in Section III.C.4.d. Even if there were an accurate calculation, a 10-year cost recovery period is too long to meet the needs of low-income and disadvantaged communities, given the substantial existing obstacles to solar access for low-income customers.[332]

The lesson here is clear: knowing that the relatively small change from NEM-1 to NEM-2 rules led to a dramatic drop in solar adoption by low- and moderate-income customers, the substantially greater changes proposed by the Pro-Transmission Parties will have a significantly greater negative effect going forward, eroding the value proposition and discouraging solar for

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[328] Exh. CSA-01 at 35:4-6, 61:1 to 62:11, 63, Fig. 15.

[329] Exh. GRD-02 at 9:21 to 10:19.

[330] *See, e.g.*, TRN-01 at 69, Table 9 (showing various payback measures for TURN's proposal, most over 20 years and none below 17).

[331] Exh. CSA-01 at 35:10-15; Exh. TRN-01 at 5:28 to 6:2.

[332] Exh. PAO-03 at 3-59:12-19 (noting barriers to adoption among low-income and disadvantaged communities, including low homeownership rates, lack of access to capital, living in underserved communities, and more).

lower-income customers and disadvantaged communities.[333] In short, the Pro-Transmission Parties' tariff proposals run counter to the need—and the mandate—to ensure growth in solar adoption by low-income customers and move toward equity.[334]

d. Impact on Solar Incentive Programs

The Commission should be particularly careful not to adopt proposals that would undermine the solar incentive programs that it and the Legislature have established, most notably, the Disadvantaged Communities–Single-Family Affordable Solar Homes (DAC-SASH) and SOMAH programs.

The Joint IOUs assert that their proposal would complement these and other existing low-income incentive programs.[335] NRDC asserts that low-income solar incentives will help assure growth of distributed generation.[336] TURN also relies on these programs rather than proposing alternatives for residents of DACs.[337] Cal Advocates refers to DAC-SASH, SOMAH, and other programs as well, noting that they may increase solar adoption in DACs.[338]

This reliance on existing solar incentive programs is problematic, because these parties do not consider the negative impacts their proposals would have on these programs and the equity goals they are meant to promote.[339]

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333 Exh. CSA-01 at 22:4-6; Exh. CSA-02 at 23:5-17.

334 Cal. Pub. Util. Code § 2827.1(b)(1); D.21-02-007, Ordering Paragraph 1(b).

335 Exh. IOU-01 at 164:3-9; 11 Tr. 1291:13-21 (IOU – Wright).

336 Exh. NRDC at 9:16-18.

337 Exh. TRN-01 at 32:8-17. Although TURN notes that an additional upfront incentive could be provided for program participants, TURN does not propose such an additional incentive. Exh. TRN-01 at 53:10-11 ("TURN supports limiting MTC eligibility to CARE eligible customer retrofits on existing properties.").

338 Exh. PAO-03 at 3-60:13-15 & Table 3-21.

339 Exh. CSA-01 at 36:3-5; Exh. GRD-01 at 16:6-13; 11 Tr. 1904:15 to 1905:20 (PAO – Buchholz).

DAC-SASH and SOMAH rely on cost savings created through the NEM and VNEM tariffs.[340] Even with upfront incentives that eliminate or greatly reduce installation costs, potential solar adopters will not be motivated to undergo the process to add a solar system if there are not sufficient bill savings.[341] Perhaps unsurprisingly, bill savings are the top reason low-income homeowners participate in incentive programs like DAC-SASH.[342] And, savings on bills over the life of the project must be great enough to outweigh disincentives including the complexity of application processes, time and effort required to complete different kinds of work needed for a solar installation (such as roof and main electrical panel upgrades), and adjusting tenant billing for multifamily projects—all of which entail significant time and resource burdens that can be particularly problematic for lower-income property owners.[343] For all these reasons, potential incentive program participants need to see a clear benefit in bill savings to agree to enter the program.[344]

DAC-SASH and SOMAH, like the Single-Family Affordable Solar Homes ("SASH") and MASH programs before them, were designed with these considerations in mind.[345] They rely on bill savings produced through the existing NEM tariff structure.[346] The Pro-Transmission Parties' proposals will erode solar incentive project economics,[347] potentially requiring additional sources of funding to maintain subsidy levels, and making the programs more difficult

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340 Exh. CSA-01 at 36:6-7.

341 Exh. CSA-01 at 36:7-9.

342 Exh. CSA-01 at 36:9-10; Exh. GRD-01 at 13:10-12.

343 Exh. CSA-01 at 36:11-19.

344 Exh. CSA-01 at 36:19-21; Exh. GRD-01 at 13:10-12, 14:18-21.

345 Exh. CSA-01 at 36:22-23.

346 Exh. CSA-01 at 36:23-25.

347 *See* Section III.C.1.c.

to administer.[348] Changes like these risk these programs' ability to continue increasing solar access for ESJ communities.[349]

The continued success of these programs should not be taken for granted as the Commission considers the future of the NEM tariff, because the equity goals DAC-SASH and SOMAH were created to advance are far from having been fulfilled, and the work is not over.[350]

e. Low-Income Customers and DACs Excluded from Low-Income Proposals

As noted, the Pro-Transmission Parties propose some subsidies and exemptions they say will help low-income customers adopt solar. But they limit those proposals in ways that cut out many of the very customers for whom they profess concern, and for that reason, the proposals do not meet equity goals.[351]

- Cal Advocates' equity charge would fund upfront subsidies to offset new system installation costs only for CARE households, and the exemption from their monthly solar fee extends only to CARE and FERA customers.[352]
- NRDC would exempt only CARE-qualified customers from their monthly fee.[353]
- TURN would give an upfront subsidy payment only to CARE-eligible customers installing systems on existing properties.[354]

[348] Exh. GRD-02 at 16:6-15; 11 Tr. 1902:22 to 1904:10, 1908:2-23 (IOU – Wright).

[349] Exh. GRD-02 at 5:1-5.

[350] Exh. CSA-01 at 37:3-6; D.21-02-007, Ordering Paragraph 1(b).

[351] Exh. CSA-02 at 26:2-18.

[352] Exh. PAO-03 at 3-56:15-17, 3-53:6-7.

[353] Exh. NRDC-01 at 18:8-10.

[354] Exh. TRN-01 at 53:8-11.

- The Joint IOUs' temporary discount off their monthly solar fee is limited to CARE and FERA customers.[355]

First, proposals that are limited to CARE customers do nothing to help FERA customers, even though those customers fall squarely within the understanding of low-income customers.[356] The CARE income threshold is 200% of the federal poverty guidelines, and the FERA threshold is 250% of those guidelines; the thresholds for different household sizes are shown in Table 3 from CALSSA's rebuttal testimony.[357]

Table 3: 2021 Income Thresholds for Federal Poverty Guidelines and CARE and FERA Programs

Household Size	Federal Poverty Guideline	200% of Federal Poverty Guidelines (CARE)	250% of Federal Poverty Guidelines (FERA)
1	$12,880	$34,840	N/A
2	$17,420	$34,840	N/A
3	$21,960	$43,920	$54,900
4	$26,500	$53,000	$66,250
5	$31,040	$62,080	$77,600
6	$35,580	$71,160	$88,950
7	$40,120	$80,240	$100,300
8	$44,660	$89,320	$111,650

In 2018, the California Energy Commission released a report including a comparison of low-income eligibility requirements for energy programs in 2017, as shown in Figure 6 from CALSSA's rebuttal testimony.[358]

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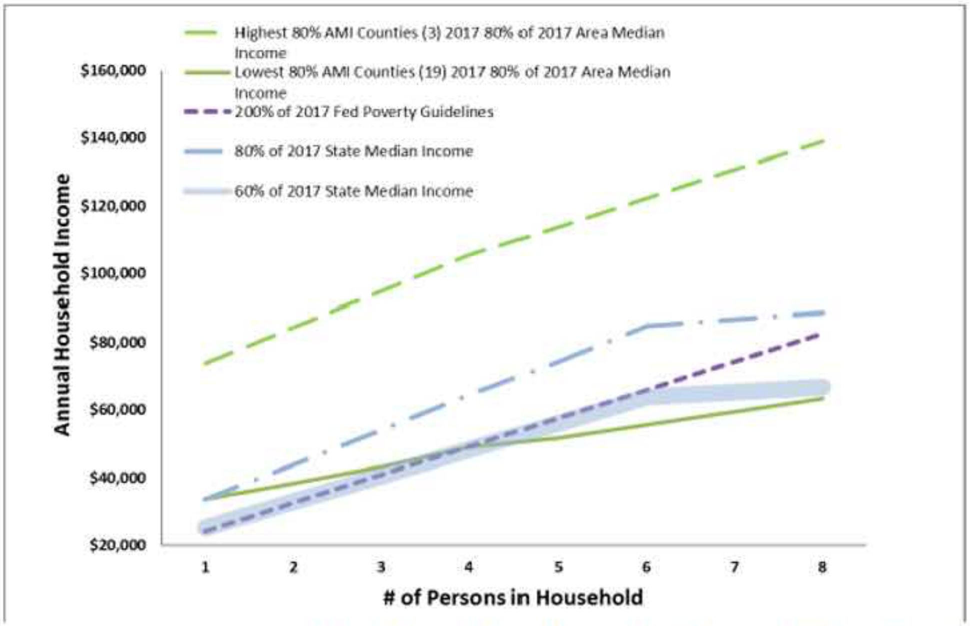
355 Exh. IOU-01 at 169:2-4.

356 Exh. CSA-02 at 26:19-21.

357 Exh. CSA-02 at 27, Table 3 (citing U.S. Department of Health & Human Services, 2021 Poverty Guidelines, https://aspe.hhs.gov/2021-poverty-guidelines#guidelines; CARE/FERA programs eligibility thresholds available at https://www.pge.com/en_US/residential/save-energy-money/help-paying-your-bill/longer-term-assistance/care/care.page?WT.mc_id=Vanity_carefera).

358 Exh. CSA-02 at 27, Fig. 6 (citing *Tracking Progress—Energy Equity Indicators*, p. 8, Figure 2, California Energy Commission (June 2018), *available at* https://www.energy.ca.gov/sites/default/files/2019-12/energy_equity_indicators_ada.pdf).

Figure 6: Comparison of Low-Income Eligibility for Energy Programs



Source: Energy Commission staff based on data from U.S. Dept. of HHS and U.S. Dept. of HUD

The figure shows that the CARE income levels (200% of the 2017 federal poverty guidelines) were at approximately the same level as 60% of the state median income for households of up to six people. Although the FERA income levels are not shown in the chart, incomes of 250% of the federal poverty thresholds for 2017 would fall below the level for 80% of state median income for households of up to six people.[359]

Going further, even if proposals include FERA customers, they exclude many low-income customers and residents of disadvantaged communities, who face financial struggles and barriers to access to clean energy, and who merit policy support in this proceeding.[360] A measure based on AMI is more inclusive and goes farther to advance equity goals.[361]

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[359] Exh. CSA-02 at 28:1-5 & fn. 89 (calculations based on U.S. Department of Health & Human Services, 2017 Poverty Guidelines, https://aspe.hhs.gov/2017-poverty-guidelines).

[360] Exh. CSA-02 at 28:11-14; Exh. GRD-02 at 15:5-9; Cal. Pub. Util. Code § 2827.1(b)(1).

[361] D.21-02-007, Ordering Paragraph 1(b).

CALSSA's proposal to use 80% of AMI as the eligibility threshold for its low-income tariff aligns net metering with a well-accepted benchmark for low-income customers that was adopted in the Commission's ESJ Action Plan.[362] It is also a measure used in existing incentive programs include SASH and SGIP.[363] Basing eligibility for equity-focused alternatives in NEM on AMI is especially appropriate because it accounts for differences in income and cost of living depending on where one resides.[364] In some regions, significantly higher incomes than CARE and FERA thresholds still represent low-income levels, and this regional context is important in ensuring inclusiveness in equity-based policy support.[365]

Moreover, many residents of disadvantaged communities are low-income customers with incomes above the CARE and FERA thresholds: Over two-thirds of four-person households in the top 25% disadvantaged communities have incomes at or below 80% of AMI.[366] Almost one-quarter of these households have incomes above the CARE threshold, which is 200% of the federal poverty level.[367] Limiting proposals aimed at equity goals to CARE and FERA limits the reach of equity proposals in a way that cuts out many residents of DACs, contrary to statute and the guiding principles.[368]

The Joint IOUs offered three other reasons for limiting low-income proposals to CARE and FERA customers: their lack of research into an approach based on median income measures,

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362 Exh. CSA-35 at 10 & fns. 6-7.

363 Exh. GRD-01 at 15:9-15.

364 Exh. CSA-02 at 28:15-17; Exh. GRD-01 at 15:16 to 16:4.

365 Exh. CSA-02 at 28:17-20; 12 Tr. 2139:10-26 (PAO – Buchholz). As a practical matter, AMI is considered at the county level. Exh. GRD-01 at 17, Table 3.

366 Exh. GRD-01 at 16:7-11.

367 *See* Exh. GRD-01 at 17, Table 3; Exh. CSA-02 at 27, Table 3.

368 Cal. Pub. Util. Code § 2827.1(b)(1); D.21-02-007, Ordering Paragraph 1(b).

customer confusion, and difficulties with tracking customer income eligibility.[369] But median-income-based measures of income are well-established, are already used in incentive programs,[370] and have been adopted in the Commission's ESJ Action Plan.[371]

Lastly, TURN feints toward suggesting that the Commission consider including alternatives for residents of disadvantaged communities based on its proposal, with mention of the SOMAH, SASH, and DAC-SASH programs.[372] But TURN declines to actually propose such alternatives, showing it has little interest in addressing these equity issues.[373]

The Commission has shown its deep and genuine interest in addressing equity concerns and expanding opportunities for low-income customers and disadvantaged communities to be part of California's clean energy future, including through its ESJ Action Plan.[374] It should reject proposals that do not further that end.

f. "Equity Fund" Proposals

The equity fund proposed by NRDC and supported by Cal Advocates would create a source of funding for programs to benefit low-income customers.[375] NRDC's proposal is not fully developed, and it is unclear how funds would be allocated.[376] In rebuttal testimony, NRDC

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369 11 Tr. 1909:14 to 1911:21 (IOU – Wright); Exh. IOU-02 at 105:15-21.

370 Exh. GRD-01 at 15:9-15.

371 Exh. CSA-35 at 10 & fns. 6-7.

372 Exh. TRN-01 at 53:15-23.

373 Exh. TRN-01 at 53:8-11.

374 Exh. CSA-35 at 6-8.

375 Exh. NRD-01 at 21:10 to 22:02; Exh. PAO-03 at 3-59:21-22.

376 *See* Exh. NRD-01 at 21:10-13 (proposing to provide clean energy benefits "such as through rooftop solar, electrification, and energy efficiency), 21:26 to 22:1 (discussing a future consultation process and new phase of this proceeding to determine how to spend funds); NRD-02 at 17:22-24 ("The arguments that NRDC's proposal would make solar unattractive to lower income customers forget that NRDC is proposing an equity fund that would completely buy down the cost of solar for lower-income Californians.").

suggests that funds would provide free solar systems to low-income customers.[377] In that event, the proposal is similar to DAC-SASH, and shares the same risk of being undermined by the low export compensation rate NRDC proposes.[378] The same is true for Cal Advocates' equity fund proposal to fund existing incentive programs.[379]

Moreover, the source of funds, a fee on existing NEM-1 and NEM-2 customers as well as on NEM-3 customers after 10 years, is not justifiable or wise.[380] It taxes clean energy investments, which is counter to state policy goals.[381] It also comes hand in hand with tariff proposals that would have deep negative impacts on the solar market, undermining its source of funding.[382] And it would be collected from all NEM customers other than those on CARE or FERA rates, so it would reduce savings for many low- and moderate-income customers who are subject to the fee.[383] The proposals applying new charges to NEM-1 and NEM-2 customers also suffer from the numerous legal and policy shortcomings discussed in Section IV of this Opening Brief.

g. Important Equity Considerations

As the Commission considers how to shape the successor net metering tariff, it should keep top of mind certain issues that are key to assuring it advances its equity goals and meets with the requirements of Public Utilities Code Section 2827.1(b)(1).

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377 Exh. NRD-02 at 16:7-8.

378 *See* Section III.C.1.d.

379 *See* Section III.C.1.d; Exh. PAO-03 at 3-61:3 to 3-62:22.

380 Exh. CSA-01 at 37:12-19.

381 Exh. CSA-01 at 105:22 to 106:10.

382 Exh. CSA-01 at 106:17-24.

383 Exh. CSA-01 at 37:18-19; Exh. PAO-03 at 3-56:10-12.

The Need to Support Multifamily Solar

Many of the proposals and deliberations in this proceeding have focused on the single-family solar sector at the risk of failing to encourage solar adoption in the multifamily segment of the housing market, impeding both equity and climate goals, contrary to state policy objectives.[384] In SB 350 (De León) and the California Energy Commission's 2016 SB 350 Barriers Report, the legislative and executive branches have expressed keen interest in solar energy's potential to serve low-income customers, including residents of disadvantaged communities, and in efforts to reduce barriers to adoption of renewable distributed energy.[385] Approximately 30% of Californians live in multifamily dwellings, and approximately 70% of them have incomes below or at the area median income, compared with 45% of those who live in single-family homes.[386]

The multifamily sector poses challenges for solar adoption in large part because the great majority—approximately 90%—of multifamily residents are renters.[387] Challenges for deploying solar on multifamily rental properties include "split incentives" that discourage property owners from making solar investments that benefit the property's tenants, complex ownership structures for low-income multifamily housing that impede decisions about energy investments, and limited

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384 Exh. CSA-02 at 24:3-6.

385 Exh. CSA-02 at 24:6-14 (citing Cal. Pub. Resources Code, § 25327(a), (b) and SB 350 Barriers Report, pp. 12-13).

386 Exh. CSA-02 at 24:1-3 (citing U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/maps/lead-tool (housing data from the U.S. Census Bureau's American Community Survey 2018 Public Use Microdata Samples); *Solar Demographics Tool*, Lawrence Berkeley National Laboratory, Electricity Markets and Policy, https://emp.lbl.gov/solar-demographics-tool).

387 Exh. CSA-02 at 24:15-16 (citing U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/maps/lead-tool (housing data from the U.S. Census Bureau's American Community Survey 2018 Public Use Microdata Samples)).

budgets and financing arrangements that make it difficult to take on new debt to fund energy projects.[388]

With the state's climate and equity goals and these challenges in mind, the Commission should focus particular attention on multifamily solar in designing the successor NEM tariff structure. Changes that reduce the benefits of net metering for multifamily customers are all but certain to reduce opportunities and constrict solar access in lower-income communities and DACs.[389] VNEM has been an instrumental element of MASH and SOMAH.[390] A strong net metering tariff is also crucial to expanding solar among multifamily customers outside those programs.[391] Also, NEM-A is sometimes used for low-income housing where rural customers provide on-site housing for employees, and a strong tariff also helps reduce energy costs for those employees.[392]

The growth trajectory of VNEM has been in the right direction, as shown in Figure 5 from CALSSA's rebuttal testimony, but 10 MW per year is not close to the level that should be pursued.[393]

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[388] Exh. CSA-01 at 24:15-18; Exh. CSA-02 at 24:16-21 (citing SB 350 Barriers Report, pp. 29-31, 38-39 and *Tracking Progress—Energy Equity Indicators*, p. 8, California Energy Commission (June 2018), *available at* https://www.energy.ca.gov/sites/default/files/2019-12/energy_equity_indicators_ada.pdf).

[389] Exh. CSA-02 at 25:1-4.

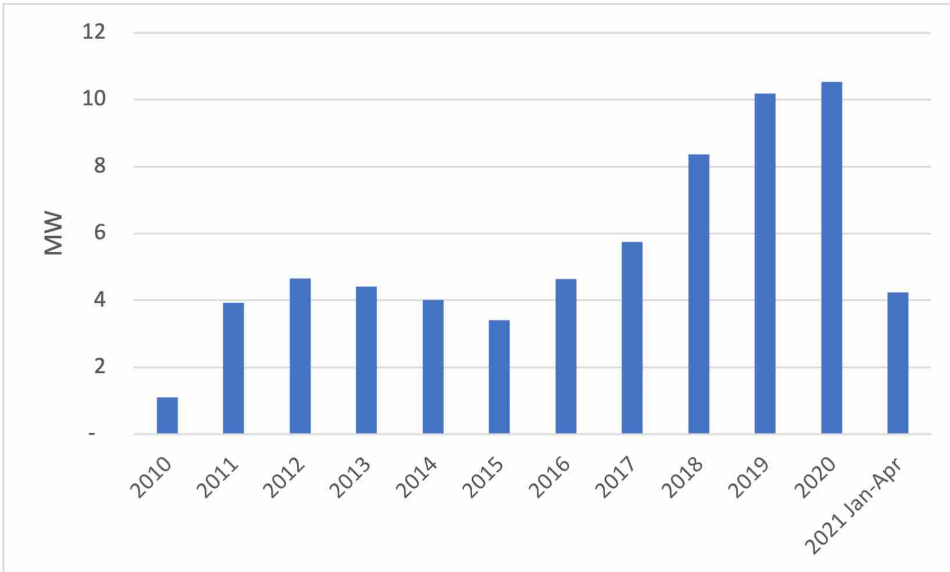
[390] Exh. CSA-02 at 25:5-7 (citing SB 350 Barriers Report, p. 54).

[391] Exh. CSA-02 at 25:7-9.

[392] Exh. CSA-02 at 25:7-11.

[393] Exh. CSA-02 at 25:12-13 & Fig. 5.

Figure 5. Annual VNEM Adoption



This figure shows interconnected systems, and data on systems under development would demonstrate an even more encouraging trend, which should be encouraged through strong policy support.[394]

The Commission should not harm VNEM and multifamily solar when it is poised for rapid growth. Expanding solar access for multifamily residents is a crucial aspect of moving toward greater equity and growth of renewable distributed energy in disadvantaged communities.[395] Providing specific alternatives that will make it easier to install distributed generation on low- and moderate-income multifamily properties is an important part of a just successor tariff.[396]

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394 Exh. CSA-02 at 25:13-15.

395 Cal. Pub. Util. Code § 2827.1(b)(1); D.21-02-007, Ordering Paragraph 1(b).

396 Cal. Pub. Util. Code §§ 451, 2827.1(b)(7).

Low-Income Electrification and Solar Adoption

The Commission should reject arguments that there is a conflict between electrification and NEM-supported solar adoption for lower-income customers.[397] Helping lower-income customers and customers in DACs participate in the benefits of the energy transition requires coordinated efforts to electrify buildings and to increase distributed clean energy generation.[398]

California is working to accelerate electrification in DACs. For example, the San Joaquin Valley Affordable Energy Proceeding was initiated following Assembly Bill 2672 (Perea) to explore methods to offer cleaner, affordable energy to 11 disadvantaged communities in the San Joaquin Valley.[399] The program includes work to replace propane and wood-burning appliances with all-electric appliances.[400] Also, the Commission and the California Energy Commission are pursuing the Building Initiative for Low-Emissions Development (BUILD) program, pursuant to Senate Bill 1477 (Stern).[401] This initiative seeks to encourage the construction of all-electric housing for low-income families.[402]

A NEM tariff that enables customers to cost-effectively generate their own energy is an important part of making these programs successful. Encouraging solar and storage installations at the sites of electrification projects like these lowers electricity costs and makes it more feasible

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397 *See, e.g.*, Exh. IOU-01 at 15:32 to 16:3; Exh. PAO-03 at 5-17:1-3.

398 Exh. CSA-02 at 28:2-5.

399 Exh. CSA-02 at 29:11-14 (citing R.15-03-010, *Order Instituting Rulemaking to Identify Disadvantaged Communities in the San Joaquin Valley and Analyze Economically Feasible Options to Increase Access to Affordable Energy in those Disadvantaged Communities* (March 26, 2015)).

400 Exh. CSA-02 at 29:14-15.

401 Exh. CSA-02 at 29:16-18 (citing California Energy Commission, *Building Initiative for Low-Emissions Development Program*, *available at* https://www.energy.ca.gov/programs-and-topics/programs/building-initiative-low-emissions-development-program).

402 Exh. CSA-02 at 29:18:19.

to add to energy loads.[403] Local solar also ensures that the energy load is met with emission-free energy, which is necessary for meeting state climate goals.[404]

CALSSA's proposal to extend NEM-2 treatment for low-income single-family customers and multifamily customers in low- and moderate-income census tracts would include most or all customers that participate in low-income electrification programs.[405] To the extent that the Commission approves a NEM-3 tariff that provides alternatives to encourage growth of distributed generation by some low-income customers and DACs, it is particularly important that the Commission ensure that participants of low-income electrification programs are eligible for the higher level of customer benefits, to meet important equity and statutory goals.[406]

Importance of Third-Party Ownership Models for Low-Income Adoption

Cal Advocates and the Joint IOUs express skepticism about third-party ownership ("TPO") models for solar adoption by low-income customers, noting that more CARE customers use these arrangements than other customers do and that these arrangements provide lower benefits than owning a solar system outright does.[407] While it is true that third-party financing can add to costs, that is not a reason to reject TPO arrangements. To the contrary, these financing models are an important and necessary element to making solar accessible for all.[408]

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403 Exh. CSA-02 at 29:20-23.

404 Exh. CSA-02 at 29:24.

405 Exh. CSA-02 at 30:1-3.

406 Cal. Pub. Util. Code § 2827.1(b)(1); D.21-02-007, Ordering Paragraph 1(b).

407 Exh. PAO-03 at 2-33:5 to 2:35:12; Exh. IOU-02 at 106:21 to 107:10.

408 Exh. CSA-02 at 30:11-15.

TPO models offers significant benefits for low-income customers, and they play an important role in expanding access to distributed generation in disadvantaged communities.[409] An obvious benefit of TPO models is that they make distributed generation accessible for customers who are not able to pay cash up front for a system.[410] Lower-income consumers generally experience more cash-flow issues than higher-income consumers do, and a TPO arrangement may be the best choice for such customers.[411]

Because reducing the need for an upfront investment can help with low- and moderate-income solar adoption, discouraging financing options would likely lead to *greater* inequity.[412] According to a recent study, TPO models can do more for low-income energy access and equity than many other initiatives, including targeted incentives for low- and moderate-income households ("LMI incentives").[413] For example, approximately 48-50% of households at or below county median income used leasing, while approximately 2-3% of those solar adopters used LMI incentives.[414] The study concluded that leasing and other TPO arrangements can address barriers to solar adoption by low- and moderate-income households and can help shift solar deployment into underserved areas.[415]

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409 Exh. GRD-02 at 5:21-24.

410 Exh. CSA-02 at 30:16-17; Exh. SVS-04 at 48:8-10.

411 Exh. CSA-02 at 30:17-21 (citing Varun Rai and Benjamin Sigrin, *Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets*, pp. 1, 7, Environmental Research Letters (2013), *available at* https://iopscience.iop.org/article/10.1088/1748-9326/8/1/014022/pdf).

412 Exh. CSA-02 at 30:22-25 and Attachment 9, p. 84 (Eric O'Shaughnessy et al., *The impact of policies and business models on income equity in rooftop solar adoption*, Nature Energy 6 (2021).

413 Exh. CSA-02 at Attachment 9, p. 88.

414 *Id.*, p. 85. Source data for Figure 1 in this article is available at https://static-content.springer.com/esm/art%3A10.1038%2Fs41560-020-00724-2/MediaObjects/41560_2020_724_MOESM3_ESM.csv.

415 Exh. CSA-92 at Attachment 9, p. 89.

TPO models provide other benefits as well, including that the third-party owner holds responsibility for equipment degradation and performance that is far greater than is typically provided in warranties for purchased systems, and guarantees these services to the customer for the duration of the agreement, relieving the customer of a major burden.[416]

Also, although financed solar systems may have higher installed costs, that does not necessarily mean third-party ownership will lead to higher costs for the solar adopter.[417] In the context of a lease, for instance, the cost of ownership can be less than the cost of an equivalent system's purchase.[418] Several factors can play into a lessee's lower costs of ownership: a leasing company's maximization of federal tax benefits; the lessor's greater access to financial incentives such as accelerated depreciation; economies of scale; and the ability of leasing companies to raise capital at lower costs, increasing the leveraged return on capital.[419]

TPO arrangements are also important for community-owned solar projects like those in CALSSA's proposal, discussed below.[420] Community ownership models can include California cooperative corporations, nonprofit organizations, and certain governmental entities, all of which may use—and indeed rely on—financing models to accomplish their goals of installing solar for the benefit of ESJ communities.[421]

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416 Exh. CSA-02 at 31:4-7.

417 Exh. CSA-02 at 31:8-9.

418 Exh. CSA-02 at 31:9-10 (citing Varun Rai and Benjamin Sigrin, *Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets*, p. 4, Environmental Research Letters (2013), *available at* https://iopscience.iop.org/article/10.1088/1748-9326/8/1/014022/pdf).

419 Exh. CSA-02 at 31:9-10 (citing Varun Rai and Benjamin Sigrin, *Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets*, p. 4, Environmental Research Letters (2013), *available at* https://iopscience.iop.org/article/10.1088/1748-9326/8/1/014022/pdf).

420 *See* Section III.C.1.h.

421 Exh. CSA-02 at 31:15-22; *see* Exh. CSA-01 at Attachment 17, pp. 2-3, 7.

These alternative models of solar adoption have substantial benefits that outweigh the concerns raised by parties in this proceeding.[422] The Commission has approved the use of TPO models for equity-based incentive programs including DAC-SASH.[423] They are an important part of fulfilling the mandate of increasing growth of distributed generation in disadvantaged communities.[424]

h. CALSSA's Community-Owned Solar Proposal

CALSSA proposes to promote community ownership and expand equity and access to solar among low-income and disadvantaged communities through a community-owned solar policy.[425] Under this proposal, solar projects and hybrid solar and storage projects that are community owned and controlled will receive NEM credits at full retail rates minus NBCs, as under the NEM-2 tariff.[426] This policy is intended to enhance energy equity by expanding access to distributed energy resources among customers in ESJ communities, which includes lower-income customers and customers in DACs.[427]

This proposal is similar to Policy B proposed by GRID Alternatives, Vote Solar, and Sierra Club ("the Joint Equity Parties").[428] Eligibility for this policy will extend to NEM projects that are owned by a California cooperative corporation, as defined by the California Corporations Code; a nonprofit organization; or certain public entities: the state, a county, a city, or a

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422 Exh. PAO-03 at 2-33:5 to 2-35:12; Exh. IOU-02 at 106:21 to 107:10.

423 12 Tr. 2143:9-15 (PAO – Buchholz).

424 Cal. Pub. Util. Code § 2827(b)(1).

425 Exh. CSA-01 at 27:21 to 32:3.

426 Exh. CSA-01 at 8:24-29, 27:24-26.

427 Exh. CSA-01 at 27:26-28.

428 Exh. GRD-01 at 21:8-17.

California community college district.[429] These projects allow community members to pool resources, such as by contributing a small, affordable amount toward a solar project, and enjoy a share of the project's financial benefits through interest payments on their upfront investment—similar to bill savings from installing solar on one's own home.[430] This allows people who cannot adopt solar on their own to participate in the energy benefits of solar and additional benefits of building community wealth, health, and jobs.[431]

This proposal does not limit participants to people who live in ESJ communities, as the proposal by the Joint Equity Parties does. With the increased adoption and decreasing cost of solar in California, low-income and disadvantaged communities have begun to address their social and economic needs to build community wealth and resilience through solar.[432] It is important to allow these historically marginalized communities to pool resources across lines of class, race, and other backgrounds, by allowing people in other geographic areas who may have greater resources to join as participants in not-for-profit projects that are community owned and democratically controlled.[433]

Case studies in CALSSA's direct testimony describe how these projects work and lay out their benefits,[434] including a project owned by a cooperative on a single-family home in East

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[429] Exh. CSA-01 at 28:2-5.

[430] Exh. CSA-01 at 28:6-10.

[431] Exh. CSA-01 at 28:10-11.

[432] Exh. CSA-01 at 28:15-17.

[433] Exh. CSA-01 at 28:17-21.

[434] Exh. CSA-01 at Attachment 17.

Oakland,[435] a youth center in Richmond,[436] an affordable-housing complex in Berkeley,[437]and projects planned by the City of Oakland.[438] All three of these models—cooperative, nonprofit, and government—offer important opportunities for improving energy equity and providing resiliency and related services to lower-income households and residents of disadvantaged communities, opening opportunities for communities to build wealth, add local jobs, improve community health, and play an increased role in California's clean energy future.[439]

The proposal intentionally does not limit participation to residents of ESJ communities, because doing so would cut off resources and limit solidarity and community building, and because of practical difficulties involved in establishing eligibility with such limits in place.[440] That said, this is not a profit-making model. The California Cooperative Corporation Code places limits on distributions, nonprofits have public benefit purposes, and governments are entities that act for the public good, and the bill savings provided through NEM-2 merely make these projects viable, with funds generated through bill savings reinvested into the community.[441]

CALSSA is mindful of the many barriers to increasing penetration of distributed generation in disadvantaged communities and among low-income residents. Designing alternatives to overcome these barriers must necessarily risk being either underinclusive or overinclusive, and CALSSA believes the former poses the greater risk of perpetuating inequities.

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435 Exh. CSA-01 at 29:4-16; *see* Exh. CSA-01 at Attachment 17, pp. 2-4.

436 Exh. CSA-01 at 29:22 to 30:14; *see* Exh. CSA-01 at Attachment 17, pp. 4-6.

437 Exh. CSA-01 at 30:15-22; *see* Exh. CSA-01 at Attachment 17, pp. 6-7.

438 Exh. CSA-01 at 30:25 to 31:22; *see* Exh. CSA-01 at Attachment 17, pp. 8-9.

439 Exh. CSA-01 at 29:17-21, 31:23-25.

440 Exh. CSA-01 at Attachment 17, pp. 3-4, 6.

441 Exh. CSA-01 at Attachment 17, pp. 4-8.

2. Export Compensation

The legal standard for export compensation under §2827.1 balances the requirement that customer-sited renewable distributed generation continues to grow sustainably,[442] with the requirement that rates be based on the costs and benefits of the renewable electrical generation facility," [443] and the requirement that total benefits of the tariff "to all customers and the electrical system are approximately equal to the total costs."[444] Export compensation rates also must be just and reasonable,[445] providing fair compensation to customer-generators for the goods and services they provide to the electric system.

Most parties, including CALSSA, utilize the Avoided Cost Calculator as a key component in setting export compensation rates to meet these standards. As the Joint IOUs state, "[t]he Avoided Cost Calculator (Avoided Cost Calculator) is an important tool for evaluating the cost-effectiveness of demand-side resources,"[446] and, therefore, its use makes sense to help meet cost-effectiveness objectives when setting export rates. However, changing NEM export compensation from the current formula of rates minus non-bypassable charges to values associated with those produced by the Avoided Cost Calculator is an extreme reduction.[447] The key question before the Commission, therefore, is what is the best use of this tool and how frequently, if at all, should compensation rates be updated to reflect the ever-changing values the Avoided Cost Calculator produces. Another key issue, whether there should be a glidepath

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442 Cal. Pub. Util. Code § 2827.1(b)(1).

443 Cal. Pub. Util. Code § 2827.1(b)(3).

444 Cal. Pub. Util. Code § 2827.1(b)(4).

445 *See* Cal. Pub. Util. Code § 451.

446 Exh. IOU-01 at 125:2-3.

447 Exh. CSA-02 at 36:13-15.

eventually converging on Avoided Cost Calculator values is addressed in Section III.C.4 of this Brief.

For general market residential NEM customers, CALSSA proposes a step down of export credits from retail rates in five steps. Each step reflects a percentage of each utility's retail rate, as shown in Table 1 of CALSSA's direct testimony, as shown below.[448] As with NEM-2, non-bypassable charges (NBCs) are deducted from the export rate.[449] A customer installing a NEM-eligible resource in a particular step will maintain NEM credits at that step's percentage for twenty years.

Table 1. NEM Export Value as Percentage Reduction from Retail Rates

Export Step-Down								
	PG&E		SCE		SDG&E		All IOUs	
	Solar	Solar + Storage	Solar	Solar + Storage	Solar	Solar + Storage	CARE/ FERA	LMI Multifamily Renters
Step 1	90%	100%	95%	100%	90%	95%	100%	100%
Step 2	80%	95%	90%	100%	80%	90%	100%	100%
Step 3	70%	90%	85%	100%	70%	85%	100%	100%
Step 4	60%	85%	80%	100%	60%	75%	100%	100%
Step 5	50%	80%	75%	100%	45%	65%	100%	100%

The first step begins upon implementation of NEM-3, and the following four steps begin for each utility when capacity thresholds have been met for solar and storage installed under NEM-3. This is designed as an eight-year glidepath with four transitions after initial implementation. Each of the steps are designed to take two years.[450]

In this proposal, each step will remain in effect until a utility reaches the levels of solar and storage adoption identified in Table 2. The solar thresholds are calculated as twice the

448 Exh. CSA-01 at 7, Table 1 and at 39, Table 4.

449 This should be calculated by first applying the percentage to the rate, then subtracting NBCs.

450 Exh. CSA-01 at 39:3-9.

average annual installation rate of the past five years. The storage threshold represents 20% of the solar threshold in Step 1, 40% of the incremental solar threshold in Step 2, 60% in Step 3, and 80% in Step 4.[451]

The step down includes a trigger for both solar and storage because solar adoption is a measure of continuity in the market, and storage market growth is a measure of when the market will be able to adjust to a tariff with lower savings potential for solar without storage. Both need to be met before a utility changes the NEM tariff to the next step.[452]

Table 2. Capacity Thresholds for Step Transition

Step-Down Thresholds						
	Cumulative Residential MW on NEM-3					
	PG&E		SCE		SDG&E	
	Solar	Storage	Solar	Storage	Solar	Storage
Step 1	770	150	520	100	300	60
Step 2	1540	460	1040	310	600	180
Step 3	2310	920	1560	620	900	360
Step 4	3080	1540	2080	1040	1200	600
Step 5	Continues until further review					

The percentages in Table 1 of CALSSA's direct testimony were calculated such that the final step has a Ratepayer Impact Measure (RIM) result greater than 0.9 using the 2020 Avoided Cost Calculator (ACC). CALSSA has not changed its proposal in response to the 2021 updates to the ACC because we believe that doing so would violate the requirement to maintain sustainable growth in NEM adoption.[453] However, in recognition that the ACC results changed significantly with the 2021 update and are likely to continue to swing dramatically, CALSSA encourages the

451 Exh. CSA-01 at 39:12-17.

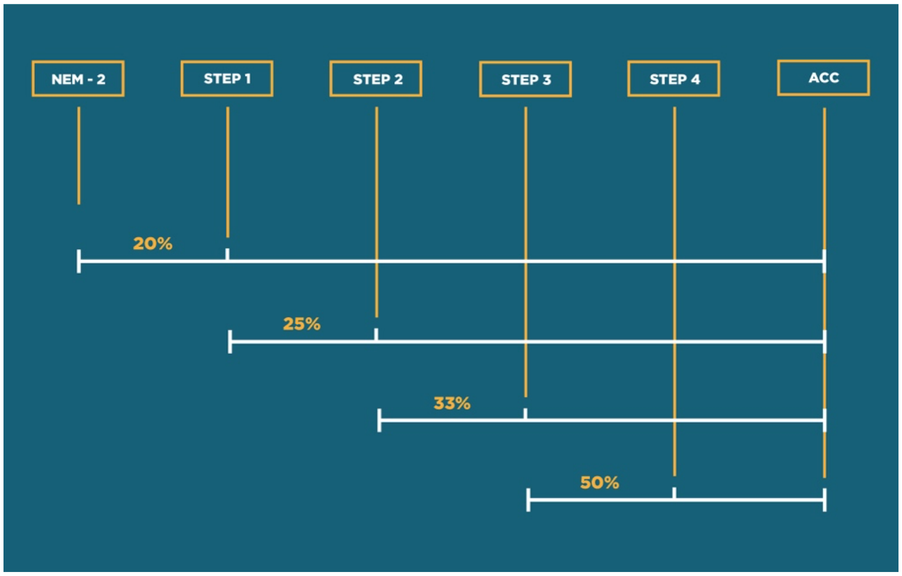
452 Exh. CSA-01 at 39:18-40-2.

453 Cal. Pub. Util. Code § 2827.1(b)(1).

Commission to consider an alternative step-down approach that avoids the need to determine the specific export compensation values that will take effect when NEM-3 is fully implemented.

Under CALSSA's alternative approach, the export compensation for each step is a percentage change between the export compensation of the previous step and the values derived from the ACC at the time that the step is implemented. If Step 1 is implemented in 2022, Step 1 export compensation is reduced 20% of the way from NEM-2 export compensation to the values derived from the 2022 ACC. If Step 2 is implemented in 2024, the Step 2 export compensation is reduced 25% of the way between Step 1 export compensation and the values derived from the 2024 ACC. The five steps are shown in Figure 11 of CALSSA's Rebuttal Testimony. Step 5 will be equal to the values derived from the ACC:[454]

Figure 11. Illustrative Glidepath for Reduction in NEM Export Value



In either step-down approach, CALSSA proposes that customers that install a NEM-eligible generator in a particular step maintain NEM export credits at that step's percentage of rates for

454 CSA-02 at 48, Fig. 11 (slightly altered version included here to state "ACC" instead of "Step 5" to more clearly communicate the concept).

twenty years. When a utility moves to the next step, new NEM customers are subject to the new step's percentage.

CALSSA's proposal best balances the various legal standards by setting export compensation rates in a manner that accommodates the year-over-year volatility of the Avoided Cost Calculator while providing a compensation framework that will still allow customers to invest in onsite systems without creating consumer protection concerns. The inflexible, dogmatic faith the Pro-Transmission Parties place in the Avoided Cost Calculator to set their export rates creates a severely imbalanced program that will be unworkable for most customers. Worse, the ever-changing compensation rates these parties propose are excessively complicated to administer and very difficult to model accurately for customers. These issues undermine customers' investment certainty, creating substantial consumer protection concerns around the ability to reasonably calculate bill savings over the lifetime of their systems.[455]

a. The Avoided Cost Calculator is Best as a Guide.

The Pro-Transmission Parties propose to use the Avoided Cost Calculator for ratesetting.[456] Under those proposals, NEM export compensation and solar fees would be directly determined by outputs from the calculator.[457] However, as the Joint IOUs' direct testimony states, the Avoided Cost Calculator "was not designed to directly inform rate

[455] The other major short-coming in the Pro-Transmission Parties' export compensation proposals is the resulting payback periods. These issues are addressed in Section III.B.1 of this Opening Brief.

[456] Exh. CSA-02 at 44:2-4.

[457] Exh. CSA-02 at 44:2-4.

design,"[458] and relying entirely on the Avoided Cost Calculator to set export compensation rates exceeds the tool's capabilities.[459]

First, the tool is volatile and ceaselessly controversial. The value of customer solar declined in the 2021 version of the Avoided Cost Calculator due mostly to a major restructuring of the methodology for production cost modeling and new assumptions about the expected future mix of wholesale generation.[460] Not only did this result in a major change in the value of customer-sited systems in one year, the debate is not over. These two factors will be debated exhaustively in the 2022 major update of the Avoided Cost Calculator and are likely to end up higher than the corresponding values in the 2021 Avoided Cost Calculator.[461] Other factors, such as the values for avoided transmission and distribution, may be increased above the corresponding values in both the 2020 Avoided Cost Calculator and the 2021 Avoided Cost Calculator.[462] This volatility in the Avoided Cost Calculator undermines its ability to serve as a ratesetting tool.

The methodology for the design of retail rate schedules, in contrast, is well established.[463] Although rate design evolves over time, the mechanics for setting rates are stable.[464] Utility witnesses attempted to draw a parallel between volatility in the Avoided Cost Calculator and changes to retail rates,[465] but that argument is hollow. The ACC values have swing wildly and

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458 Exh. IOU-01 at 125:3-4.

459 Exh. CSA-02 at 44:4.

460 Exh. CSA-02 at 1-3.

461 Exh. CSA-02 at 45:3-5; *see* R.14-10-003, *E-mail Ruling Noticing Evidentiary Hearing for the Major Update of the Avoided Cost Calculator* (Aug. 17, 2021).

462 Exh. CSA-02 at 45:5-6.

463 Exh. CSA-02 at 45:7-8.

464 Exh. CSA-02 at 45:8-9.

465 *See* 4. Tr. 698:14-696:27 (IOU – Kerrigan).

even policy makers have difficulty predicting where they will go. In contrast, while rate levels will tick up and down, and experimental designs will be developed, the core influences of rates are well understood.[466]

The Commission should use the Avoided Cost Calculator as a guide to inform export compensation levels but allow traditional ratesetting tools to determine specific values. The most important thing is to begin the transition. Rather than trying to decide on the precise values of the end state of the transition, the Commission should use the Avoided Cost Calculator results as a whole to begin a glidepath downward on export compensation rates as soon as possible. This can best be accomplished by stepping down export values as a percentage of rates without a complicated restructuring of net metering that is difficult to implement and based on a volatile tool.[467]

b. Levelization Must Reflect the Nature of the Underlying Assets.

The Avoided Cost Calculator calculates the levelized lifetime benefits of distributed energy resources.[468] It establishes 8,760 hours of values for each year of an asset through 2050.[469] To determine an export compensation rate under most parties' proposals, the Commission must modify those outputs in two ways: (1) it must determine the period of time over which those values are levelized and (2) it must weight those values based on when a system is likely to produce energy, thereby calculating average values.[470]

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466 Exh. CSA-01 at 20:5-7.

467 Exh. CSA-02 at 45:17-22.

468 Exh. CSA-02 at 37:2-3.

469 4 Tr. 676:2-4 (IOU – Kerrigan); Exh. IOU-01 at 125:8; Exh. CSA-02 at 41:17-19.

470 Exh. CSA-02 at 36:24-26.

CALSSA's proposal reflects the 25-year levelized value of exported energy from the Avoided Cost Calculator as a guide to set NEM export compensation as a percentage of rates.[471] Solar energy systems are a 25-year resource and, therefore, the correct levelization period in the Avoided Cost Calculator is 25 years. [472] Levelizing lifecycle costs and benefits is a legitimate way to measure the average impact of a resources that will be producing energy for 25 years. [473]

In contrast, the Pro-Transmission Parties essentially propose to use unlevelized, one-year avoided cost values and believe the results of the 2021 Avoided Cost Calculator are indicative of where Avoided Cost Calculator results will remain.[474] Specifically, the Joint IOUs and TURN recommend no levelization period, and NRDC recommends a three-year levelization period.[475] Cal Advocates recommends a four-year average of single-year ACC values. [476] These approaches leave customers with excessive uncertainty on whether their investments will be worthwhile.[477] If a customer reaches out to a contractor and expresses interest in solar, and the contractor demonstrates the benefits in the initial years but says future year benefits are unknown, the customer cannot be expected to make the investment. [478] This single factor would be a poison pill for the entire market. [479] Although retail rate changes provide some amount of uncertainty in future year savings, customers have experience with gradually increasing rate

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471 Exh. CSA-01 at 13:13-14; Exh. CSA-02 at 36:18-23.

472 Exh. CSA-02 at 37:9-10.

473 Exh. CSA-02 at 41:6-7.

474 Exh. CSA-02 at 36:16-17. While the Joint IOUs, for example, state they use "levelized" avoided costs, these are only levelized over the course of one year. Exh. IOU-01 at 125:9-10.

475 Exh. CSA-02 at 19:5-8.

476 Exh. PAO-02 at 5-4:27-28.

477 Exh. CSA-01 at 20:1-2.

478 Exh. CSA-01 at 20:2-4.

479 Exh. CSA-01 at 20:4-5.

structure but will have no confidence in an obscure calculator that has never been used for setting rates.[480]

Cal Advocates' proposal for "[b]asing export compensation on a going-forward 4-year average of avoided costs from the most recently adopted two ACCs"[481] is excessively complicated and would be difficult for stakeholders to compute. The ACC has levelization period as a primary input.[482] Export compensation should be derived from ACC values using a levelization term within the most recently adopted calculator to avoid disputes in implementation and allow participants to quickly calculate changes when the ACC is updated rather than waiting for official publication of values from utilities or the Commission.

Not only do these proposals result in uncertainty, they are likely to undervalue exports. Figures 7-9 and Tables 4-6 in CALSSA's rebuttal testimony demonstrate the difference between levelized lifetime avoided cost values and non-levelized, single-year values,[483] with Figure 7 reproduced below:[484]

[480] Exh. CSA-01 at 20:5-7.

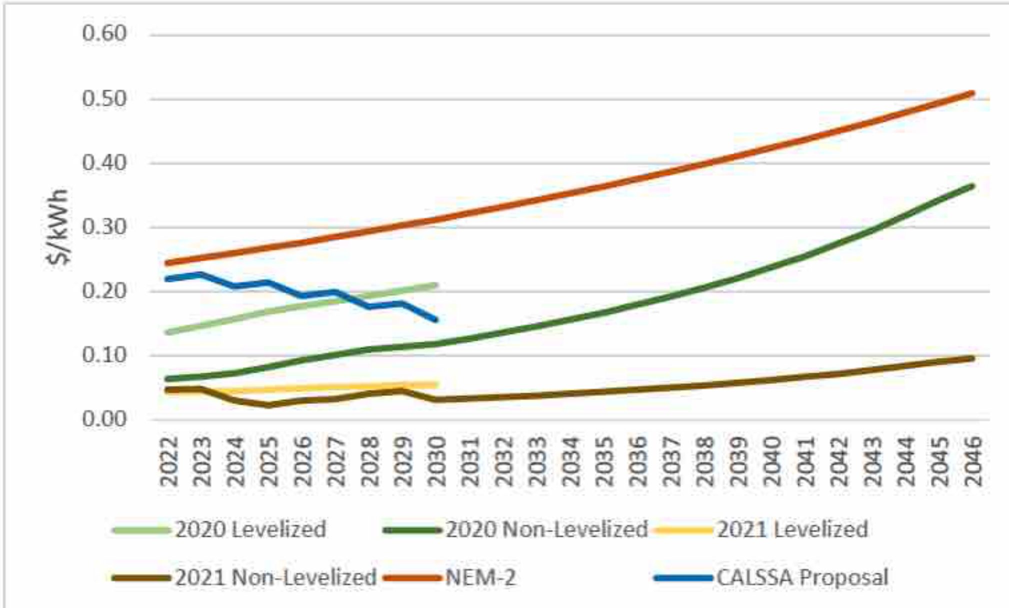
[481] Exh. PAO-02 at 5-4:27-28.

[482] Exh. CSA-02 at 37:3-4.

[483] Exh. CSA-02 at 37:9-10.

[484] Exh. CSA-02 at 37, Fig. 7.

Figure 7. PG&E ACC Outputs and Residential Solar Export Values



Because the 2021 Avoided Cost Calculator has less growth over time, the levelized values (yellow line) are closer to the non-levelized values (brown line).[485] In the 2020 Avoided Cost Calculator, the levelized values (light green line) are much higher than the non-levelized values (dark green line).[486] While less of an issue under the current Avoided Cost Calculator, if the Avoided Cost Calculator stabilizes next year, with later year values between the two versions in the chart above, using non-levelized values would significantly undercount the lifetime avoided costs of solar energy systems.[487]

TURN's Lock-In Mechanism Is Inferior to Levelization

In an effort to address the uncertainty that its market-based proposal provides, TURN provides an option for customers to either be exposed to market prices or to lock in export rates

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485 Exh. CSA-02 at 37:10-11.

486 Exh. CSA-02 at 37:11-12.

487 Exh. CSA-02 at 3712-14.

for 5-10 years.[488] However, the value of those exports would not be based on a levelization of future benefits over that time period.[489] The values could be expected to follow a mostly upward trend based on the single-year ACC values for the following years, but compensation would still be a collection of single-year ACC values rather than a levelization across the period. If TURN is willing to accept the current-year ACC as a trustworthy estimate of benefits over a ten-year term, there is no reason to use that estimate as a collection of separate values, which would backload the utility costs and customer benefits, rather than a levelized value, which would front-load those costs and benefits with an equivalent total impact.[490]

c. A Balanced Weighting of Avoided Cost Calculator Values.

In addition to the timeframe over which to levelize costs, the Commission must also decide whether and how to average the Avoided Cost Calculator outputs, translating 8,760 hourly values into values per TOU period. Weighted averaging applies the Avoided Cost Calculator value in each individual hour ($/kWh) to the resource output in that hour (kWh), then averages the resulting dollar values over the period.[491] Basic methodologies for weighted averaging are well understood and can be done without excessive complexity.

For solar, in recognition that output is weighted toward certain hours, it is reasonable to apply the hourly Avoided Cost Calculator values to a standard profile of solar output, with the resulting weighted hourly values binned into time-of-use periods.[492] Weighting for solar

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488 Exh. TRN-01 at 37:16-18.

489 Exh. TRN-01 at 37:16-18. TURN clarified its proposal during cross examination, but these shortcomings remain. See 7 Tr. 1174:3-18 (CSA – Heavner/Plaisted).

490 Exh. CSA-01 at 20:8-16.

491 Exh. CSA-02 at 42:15-17.

492 Exh. CSA-01 at 13:18-20.

systems with energy storage can follow a standard solar plus storage operating profile.[493] CALSSA recommends weighting Avoided Cost Calculator values according to the solar profile when calculating export rates because it is the most objective approach and would be relatively simple to administer.[494] That is, it can serve as a middle ground for all purposes.[495]

Two of the Pro-Transmission Parties, the Joint IOUs and NRDC, represent two extremes for addressing ACC rates, neither of which should be adopted. The Joint IOUs, at one end of the spectrum, create an enormously complex weighting framework based on actual customer usage; while NRDC, on the other end, avoids the use of average rates altogether. Both proposals would be administratively complex endeavors for the Commission to undertake and create substantial consumer protection concerns.

Weighting Must Be Implementable Over the Long-Term

First, while the Joint IOUs have acknowledged the Avoided Cost Calculator is not a ratesetting device, instead of simplifying their proposal in response to this short-coming, they create an enormously complex approach to weighting the values. The IOUs' export compensation rates weight each of the 8,760 hours in the Avoided Cost Calculator by "the

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[493] Exh. CSA-01 at 13:20-21. For solar plus storage, CALSSA uses a "solar self-consumption" operating mode. In this mode, solar generation is first used to charge the battery each day. When the battery is fully charged, solar generation offsets customer load. Only when the battery is fully charged and generation exceeds load does the solar system export power to the grid. During the TOU peak period, customer load that exceeds solar generation is satisfied with battery discharge until the battery is reaches its minimum charge level. Customer consumption that exceeds generation outside of the peak period is powered by the grid. During the peak period, consumption that exceeds solar generation draws from the grid after the battery is discharged. Exh. CSA-01 at 14:22-15:2.

[494] Exh. CSA-02 at 43:3-4.

[495] Exh. CSA-02 at 43:4-5.

recorded exports from the export channel of the meter that meters customers within each rate class that are on the reform tariff."[496]

The IOUs would then assign the weighted values for each of the 8,760 hours to six different time-of-export periods, which coincide with the time-of-use periods within each day.[497] Simply calculating the six correct rates – and then updating them *each year after that* – will require the Commission to rely on the advice letter process to ensure that the values in the Avoided Cost Calculator were weighted correctly, included in the correct time-of-export buckets, and, for departed load customers, only include the generation component of the Avoided Cost Calculator.[498] As Witness Kerrigan admitted, in order to verify the weighting, the Commission and parties "would need to have access to the raw meter data to make sure that the profile is accurate, based off of the measure meter" from *each customer* on the IOUs' successor tariff.[499] We do not know how volatile the aggregated metered load would be or whether the IOU methodology would have accuracy concerns.

Equally problematic, annual updates to the generation profile are a substantial consumer protection concern for customers making a 25-year investment in standalone solar. The IOU proposal will update the export profile used to calculate the compensation rates each year to account for the "mix of technologies participating in the successor tariff."[500] As the IOUs explain, the storage-paired generation can be expected to be stored and shifted to higher retail

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496 4 Tr. 676:21-24 (IOU – Kerrigan).

497 4 Tr. 677:26-678:23 (IOU – Kerrigan).

498 4. Tr. 688:22-690:4; 694:20-26 (IOU – Kerrigan).

499 4. Tr. 690:11-22 (IOU – Kerrigan).

500 Exh. IOU-01 at 127:5-6.

cost periods, thus changing the export compensation rate over time."[501] As that occurs, the Commission can expect that the on-peak compensation rates would go up while the off-peak compensation rates will go down, assuming customers are following price signals.[502]

If solar-plus-storage customers follow those price signals, customers with solar-only systems, which produce in the off-peak periods under the IOUs' proposal,[503] will see their exports become less valuable at unknown rates over the lifetime of the system.[504] Such a result hurts their cost recovery periods and raises an important consumer protection concern: customers will have no ability to reasonably predict the value of future exports. As Witness Kerrigan admitted, a customer would not be able to accurately forecast the technologies that other people in that customer's service territory would deploy,[505] meaning they cannot predict how the weighting of export values might change. Thus, unlike under NEM-2, which compensates customers at rates that are unlikely to go down, the IOUs' proposal is likely to hurt standalone solar customers as more customers adopt storage and follow on-peak price signals in configuring their exports.

Lastly, the annual update to the export profile the IOUs propose is one of up to three or four potentially major changes to the value of a solar PV system that a customer would see *each year*, at different times of the year, when considering IOUs' solar fee also may change two-three times per year.[506] Customers would need to be able to understand at the outset the degree to

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[501] 4 Tr. 691:22-27 (IOU – Kerrigan).

[502] *See* 4 Tr. 692:3-694:13; 5 Tr. 753:24-755:3; and 5 Tr. 817:17-821:11 (IOU – Kerrigan).

[503] 4 Tr. 693:15-18 (IOU – Kerrigan).

[504] *See* 4 Tr. 692:3-694:13; 5 Tr. 753:24-755:3; and 5 Tr. 817:17-821:11 (IOU – Kerrigan).

[505] 4 Tr. 821:3-9 (IOU – Kerrigan).

[506] 4. Tr. 696:19-27 (IOU – Kerrigan); 3 Tr. 459:26-461:28; 479:22-480:1 (IOU – Morien); Exh. IOU-01 at n. 207.

which their export values might go down *and* the degree to which their solar fee might go up – a difficult task in the near term and an impossible task over the long term.

The Absence of Weighting Creates an Unworkable Tariff.

At the other end of the spectrum is NRDC's proposal on how to utilize the Avoided Cost Calculator. While NRDC's proposal lacks sufficient detail overall, one of the three bullets it uses to describe its export compensation proposal requires the utility to calculate – and the Commission to verify – 8,760 different export rates for each service territory every two years.[507] When asked the process through which the Commission would update rates every two years, NRDC's witness stated NRDC has not "thought that through." [508]

The reality is NRDC's proposal would be excessively complicated to administer and difficult to model accurately for customers.[509] For example, outcomes could change radically based on decisions of how to assign capacity values.[510] In the 2021 Avoided Cost Calculator, all transmission capacity costs are considered to be caused by 22 specific hours in the year for PG&E, 45 hours for SCE, and 27 hours for SDG&E.[511] That is a policy decision concerning how outage risk is measured, and every time that policy might change it could upend the export compensation rates under NRDC's proposal. [512] This is just one example. As discussed above, ratesetting should not rely too heavily on a tool that was not intended for setting specific rates.

[507] Exh. NRD-01 at 16:4-5; 10 Tr. 1765:14-17 and 1766:3-7 (NRD – Chhabra).

[508] 10 Tr. 1766:22 (NRD – Chhabra).

[509] Exh. CSA-02 at 41:19-20.

[510] Exh. CSA-02 at 41:20-21.

[511] Exh. CSA-02 at 41:21-23.

[512] Exh. CSA-02 at 41:23-24.

For the same reason that the Commission smooths out time-differentiated rates into TOU periods, it should smooth out export compensation values.[513] NRDC's proposal is unreasonable.

d. The Joint IOUs' Export Proposal is Unreasonable.

Installers Cannot Create Reasonable Savings Estimates Under the Joint IOUs' Export Proposal.

While not as egregious as NRDC's 8,760 different export rates, the Joint IOUs would require customers and solar installers to predict the values for thirteen separate export rates in order to calculate the benefits from a customer's system over its lifetime. While the base of the IOUs' proposal consists of six time-of-export rates, the IOUs also propose that if a customer's exports during a particular time-of-export period exceed those imported during the corresponding time-of-use period, the customer will receive a different rate, the net-surplus compensation rate, for those kWh that exceed the amount imported.[514]

Beyond this seventh rate, customers may be compensated at their retail rates instead of the export compensation rate.[515] Retail rates come into play as a compensation rate because of yet another complexity in the IOUs' proposal: If the export compensation rate for a particular time-of-export period is higher than the retail rate for that same time-of-use period, then the retail rate would replace the net export compensation rate.[516] Asked when or how often that might happen, the Joint IOUs' witness stated "that is difficult to say;"[517] however, it could happen as often as annually since compensation rates would be revised annually.[518] When asked what

513 Exh. CSA-02 at 42:1-2.

514 4 Tr. 679:14-22 (IOU – Kerrigan).

515 4 Tr. 680:23-681:11 (IOU – Kerrigan).

516 4 Tr. 681:3-11 (IOU – Kerrigan).

517 4 Tr. 681:18 (IOU – Kerrigan).

518 4 Tr. 681:19-24 (IOU – Kerrigan).

happens when retail rates change, requiring a change in the compensation rate, the IOU Witness did not know the answer, stating he "did not consider that specific scenario." [519]

In each season, six export rates, six retail rates and the net surplus compensation rate may all form the basis for compensation rates under the Joint IOUs' proposal. When discussing an investment with a customer, a solar contractor will be required to estimate bill savings under these thirteen different possible rates without a clear sense of which might be used at a particular time over the system's lifetime, a substantial consumer protection concern.

The Joint IOUs' Export Proposal Creates a Double-Standard.

In addition to customer understanding and consumer protection concerns, the IOUs' proposal to cap export rates at retail rates is a double-standard. Generally, the IOUs propose to compensate exports at a measured value of solar when that value is less than rates, but will not use the measured value of solar when that value is greater than rates. [520] That is, the utilities distance themselves from the Avoided Cost Calculator at the same time as they are proposing to use it directly, *i.e.*, they are trying to have it both ways.

3. Export Compensation for Agricultural and Commercial Customers.

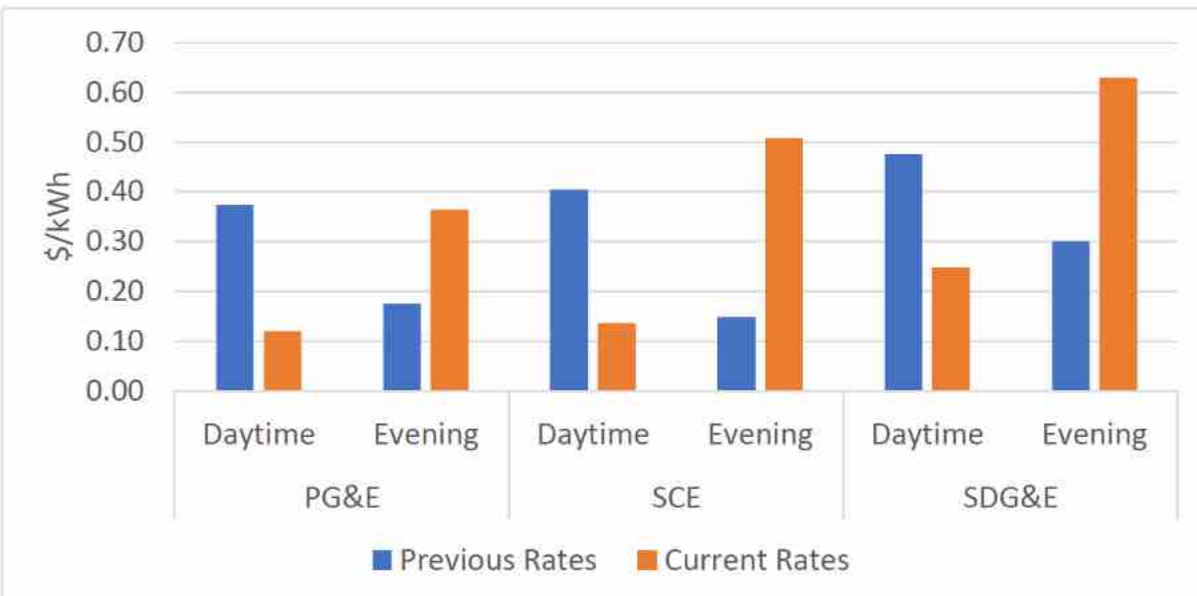
While many of the issues in the previous section apply equally to successor tariffs for agricultural and commercial customers, including the legal standards under which they are judged, CALSSA and other parties put forward specific provisions for these customer groups. The NEM-3 tariff for commercial and agricultural customers should be identical to the NEM-2

519 4 Tr. 682:26-27 (IOU – Kerrigan).

520 4 Tr. 681:3-11 (IOU – Kerrigan).

tariff, a position supported by the E3 white paper.[521] The shift to evening-peaking time-of-use periods has already achieved the objective of greatly reducing the value of mid-day NEM credits, while it also increased the cost of electricity purchased from the utilities in the evening. Figure 2 of CALSSA's direct testimony shows how sharp this change has been.[522] The change in TOU structure reduced daytime NEM credit value by 68% for PG&E, 66% for SCE, and 48% for SDG&E.[523]

Figure 2. Commercial Option R Summer Rates



This has slowed the commercial solar market, minimizing concerns of runaway impacts and threatening compliance with the requirement for sustainable growth in NEM systems. The

521 Exh. CSA-01 at 17:8-9, referencing *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California*, California Public Utilities Commission (January 28, 2021).

522 Exh. CSA-01 at 17, Fig. 2.

523 Exh. CSA-01 at 17, Fig. 2.

number of submitted applications declined 25% in 2020 compared to the 2018-2019 average across the three IOUs.[524]

Changing NEM for commercial and agricultural customers is not necessary and is unwarranted. The NEM 2.0 Lookback Study finds that nonresidential solar customers more than cover their average cost of service, as shown in Figure 4 below from CALSSA's Direct Testimony.[525] On aggregate, commercial and agricultural NEM-2 customers interconnected as of December 2019 pay $117 million more per year than the cost to serve them.[526] As more commercial and agricultural customers have taken service under NEM-2 since the study period, this number can be presumed to be proportionally higher. They are overpaying less after installing solar than they were overpaying before installing solar. Because they are covering their cost of service, it is not reasonable to slash their export credits or charge additional fees.

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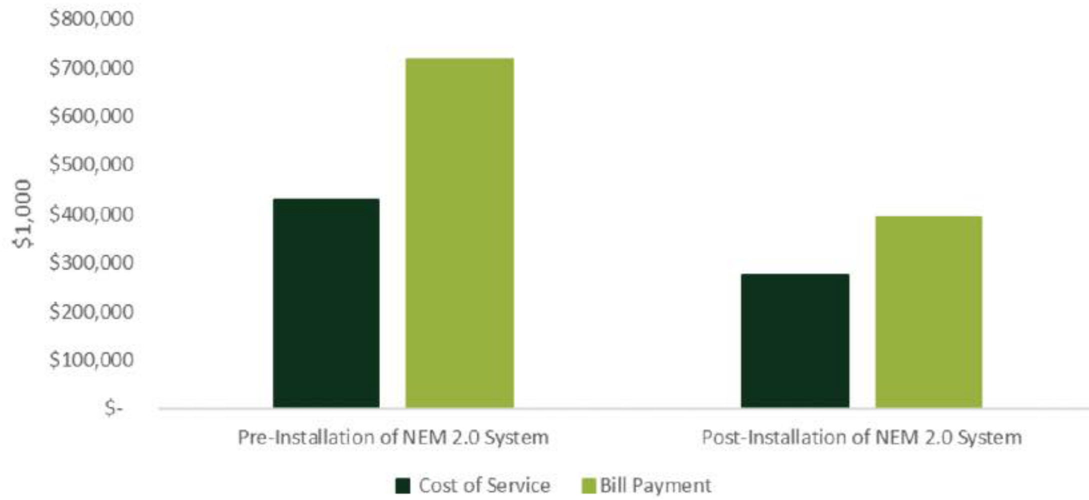
524 Exh. CSA-01 at 18, Fig. 3. The data from this figure was obtained from CALSSA-IOU-DR-02 (see Exh. CSA-01, Attachment 4), which was intended to document the increasing percentage of solar systems that include energy storage over the past three years. The data request did not request data for agricultural customers, so CALSSA did not include in Figure 3 the incomplete agricultural data sent by some of the IOUs. CALSSA excluded SCE military customers because it appeared to include a large number of individual systems on military housing which likely take service under residential rates.

525 Exh. CSA-01 at 19, Fig. 4 (with n. 12 citing to the NEM 2.0 Lookback Study, p. 10, (Figure 1-2)).

526 Exh. CSA-01 at 18:7-9.

Figure 4. Commercial and Agricultural Solar Customer Bills and Cost of Service[12]



Lastly, the Joint IOUs' rate cap proposal is especially problematic for commercial customers. While CALSSA agrees that the cap may only have an impact on rate schedules with demand charges, there is no reason to create a double standard for commercial customers. The IOUs' justification for this limit makes no sense, stating:

> Export rates exceeding the retail rate would lead to unintended suboptimal discharge behavior. For example, many behind-the-meter batteries can only discharge at maximum capacity for less than three hours. If customers can minimize their bill by exporting at much as possible for the first few hours of the peak window, that will result in the customers returning to their unmitigated usage in the latter half of the peak period.[527]

However, if export compensation is averaged over TOU periods, either as a straight average or with weighted averaging, there will be no more incentive for discharging earlier in the period than later in the TOU period.[528] If export compensation is different for each hour, the later hours would have more value if they were not capped at rates than if they were capped at rates, and the

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527 Exh. IOU-01 at 128:5-9.

528 Exh. CSA-02 at 46:16-18.

customer incentive would be the opposite of what the IOUs claim.[529] The IOUs' proposal is unreasonable because the argument justifying it makes no sense.

4. A Glidepath is Essential.

A glidepath is necessary under §2827.1 to ensure customer-sited renewable distributed generation continues to grow sustainably,[530] and to maintain the small business workforce that will install local clean energy storage.[531] When drafting and approving AB 327, as discussed above, the Legislature recognized the need to avoid the boom and bust that can result from policy changes by requiring a successor tariff to ensure the sustainable growth of distributed solar. [532] Solar companies will require time to understand the regulatory framework in which they will be operating, ramp up new product offerings in response to that framework, educate and train their personnel on the new offering, and develop strategies for bringing the products to market.[533] That takes years, especially with the current need to refocus on energy storage. The army of local contractors skilled in solar design and installation is a valuable asset in the long road to meeting the state's greenhouse gas reduction imperative.[534] Abrupt policy changes will drive many of those contractors out of business and harm the State's long-term objectives. [535]

All parties, including CALSSA, are proposing a net metering credit structure vastly different from the current structure.[536] However, the Pro-Transmission Parties' proposals to link

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529 Exh. CSA-02 at 46:18-20.

530 Cal. Pub. Util. Code § 2827.1(b)(1).

531 Exh. CSA-01 at 38:21-24.

532 Exh. CSA-01 at 119:11-120:8.

533 Exh. CSA-01 at 119:11-120:8.

534 Exh. CSA-01 at 119:11-120:8.

535 Exh. CSA-01 at 119:11-120:8.

536 Exh. CSA-01 38:19-20.

NEM export compensation with values from the Avoided Cost Calculator without a glidepath transition would be an extreme shock that would devastate the market for distributed energy resources. [537] This is especially true after adoption of Resolution E-5150, under which export compensation rates *would be reduced from current levels by 81% (PG&E), 68% (SCE), and 84% (SDG&E)*, respectively for residential solar customers.[538] The State's solar industry, especially its small solar installation companies, cannot survive such an abrupt change while maintaining the workforce necessary to install the distributed energy storage systems necessary to meet the State's goals.

a. Growth in Solar Installations Slowed under NEM-2.

Growth in distributed energy resource installations levelled off under NEM-2. [539] This is the result of the combination of (1) requiring time-of-use rates for residential customers, (2) the introduction of non-bypassable charges in the NEM-2 structure, and (3) the reduction in the federal solar ITC. [540]

Under NEM-1 from 2012 through 2015, annual expansion of the solar market was 68% per year. [541] NEM-2 changes as a whole eliminated that growth, as can be seen in Figure 7 from CALSSA's direct testimony, but market activity has been steady. [542] The recent rate of installation is roughly equivalent to the amount that is included in modeling for the Integrated Resource Plan and modeling to achieve the SB 100 targets.[543] The Commission should strive to

[537] Exh. CSA-02 47:5-7.

[538] Exh. CSA-02 47:7-17.

[539] Exh. CSA-01 at 43:16 to 44:6.

[540] Exh. CSA-01 at 43:16 to 44:6.

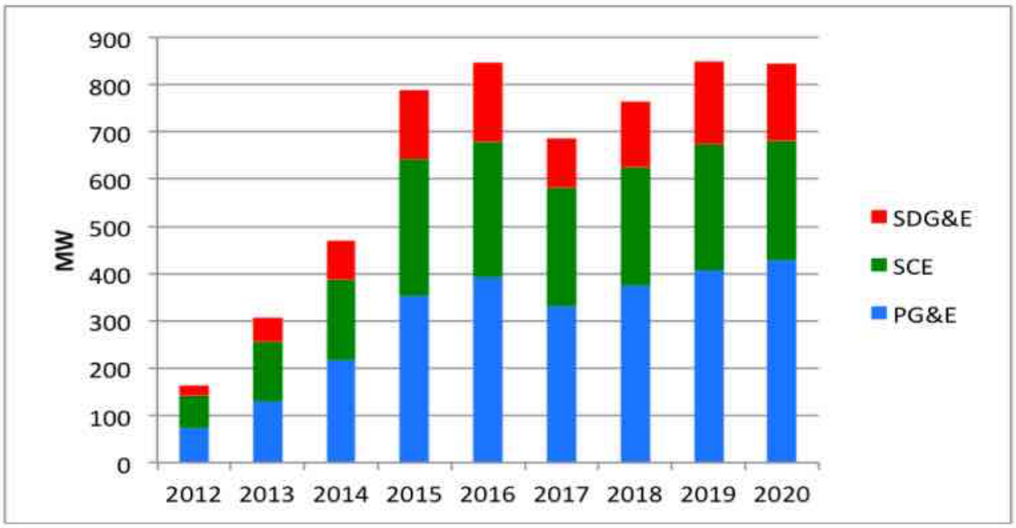
[541] Exh. CSA-01 at 43:16 to 44:6.

[542] Exh. CSA-01 at 43:16 to 44:6.

[543] Exh. CSA-01 at 82:16-18; Exh. SCL-01 at 28:19-20.

maintain that level of adoption so that customer solar can do its part in the state's long term goals.

Figure 7. Residential Solar Interconnections[50]



Without cost reductions, further changes to NEM can only be expected to result in negative market growth in the future, especially until energy storage can effectively mitigate changes to NEM structure and value. [544] The most likely areas of cost reduction for solar are permitting and interconnection. [545] For energy storage, there are opportunities for cost reduction, but progress has been and likely will continue to be very gradual. [546] A transition to the NEM-3 endpoint should be equally gradual. [547]

544 Exh. CSA-01 at 43:16 to 44:6.

545 Exh. CSA-01 at 43:16 to 44:6.

546 Exh. CSA-01 at 43:16 to 44:6.

547 Exh. CSA-01 at 43:16 to 44:6.

b. CALSSA's Proposal Provides a Bridge to Energy Storage.

A critical component of CALSSA's proposal is the gradual stepdown in export rates discussed in Section III.C.2 that provides a necessary bridge to customer-sited systems that are storage-paired. Energy storage will be a major part of the market when the successor tariff reaches its end point under CALSSA's proposal.[548] Storage costs and technologies have advanced, but it will be several years before storage is ready to be truly mainstream.[549] It is critical for the Commission's successor program to be designed to ensure that the overall market for DERs remains strong while energy storage has time to reach full maturity.[550] A number of obstacles remain to maintain recent increases in energy storage installations.

First, the price of storage has declined much more slowly than anticipated in recent years. The IOUs hired an expert to attempt to show otherwise,[551] but Dr. Tierney admitted during cross examination that much of her testimony on storage costs was limited to lithium-ion cells and did not reflect the cost of market-ready products like Tesla's Powerwall.[552] Thus, at the outset, Dr. Tierney's conclusion that storage is ready to be deployed on a broad scale in the residential market underestimates storage costs.[553]

Further, she admitted the timing of storage cost declines is highly uncertain, with projections of when storage will achieve certain cost levels such as $20/kWh ranging as much as *25-30 years*.[554] Indeed, many models predicted the current cost of storage capacity of $140/kWh

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548 Exh. CSA-01 at 38:25-26.

549 Exh. CSA-01 at 38:26-27.

550 Exh. CSA-01 at 38:26-27.

551 Exh. IOU-01 at 40:1-42:2.

552 Exh. IOU-01 at 41, Figure II-13; 1 Tr. 113:7-28.

553 Exh. IOU-01 at 40:1-2.

554 Exh. CSA-05; 1 Tr. 114:4-117:26.

would have been reached many years ago.[555] While CALSSA certainly hopes storage costs will decline more quickly, and reach important milestones like $100/kWh in the near future,[556] the fact is that costs have not declined as quickly as the Joint IOUs suggest.

Clear evidence that storage-paired distributed generation is not ready to be the focus of a successor tariff on day one is provided by the IOUs' own testimony. Under the IOUs' suggested default rates, the benefit to the customer for shifting 1 kWh of load is between 18 and 32 cents while the cost of an energy storage system in order to shift that load is between 40 and 50 cents.[557] That is, the cost of storage is still almost twice the benefit of using that storage to shift load into the on-peak period under the IOUs' rate differentials. Therefore, as IOU witness Tierney admitted, the cost of storage has not quite decreased to the point where the customer would see more economic benefit than cost when it comes to shifting from an off-peak or shoulder-peak period into an on-peak period.[558]

Second, storage resources remain difficult to access in light of electric vehicle proliferation, particularly for small installers. There is tremendous worldwide demand for battery cells, and global lithium supply and demand are out of balance, with demand rebounding after pandemic-related drops earlier in 2020 and now increasing much more quickly than anticipated.[559] At the same time, supply is limited, constraining EV production.[560] Supply chain

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555 Exh. CSA-05; 1 Tr. 114:4-117:26.

556 *See* Exh. CSA-05.

557 Exh. IOU-01 at 42, Table II-5, 113, Table IV-16, and 116, Table IV-17; 1 Tr. 120:19-22.

558 Exh. IOU-01 at 42, Table II-5; 1 Tr. 117:1-121:21.

559 Exh. CSA-02 at Attachment 4 (Mitalee Gupta and Shijie Liu, *Surging Demand for Batteries: Will the Supply Keep Up?*, Wood Mackenzie Power and Renewables Insight).

560 Exh. CSA-02 at Attachment 5 (Morgan Stanley, *A Looming Battery Cell Supply Shortage?*, Feb. 10, 2021).

bottlenecks will continue until battery manufacturers can ramp up.[561] Prices of materials, including lithium carbonate, have spiked, with highs expected in 2024.[562] Thus, global lithium-ion shortages will reduce access to these technologies with electric vehicle manufacturers being the first to absorb the remaining supply.[563] Production is increasing, but this will translate slowly to energy storage product supply specific to energy storage for homes and small businesses in California.[564]

This obstacle will hit small solar companies, *i.e.*, a solar company that employees between 25-50 people,[565] the hardest since they often cannot obtain energy storage hardware.[566] IOU Witness Tierney asserted in direct that "cost trends in solar and solar paired with storage installations will tend to support households' continued adoption of new solar installations through small companies."[567] However, during cross examination, she admitted that small companies are likely to only be supported by standalone solar installations and not solar + storage installations because smaller solar companies have more difficulty in accessing supplies of energy storage than larger solar companies.[568] To the extent storage becomes necessary for DER viability, the large national solar providers will likely lock up supply contracts and make storage even more out of reach for small contractors.[569] For this and other reasons, it will be

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561 Exh. CSA-02 at Attachment 4.

562 Exh. CSA-02 at Attachment 4 and Attachment 6 (Will Horner, *Booming Electric Vehicle Demand Supercharges Lithium Prices,* Wall Street Journal (March 10, 2021)).

563 Exh. CSA-01 at 42:2-4 (citing to various recent articles discussing the lithium-ion shortage).

564 Exh. CSA-01 at 42:4-7.

565 1 Tr. 122:28-123:3 (IOU – Tierney).

566 Exh. CSA-01 at 42:4-7.

567 Exh. IOU-01 at 48:7-8.

568 Exh. CSA-06; 1 Tr. 122:4-124:6.

569 Exh. CSA-01 at 42:7-9.

more difficult for smaller solar companies to cope with a new tariff that is aimed at the installation of energy storage systems as opposed to just standalone solar systems in the near term.[570]

Third, the modernization of building codes and standards has been slow to catch up to technology advancement. Utilities and local governments are extremely conservative in reviewing proposed installations for grid safety and compliance with building, electrical, and fire codes.[571] National codes and standards are evolving to ensure safety and reliability with minimal site-specific review, but the process is extremely slow. [572] Questions on where batteries can be installed with and without fire suppression measures are not settled. [573] Until those codes and standards are widely deployed and understood, site-specific review will add major costs to projects. [574] Municipal permitting and utility interconnection processes simply take longer (adding cost) with solar plus storage in California than solar-only systems. [575] No party to this proceeding has disputed these assertions in CALSSA' testimony.

Lastly, contractor expertise will take time to develop. The most important element of a contractor's work is code compliance. [576] They must do quality work that meets all safety standards. [577] They cannot jump into offering a product without thoroughly understanding how it

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570 Exh. CSA-06; 1 Tr. 124:8-125:16.

571 Exh. CSA-01 at 42:10-43:5.

572 Exh. CSA-01 at 42:10-43:5.

573 Exh. CSA-01 at 42:10-43:5.

574 Exh. CSA-01 at 42:10-43:5.

575 Exh. CSA-01 at 42:10-43:5.

576 Exh. CSA-01 at 43:6-10.

577 Exh. CSA-01 at 43:6-10.

works and how to do it right.[578] With variations in the electrical characteristics and energy management approaches between storage devices, contractors must proceed cautiously.[579] No party to this proceeding has disputed these assertions in CALSSA's testimony either.

CALSSA's proposal maintains a glidepath around an eight-year transition to ensure the Commission's successor tariff can get past these obstacles over the next four years[580] and then in the following years allow energy storage to reach scale as the glidepath approaches the end point. Unlike the Pro-Transmission Parties' proposals, CALSSA's will not put small companies out of business.

The Joint IOUs assert that "transitions triggered by capacity caps rather than clear calendar dates would create unpredictability and customer confusion."[581] But these issues have already been addressed. As described in CALSSA's testimony:

> The MW threshold should therefore be converted to a date certain as adoption nears the threshold. Under CALSSA's Proposal, the utilities will track progress toward the threshold and file a Tier 1 advice letter before the threshold is projected to be hit that establishes a firm date for the transition in place of the MW threshold.[582] The date should be at least three months after the advice letter is filed. The methodology for setting the date should be based on the monthly average installation from the prior three months and should use a transparent formula. This approach would obviously result in the transition happening at a capacity level that is not exactly the same as the defined capacity trigger; but a clear methodology will minimize the difference, and the benefits of

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578 Exh. CSA-01 at 43:6-10.

579 Exh. CSA-01 at 43:6-10.

580 7 Tr. 1219:2-15 (CSA – Heavner).

581 Exh. IOU-02 97:10-11.

582 Effectuating step downs via Tier 1 advice letters would be procedurally appropriate, as these tariff changes would be in compliance with the specific requirements of the Commission decision establishing the successor, and the wording of these changes would follow directly from that decision. *See* General Order No. 96-B, Energy Industry Rule § 5.1.

> avoiding disruption far outweigh precise adherence to a capacity trigger.[583]

In response to this evidence, all the Joint IOUs could state is that "there can be significant month-to-month variability in solar capacity interconnections that limits the ability of utilities to forecast when a MW cap will be reached" and "the parties who proposed step downs did not clarify whether the transition would be triggered if the capacity reached did not match the utilities' forecast."[584] But that is not accurate. The above block quote addresses this question head on.

c. Proposals With No Glidepath Lack Credibility.

In contrast to the E3 white paper's suggestion that there be a gradual pace of change,[585] none of the Pro-Transmission Parties include any glidepath to their new, ACC-based export compensation values.[586] They propose to drop export compensation values to a fraction of the NEM-2 level and impose large new fees immediately upon implementation.[587] One way to measure the immediate market impacts of such changes is with NREL's dGen tool, a highly granular market diffusion model representing almost 2000 representative residential classes of customers within California across geography, utility, territory, and load size.[588] The tool

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583 Exh. CSA-01 at 40:13-41:5.

584 Exh. IOU-02 (Molnar), p. 97, line 22 to p.98, line 3.

585 *See* E3 White Paper, pp. 27-32.

586 Exh. CSA-01 at 44:7-46:16 (citing to Joint IOUs Proposal, pp. 14-17, 19-21; TURN Proposal, pp. 8-17; R.20-08-020, Cal Advocates Proposal at 22-28 and 31-38, NRDC Proposal, pp. 8-10, 14-17).

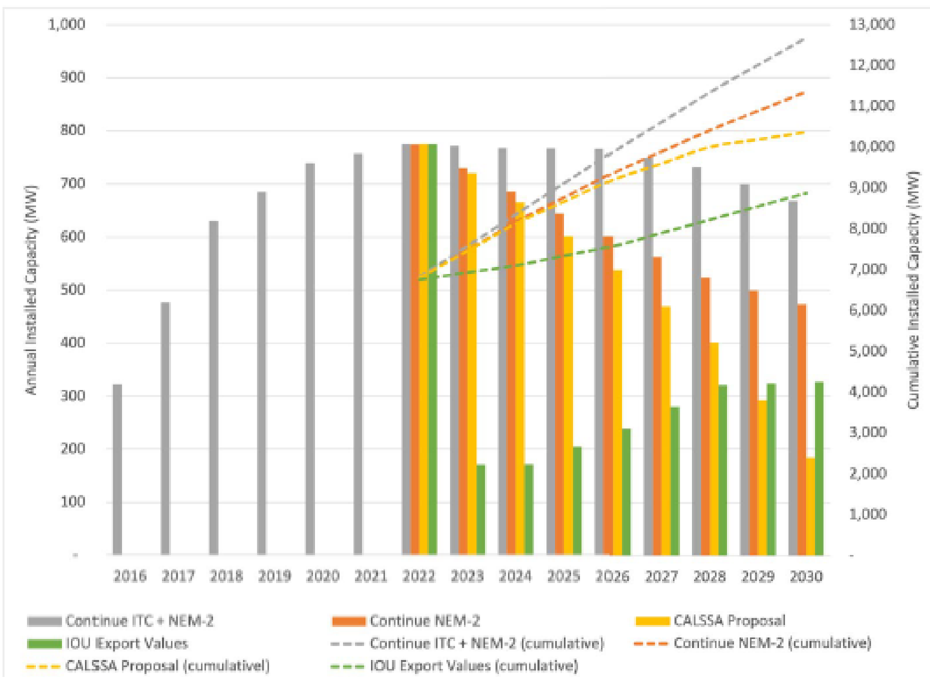
587 *Id.*

588 Exh. CSA-01 at 73:1-74:1.

analyzes how many customers have electricity usage patterns, tariffs, and spatial availability that are favorable to solar adoption.[589]

Using dGen, the green bar labeled "IOU Export Values" in Figure 21 below from CALSSA's Direct Testimony clearly demonstrates the cliff off of which the Pro-Transmission Parties propose to push the State's 70,000 solar employees from 2022 to 2023: [590]

Figure 21. Single-Family Residential Results from the NREL Distributed Generation Market Demand Model



The green bar sets the export rate at the single-year avoided cost values from the Avoided Cost Calculator that most of the Pro-Transmission Parties propose. [591] The other bars include three

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[589] Exh. CSA-01 at 73:1-74:1. dGen assumes the best customers adopted first and future customers will be more challenging. CALSSA believes that assumption is overly conservative and that market saturation 8 is not an impact that will be experienced in the near future. *Id.* Based on conversations with contractors who relate that there continues to be a strong universe of customers showing interest in solar, CALSSA believes the solar industry can maintain current market activity throughout this decade. However, dGen is still useful for comparing different scenarios against each other. *Id.*

[590] Exh. CSA-01 at 74, Fig. 21.

[591] Exh. CSA-01 at 73:1-74:1 and 74, Fig. 21.

scenarios for single-family residential customers – continuing NEM-2 with ITC extension (grey), continuing NEM-2 without ITC extension (orange), and the CALSSA proposal (gold). [592] It is critical to note that the impacts of the Pro-Transmission Parties' proposals would be even worse than the green bar since these model results do not include any solar fee or requirement to be on a particular rate structure and were based on the 2020 ACC.[593]

This cliff, *i.e.*, the lack of *any* transition period in the Pro-Transmission Parties' proposals, demonstrates a significant lack of knowledge regarding the time it takes to translate new regulatory frameworks into marketable products, an interest in killing off the competition,[594] an indifference to the fate of the workers and small companies within the DER industry, a disregard for or ignorance of the experiences of other states that abruptly ended a NEM program, or some combination of these factors.[595]

d. Market Transition Credits are Bad Policy.

Market transition credits are difficult to administer, and the Commission historically has found it very difficult to determine functional incentive amounts. [596] In implementing the SOMAH program, for example, parties submitted recommendations for the incentive levels in August 2016 and the Commission did not issue a decision until December 2017.[597] Even after the

592 Exh. CSA-01 at 73:1-74:1 and 74, Fig. 21.

593 Exh. CSA-01 at 73:1-74:1.

594 *See* Exh. CSA-01 at Attachment 10 (Each of the Joint IOUs' Form 10k filings at the United States Securities and Exchange Commission identifies distributed solar and solar and storage resources as a source of competition and market risk).

595 Exh. CSA-01 at 46:11-16.

596 Exh. CSA-01 at 46:17-47:19.

597 Exh. CSA-01 at 46:17-47:19 (noting "Opening comments were submitted in R.14-07-002 on August 3, 2016 and reply comments were submitted on August 16, 2016. The Commission issued D.17-12-022 on December 18, 2017.").

decision was issued, program performance has been disappointing due to incentive levels being misaligned with project economics.[598] Another example is the commercial storage budget in the Self Generation Incentive Program, which lingered for years with minimal activity before finally gaining momentum.[599] The Commission is simply not positioned to understand market pricing at the level of granularity necessary to create an accurate, current and evolving credit amount on day one.[600]

TURN's $400 Million Proposal Relies on a Model that Produces Unreasonable Results.

TURN's proposal for a market transition credit targets a 10-year payback for residential customers and results in a substantial incentive for customers to install DERs,[601] reaching $2,331 *per kW* in SDG&E's service territory.[602] The cause of the need for this enormous charge is that TURN is supporting a high solar fee for solar customers and very low export compensation rates.[603] "[I]n essence, TURN's proposal is that CARE customers would have most of their solar system paid for by other ratepayers, but the customer who receives such a system would save only small amounts on their energy bills."[604] The total cost of TURN's proposal would be $400

[598] Exh. CSA-01 at 46:17-47:19 (noting "After an initial burst of applications from projects that were previously waitlisted in the MASH program, application volume has been far less than available funds. Only 35% of funds have been reserved, leaving $275 million that should be going to work for low-income customers.").

[599] Exh. CSA-01 at 46:17-47:19.

[600] Exh. CSA-01 at 46:17-47:19 (stating "The Commission spent Self Generation Incentive Program funds quickly when resilience for vulnerable customers in fire zones became the main focus of concern, but the systems were fully subsidized at a generous rate.).

[601] Exh. SVS-04 at 49.

[602] Exh. SVS-04 at 50:3-5.

[603] Exh. SVS-04 at 49:7-12.

[604] Exh. SVS-04 at 50:8-11.

million per year.[605] These figures illuminate the risk that market transition credit proposals create, with errors costing hundreds of millions in either direction if the Commission gets the numbers wrong.

Moreover, TURN's model to calculate its market transition credits is a black box, produces odd results and should not be relied upon. For example, when modeling the scenario in which a solar system is purchased rather than leased, and where TURN's market transition credit would apply,[606] certain customers' bill savings would be negative, meaning their bills would *increase* after installing solar.[607] TURN's market transition credit would be calculated to make the customer neutral at the ten-year point,[608] but after that the negative savings would cause these customers to be worse off over the life of the system. In addition, the size of a customer's usage is either "small" or "large", but TURN defines that differently for each utility, with odd results such as a small CARE customer installing a 10 kW system.[609] In fact, system size is excluded altogether from Exhibit TRN-03.[610] Lastly, the model suggests a 10kW system would be installed at the same cost as a 2 kW system.[611] These absurd results and unreasonable assumptions cast significant doubt on TURN's market transition credit proposal and the modeling it relies upon.

605 Exh. SVS-04 at 51:3.

606 9 Tr. 1537:5-1538:8 (TRN – Chait).

607 9 Tr. 1541:5-1543:5 (TRN – Chait).

608 9 Tr. 1540:20-27 (TRN – Chait).

609 9 Tr. 1537:12-17 (TRN – Chait).

610 9 Tr. 1543:14-17 (TRN – Chait).

611 9 Tr. 1545:4-1546:13 (TRN – Chait).

NRDC's "Proposal" is Not Actionable.

The difficulty in finding the right number, and then administering it going forward, could not be clearer from NRDC's attempt at a market transition credit proposal in this proceeding. The purpose of NRDC's market transition credit is to ensure customers are able to achieve a 10-year payback period.[612] NRDC's proposal essentially consists of a bullet point in NRDC's testimony stating "[i]f the payback period is greater than ten years, then add in an upfront incentive such that the typical/average customers' payback period is approximately ten years."[613] That is, despite being a "critical part of the NRDC successor tariff",[614] NRDC's witness admitted NRDC has not presented any illustrative example of what that credit would be, limiting the description of it, in total, to four bullet points in NRDC's direct testimony.[615] In discovery, NRDC stated it did not conduct any calculations to estimate its market transition credit.[616]

Instead, NRDC asked E3, the *Commission's* consultant, to do NRDC's work for it.[617] Specifically, NRDC requested "E3 to estimate an upfront incentive so that the average customer achieves a payback of 10 years."[618] E3 complied, stating on page 31 of its updated report that "[a]s requested by NRDC, E3 calculated the upfront incentives necessary for each customer to reach a 10-year payback period."[619] However, E3's report also does not include any illustration

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612 10 Tr. 1774:10-20 (NRD – Chhabra).

613 Exh. NRD-01 at 19:

614 Exh. NRD-01 at 19:3.

615 10 Tr. 1773:24-1774:9 (NRD – Chhabra).

616 Exh. CSA-30; 10 Tr. 1787:10-11 (NRD – Chhabra).

617 Exh. CSA-31 (stating "NRDC did not propose a specific value for the upfront incentive. We propose and kindly request E3 to estimate an upfront incentive so that the average customer achieves a payback of 10 years.").

618 Exh. CSA-31.

619 Exh. CSA-32, page 31 of E3's report.

of what market transition credit was needed to achieve a ten-year payback under NRDC's proposal,[620] meaning the record in this proceeding still has no details on NRDC's market transition credit.

More damning of the concept, E3, a proponent of the idea of a market transition credit,[621] could not complete NRDC's request accurately. NRDC Witness Chhabra admitted during hearings that, despite E3 applying the MTC for some customer segments, *not one* of the results shown in E3's report includes a ten-year payback.[622] That is, not only is there no figure on the record for what NRDC's proposed market transition credit will be for any of the IOUs' service territories, E3 could not accurately complete what seemed to be a simple task: calculating a market transition credit that resulted in a ten-year payback.[623]

Beyond these challenges, NRDC's less-than-half-baked proposal also demonstrates the difficulty in administering a market transition credit. Because NRDC's proposal targets a specific payback period, the elements of payback also need to be ascertained, and those elements are constantly in flux.[624] Solar costs increase and decrease, as do the underlying rates that form customer bill savings.[625]

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[620] Exh. CCS-01 at Attachment, E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020* (May 28, 2021).

[621] E3 White Paper at 17-19.

[622] *See, e.g.,* Exh. CSA-32, pp. 34-35 of E3's report (including payback periods of 8.0, 8.9 and 9.0 years and 6.6, 7.9 and 8.1 years).

[623] 10 Tr. 1791:7-10 (NRD – Chhabra) ("Q. Right.· But you specifically asked E3 for this number to be 10.· And none of the numbers are 10; right? A. Sure.").

[624] 10 Tr. 1774:10-1777:5 (NRD – Chhabra).

[625] 10 Tr. 1775:3-8 (NRD – Chhabra).

However, NRDC does not include any details in its proposal on how to calculate the customer cost component of payback,[626] other than stating trusted sources should be used, including data from Lawrence Berkeley National Laboratories.[627] As Witness Chhabra stated, "if NRDC's proposed methodology was adopted, the Commission would have to determine the average cost" of solar.[628] NRDC proposed further that once the market cost component of its market transition credit is established, it should be adjusted to account for changes in installation costs of systems,[629] but as its witness admitted, NRDC "did not provide a methodology to make that adjustment."[630] Nor has NRDC made a proposal on how to calculate the bill savings side of the question of payback,[631] how that calculation would change based on location, orientation, shading, and system design and components,[632] or what assumptions to make about the operating mode the storage system would use.[633]

Stepping back from methodology to address process, NRDC was asked about how the Commission would update the market transition credit, a proposal NRDC had made as part of its direct testimony.[634] However, Witness Chhabra stated he had not thought that through yet,[635] later adding "that's the Commission's job to establish a process for updates."[636]

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626 10 Tr. 1775:3-1777:5 (NRD – Chhabra).

627 10 Tr. 1776:1-4 (NRD – Chhabra).

628 10 Tr. 1775:27-28; 1778:11-13 (NRD – Chhabra).

629 Exh. NRD-01 at 19:14-15.

630 10 Tr. 1777:4-5 (NRD – Chhabra).

631 10 Tr. 1781:3-7 (NRD – Chhabra).

632 10 Tr. 1781:8-14 (NRD – Chhabra).

633 10 Tr. 1781:15-17 (NRD – Chhabra).

634 Exh. NRD-01 at 19:22-23.

635 10 Tr. 1781:15-17 (NRD – Chhabra).

636 10 Tr. 1786:13-14 (NRD – Chhabra).

CALSSA's proposal is superior to a difficult-to-determine and even more difficult-to-administer market transition credit. Tying transition steps to market adoption rates is a self-correcting mechanism.[637] If the economics are more favorable than anticipated, the capacity will be used quickly and the following step will be reached.[638] If the economics are more challenging than anticipated, the step will last longer but that will not create excessive impacts because market activity will be low.[639]

e. The Impacts of NEM Changes in Other States Provide a Cautionary Tale.

While SEIA/Vote Solar will address the issue more completely in their Opening Brief, the impacts from abrupt changes to NEM policy in other states included in both CALSSA and SEIA/Vote Solar's testimonies illustrate how proposals like those of the Pro-Transmission Parties can result in devastating effects on the solar market.[640] The Commission cannot achieve its statutory mandate to ensure sustainable growth without ensuring any changes are gradual so that solar and storage providers can maintain the efficiencies they have worked hard to develop. The experience of these states and utilities cautions against drastic changes to NEM, and demonstrates the need—also enshrined in statute—for any changes to NEM to be reasoned and measured.

The Joint IOUs primarily rely on a survey in Attachment B to their testimony to suggest California's solar industry can easily handle NEM reform.[641] However, no other state has

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[637] Exh. CSA-01 at 46:17-47:19.

[638] Exh. CSA-01 at 46:17-47:19.

[639] Exh. CSA-01 at 46:17-47:19.

[640] Exh. CSA-01 at 47:20-55:3; Exh. SVS-01 at 2:10-22:9; Exh. SVS-02 at 2:17-16:2.

[641] Exh. IOU-01 at 31:11-36:11 and Attachment B.

adopted NEM reform with a tariff as riddled with poison pills as that the Joint IOUs put forward in this proceeding. For example, as Witness Tierney admitted, while New York and South Carolina may have implemented some flavor or a grid access charge, those states still allow monthly true-up unlike the Joint IOUs' proposal,[642] and, in Minnesota, the grid access charge replaced the fixed charge and minimum bill. [643] As discussed in the next section, and in a number of other places in this Brief, no state has come close to the draconian measures the Cal Advocates and the other Pro-Transmission Parties have proposed.

5. Solar Fees and Rate Requirements

The Commission should not adopt a successor tariff structure that includes any kind of monthly fixed charge or requirement that customers take service on a rate that includes a fixed charge. The Pro-Transmission Parties have proposed high, unavoidable residential solar fees, misleadingly labeled as a "Grid Benefits Charge" (Cal Advocates, NRDC, and Joint IOUs) or a "Nonbypassable, Unavoidable and Shared" costs charge (TURN). These fixed solar fees would add between $34 and $73 to residential NEM customers' monthly bills, dramatically increasing rates for NEM customers,[644] thereby reducing the savings associated with self-generation.

The Commission should reject these solar fee proposals as contrary to State and Federal law, as well as significant Commission precedent. These fees (1) are not just and reasonable, (2) are discriminatory under State law and would disincentivize self-generation, contrary to State

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642 1 Tr. 106:6-24 (IOU – Tierney); Exh. IOU-01, Attachment B at B-29, Table 14; 1 Tr. 109:3-110:15 (IOU – Tierney).

643 *See* Minnesota Public Utilities Commission, Docket No. 16-512 (*In the Matter of a Commission Investigation into Fees Charged to Qualifying Facilities by Cooperative Electric Associations under the 2015 Amendments to Minn. Stat. § 216B.164, Subd. 3*), Order, December 15, 2017.

644 *See* Exh. CSA-01 at 90:19-20 n. 144 (updated to account for Exh. IOU-01 at 143, Table IV-28). These figures are based on a 6 kW-DC solar system.

law, (3) contravene the antidiscrimination provisions set forth in PURPA, (4) operate as a back-door buy-all/sell-all arrangement in effect, infringing on customers' right to self-generate, (5) will either be based on estimates of usage, contrary to State law, or will require State-sanctioned tracking of customers' private activities behind the meter, (6) contravene many of the Commission's rate design principles for residential customers, and (7) create substantial problems surrounding consumer protection and administrative oversight.

In addition to these solar fee proposals, several parties propose that residential solar customers be required to take service under rate designs that include high fixed charges and/or a high TOU rate differential. Singling out NEM customers for additional fixed charges via these rate requirements would be unjust, unreasonable, and discriminatory. Similarly, proposals to require NEM customers to take service under rate designs with a high TOU differential unnecessarily single out NEM customers for disparate treatment. Combining these rate elements with solar fees would be unprecedented, creating the highest unavoidable charges in the country for solar customers.

To the extent some utility costs are truly fixed in the long term, the issue should be considered holistically for all customers. For instance, if through a comprehensive cost of service assessment of all ratepayers the Commission were to determine that low-usage customers do not meet their cost of service, it could then assess the appropriate amount to include in either fixed charges or minimum bills for all such customers. To equitably approach this issue in line with State and Federal law, and the Commission's rate design principles, the Commission must resolve these cost of service questions on behalf of all ratepayers, utilizing a consistent methodology across all relevant customer classes and categories, rather than singling out NEM customers for discriminatory treatment.

a. Not Based on Cost of Service Means Not "Just and Reasonable."

The Pro-Transmission Parties' Solar Fees Fail to Meet the Statutory "Just and Reasonable" Standard Because They Are Not Based On Cost Of Service.

As discussed in Section II.B herein, "[h]istorically, the determination of just and reasonable has emphasized cost-causation[,]"[645] with the fair allocation of costs among different groups of ratepayers determined by cost of service studies.[646] The Pro-Transmission Parties' fees cannot be defended as cost of service ratemaking because they are not designed to account for any incremental cost to the utility of providing service to NEM customers, as compared to comparable non-generating customers. These fees are therefore not just and reasonable, and cannot be adopted.

The Pro-Transmission Parties' fees are based on the extent to which NEM customers self-supply, with fees assessed on energy that never crosses over to the utility's side of the meter and charging customers for services they never receive.[647] Specifically, the fees are based on either estimated or measured self-consumption, with fees designed to increase as the amount of generation produced and consumed behind the meter increases, and set at a level estimated to collect an amount that is equivalent to the amount that would be collected by charging a portion

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645 *See* Cal. Pub. Util. Code § 451; D.15-07-001, p. 2 (citing *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982) ("[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity."); *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973) (recognizing the desirability of each group's bearing its fair share of the cost of service, as such share is measured by the cost of service study); *In the Matter of the Application of PacifiCorp*, D.10-09-010 (2010)). The decision further notes: "For this reason a cost of service study is part of each general rate case for establishing electricity rates." D.15-07-001, pp. 2-3 n. 3.

646 D.15-07-001, p. 2 (citing *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973)).

647 3 Tr. 475:19-22 (IOU – Morien); Exh. CSA-01 at 92:11-12.

of retail rates on that electricity. [648] Adopting these fees would therefore mean that a customer will pay *more* for installing technologies aimed at using *less* grid-generated electricity, holding all other variables equal. [649] Stated another way, the Pro-Transmission Parties ask the State of California to charge customers for reducing their load.[650]

The Pro-Transmission Parties' charges are premised on the purported lost revenues associated with self-generation, *i.e.*, a group of customers paying less to support the utility's revenue requirements.[651] However, lost revenues cannot be equated to an increase to cost of service; basing charges on an estimated cost recovery *decrease* associated with behind-the-meter generation is not equivalent to basing charges on a demonstrated cost of service *increase* associated with this self-generation.[652]

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[648] *See* Exh. IOU-01 at 135:10 to 142:4; Exh. TRN-01 at 48:14-51:14; Exh. PAO-03 at 3-24:15 to 3-26:17; Exh. NRD-01 at 17:3 to 19:1.

[649] Exh. CSA-01 at 92:2-8.

[650] Exh. CSA-01 at 92:2-8.

[651] Exh. CSA-01 at 97:13-15 n. 166 (citing Joint IOUs Proposal, p. 19 ("*To eliminate this type of cost avoidance*, the Joint IOUs propose to assess a $/kW-month Grid Benefits Charge based on a customer's installed solar system size . . . A Grid Benefits Charge is necessary alongside value-based export compensation and default cost-based retail rates because -- as more customers adopt solar-paired storage systems over standalone solar systems -- the amount of self-generation they export will decrease. If the DG-ST were only to adopt a change in export compensation, California would see a significant cost shift in the future from solar-paired storage customers") (emphasis added); CalAdvocates Proposal, pp. 33 ("The utility, however, still incurs these costs to serve its customers, including NEM customers, and must recover its Commission-approved revenue requirement. Any costs to serve NEM customers that are not collected from NEM customers are instead recovered from non-participants, directly increasing non-participants' costs . . . As on-site generation grows, the cost burden of maintaining, repairing, upgrading, and ensuring the safety and reliability of the distribution and transmission systems will compound the cost burden to non-NEM customers."); TURN Proposal, p. 13 ("This charge is designed to recover the amount of non-generation costs that would be paid by the participating customer but for the operation of the BTM resource")).

[652] *See* Exh. CSA-01 at 98 n. 167 (citing *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, PDF p. 231, National Energy Screening Project (August 2020), *available at* https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf ("lost revenues from DERs are not a new, incremental cost created by investments in those resources. Rate impacts from lost revenues are caused by the need to recover existing costs over fewer sales. These existing costs that would be recovered through rate increases are not caused by the DERs themselves: They are caused by historical investments in other utility resources that become fixed

Given this fee design is focused on recovering a portion of avoided costs associated with self-consumption, it is clear these charges are not designed to account for distinct usage patterns of customer-generators causing incremental costs, distinct services provided to customer-generators, or a customer generator-imposed need for additional distribution-system infrastructure. In fact, none of the parties advocating for these charges have attempted to demonstrate that these fees are designed to account for the incremental cost to the utility of providing service to NEM customers, as compared to comparable non-generating customers. Instead, they are based on arguments lamenting the fact that these customers no longer purchase as much electricity from the utility as they did before they installed solar.[653]

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costs. In economic terms, these existing fixed costs are referred to as 'sunk' costs. In economic theory, sunk costs should not be considered when assessing future investments because they are incurred regardless of whether the future investment is undertaken.")).

653 *See* Exh. IOU-01 at 139:10 to 141:2; Exh. IOU-02 at 58:10 to 60:19; Exh. PAO-03 at 3-25:3 to 3-29:16; Exh. TRN-01 at 48:18-19; Exh. NRD-01 at 18:4-5; Exh. NRD-01 at 10:22-23. *See also* Exh. CSA-01 at 96 n. 161 (noting how the Pro-Transmission Parties instead attempt to justify the charges based on the contention that NEM customers are unfairly avoiding certain costs that are incurred on behalf of all customers. *See, e.g.*, Joint IOUs Proposal, p. 19 ("*To eliminate this type of cost avoidance*, the Joint IOUs propose to assess a $/kW-month Grid Benefits Charge based on a customer's installed solar system size.") (emphasis added); CalAdvocates Proposal, p. 32 ("The Grid Benefits Charge should be assessed as a $/kW charge per month, based on the size (kW) of the generation system a customer installs, to properly collect the aforementioned distribution, transmission and public program costs that such customers benefit from . . . The costs above marginal costs include costs to maintain, replace, and upgrade capacity are a critical part of cost of service for all ratepayers and are not affected by customers' consumption or generation decisions."); CalAdvocates Proposal, p. 39 ("in order to achieve financial indifference between NEM and non-NEM participants, NEM participants should not be allowed to avoid paying these costs"); NRDC Proposal, p. 14 ("The NEM 3.0 tariff should include a demand related charge – a grid benefit charge (GBC) – for new NEM customers to recoup a fair share of distribution charges . . . An estimate of the costs to serve a NEM customer, absent the value of electricity generation, should account for both the grid investments already made by the utility with consideration for the NEM customer and the benefits of avoided future investments that the NEM customer may provide in excess of those already accounted for in the avoided costs"); TURN Proposal, p. 13 ("TURN also proposes a separate monthly charge to recover Nonbypassable, Unavoidable and Shared (NUS) costs associated with self-consumption of output provided by BTM resources. This charge is designed to recover the amount of non-generation costs that would be paid by the participating customer but for the operation of the BTM resource")).

Arguments justifying these charges are therefore based on the unstated assumption that the utilities have some entitlement to a particular level of usage from customers and that customers should not be able to avoid that usage. No such entitlement exists apart from residential customers' minimum bills and commercial customers' monthly charges.[654] For the residential class, the Commission collects demand-related costs through a $/kWh charge for each kilowatt-hour of customer usage.[655] Thus, residential customers pay for whatever demand-related costs they impose based only on how much electricity they use during the month.[656] Under such a rate design, the utilities have no entitlement to any particular level of usage (and resulting revenue) from any residential customer, apart from their minimum bills.

While these fees are clearly not *designed to recover* an amount equivalent to any demonstrated incremental cost to serve NEM customers, some of the Pro-Transmission Parties nonetheless attempt to point to distinct costs to serve NEM customers as indirect support for these proposals. These efforts fail to show any such distinct costs, or a relationship between these purported costs and the parties' fee designs. For example, while NRDC initially posited in its proposal that there are "costs to serve solar customers under NEM 1.0 and 2.0 policies that do not exist for other classes of customers[,]"[657] this statement was unsupported. When asked via discovery to identify these specific costs, NRDC was unable to do so, suggesting it would seek to

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[654] Exh. CSA-01 at 98:4-13.

[655] Exh. CSA-01 at 98:4-13.

[656] Exh. CSA-01 at 98:4-13.

[657] Exh. CSA-01 at 96:13 to 97:2 (citing NRDC Proposal, p. 16).

identify those costs at a future date.[658] Neither NRDC's Direct Testimony nor its Rebuttal Testimony identified such costs.[659]

Cal Advocates admits its solar fee proposal is not based on any approved cost of service study that considers the cost to serve NEM customers separately from the cost to serve non-NEM customers.[660] While Cal Advocates' testimony refers to data from PG&E's testimony in a *pending proceeding* to suggest a higher cost of service for NEM customers,[661] it admits that no such tentative cost of service data from SCE or SDG&E even exists.[662] Importantly, while Cal Advocates references this data from a pending PG&E proceeding, and SCE and SDG&E data that it suggests provides evidence that a cost of service difference may exist,[663] its solar fee is not designed to account for any purported cost of service differences derived from any of this data.

Instead, Cal Advocates explains that the "shortfall in cost of service" its fee is designed to recover is derived from the NEM 2.0 Lookback Study cost of service results.[664] The Lookback Study results referenced by Cal Advocates do not look at the cost of service of NEM customers as compared to that of non-NEM customers—rather, they compare residential NEM-2 customers' annual bills to cost of service.[665] Focusing solely on NEM customers' contributions

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658 Exh. CSA-01 at Attachment 7 (NRDC Response to CALSSA DR 4.01).

659 *See* Exh. NRD-01 at 17:3 to 19:1; Exh. NRD-02 at 10:1 to 15:12. Although NRDC refers to the Lookback Study for other purposes, it fails to acknowledge that the study finds NEM customers have a lower cost of service after installing solar than before. Exh. CSA-01 at 97:10-12 n. 165 (citing NEM 2.0 Lookback Study, pp. 10-11, 95-97).

660 Exh. CSA-02 at Attachment 13 (Cal Advocates Response to CALSSA DR 7.05 and 7.07); *see also* Exh. PAO-03 at 3-32:2-4 (admitting SCE and SDG&E have not performed a full cost of service analysis for NEM and non-NEM customers).

661 Exh. PAO-03 at 3-30:3 to 3-31:8; Exh. PAO-02 at 4-3:8 to 4-4:11; Exh. PAO-02 at 4-8:4-8.

662 Exh. PAO-03 at 3-30:3 to 3-32:6.

663 Exh. PAO-03 at 3-31:9 to 3-32:6.

664 Exh. CSA-02 at Attachment 13 (Cal Advocates Response to CALSSA DR 7.07).

665 Exh. PAO-03 at 3-32:13-19.

to their cost of service does not allow the Commission to assess whether there are incremental costs imposed by NEM customers, or how to design rates for NEM customers in line with their cost responsibility, while ensuring equitable treatment for similarly situated customers. And importantly, rather than finding incremental costs associated with NEM customers, the study in fact finds the opposite—that cost of service is lower after customers install solar, for both residential and commercial customers.[666]

Similarly, the Joint IOUs have not identified any significant costs to serve NEM customers that do not exist for non-NEM customers. While the Joint IOUs, like Cal Advocates, point to the same PG&E testimony in a pending proceeding as generally providing support for a cost of service difference between NEM and non-NEM customers,[667] they do not make similar claims for SCE or SDG&E, because those utilities have not completed any such study.[668] And, the Joint IOUs' proposed fees are similarly not designed based on this data to recover this purported cost of service difference.[669]

While the Joint IOUs stated in testimony that the utility provides "additional services for accommodating exported energy when solar customers are over-generating during the day[,]" this claim was unsupported.[670] Referencing this claim, CALSSA submitted a data request to the

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[666] Exh. CSA-01 at 97:10-12 n. 165 (citing NEM 2.0 Lookback Study, pp. 10-11, 95-97).

[667] Exh. IOU-01 at 109:13-15 (citing to PG&E's testimony as though it is a foregone conclusion it will be adopted by the Commission). The testimony referenced by Cal Advocates and the Joint IOUs in this proceeding is from PG&E's most recent Phase II general rate case proceeding (A.19-11-019). In that proceeding, the utility submitted cost of service testimony that requested that the Commission approve a new generation energy and capacity cost of service methodology and associated results. This cost-of-service analysis estimated cost of service for NEM and non-NEM customer sub-groups. These cost-of-service issues were contested in the proceeding, and none of the settlement agreements pending in the proceeding resolved these issues. This proceeding is still awaiting Commission decision.

[668] Exh. CSA-02 at Attachment 8 (Joint IOUs Response to CALSSA DR 11.07).

[669] *See* Exh. IOU-01 at 137:16-18.

[670] Exh. IOU-01 at 139:11-13.

Joint IOUs, asking, "What does each utility do to accommodate exported energy that they would not do otherwise?" The response was entirely about interconnection review and facilities needed at the time of interconnection.[671] Interconnecting customers already pay for interconnection review via the application fee that was instituted with NEM-2. If any interconnection facilities are required, *i.e.*, grid upgrades that are entirely for the purpose of accommodating that system, the interconnecting customer pays for that work, regardless of system size.[672] If grid upgrades are triggered by the interconnection request, *i.e.*, broader upgrades that enhance grid capacity for multiple customers, the interconnecting customer pays if the system is larger than 1 MW but does not pay if the system is smaller than 1 MW.[673] It is only this last category that is a cost to non-participating ratepayers, and utility filings mandated in the NEM-2 decision have revealed the costs to be relatively minor.[674] Not only are these costs minor, but more importantly, by the Joint IOUs' own description, its solar fees are not based on these costs or designed to recover them.[675] Therefore, these claims regarding these "additional services" do not support an argument that the Joint IOUs' fees are cost-based.

In addition, the Joint IOUs claim in Rebuttal Testimony that "[r]esidential NEM customers have higher maximum noncoincident demands and higher coincident peak demands, on average, than non-NEM residential customers."[676] However, this claim is only supported by a

671 Exh. CSA-02 at Attachment 8 (Joint IOUs Response to CALSSA DR 9.25).

672 Exh. CSA-02 at 55:7-19.

673 Exh. CSA-02 at 55:7-19.

674 PG&E Advice Letters 4660, 4918, 5143, 5383, 5640, and 5964; SCE Advice Letters 3239, 3473, 3658, 3866, 4074, and 4296; SDG&E Advice Letters 2761, 2984, 3131, 3273, 3426, and 3601. The total is $15 million per year for the three IOUs combined, which is a drop in the bucket compared to the more than $11 billion the utilities spend each year on the distribution system (per 2020 AB 67 report).

675 *See* Exh. IOU-01 at 137:16-18.

676 Exh. IOU-02 at 63:10-12.

table with *one* year of data (2018) in *one* utility's (SDG&E) service territory,[677] and therefore these data do not provide sufficient support for the Joint IOUs' broad claim. Further, Witness Morien recognized during cross examination that some of the data in this table appears to be faulty, bringing into question the accuracy of the table as a whole.[678] Even if there were more robust data supporting such a claim that NEM customers' demand patterns cause incremental costs, unless the solar fees were designed to specifically account for that demonstrated cost of service difference—which they are not[679]—the fees still would not be based on cost of service, and they still would not be just and reasonable.

In sum, the Pro-Transmission parties have failed to demonstrate any incremental costs caused by NEM customers. This failure likely stems from the fact the Commission has not yet approved any cost of service study specific to NEM customers in any of the utilities' service territories.[680] Regardless, the methodologies the Pro-Transmission Parties employ are not cost-based because they are designed to recover reduced bill amounts associated with self-consumption, rather than any purported incremental costs. The Commission has emphasized the importance of determining each customer group's fair share of total cost of service based on cost of service studies,[681] and it should not depart from this precedent here.

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677 Exh. IOU-02 at 63:10 to 64:1.

678 3 Tr. 489:8-490:16 (IOU – Morien).

679 *See* Exh. IOU-01 at 137:16-18.

680 Exh. CSA-01 at 97:4-12.

681 D.15-07-001, p. 2 (citing *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973)).

The Justification for New Solar Fees for Commercial and Agricultural Customers is Even Worse Than That for Residential Customers.

In addition to not being based on cost of service, the new solar fees for commercial and agricultural customers proposed by the Joint IOUs and Cal Advocates[682] are also unwarranted in light of the fact that commercial and agricultural customers already pay high fixed charges within their rate schedules.[683] Table 15 of CALSSA's Direct Testimony documents the current fixed charges in common commercial and agricultural rate schedules. The fixed charge is $838 per month for the rate used by most PG&E large commercial solar customers.[684] In addition to those monthly fixed charges, most commercial customers pay demand charges, which effectively act like additional minimum monthly charges.[685] Monthly charges and demand charges in commercial and agricultural rate schedules are based on cost of service studies approved in Commission rate cases. It would be unjust and unreasonable to pile additional charges—that are not cost-based—on these customers that already pay these significant charges.

Other States Have Rejected Capacity-Based Charges When Such Charges Are Not Designed to Recover Specifically Identifiable, Incremental Costs.

Following traditional principles of cost of service ratemaking, other states have rejected capacity-based charges when such charges are not actually designed to recover "the costs of specifically identifiable and different services, like exporting."[686] The Kansas Corporation

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682 Exh. IOU-01 at 146-148; Exh. PAO-03 at 3-46:4 to 3-48:8. *See* Exh. CSA-02 at 53 (Table 9) and 54 (Table 10).

683 Exh. CSA-01 at 93:15.

684 Exh. CSA-01 at 94, Table 15.

685 Exh. CSA-01 at 93:16-18.

686 The State Corporation Commission of the State of Kansas, Docket No. 18-WSEE-328-RTS, *Order*, P 47 (February 25, 2021), *available at* https://estar.kcc.ks.gov/estar/ViewFile.aspx/20210225103241.pdf?Id=dbf0d78a-209e-4c08-82a9-8a58810d3cef.

Commission recently rejected a proposed monthly residential grid access charge of $3.00 per kW of installed DG capacity,[687] noting "a permissible and non-discriminatory grid access charge should be based upon identifiable costs that distinguish the services provided to DG residential customers from the services provided to non-DG residential customers, most prominently including the distinct and distinguishable costs of exporting electricity onto [the] distribution system."[688] Here, the charge was designed to estimate and partially eliminate a purported subsidy to distributed generation customers; it did not identify and reflect the incremental costs associated with an additional service provided to these customers.[689] On this basis, it was rejected.

The Commission should similarly reject the proposed fees here, as they are not designed to recover any incremental costs caused by NEM customers, and therefore are not just and reasonable.

b. Arbitrarily Discriminatory and Disincentivize Self-Generation

The Solar Fees Arbitrarily Discriminate Against Solar Customers.

The Pro-Transmission Parties' solar fees also violate the Public Utilities Code's prohibition on utilities establishing "any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[690] As discussed above in Section III.C.5.a, proponents of these fees have failed to demonstrate that the cost of serving NEM customers is significantly different from the cost of serving non-NEM customers, and that these fees are designed to account for that cost of service difference. As a

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687 *Id.*, P 17.

688 *Id.*, P 45.

689 *Id.*, P 46.

690 Cal. Pub. Util. Code § 453(c).

result, the solar fees result in a rate structure in which similarly situated customers with the same consumption patterns would be treated differently based on NEM status.[691] This constitutes an "unreasonable difference as to rates" that is discriminatory.

Apart from exports, self-generation is a form of load management.[692] Assessing fees on behind-the-meter usage is akin to charging energy efficiency and demand response customers for the grid consumption that those customers avoided through their energy efficiency investments or demand response measures.[693] While other customers with similar load profiles that have reduced their demand through other measures besides self-consumption are not charged distribution, transmission, and nonbypassable charges on their estimated demand reduction, NEM customers would be. Therefore, the Pro-Transmission Parties' proposals to single out NEM customers for special charges, when similar differences in cost recovery can result from a multitude of other circumstances, discriminate against NEM customers.

Each class of customers exhibits load diversity, and while the utilities base their rates on projections of usage, customers may lower their consumption of utility-supplied electricity in myriad ways, only one of which is to make a sizeable private investment in onsite solar.[694] For instance, the utilities cannot bill a family for lost revenues from reduced usage when their children leave home for college or bill an industrial customer that closes down a production

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691 Exh. CSA-01 at 94:8 to 97:12.

692 Exh. CSA-01 at 99:6-14.

693 Exh. CSA-01 at 99:6-14.

694 Exh. CSA-01 at 98:14 to 99:5.

line.[695] But the solar fees single out one customer group—NEM customers—by charging them for reduced usage due to a private investment in onsite generation. [696]

The Pro-Transmission Parties argue that these fees are necessary to avoid cost shifts between customer groups and to ensure that all customers pay their fair share of the utility expenditures that benefit all customers.[697] If the Commission determines that higher fees are needed for specific grid access costs in order to ensure that utilities are able to recover their full cost of service equitably from all their customers, it can approve a monthly service charge for all residential customers or increase the level of the minimum bill. Singling out NEM customers for high fees, and excluding customers that participate in other demand-side programs, is discriminatory.

The Solar Fees Discourage Investment in Self-Generation Contrary to State Law.

Singling out NEM customers for high fees would *specifically disincentivize* self-generation as a method of achieving demand reductions by directly reducing the savings that these customers are able to obtain from their investments in NEM systems. This disincentive would undermine the California Legislature's clear direction to encourage customer-sited generation. Public Utilities Code Section 2801 provides:

> [I]t is desirable and necessary to *encourage* private energy producers to competitively develop independent sources of natural gas and electric energy not otherwise available to California consumers served by public utilities, to require the transmission by public utilities of such energy for private energy producers under certain conditions, and remove unnecessary barriers to energy transactions involving private energy producers.[698]

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[695] Exh. CSA-01 at 98:14 to 99:5.

[696] Exh. CSA-01 at 98:14 to 99:5.

[697] Exh. CSA-01 at 97:13-15 n. 166.

[698] Cal. Pub. Util. Code § 2801 (emphasis added).

Instead of *encouraging* private energy production, these charges arbitrarily *discriminate* against such energy production, as compared to other forms of load management like energy efficiency and demand response measures. These fees are therefore not only discriminatory, but they are also contrary to California's codified goal of incentivizing private energy production.

c. Contravene the Antidiscrimination Provision in PURPA.

The Pro-Transmission Parties' solar fees also contravene the federal antidiscrimination provision set forth in PURPA. PURPA regulations provide that rates for sales to QFs[699] must be "just and reasonable and in the public interest" and "[s]hall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility."[700] Further, these regulations provide that rates for sales that are based on accurate data and consistent systemwide costing principles will not be considered to discriminate against any QF to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.[701]

FERC Order No. 69, explicating these provisions and the underlying statute, provides that "[t]his section contemplates formulation of rates on the basis of traditional ratemaking (*i.e.*, cost-of-service) concepts."[702] It further explains:

> [F]or qualifying facilities which do not simultaneously sell and purchase from the electric utility, the rate for sales shall be the rate that would be charged to the class to which the qualifying facility would be assigned if it did not have its own generation . . . [unless]

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699 *See* Section II.D herein discussing how solar facilities up to 1 MW are afforded all the rights and protections afforded to QFs under PURPA.

700 18 C.F.R. § 292.305(a)(1). *See also* 16 U.S.C. § 824a-3(c).

701 18 C.F.R. § 292.305(a)(2).

702 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).

> on the basis of *accurate data* and *consistent system-wide costing principles*, the utility demonstrates that the rate that would be charged to a comparable customer without its own generation is not appropriate, [in which case] the utility may base its rates for sales upon those data and principles. *The utility may only charge such rates on a nondiscriminatory basis*, however, so that a cogenerator will not be singled out to lose any interclass or intraclass subsidies to which it might have been entitled had it not generated part of its electric energy needs itself.[703]

FERC Commissioners have recently provided further guidance regarding how to interpret these provisions. In a joint statement by Chairman Glick and Commissioner Clements issued in a proceeding concerning a challenge to the Alabama Public Service Commission's approval of rates for back-up services for QFs, the Commissioners expressed concern that the Alabama Commission may be violating PURPA's regulations.[704] The Commissioners made clear that, in order "[t]o charge a different rate consistent with Order No. 69, the rate must (1) be 'based on accurate data'; (2) be established using 'consistent system wide costing principles'; and (3) 'apply to the utility's other customers with similar load or other cost-related characteristics.'"[705] Further, they noted that "a demonstration that the [Commission] had violated *any single prong* of these rules in establishing [the tariff] would be enough to show that it failed to adhere to Order No. 69."[706]

[703] 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) (emphasis added).

[704] FERC Docket No. EL21-64-000, *Joint Statement by Chairman Glick and Commissioner Clements Concurring with the June 1, 2021 Notice of Intent Not to Act re James H. Bankston, Jr. et al v. Alabama Public Service Commission under EL21-64*, p. 1 (June 2, 2021).

[705] FERC Docket No. EL21-64-000, *Joint Statement by Chairman Glick and Commissioner Clements Concurring with the June 1, 2021 Notice of Intent Not to Act re James H. Bankston, Jr. et al v. Alabama Public Service Commission under EL21-64*, pp. 1-2 (June 2, 2021) (citing 18 C.F.R. § 292.305(a)(2)).

[706] FERC Docket No. EL21-64-000, *Joint Statement by Chairman Glick and Commissioner Clements Concurring with the June 1, 2021 Notice of Intent Not to Act re James H. Bankston, Jr. et al v. Alabama Public Service Commission under EL21-64*, p. 2 (June 2, 2021) (emphasis added).

Applying this three-prong test, the solar fees at issue in this proceeding violate 18 C.F.R. § 292.305(a) because (1) they are not based on accurate data demonstrating a cost of service difference between NEM and non-NEM customers, (2) they are not established using consistent system wide costing principles demonstrating this cost of service difference, and (3) they do not apply to the utility's other customers with similar load or other cost-related characteristics.

First, these fees are not based on accurate data showing a cost of service difference between NEM and non-NEM customers. Courts interpreting PURPA regulations and FERC Order No. 69's guidance that PURPA's antidiscrimination provision "contemplates formulation of rates on the basis of traditional ratemaking (*i.e.*, cost-of-service) concepts[,]"[707] have made clear that the relevant analysis is whether QFs are imposing *incremental costs* on the utility's system. For instance, the FERC has found that, to support a separate standby rate for QFs, a proponent must "show that QFs, as a separate class, are *imposing costs above that which would have been incurred had the QFs remained within the class they would have belonged to had they not decided to self-generate* . . . In the absence of any such findings, utilities must provide service at a rate applicable to the customer class that the QF would have belonged if it did not have its own generation."[708] In interpreting PURPA's antidiscrimination provision, states like Iowa have found that differences in the rate structures of tariffs are not "cost-based" when the utility had no data showing that the cost of service of co-generators was significantly different than that of regular customers.[709] The relevant analysis is whether proponents have

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707 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).

708 *Industrial Cogenerators v. Florida Public Service Commission*, 43 FERC ¶ 61,545, 62,352 (June 27, 1988) (emphasis added).

709 *In re: Mr. and Mrs. Gregory Swecker v. Midland Power Cooperative*, 2000 Iowa PUC LEXIS 1528, **161-163, 184 (March 28, 2000). Note that the Iowa Utilities Board here focuses on the question

demonstrated, with accurate data, a cost of service difference between NEM and non-NEM customers that justifies the disparate treatment.

As discussed above in Section III.C.5.a, none of the Pro-Transmission parties have put forth credible evidence demonstrating a cost of service difference between NEM and non-NEM customers; none have relied on any Commission-approved cost of service study specific to NEM customers to demonstrate cost of service differences; and none of them present a cost of service study demonstrating that self-generated electricity causes the utility costs that the individual rate components comprising these fees are designed to recover.[710] In other words, not only is there no "accurate data" demonstrating that these fees are based on a cost of service difference between NEM and non-NEM customers—there is simply no data showing this at all.

Looking to the second prong of this test, these fees also violate 18 C.F.R. § 292.305(a) because they were not established using consistent system wide costing principles. The FERC has found that, to support a separate rate for QFs, proponents must show that QFs cause incremental costs, and the "showing of such costs must be consistent with system wide costing principles."[711] This provision contemplates using consistent cost of service principles across all ratepayers to fairly determine cost responsibility of QFs. Instead of undertaking or relying on such an analysis, the Pro-Transmission Parties created proposed fees based on the estimated cost

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of whether the utility's tariffs discriminate against co-generators in violation of Iowa statute, but it approaches this question through a concurrent analysis pursuant to PURPA regulations, concluding: "In order to determine whether different treatment is reasonable or discriminatory, it is helpful to look to federal statutes and regulations dealing with the same subject as guidance in interpreting Iowa Code § 476.21, since the Iowa statute is consistent with the federal. Iowa Code § 476.21 (1999); 16 U.S.C. § 824a-3(a) and (c); 18 CFR § 292.305(a)(1) and (2)." *Id*. at **188-192.

[710] These proposals also do not show bill impacts for different types of customers that may be impacted differently by the various estimates in the design. The fee proposals constitute rate design, and should be held to rate design process and standards.

[711] 43 FERC ¶ 61,545, 62,352 (June 27, 1988).

avoidance of one customer group—while failing to consider any similar cost avoidance that may exist among other groups of ratepayers.[712]

Finally, looking to the third prong of this test, these fees also violate 18 C.F.R. § 292.305(a) because they are not designed to apply to other customers with similar load or other cost-related characteristics. In their joint statement concerning the challenge to the Alabama Public Service Commission's approval of rates for back-up services for QFs, FERC Chairman Glick and Commissioner Clements commented specifically on the application of this third prong of the PURPA requirement[713] to the rate at issue in the Alabama case. The Commissioners found that the current application of that charge "may be discriminatory" if QF customer usage patterns are comparable to those of customers without on-site generation who reduce volumetric consumption through other means. The Commissioners concluded that neither the Alabama Commission nor Alabama Power "sufficiently demonstrate[d] that QF customer load profiles are in fact different from those of customers without on-site generation (who are not required to pay the [charge])."[714]

Similarly here, the Pro-Transmission parties have not proposed that these fees apply to any other customer group besides NEM customers, and they have not sufficiently demonstrated that NEM customer load profiles are different from those of customers without onsite

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712 Exh. IOU-01 at 135:13-17; Exh. IOU-01 at 137:16-18; Exh. TRN-01 at 48:18-19; Exh. NRD-01 at 17:12 to 18:7; Exh. PAO-03 at 3-25:3-14.

713 FERC Docket No. EL21-64-000, *Joint Statement by Chairman Glick and Commissioner Clements Concurring with the June 1, 2021 Notice of Intent Not to Act re James H. Bankston, Jr. et al v. Alabama Public Service Commission under EL21-64*, pp. 1-2 (June 2, 2021) (citing 18 C.F.R. § 292.305(a)(2)).

714 FERC Docket No. EL21-64-000, *Joint Statement by Chairman Glick and Commissioner Clements Concurring with the June 1, 2021 Notice of Intent Not to Act re James H. Bankston, Jr. et al v. Alabama Public Service Commission under EL21-64*, p. 2 (June 2, 2021).

generation.[715] Similarly, these parties have not put forth any comprehensive cost of service assessment of other customer groups—such as energy efficiency or demand response customers—that may in fact exhibit similar load or other cost-related characteristics as NEM customers.

The solar fees violate 18 C.F.R. § 292.305(a) by failing to meet each prong of the analysis required by this antidiscrimination provision.[716] These proposed fees do not account for incremental costs to the utility arising from a distinct or additional service, but rather use a customer's NEM status as a basis for charging more for the same goods and services than the utility charges to non-NEM customers. This is discriminatory treatment under federal law.

d. Create a Back-Door Buy-All/Sell-All Tariff.

The Pro-Transmission Parties' solar fees amount to a back-door buy-all/sell-all arrangement and infringe on customers' right to self-generate. A buy-all/sell-all solar model is one in which self-generators cannot self-consume electricity and instead are required to sell all their generated electricity to their utility at a predetermined sell rate.[717] Self-generators are only permitted to "use" electricity from the grid, and they pay the retail rate for all electricity

715 *See* Section III.C.5.a (none of the Pro-Transmission Parties justified their proposed fees by demonstrating that NEM customer load profiles are different from those of customers without onsite generation, and that their fees are designed to recover the costs associated with difference). Note that the Joint IOUs' efforts to distinguish demand patterns of NEM customers relied on minimal and unrepresentative data. *See* Section III.C.5.a (discussing the Joint IOUs' claims in Exh. IOU-02 at 63:10-12).

716 18 C.F.R. § 292.305(a)(2); FERC Docket No. EL21-64-000, *Joint Statement by Chairman Glick and Commissioner Clements Concurring with the June 1, 2021 Notice of Intent Not to Act re James H. Bankston, Jr. et al v. Alabama Public Service Commission under EL21-64*, pp. 1-2 (June 2, 2021) (citing 18 C.F.R. § 292.305(a)(2)).

717 Exh. CSA-01 at 95:21 to 96:5.

consumed, even though from an electrical perspective they are consuming power they generate themselves.[718]

While on their surface the Pro-Transmission Parties' proposals allow physical netting of generation and consumption, they then claw back the benefits of that netting via the solar fees. Indeed, by their own description, these fees are designed to recover a significant portion of the charges that current NEM customers avoid through self-generation.[719] Specifically, TURN's proposal would allow customers to avoid *only* the wholesale market price of generation for electricity they generate and consume onsite,[720] while the other Pro-Transmission Parties' proposals are not much better, effectively stripping all the value from self-generation except values measured in the ACC.[721] In practice, given the extent to which this framework would depress the value of self-generation, it would effectively operate like a buy-all/sell-all arrangement by denying customers all the benefits of load reduction from their self-generation but for the avoided wholesale value of self-consumption.

Buy-all/sell-all models are rife with legal shortcomings, as they implicate the right of customers to self-generate their own electricity, which is rooted in both State and Federal law. Under common law property principles, a property owner has a legal right to generate their own electricity. Self-generation falls within the property owner's right to use and enjoy their

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718 *See* Exh. CSA-01 at 96 n. 159 (citing *Back to Basics: Unraveling How Distributed Generation is Compensated and Why It's Important*, NREL, https://www.nrel.gov/state-local-tribal/blog/posts/back-to-basics-unraveling-how-distributed-generation-is-compensated-and-why-its-important.html).

719 Exh. IOU-01 at 137:16-18; Exh. PAO-03 at 3-25:3-14; Exh. TRN-01 at 48:18-19; Exh. NRD-01 at 18:3-10.

720 *See* Exh. CSA-01 at Attachment 5 (TURN Response to CALSSA DRs 2.04 and 2.05).

721 *See, e.g.*, Exh. IOU-01 at 137:16-18 ("Our proposed GBC recovers the portion of distribution, transmission, nonbypassable charges, and generation that current NEM customers avoid by consuming their self-generation onsite, after accounting for avoided costs.").

property, as "a private use such as self-generation is within the appropriate discretion of the property owner."[722] A buy-all/sell-all model contravenes this right by requiring the sale of all of a customer-generator's solar production to the utility. While courts have in some instances restricted owners' use of their property to self-supply public services, such restrictions are generally only permissible when they are deemed necessary to protect public health and safety.[723] Such limitations do not apply in the context of the self-generation of electricity,[724] which generally does not trigger such risks to the community, as the IOUs' Rule 21 tariffs address safety and reliability concerns.

A property owner's right to self-generate is also implicit in various state[725] and Federal laws.[726] As one notable example, this right is implicit in PURPA in light of the explicit rights granted to QFs under PURPA. The right to self-supply is most clearly apparent within sections of Federal regulations addressing a QF's right to sell energy and capacity to its host utility, at a

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722 *See* R.20-08-020, *Opening Comments of CALSSA on Proposed Decision Adopting Guiding Principles for the Development of the Successor to the Current Net Energy Metering Tariff*, p. 7 n. 24 (January 25, 2021) ("CALSSA January 25, 2021 Comments") (citing Jon Wellinghoff and Steven Weissman, *The Right to Self-Generate As A Grid-Connected Customer*, Energy Law Journal vol. 36:305, pp. 309-314 (November 16, 2015)). *See also People v. Truckee Lumber Co.*, 116 Cal. 397, 402 (1897).

723 *See* CALSSA January 25, 2021 Comments, p. 8 n. 25 (citing Jon Wellinghoff and Steven Weissman, *The Right to Self-Generate As A Grid-Connected Customer*, Energy Law Journal vol. 36:305, pp. 312-313 (November 16, 2015)). *See also Sanitation Dist. v. Campbell*, 249 S.W.2d 767, 772 (Ky. 1952).

724 *See* CALSSA January 25, 2021 Comments, p. 8 n. 26 (citing Jon Wellinghoff and Steven Weissman, *The Right to Self-Generate As A Grid-Connected Customer*, Energy Law Journal vol. 36:305, p. 313 (November 16, 2015)).

725 *See, e.g.*, Cal. Pub. Util. Code § 2801 ("it is desirable and necessary to *encourage* private energy producers to competitively develop independent sources of natural gas and electric energy not otherwise available to California consumers served by public utilities, to require the transmission by public utilities of such energy for private energy producers under certain conditions, and remove unnecessary barriers to energy transactions involving private energy producers") (emphasis added). This facilitative language suggests a pre-existing right to self-generate.

726 *See* CALSSA January 25, 2021 Comments, p. 8 n. 30 (citing Jon Wellinghoff and Steven Weissman, *The Right to Self-Generate As A Grid-Connected Customer*, Energy Law Journal vol. 36:305, pp. 316-325 (November 16, 2015)).

price equal to the particular utility's avoided cost.[727] Under the FERC's regulations, QFs may "provide energy as the [QF] *determines such energy to be available for such purchases*."[728] This language grants a QF customer the ability to determine (a) exactly how much energy and capacity the customer would like to use on-site, and (b) exactly how much energy and capacity the customer would like to sell to the utility. That is, self-generators have the implied right to choose to supply all of their own electricity without selling any to the utility, or to sell some portion of their electricity to the utility.

This right to self-generate under PURPA is not undermined by the Iowa state court precedent cited by the IOUs earlier in this proceeding, in which the court concluded that PURPA permits but does not require a system of net metering.[729] A buy-all/sell-all model was not at issue in this case, and the case does not address whether such a model would violate a QF's right to self-supply under PURPA.[730] Therefore, the IOUs' reliance on this case to support a conclusion that PURPA provides "no legal right to self-serve onsite load" is misplaced.[731]

A buy-all/sell-all model denies customers their right under PURPA to choose to determine how much load they serve with on-generation because it requires all energy to be sold at wholesale.[732] Self-generators like NEM QFs typically do not sell electricity at wholesale

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727 18 C.F.R. § 292.303(a).

728 18 C.F.R. § 292.304(d)(1) (emphasis added).

729 R.20-08-020, *Joint Reply Comments of SCE, PG&E and SDG&E on Proposed Guiding Principles*, pp. 7-8 (December 11, 2020) ("Joint IOUs Reply Comments on Guiding Principles").

730 *See Windway Techs., Inc. v. Midland Power Coop.*, 696 N.W.2d 303, 304-305 (Iowa, 2005) ("Midland took the position that purchases and sales of energy by the AEPs should be separately measured and billed . . . under the approach urged by Midland, two separate measurements would be required—one to measure power flowing from Midland and the other to measure power flowing from the cogenerator. The applicable billing rates would then be separately applied to each measurement and the resulting dollar amounts would be offset against one another").

731 Joint IOUs Reply Comments on Guiding Principles, p. 8.

732 Note that PURPA also grants QFs the right to operate in parallel with their utility. *See* 18 C.F.R. § 292.303(e) ("Each electric utility shall *offer to operate in parallel with a qualifying facility*, provided

because they are sized to meet onsite load requirements over the course of the billing year. However, if a California NEM QF generated more bill credits than they bought at retail, they would receive net surplus compensation for the excess at wholesale avoided cost rates. Thus, these customers have the same ability to determine how much onsite generation is consumed and how much is sold as other QFs. By denying successor tariff QF customers all but the benefits of wholesale avoided costs, the Pro-Transmission Parties' proposals act like a buy-all/sell-all model in effect, compensating customers in the same manner as a buy-all/sell model. These solar fees thereby infringe on customers' right to self-generate and serve their load with electricity they produce.

e. Methods of Calculating Fees Violate State Law and Policy.

The Pro-Transmission Parties present various methods of calculating these solar fees, which are based on customers' level of self-consumption. The Joint IOUs and NRDC propose to estimate self-consumption[733] while Cal Advocates and TURN[734] propose to allow customers to choose between an estimate of self-consumption and the installation of an additional meter to track actual self-consumption. The estimation approach violates State law and the metering approach inappropriately encroaches on customers' private activities.

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that the qualifying facility complies with any applicable standards established in accordance with § 292.308") (emphasis added).

[733] Exh. IOU-01 at 138:6 to 139:9; Exh. NRD-01 at 18:8-10; Exh. NRD-01 at 20:25-30.

[734] Exh. PAO-03 at 3-40:19 to 3-41:7 (describing the customer choices to assess the NBCs components of the solar fee; Cal Advocates' solar fee is assessed based on the system's size for distribution and transmission cost recovery (*see* Exh. PAO-03 at 3-25:11-14)); Exh. TRN-01 at 48:19-23; Exh. TRN-01 at 50:15 to 51:6.

The Solar Fees Are Based on Estimates of Usage, Contrary to State Law.

Parties' proposed methods of estimating self-consumption for the purpose of calculating the NBC component of these fees would violate State law. Public Utilities Code Section 381(a) requires that certain NBCs be "collected on the basis of usage."[735] The Pro-Transmission Parties' proposals all include either the option or the requirement that estimates of self-consumption be used to calculate the NBC element of the fees.[736] Collecting NBCs on the basis of *estimates* of self-consumption is not the same as collecting these charges "on the basis of usage." These estimates will be highly complex and difficult to implement.[737] The only certainty associated with such estimates is that they will be wrong every month, and customers will not be assessed the correct portion of NBCs based on their actual usage. [738] These proposals therefore violate Public Utilities Code Section 381(a).

Cal Advocates' and TURN's Solar Fees Involve the Tracking of Consumption Behind the Meter, in Violation of Customers' Right to Privacy.

Cal Advocates and TURN propose to allow customers to choose between these estimates of self-consumption and the installation of an additional meter on customers' private property to

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735 Cal. Pub. Util. Code § 381(a).

736 Exh. IOU-01 at 139:4-9; Exh. PAO-03 at 3-40:19-23; Exh. TRN-01 at 48:19 to 51:6; Exh. NRD-01 at 20:25 to 21:1.

737 *See, e.g.*, 9 Tr. 1518:22-1520:13 (TRN – Chait) (confirming that there could be a different self consumption estimate for all 8,760 hours in the year); Exh. PAO-03 at 3-40:25 to 3-41:7 (describing how estimates would "be based on a typical or average annual residential PV production profile scaled to the customer's PV system size (kWCEC-AC) to estimate total annual production (kWh)[,]" while "[m]onthly on-site consumption would be estimated by taking the total monthly production from the typical PV profile and subtracting the customer's total Channel 2 meter readings (net exports) during the billing cycle").

738 Exh. CSA-01 at 103:19 to 104:7.

track actual self-consumption.[739] Under TURN's proposal, solar plus storage customers would be *required* to install this second meter behind the utility's meter.[740]

The Commission should consider this proposed privacy intrusion in the context of prior Commission precedent, through which the Commission has reinforced its commitment to protecting Californians' right to privacy over various commercial interests.[741] In particular, in the context of privacy concerns related to Smart Grids and the collection and use of customers' electricity usage data, the Commission has affirmed "California's long-standing interest in the protection of the privacy of utility customers[,]"[742] recognized that energy consumption data can reveal private information,[743] and adopted a policy framework that stresses the importance of "[a] principle and practice of 'Data Minimization'" and "[l]imiting the collection of personal data to just what is needed."[744] In line with this reasoning, the Commission should continue to protect utility customers' privacy rights, especially in the more intrusive context of the tracking of behind the meter consumption, by rejecting these proposals.

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739 Exh. PAO-03 at 3-40:19 to 3-41:7; Exh. TRN-01 at 48:19-23; Exh. TRN-01 at 50:15 to 51:6.

740 9 Tr. 1523:25-1524:13 (TRN – Chait).

741 *See In the Matter of the Application of Pacific Bell*, Decision No. 92-06-065, 44 C.P.U.C.2d 694, 1992 Cal. PUC LEXIS 688, *54-60, Conclusion of Law 15 (June 17, 1992) (finding, in the context of caller identification technology, "If the service is to be offered consistently with constitutional guarantees and the public interest, it must be offered in a way that maximizes the ease and freedom with which California citizens may choose not to disclose their calling party numbers. We will not compromise an individual's free exercise of his or her right of privacy in order to place in the hands of the Caller ID subscriber a more valuable mailing list, a marginally better method of screening or managing telephone calls, or even a slightly more effective deterrent to unlawful or abusive uses of the telephone").

742 D.11-07-056, p. 10.

743 *Id.*, p. 22 ("access to detailed, disaggregated data on energy consumption can reveal some information that people may consider private.").

744 *Id.*, pp. 21, 71-72 (in adopting the Fair Information Practice principles as California policy for the Smart Grid, the Commission specifically found that "[a] principle and practice of 'Data Minimization' will clearly promote the security of data. Limiting the collection of personal data to just what is needed reduces the amount of data that requires protection and reduces the risks that arise from a security breach.").

f. Violate the Rate Design Principles.

The Commission adopted ten rate design principles as part of its residential rate reform proceeding,[745] R.12-06-013, and the proposed solar fees violate at least half of them, including the following:

2. Rates should be based on marginal cost;

3. Rates should be based on cost-causation principles;

4. Rates should encourage conservation and energy efficiency;

5. Rates should encourage reduction of both coincident and non-coincident peak demand;

6. Rates should be stable and understandable and provide customer choice.

On Principles 2 and 3, as noted above, the solar fees are neither based on the marginal costs to serve solar customers nor any incremental costs the DER customers cause that other similarly situated customers do not cause. On Principles 4-6, the solar fees would strip from NEM customers most of the benefits of self-supplying electricity, and significantly increase rates for self-generators. The decrease in DER installations that would result from elongated cost recovery periods discussed in Section III.B.1 herein would discourage conservation, prevent the reduction of both coincident and non-coincident peak demand, and all but eliminate customers' options to invest in onsite generation. The solar fees also violate Principle 6 in myriad ways that trigger significant consumer protection concerns, as discussed in more detail in the next section.

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[745] D.14-06-029, Ordering Paragraph 4.

g. Complicated and Nearly Impossible to Predict

The Mechanics of These Solar Fees are Incredibly Complicated and Would Be Difficult To Communicate Clearly To Customers.

For the Joint IOUs' proposed fees, the average rate calculation is complex, resolving four cost categories (generation, distribution, transmission, and nonbypassable charges), organized into two rate components (generation and delivery), modified by three time-of-use periods in each season, which are then weighted by a solar, but not solar plus storage, production profile.[746] Cal Advocates' proposed fee would have similar building blocks, and then part of the fee would be assessed per kW of installed capacity and part would be assessed per kWh of a portion of a customer's electricity usage.[747] Calculating potential bill savings under a tariff with these fees would be quite complicated,[748] and as a result, potential customers are likely to have difficulty understanding their projected savings under this proposal.

For NRDC's proposed solar fee, not only are the mechanics not understandable—they are unknown, and have not been presented on the record. The Commission will have no way to implement NRDC's solar fee since its witness did not provide any details on the record on how its solar fee would be calculated. NRDC's testimony on its proposed solar fee consists almost entirely of a statement that it asked E3 to model a solar fee for its proposal using Cal Advocates' proposal.[749] During cross examination, NRDC's witness provided no further details regarding his proposed solar fee other than the vague statement that it should "recoup fixed costs of

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[746] 3 Tr. 454:26-457:17 (IOU – Morien); Exh. CSA-17.

[747] Exh. PAO-01 at 3-24:11-13.

[748] Exh. IOU-01, Table IV-27 presents the complex formulae a customer and solar provider would need to calculate in order to present an honest assessment of potential bill savings.

[749] Exh. NRD-01 at 18:11-13.

transmission and distribution." [750] However, he then admitted that NRDC had not estimated any of the transmission and distribution values that would need to be included in its solar fee.[751]

Despite stating that E3's modeling borrows Cal Advocates' proposal in order to measure NRDC's proposal, NRDC's witness insisted during cross examination that NRDC's proposal was different than Cal Advocates' proposal. [752] Witness Chhabra went on to explain that the difference is that NRDC still has not decided which nonbypassable charges to include in the fee. In the end, NRDC's witness admitted that "[w]e don't have a specific proposal for the Grid Benefits Charge,"[753] *i.e.*, NRDC's solar fee. However, despite not having a specific proposal, Witness Chhabra did state that any drawbacks of Cal Advocates' proposal would apply to NRDC's proposal, as well.[754] The Commission should not adopt a new fee for NEM customers without understanding how such a fee would be calculated and ensuring such a fee would be stable and understandable to customers as well.

The Fees Will Vary Frequently and to an Unknown Degree Over The Lifetime Of The System.

The IOUs' solar fee, and the components of the Pro-Transmission's Parties' solar fees that mirror the IOUs' fee, will vary frequently and to an unknown degree over the lifetime of the system. For instance, a customer's solar fee calculation will change based on any changes to the four rate components underlying the fee. [755] In addition, a customer's solar fee calculation would

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750 *See* 10 Tr. 1768:20-28 (NRD – Chhabra).

751 10 Tr. 1768:20-28 (NRD – Chhabra).

752 10 Tr. 1769:1-10 (NRD – Chhabra).

753 10 Tr. 1773:9-11 (NRD – Chhabra).

754 10 Tr. 1769:20-1770:5 (NRD – Chhabra).

755 3 Tr. 458:25-459-15(IOU – Morien); Exh. IOU-01 at 148:1-9.

change each time the time-of-use periods for the underlying rate are modified.[756] If, for example, the peak time-of-use period shifts an hour later, the solar fee the customer pays would change because the rate is weighted by when the IOUs expect solar to produce energy for behind-the-meter consumption.[757] Notably, the Joint IOUs' witness was unable to recall the number of times SDG&E changed the rate components underlying the IOUs' solar fee in 2020,[758] and to date, in 2021, she stated the utility has already revised these rate components three times. [759] Further, the avoided cost calculator component of the solar fee calculation also will vary by utility,[760] and it will be updated at least once per year. [761] Finally, the estimate of onsite consumption will be updated at least once per year.[762]

In total, while the Joint IOUs may not intend the solar fee to change every time the underlying rates, avoided cost, and time-of-use periods change, the underlying components change numerous times over the course of the year, and the per-kW solar fee a customer pays may change as often as 2-3 times per year. [763] This is a substantial consumer protection concern. Augmenting this concern is the fact that the IOU witness sponsoring the solar fee could not provide a responsive answer to the question of how much the IOUs expect their solar fee will change each year,[764] admitting that solar customers will not know the potential degree of such

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756 3 Tr. 455:14-24 (IOU – Morien).

757 3 Tr. 455:14-24 (IOU – Morien).

758 3 Tr. 460:3-461-3 (IOU – Morien).

759 3 Tr. 461:4-6 (IOU – Morien).

760 3 Tr. 465:5-8 (IOU – Morien).

761 3 Tr. 465:10 (IOU – Morien).

762 3 Tr. 477:9-478:11 (IOU – Morien).

763 3 Tr. 459:26-461:28; 479:22-480:1 (IOU – Morien); Exh. IOU-01 at n. 207.

764 3 Tr. 462:6-11 (IOU – Morien).

changes at the time they invest in solar.[765] Indeed, witness Morien stated that, with regard to the expected degree of changes to the avoided cost calculator components of the solar fee, "I think it's really difficult to say because we don't know what major updates or minor updates are going to be made to the Avoided Cost Calculator." [766] When asked about how much the avoided cost-related components might change over the course of ten years, she stated "I don't think anybody has a forecast of what the ACC is going to be in 10 years." [767]

This degree of complexity and uncertainty will make it difficult for the Commission to track and verify all these changes. Even assuming the Commission is able to do so, the customer impact of this volatile structure would still be profound: customers would not have any assurance regarding their expected savings of an investment in distributed generation. Indeed, witness Morien admitted she would not be able to give customers "reasonable assurance that the Grid Benefits Charge will not change so much over the lifetime of the system so as to put [the customer's] investment under water."[768] While witness Morien stated that customers do not know how much rates change under the current NEM program,[769] the structure of rates is relatively consistent while results from the ACC have been unpredictable.[770] There is also a difference between changes to volumetric rates, which customers can respond to, and changes to fixed charges, to which customers cannot respond.

765 *See* 3 Tr. 462:12-14 (IOU – Morien).

766 *See* 3 Tr. 465:18-21 (IOU – Morien).

767 *See* 3 Tr. 466:9-11 (IOU – Morien).

768 3 Tr. 486:19-487:2 (IOU – Morien).

769 3 Tr. 462:16-17; 487:1-2 (IOU – Morien).

770 Exh. CSA-01 at 20:5-7.

Yet another consumer protection issue arises given the blackbox nature of the IOUs' solar fee calculation. First, it is unclear how the IOUs propose to estimate on-site consumption for purposes of calculating the solar fee. In order to do so, the utility will need to estimate customers' generation based on their system size and then subtract estimated exports based on assumed customer load.[771] SDG&E used a 40% estimate,[772] but when asked how the utility arrived at that figure, IOU witness Morien was unable to explain its origins other than to suggest the IOUs used "load data."[773] When pressed for further details, she was unable to provide any detail on how it was done other than to say how it "could" be done.[774] Moreover, for commercial customers, it is much more difficult to estimate on-site usage because different businesses have different operating hours and greater diversity in electricity usage patterns, meaning a solar fee based on a typical load profile for commercial customers will result in more customers being farther away from an average than for residential customers.[775]

The capacity factor assumptions from the IOUs are similarly unclear. Capacity factor is an essential element because these parties' solar fee methodologies require an assumption for how much electricity a customer's solar system will produce. However, even in a formal Commission proceeding where discovery is allowed, neither the IOUs' responses to data requests nor the IOUs' witness could explain the origins of the capacity factor assumptions the IOUs used to calculate their solar fee.[776] The IOUs were asked specifically to provide

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771 3 Tr. 475:19-476:21 (IOU – Morien).

772 Exh. IOU-01 at Table IV-27, Line I.

773 3 Tr. 475:25-476:2 (IOU – Morien).

774 3 Tr. 476:12-26 (IOU – Morien).

775 3 Tr. 478:12-479:21 (IOU – Morien).

776 3 Tr. 468:7-472-14 (IOU – Morien); Exh. PAO-02, Attachment 3-E.

workpapers showing the source of the capacity factor calculation they used in different parts of their testimony.[777] In response, the IOUs pointed to workpapers that did not contain a citation for SCE,[778] and the Verdant studied relied upon by the other IOUs did not contain similar information for SCE. [779] When asked directly about the origin of SCE's capacity factor, the witness who sponsored the IOUs' testimony on the calculation of solar fee was unable to answer the question, suggesting counsel ask another witness for whom no parties had reserved time.[780] Thus, the Commission has no knowledge on the record of where the capacity factor originated for SCE. Similarly, for SDG&E and PG&E, the Verdant study does not explain from where the capacity factors were derived, and the IOU witness could not explain the origins of those figures either.[781]

Finally, the Joint IOUs' proposal creates even more uncertainty for solar plus storage customers. While at the outset, the IOUs' solar fees would apply to solar-plus-storage customers in the same manner as standalone solar customers,[782] the IOUs may propose a fee be placed on those customers at a later date,[783] which would increase the fee for solar customers if, as is presumably the case, an energy storage customer would use more electricity on site.[784] This is an

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[777] Exh. CSA-8.

[778] Exh. CSA-15.

[779] 3 Tr. 469:24-28 (IOU – Morien).

[780] 3 Tr. 471:16-21 (IOU – Morien).

[781] 3. Tr. 472:11-473:17 (IOU – Morien).

[782] 3 Tr. 458:1-9 (IOU – Morien).

[783] *See* Exh. IOU-01 at 138:10-23.

[784] 3 Tr. 477:9-20 (IOU – Morien) (admitting the solar fee will increase if onsite consumption increases).

enormous consumer protection concern, as customers would have no knowledge of when or whether the increased fee would apply to them and the degree of that potential increase.[785]

TURN's Production Meter Proposal Presents Unaddressed Implementation Problems.

As discussed above, TURN's solar fee "would be dynamically calculated based on either the actual or estimated self-consumption attributable to BTM generation."[786] For the NUS to be based on actual self-consumption, the customer would have to install a second meter on the resource itself.[787] TURN's proposal presents unique implementation challenges for which TURN provides no clear solution.

Specifically, TURN does not address clearly whether the utility, the customer, or the solar provider would own the production meter,[788] or whether the utility or the solar providers would install the production meter.[789] TURN agreed during hearings that if the solar provider installed the production meter, there would need to be a yet-to-be specified communication platform and protocol to communicate that data to the utility.[790] Moreover, under this scenario, the utility would need to resolve the problem of different solar companies providing onsite consumption data to the utility in different formats.[791] TURN did not specify whether current

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785 *See* 3 Tr. 480:19-482:25 (IOU – Morien) (admitting the IOUs are not proposing vintaging (meaning all customers will pay the same solar fee) and then repeatedly refusing to directly answer the question of whether customers will know whether they will have to pay the fee, suggesting somehow a communications team person would be more appropriate to answer rather than the witness directly sponsoring the solar fee testimony).

786 Exh. TRN-01 at 48:19-21.

787 9 Tr. 1523:8-12 (TRN – Chait).

788 9 Tr. 1525:28-1526:7 (TRN – Chait).

789 9 Tr. 1525:28-1526:7 (TRN – Chait).

790 9 Tr. 1526:14-24 (TRN – Chait).

791 9 Tr. 1526:25-1527:8 (TRN – Chait).

utility practice *allows* solar contractors to install utility meters, which the Commission would need to verify before approving this option (CALSSA does not believe the utilities allow this practice).

TURN also acknowledged in hearings the shortcomings of the utility installing the meter, stating that the timeline for the utility to install such a meter "can be lengthy,"[792] and that TURN has not completed any estimate of how many people the utility would need to hire to install production meters for every customer who takes service under TURN's tariff and manage the associated coordination.[793] TURN suggests that all of these thorny problems its proposal creates "would just need to be resolved in the Commission's processes."[794] CALSSA urges the Commission not to adopt proposals that, like this one, have failed to provide sufficient detail and clarity as to how they could be implemented in a timely and efficient manner.

The Complexity of TURN's Proposal for Calculating Its Solar Fee is Also Highly Problematic.

When TURN's NUS is based on estimates of self-consumption rather than metering, it would require the IOUs to develop engineering estimates for *each customer* for *all 8,760 hours in the year*, with some to-be-developed degradation rate also applied to that estimate.[795] These estimates are intended to account for all of the unique differences in location, orientation, and "other relevant factors" that each solar installation may warrant.[796] TURN's witness Chait clarified during cross examination that, for customers utilizing the engineering estimate method

792 9 Tr. 1527:16-1528:1 (TRN – Chait).

793 9 Tr. 1528:2-19 (TRN – Chait).

794 9 Tr. 1527:10-12 (TRN – Chait).

795 9 Tr. 1515:25-1517:7 (TRN – Chait).

796 9 Tr. 1514:19-23 (TRN – Chait).

of establishing the NUS, there would be different self-consumption estimates "for all 8,760 hours in the year." [797] She further clarified that the 8,760 different self-consumption estimates would then change annually "to the extent degradation impacted them, and I would expect the degradation rate to be a discount on all of the generation hours." [798] Notably, despite this immensely complicated process to develop engineering estimates for each hour of the year, the TURN proposal does not take have a specific methodology to address shading and potential changes in shading over the system's lifetime. [799] TURN does not include a proposal in its testimony on how a customer or solar company could challenge the accuracy of these estimates.

CALSSA urges the Commission to consider how the significant complexity and volatility of these proposed fees—along with the lack of sufficient detail and clarity provided in many of the associated proposals—will impact customers. The Commission should reject these proposed fees as inconsistent with many of the Commission's rate design principles.

h. Rates With High Fixed Charges and TOU Rate Differentials.

In addition to solar fees, several parties propose that residential solar customers be required to take service under rate designs that include high fixed charges and/or a high TOU rate differential. These additional fixed charges singling out NEM customers would be unjust, unreasonable, and discriminatory, and would undermine the benefits of installing a DER, including energy storage. Similarly, given that the TOU differential is likely to grow wider over time in the default residential rate schedule, proposals to require NEM customers to take service

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[797] 9 Tr. 1518:23-1519:3 (TRN – Chait).

[798] 9 Tr. 1519:27-1520:5 (TRN – Chait).

[799] 9 Tr. 1520:6-13 (TRN – Chait).

under rate designs with a high TOU differential unnecessarily single out NEM customers for disparate treatment.

Rates with High Fixed Charges are Unjust, Unreasonable, and Discriminatory.

The Joint IOUs propose new distributed generation customers take service under two brand new rates for PG&E and SDG&E's service territories,[800] and that SCE NEM customers take service under the TOU-D-PRIME rate.[801] The fixed charges in these rates are summarized in Table 4 of the IOUs' proposal, reproduced in CALSSA's Direct Testimony and below as Table 16.[802] Most residential customers today are on rates without any fixed charges, and none are required to be on the few rate schedules that have fixed charges.

Table 16. Excerpt on Required Fixed Charges from Joint IOU Proposal

Table 4

Illustrative Proposed Residential Default Rate Customer Charges

Utility	Proposed Default Rate	Tariff Currently Effective?	Customer Charge (/month)
PG&E	E-DER	No	$ 20.66
SDG&E	TOU-DER	No	$ 24.10
SCE	TOU-D-PRIME	Yes	$ 12.02

The IOUs justify the requirement to take service under these rates, in part, by arguing that these rates will provide incentives to "shift usage to non-peak hours or exports during peak hours" to "provide the greatest benefit to the grid and support the state's climate goals."[803] While time-of-use energy charges provide some of these signals, the large customer charges embedded

800 Exh. CSA-01 at 107:11-13 (citing Joint IOUs Proposal, p. 10).

801 Exh. CSA-01 at 107:11-13 (citing Joint IOUs Proposal, p. 10).

802 Exh. CSA-01 at 107 (Table 16).

803 Exh. CSA-01 at 108:1-3 (citing Joint IOUs Proposal, p. 10).

in these rates undermine these very goals. High fixed charges discourage load-shifting because they are unavoidable. Customers will be less likely to invest in energy storage to shift load when the value of doing so is muted by a $24 per month fixed charge.

These rate requirements are unjust and unreasonable,[804] and discriminatory under both State[805] and Federal law.[806] Like the Pro-Transmission Parties' proposed solar fees, these proposed rate requirements are not based on any demonstrated cost of service differences between NEM and non-NEM customers.[807] Further, the Joint IOUs are proposing that these requirements only apply to NEM customers, despite the fact that they have not demonstrated that NEM customer load profiles are different from those of customers without onsite generation who reduce their consumption through other means.[808]

The Joint IOUs provide no legitimate explanation for why it is appropriate to charge solar customers these high fixed charges without charging the same to other customers that use the same amount of electricity.[809] The justifications the IOUs provide are not solar-specific, yet the proposed requirements are for NEM customers only. The Joint IOUs attempt to suggest that, because the rates "are based on average residential cost of service,"[810] and "[b]ecause the Joint

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804 Cal. Pub. Util. Code § 451.

805 Cal. Pub. Util. Code § 453(c).

806 18 C.F.R. § 292.305(a).

807 *See* Section III.C.5.a herein, discussing how none of the Pro-Transmission Parties have demonstrated cost of service differences between NEM and non-NEM customers.

808 *See* Section III.C.5.a herein, discussing how the Joint IOUs have not demonstrated that NEM customer load profiles are different from those of customers without onsite generation who reduce their consumption through other means. Note that the Joint IOUs' efforts to distinguish demand patterns of NEM customers relied on minimal and unrepresentative data. *See* Section III.C.5.a (discussing the Joint IOUs' claims in Exh. IOU-02 at 63:10-12).

809 *See* Exh. IOU-01 at 110:10 to 123:1; Exh. IOU-02 at 44:11 to 49:6.

810 Exh. IOU-02 at 46:5-6.

Utilities are proposing their respective default Reform Tariff rates also be *available on an optional basis* to all residential customers, these charges are not discriminatory."[811] However, it is simply illogical to argue that, because a rate with a fixed fee is also *made available* to other customers on an optional basis, imposing a *requirement* that NEM customers take service on this rate is not discriminatory.

As discussed throughout this Section III.C.5, if the Commission is to equitably approach the issue of rate reform to ensure that all customers with varying load profiles pay their full cost of service, it must perform analyses across all relevant customer classes and categories to determine the appropriate rate classes and rate designs to accurately recover utility revenue requirements from all customers, including those that participate in other demand side programs. While such work has not been completed as part of this proceeding, or otherwise, CALSSA anticipates that the Commission may very well approve a fixed charge for all residential customers in the near future, given recent developments in the default TOU proceeding.[812] NEM customers would be included in such a fixed charge. The Commission should wait for the opportunity to equitably approach this rate reform issue, and should reject proposals to impose solar-specific fixed charges as part of this proceeding.

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[811] Exh. IOU-02 at 46:7-9 (emphasis added).

[812] A.17-12-011, consolidated with A.17-12-012 and A.17-12-013. Here, the IOUs proposed fixed charges ranged from $6.37-$10. D.20-03-003 rejected the IOUs' proposals for fixed charges because the proposals lacked sufficient marketing, education, and outreach plans, but did not say small fixed charges on all customers are unjustified. D.20-03-003, p. 21, Finding of Fact 1, and Conclusion of Law 1. The decision "does not prejudice any future applications for default residential fixed charges. The IOUs may, if they wish, file individual applications or a joint application in the future that proposes default fixed charges for residential customers." *Id.*, p. 21. It is CALSSA's expectation that the utilities will soon file applications with residential fixed charges that include customer outreach plans sufficient to satisfy the Commission's rate design principles.

Sierra Club proposes that NEM-3 customers use rates with fixed charges. For PG&E, they propose Schedule E-ELEC, which has been proposed as an optional rate with a $15/month fixed charge in a settlement agreement that is pending in PG&E's current GRC.[813] For SCE, the required rate would be TOU-D-PRIME.[814]

For SDG&E, Sierra Club proposes to require on an interim basis the TOU-DER rate that SDG&E proposes within the instant proceeding, modified to reduce the fixed charge to $14.10/month.[815] The requirement would switch to a new electrification rate that SDG&E has committed to introducing in a forthcoming rate case, with an expectation that "[t]he Commission should ensure this rate falls within the differentials and fixed charges of the electrification-friendly rates adopted by PG&E and SCE to ensure consistent treatment across utilities."[816] Sierra Club has no proposal to waive the requirement if the Commission approves an SDG&E electrification rate that is different from Sierra Club's expectations.

While Sierra Club elsewhere in testimony states that the Commission should only require rates that "have undergone substantial stakeholder input,"[817] here it is recommending that a rate be required before it has been approved or even proposed. If the Commission were to require a rate that is yet to be designed, it would need to set hard boundaries within the NEM-3 decision on the structure of that rate. Without record evidence of the dynamics of SDG&E electrification rate options, establishing a new rate in this proceeding is not possible.

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813 SCL-01 at 23:17-18 and 17 (see bottom row of the second table).

814 SCL-01 at 23:18.

815 SCL-01 at 19:9-12.

816 SCL-01 at 18:12-19:2.

817 SCL-01 at 24:19.

Rates With High TOU Differential are Unnecessary.

NRDC and SEIA/Vote Solar propose that NEM customers be required to take service under specific rate schedules that have a wider differential between peak and off-peak rates than the default TOU rate.[818] These proposals unnecessarily single out NEM customers for disparate treatment. Since the TOU differential is likely to grow wider over time in the default residential rate schedule, it is not necessary to limit NEM customers' rate options in this proceeding.

A transition to a wider TOU differential is likely in light of past Commission guidance on TOU rates, as well as a pending settlement currently before the Commission. In D.15-07-001, the Commission concluded that "[t]he shift toward more fully cost-based price differentials may be made later, informed by data and experience gathered during the course of pilot implementation and ongoing review of the glidepath transition."[819] The decision approved a plan to start with a "TOU Lite" structure with a mild differential between peak and off-peak rates, then moving to rates with larger differentials.[820] In PG&E's current General Rate Case, a proposed settlement agreement on residential rate design proposes to widen the differential in steps throughout the coming years. For the default rate, E-TOU-C, the settling parties agree "to keep the Schedule E-TOU-C peak versus off-peak price (POPP) differentials at their current levels until twelve months after the last cohort of PG&E's customers are migrated to default TOU rates."[821] If the settlement is approved, in each of the following three years the differential

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818 Exh. CSA-01 at 109:14-19.

819 D.15-07-001, p. 136.

820 Exh. CSA-01 at 109:21-22.

821 A.19-11-019, *Motion of Pacific Gas and Electric Company for Adoption of Residential Rate Design Supplemental Settlement Agreement* (March 29, 2021). Settling parties are PG&E, TURN, Cal Advocates, Center for Accessible Technology, Western Manufactured Housing Communities Association, Joint Community Choice Aggregators, NRDC, Sierra Club, SEIA, and CALSSA.

will increase by 2 c/kWh – from 6.3 c/kWh in 2023, to 8.3 c/kWh in 2024, to 10.3 c/kWh in 2025, and to 12.3 c/kWh in 2026.[822] If approved, this proposal will achieve the desire for stronger TOU price signals while allowing NEM customers to continue to take service under the default rate.[823]

Although these parties state that their objective is to require residential rates with high differentials,[824] it could also have the impact of requiring rates with fixed charges. NRDC only proposes that, "Distribution and generation consumption charges should accurately reflect time of use variation in costs to deliver electricity."[825] However, the rates that NRDC instructed E3 to model for its Comparative Analysis all have fixed charges in addition to high differentiation.[826] Requiring these rates under the guise of TOU differentiation would be a backdoor requirement for fixed charges, which would discourage storge adoption. NRDC concludes with the loose statement that "NRDC is open to other TOU rate structures if they better align electric consumption charges with grid needs."[827]

SEIA/Vote Solar would specifically allow rates with high TOU differential that do not have fixed charges, including PG&E's EV-2 rate and SCE's default residential TOU rate.[828] To address the problem of SDG&E not having an electrification rate currently available, SEIA/Vote Solar proposes that two existing rates that are not available to new solar customers be made available. While this is far better than Sierra Club's proposal to require a rate that does not exist,

[822] Exact dates depend on the completion of the migration to residential default TOU rates.

[823] Exh. CSA-01 at 110:3-11.

[824] Exh. NRD-01 at 16:17-18; Exh. SVS-03 at 41:13-19.

[825] Exh. NRD-01 at 16:17-18.

[826] Exh. NRD-01 at 16:20-17:1.

[827] Exh. NRD-01 at 17:1-2.

[828] Exh. SVS-03 at Attachment RTB-2, p. 17, Table 6.

the Commission would need to consider why those rate schedules are currently closed to new solar customers. Such analysis is not on the record of this proceeding.

i. Solar Fees and Rate Requirements, in Combination, are Unprecedented.

Finally, CALSSA urges the Commission to consider the impact that these solar fees and rate requirements would have in combination, as well as the broader national context surrounding these proposals. This context demonstrates just how rare these solar fee and rate requirement proposals are, and how high these proposed fees are as compared to those adopted in other states. While the significant violations of State and Federal law and conflicts with Commission precedent associated with these proposals are of primary importance, and *require* the Commission to reject these proposals, this context illustrates the uniquely damaging impact such fees are likely to have.

As detailed in CALSSA's Direct Testimony, the fixed solar fees the Pro-Transmission Parties have proposed in this proceeding are exceptionally rare and would be the highest, or among the highest, in the country.[829] This is true for the solar fees proposed by Cal Advocates and NRDC, and obviously even more true for the massive fees proposed by the Joint IOUs and TURN. EQ Research provided CALSSA with a listing of instances where IOUs across the country have made proposals to establish additional solar-specific fixed charges, mandatory demand rates, standby charges, or charges based on the size of a DG system.[830] Since November 2012, thirty-one different IOUs have proposed to establish such solar-specific fixed fees.[831] *All but one* of those 31 proposals were withdrawn by the proponent, denied by regulators or

[829] Exh. CSA-01 at 110:12 to 115:1.

[830] *See* Exh. CSA-01 at Attachment 13.

[831] *Id*.

overturned in court on appeal.[832] Not only are fixed solar fees extremely rare—not one state in the country has done what the Joint IOUs ask the Commission to do here: approve them in addition to a rate with high fixed charges. The results of EQ Research's analysis also confirm that the Pro-Transmission Parties' proposed solar fees would increase current unavoidable charges in a range of about 250% and 900%, and would be the highest, or among the highest, in the country.[833]

The Joint IOUs' Rebuttal Testimony attempts to demonstrate that the solar fees the IOUs propose in this case are more commonplace than CALSSA has suggested, citing to *three* investor-owned utilities in South Carolina, New York, and Arizona, and, perhaps most remarkably, a *19,000-customer cooperative in rural Minnesota*.[834] However, Joint IOU witness Tierney's admissions on the stand regarding these other utilities show that only one charge in the country resembles the type of charge the IOUs propose here and, as demonstrated in CALSSA's Direct Testimony, the IOU charge would far surpass anything any other state has adopted.

The first false parallel drawn by the IOUs is to fees in South Carolina.[835] As the IOUs admitted during hearings, very few residential customers will actually pay the fee in South Carolina because it only applies to very large solar PV systems, *i.e.*, those greater than 15 kW (more than twice the size of an average system).[836] Moreover, for those few customers that do pay the fee, it will be miniscule since it only applies to capacity *beyond* 15 kW, such that if a

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832 *Id.*

833 Exh. CSA-01 at 110:12 to 115:1.

834 Exh. IOU-02 at 66:6-67:5; 1 Tr. 110:23-25 (IOU – Tierney).

835 Exh. IOU-01 at 66:9-12.

836 1 Tr. 105:20-106:5 (IOU – Tierney).

customer installed a 17 kW system, the fee would be based only on the 2 kW beyond the 15 kW threshold.[837]

The second false parallel drawn by the IOUs is to fees in New York.[838] As the IOUs admitted during hearings, the New York charge expressly does *not* include any of the distribution and transmission costs the Pro-Transmission Parties seek to recover here,[839] and is limited solely to public purpose costs.[840] Indeed, the New York commission specifically rejected such a proposal.[841]

The third false parallel the IOUs attempt to draw is to fees in Arizona.[842] However, this fee is \$0.93/kW-dc,[843] which is much smaller than the IOUs' proposed fee in this proceeding. Further, when combined with the otherwise small fixed charges customers would pay of about \$12/month,[844] the resulting combined fixed fee of \$18 per month for a 6 kW system is nowhere near the \$36 per month fee proposed by Cal Advocates, much less the \$97 per month fee the Joint IOUs are suggesting for SDG&E's service territory.

Finally, the last false parallel drawn by the IOUs is to a tiny electric cooperative in rural Minnesota. First, the Joint IOUs' Rebuttal Testimony is simply wrong, suggesting that the solar fee could go as high as \$37/month when in fact it can only reach \$22/month.[845] Moreover,

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837 1 Tr. 105:20-106:5; 106:25-107:1 (IOU – Tierney).

838 Exh. IOU-01 at 66:13-15.

839 Exh. CSA-03; 1 Tr. 107:6-109:2 (IOU – Tierney).

840 1 Tr. 10 (IOU – Tierney).

841 1 Tr. 10 (IOU – Tierney).

842 Exh. IOU-01 at 66:16-19.

843 Exh. IOU-01 at Attachment B, p B-10, Table 5, Schedule TOU-E.

844 Exh. IOU-01 at Attachment B at B-9 to B-10, Tables 4 and 5.

845 Exh. CSA-04; 1 Tr. 110:20-111:21.

witness Tierney failed to uncover and mention a 2017 case in Minnesota that disallows cooperatives in Minnesota from charging both a grid access charge and a minimum bill.[846] Lastly, witness Tierney admitted that the IOUs are prevented from assessing these types of charges in Minnesota.[847]

Thus, despite Witness Tierney's assertions in Rebuttal Testimony, her admissions during cross examination show there is no parallel to the fees the IOUs propose here, which are completely unprecedented.

j. Standby Charges

The Joint IOUs propose to assess standby charges on non-NEM customers that "interconnect to the grid under Rule 21 non-export provisions."[848] This would mean standalone storage customers would be subject to massive new fees that have not be examined in this proceeding. The IOUs did not present any data on how high those charges would be, whether all non-NEM customers would pay them, whether non-NEM customers have usage patterns that justify standby charges, and what the impact would be on adoption of standalone storage.

This request to assess standby charges for non-NEM systems should not be approved in the NEM decision because it is not supported by substantial evidence, and it should not even be considered by the Commission for future adoption given the lack of any real justification. It would be a major change that the Commission should not take lightly.

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846 Minnesota Public Utilities Commission, Docket No. 16-512 (*In the Matter of a Commission Investigation into Fees Charged to Qualifying Facilities by Cooperative Electric Associations under the 2015 Amendments to Minn. Stat. § 216B.164, Subd. 3*), Order, December 15, 2017.

847 1 Tr. 112:5-16 (IOU – Tierney).

848 Exh. IOU-01 at 152:15-16.

6. Eligibility Periods

Adopting a successor tariff structure with understandable terms that allow potential NEM customers to assess in advance the $/kWh or $/kW costs and benefits of investing in a DER is critical. Without stable terms and the ability to understand the expected timeline for recouping initial costs, and eventually earning savings from an investment in onsite generation, customers will not have the ability to educate themselves about the terms of their investment, and it is unlikely they will be motivated to invest in onsite generation. Therefore, establishing clear eligibility periods that allow potential customers to assess in advance the expected savings from their investment over a set time-period is essential to ensuring that the tariff promotes consumer protection goals and achieves sustainable growth.

CALSSA's Proposal Continues Established Commission Practices.

The Commission recognized the importance of clear eligibility terms for the NEM tariff in its design of the NEM-1 and NEM-2 tariffs, setting clear 20-year eligibility periods for both of these tariffs.[849] The Commission did so, in part, to "allow customers to have a uniform and reliable expectation of stability of the NEM structure under which they decided to invest in their customer-sited renewable DG systems."[850] The Commission has similarly emphasized the importance of solar installers disclosing to their customers "the terms that will apply to [their] systems for the foreseeable future, including the applicable tariffs as well as the timing and terms for transition to a successor tariff."[851] These kinds of disclosures that allow ratepayers to be

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[849] D.14-03-041, p. 2, Findings of Fact 4-6, and Conclusion of Law 2; D.16-01-044, pp. 100-101 and Conclusion of Law 14.

[850] D.16-01-044, p. 100.

[851] D.14-03-041, Conclusion of Law 7.

educated consumers as they decide whether to invest in onsite generation will only remain possible under a successor tariff structure that has clear terms and set eligibility periods.

Consistent with NEM-1 and NEM-2 treatment, CALSSA has proposed that the Commission adopt a successor tariff structure that allows customers to maintain their eligibility in the NEM structure that was in place at the time of interconnection for 20 years.[852] Many parties to this proceeding advocate for a 20-year or longer term,[853] and others like TURN note for purposes of their analyses that a 20-year term represents a reasonable baseline assumption.[854] Under this structure, customers will have a reasonable expectation of stability, the ability to calculate their expected savings over a set time period that reflects an estimate of system lifetime,[855] and a set eligibility period that exceeds the expected payback periods under CALSSA's proposal.[856] These tariff elements will promote customer understanding and will incentivize investments in onsite generation.

Cal Advocates' and the Joint IOUs' Proposals Significantly Undermine Investment Certainty.

Cal Advocates proposes that the successor tariff have no set term, and that customers should not be guaranteed service on the tariff for any set period of time.[857] With cost recovery

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852 Exh. CSA-01 at 58:17-19.

853 *See* Exh. SVS-03 at 24; Exh. CCS-01 at 20:5-8; Exh. SCL-01 at 3:26 to 4:8; *id.* at 26:32 to 27:1.

854 Exh. TRN-01 at 22:4-5 (while TURN does not seem to otherwise advance a particular proposal on the tariff term, it bases some of its analysis in testimony on a horizon of "20 years to reflect the expected term of the NEM 3.0 tariff.").

855 Exh. CSA-01 at 58:19-21; *see also* D.14-03-041, Finding of Fact 6.

856 *See* Exh. CSA-01 at 72 (Table 8).

857 6 Tr. 923:10-27 (PAO – Gutierrez) (witness Gutierrez offers the caveat that each customer's export rate will be locked in for a four-year period).

periods under Cal Advocates' proposal of 15 years or more,[858] customers will have no assurance that they could stay on the tariff long enough to recover their investments. Not only would the ability to achieve cost recovery be unknown, but *any* estimate of customer savings would be highly uncertain. Witness Gutierrez admitted at hearings that if a solar company were to attempt to advise customers about their long-term savings under the tariff, they would need to either make "some sort of assumption" about the continuation of the successor tariff, or "incorporate some level of uncertainty of savings" into their estimates.[859] Neither of these options would give customers a clear and accurate sense of expected savings over the long-term. Because many systems are financed, "incorporating uncertainty" means raising costs for customers. If lenders are less certain that customers will be have positive investments, they will estimate higher default rates and raise interest rates to compensate. That type of dynamic is not unique to solar; it is a basic principle of commerce.

In addition, this proposal would also significantly undermine rate stability. Under this proposal, customers would have no way to know what the terms of the NEM tariff under which they take service will be over the lifetime of their system,[860] and there would be no mechanism that would operate to prevent rate shock at the point of transition from the successor to future versions of the NEM tariff.[861]

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[858] *See* Exh. CCS-01 at Attachment, E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020*, p. 34 (May 28, 2021) (listing simple paybacks in 2023 for Non-CARE customers between 9 and 16 years for Cal Advocates proposal for standalone solar). *See also* Exh. CSA-02 at 9, Table 1, showing discounted cost recovery periods of 9-18 years under the non-levelized 2021 ACC without any solar fee.

[859] 6 Tr. 925:14 to 926:12 (PAO – Gutierrez).

[860] 6 Tr. 926:23 to 927:2 (PAO – Gutierrez). Witness Gutierrez confirmed that if a solar company were to attempt to accurately explain to a potential customer the terms of this tariff, they would need to convey that there's no assurance of the current terms beyond the four-year locked in export compensation rate. 6 Tr. 927:24 to 930:1 (PAO – Gutierrez).

[861] 6 Tr. 930:2-8 (PAO – Gutierrez).

While Cal Advocates contends, on the one hand, that customer understanding and rate stability are important principles of rate design,[862] it is clear that its proposed tariff does not promote those principles. Even witness Gutierrez himself admitted that a tariff with no set term promotes rate stability less well than a tariff with a set term.[863] In addition to the impacts on customer understanding and rate stability, impacts on sustainable growth of the industry would be significant—customers are highly unlikely to make investments when they do not have any insight into the expected payback of that investment. Witness Gutierrez effectively admits that the State's ability to achieve sustainable growth under this proposal is uncertain, acknowledging that Cal Advocates did not perform any analyses regarding customers' propensity to adopt solar under a tariff with no set term.[864]

All of these same concerns regarding customer understanding, rate stability, and the ability of the industry to grow sustainably apply with equal force to the Joint IOUs' proposal. The Joint IOUs also propose a tariff with no set term, providing that "[t]he term of the new successor tariff will remain open-ended, and its rates and rate design will be subject to periodic changes."[865] With estimated simple cost recovery periods in the range of 30 years for the IOU proposals, cost recovery simply would not happen.[866] But even under more reasonable proposals cost recovery periods become essentially meaningless, from a customer's prospective, if the customer has no assurance that they can expect to actually *achieve* cost recovery by continuing to take service on the tariff for a set period of time that exceeds the length of the estimated cost

862 6 Tr. 930:25 to 931:1 (PAO – Gutierrez).

863 6 Tr. 933:16-22 (PAO – Gutierrez).

864 6 Tr. 935:5-10 (PAO – Gutierrez).

865 Joint IOUs Proposal, p. 9.

866 Exh. CSA-02 at 4:19-5:7.

recovery period. The Commission should reject these proposals that would leave NEM customers in the dark about the terms of their investment, thereby significantly disincentivizing such investment.

7. Instantaneous Netting

The Joint IOUs and Cal Advocates propose changing to instantaneous netting.[867] This would lead to consumer protection problems since any benefits of more precise measurement of exported energy versus self-consumed energy would be small in comparison to the reduced accuracy of solar savings estimates that would result from the proposal.

Residential customers have hourly billing intervals, and solar generation calculators such as PV Watts produce hourly data.[868] Comparing expected hourly production to historic hourly consumption produces an estimate of customer bill savings from installing solar that is straightforward and simple. This is fundamental to customer and contractor interactions.[869]

The Commission issued D.20-08-001 to establish rules for contractors to provide consumers with accurate solar savings estimates. The decision adopted the staff proposal, which states: "To calculate the consumer's estimated annual electricity consumption for all years of the cost estimate calculation, assume that the consumption patterns during the previous 12 months before installing solar will be the same as the consumption patterns for each 12 months following interconnection. Use the consumer's ***one-hour interval electric consumption data*** from the consumer's past 12 months of data (e.g., Green Button Data) for this calculation."[870]

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[867] Exh. IOU-01 at 130:16-19; Exh. PAO-01 at 3-5:25 to 3-26:5.

[868] Exh. CSA-01 at 115:6-8.

[869] Exh. CSA-01 at 115:8-9.

[870] D.20-08-001, Attachment A, p. 7 (emphasis added).

Customers and contractors do not have reasonable access to instantaneous billing data.[871] If NEM billing were calculated with instantaneous netting but data were only reasonably available on an interval basis, it would be impossible to provide consumers with an accurate solar savings estimate.[872] Even if the data were made available, it would not align with the PV Watts solar generation projection that D.20-08-001 also requires contractors to use.[873]

The Joint IOUs claimed in rebuttal testimony that PG&E has recently made instantaneous data available and SCE would soon do the same. However, that data is available only through the "Share My Data" portal.[874] That portal is maintained for demand response providers and has very high technical requirements designed for ongoing access to customer data, including construction of an Application Programming Interface linking a vendor's computer with the utility's database.[875] It is not designed for contractors to do a one-time download of static usage data, and the technical specifications are far beyond what should be expected of a solar installer.[876]

A utility proposal for instantaneous netting in Connecticut was recently rejected by that state's utilities commission. The decision stated, "the Authority finds that an instantaneous netting tariff currently presents a significant barrier to the deployment of behind-the-meter solar PV systems for residential customers ... the netting interval should not only seek to minimize costly changes to the EDCs' billing systems and metering infrastructure, but should also be easy

[871] Exh. CSA-01 at 116:3.

[872] Exh. CSA-01 at 116:3-5.

[873] Exh. CSA-01 at 116:5-7.

[874] Exh. IOU-02 at 54:6-9.

[875] Exh. CSA-01 at 57:8-15.

[876] Exh. CSA-01 at 57:8-15.

for customers to understand and provide customers with the ability to reasonably estimate the economics of their solar PV system before purchase or signing a lease. Indeed, a netting interval that is not compatible with estimating system economics and individual customer benefits would likely impede, if not entirely prohibit, robust customer participation."[877] Here, the Joint IOUs' and Cal Advocates' instantaneous netting proposal would similarly fail to provide customers with the ability to reasonably estimate the economics of their solar PV system before purchase or signing a lease, impeding, if not entirely prohibiting, robust customer participation.

8. Monthly True-up Cycle

Currently, if a customer generates more electricity than they use in the course of a month, they are able to carry forward excess credits to following months within an annual true-up cycle. This is a core concept of net metering. It is necessary because solar conditions have a natural annual cycle. There are more daylight hours in the summer than the winter, and the sun is higher in the sky.[878] Depending on the orientation of the panels and shading conditions, a typical solar system will generate 2-3 times as much electricity in the summer than the winter in a predictable pattern, as can be seen in Figure 24 from CALSSA's Direct Testimony.[879]

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[877] Exh. CSA-01 at 117:1-17, referencing Docket No. 20-07-01, Connecticut Public Utility Regulatory Authority, *PURA Implementation of Section 3 of P.A. 19-35, Renewable Energy Tariffs and Procurement Plans*, 2021 Conn. PUC LEXIS 43, **26-27 (January 20, 2021).

[878] Exh. CSA-01 at 117:19-25.

[879] Exh. CSA-01 at 119, Fig. 24 (stating in n. 221 that "Data from the Enphase monitoring platform for a 3 kW system. Note that this profile is different from that of most large-scale solar farms, which tend to have higher DC-to-AC ratios and use trackers to follow the angle of the sun. This creates a flatter profile, but also leads to springtime overgeneration when production is high but large air conditioning load has not begun.")

Figure 24. System Monitoring Report from a Typical Residential Solar System[221]

The Joint IOUs propose to change to a monthly true-up cycle. [880] In such a system, if there is more generation than consumption in a month, the utility would pay the difference in net surplus compensation rather than carrying NEM credits to the following month. [881]

This is distinct from CALSSA's proposal for default monthly payments in the following section. In that proposal, if a customer owes money at the end of a month, they pay the amount owed. It does not change the current practice that if they have credits they can carry them forward.[882] The IOU monthly true-up proposal does not speak to whether customers pay if they have an amount owed at the end of a month, but is says if they have credits they cannot carry them forward.

In general, agricultural customers and schools would be hurt the most by monthly true-ups because their load is seasonal. Most agricultural meters are either irrigation wells or processing plants. Irrigation is not needed throughout the year due to changing crop needs and

880 Exh. IOU-01 at 134:14-15.

881 Exh. IOU-01 at 135:5-6.

882 Exh. CSA-01 at 55:6-56:24.

weather, and processing plants only operate following the harvest.[883] Figures 12 and 13 from CALSSA's Rebuttal Testimony depict typical solar production and energy usage for a deep irrigation well and an almond huller.[884]

Figure 12. Energy Use and Solar Production for a Deep Irrigation Well

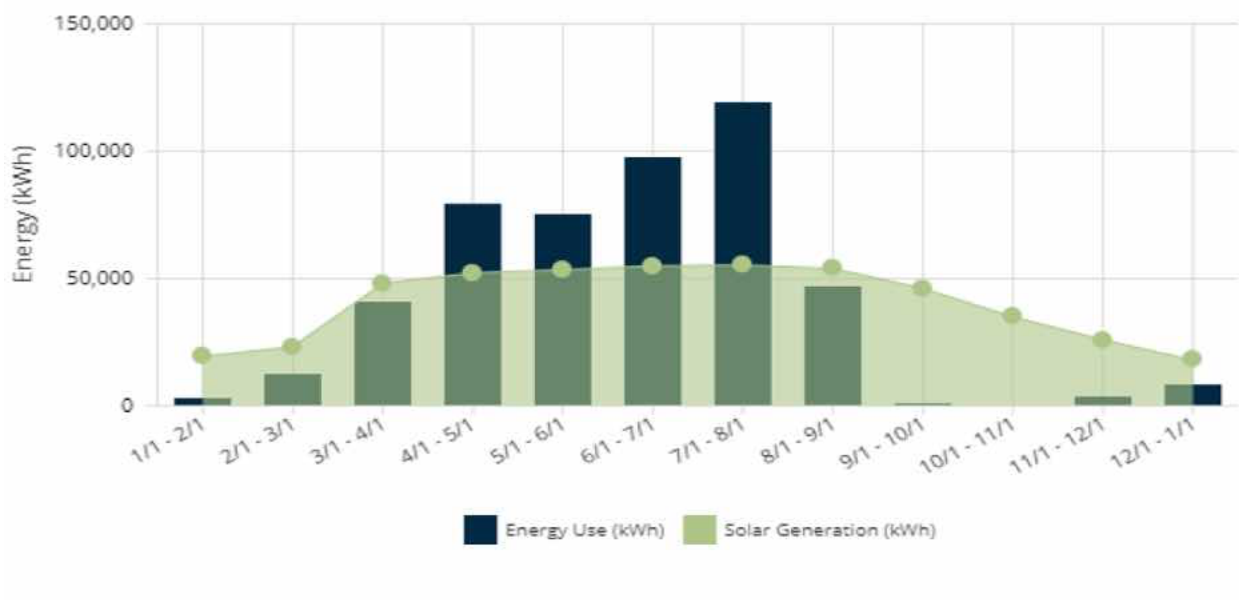
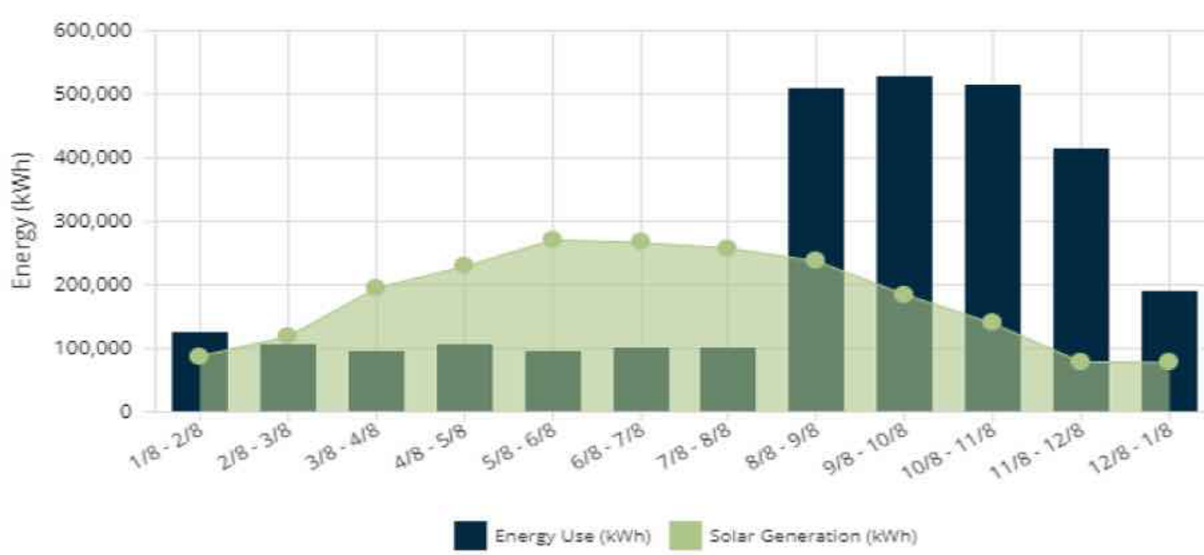


Figure 13. Energy Use and Solar Production for an Almond Huller



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883 Exh. CSA-02 at 50:4-7.

884 Exh. CSA-02 at 51-52, Figures 12 and 13.

Energy cost stabilization for farmers through self-generation has been a great benefit to the farming economy. Farming revenue is turbulent due to changes in farm output that are often beyond the control of the farmer, and volatile energy costs can therefore be especially painful. High energy costs during a low yield year can put severe strain on a farm's balance sheet. Stabilizing energy costs can help farmers ride through low and high yield years.[885] Continuing to give agricultural customers a realistic opportunity to invest in self-generation is important for rural California. [886]

The Joint IOUs additionally propose that true-ups happen within each TOU period. [887] This is a major change from current rules. Currently, if a customer has excess credits in the off-peak period and net consumption during the peak period, the credits are valued at the off-peak rate and the net consumption is valued at the peak rate, but they are netted in combination. [888]

The result of the IOU proposal would be that most mid-day NEM credits would not actually be at the time-of-export (TOE) values shown in testimony,[889] but rather at the net surplus compensation rate. In the sample table in Figure 25 from CALSSA's Direct Testimony,[890] taken from an actual PG&E bill, the 447 kWh of net exports during the peak period would be compensated at wholesale rates rather than valued at the TOE rate and netted against consumption in other TOU periods in the same month. The customer has net

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885 Exh. CSA-02 at 51:8-14.

886 Exh. CSA-01 at 51:8-14.

887 Exh. IOU-01 at 135:3-9.

888 Exh. CSA-01 at 118:12-119:1.

889 Exh. IOU-01 at 124-125, Tables IV-21, IV-22, and IV-23.

890 Exh. CSA-01 at 120, Fig. 25.

consumption in all months but still has exports valued outside of net billing. This scheme is closer to a buy-all/sell-all structure than net billing.[891]

Figure 25. NEM Charges Table from Sample PG&E Annual True-Up Statement

Bill Period End Date	Net Peak Usage (kWh)	Net Part Peak Usage (kWh)	Net Off Peak Usage (kWh)	Net Usage (kWh)	Estimated NEM Charges Before Taxes	Estimated NEM Charges After Taxes
03/03/2020	0	70	180	249	$32.52	$34.32
04/01/2020	0	58	152	211	27.33	28.84
05/03/2020	-3	32	106	136	17.96	18.95
06/02/2020	-64	15	200	151	22.06	23.25
07/01/2020	-94	-4	187	89	11.59	12.23
07/30/2020	-114	-13	183	56	5.88	6.21
08/31/2020	-83	22	278	217	31.93	33.67
09/30/2020	-43	49	241	247	38.13	40.20
11/01/2020	-46	33	193	180	27.49	28.97
12/02/2020	0	66	246	312	45.04	47.49
01/03/2021	0	74	338	412	66.64	70.22
02/01/2021	0	56	261	317	53.85	56.70
TOTAL	-447	458	2565	2577	$380.42	$401.05

The IOUs' justification for their proposal implies that a kWh credit in off-peak hours in March and April is treated equally with kWh consumption in a peak hour in the summer. [892] That is not true. Each is valued according to the rate in that hour. The Joint IOUs state that "the marginal emissions intensity of this kWh exchange is not 1-for-1" if credits are generated at one time to offset consumption at another time.[893] This implies that NEM credits are a 1-for-1 exchange in kWh. They are not. Monthly net generation during mid-day hours in the spring are valued at winter off-peak rates. Export credits during off-peak hours are lower value than the rates for on-peak energy consumed from the grid.[894]

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891 Exh. CSA-01 at 119:8-10.

892 Exh. IOU-01 at 134:23-135:2.

893 Exh. IOU-01 at 132:7.

894 Exh. CSA-01 at 51:5-7.

9. CALSSA's Tariff Feasibility Proposal

Currently, most residential NEM customers pay energy charges once per year at the end of the annual true-up period.[895] They pay a minimum bill each month. At the end of the year if they owe more than the cumulative minimum bill payments, they must pay that amount all at once. For customers with solar systems that offset much less than their total annual electricity usage, this can result in a very large bill that is sometimes unexpected.[896]

CALSSA recommends that the default billing mechanism be changed so that customers pay the full amount they owe each month. This is currently an option for NEM customers, but it is not the default and it is seldom used. Nine percent of SCE NEM customers use monthly payments and 2% of PG&E's NEM customers.[897]

To avoid the conditions in which customers have an amount they owe in the early months of the true-up cycle that is refunded at the end of each year or carried forward each year, CALSSA recommends that all true-up cycles for NEM-3 customers begin in the April billing month. Under this proposal, customers installing solar in any month other than April will have a partial year in their first true-up cycle. This may result in an amount owed in the partial year that is proportionally higher than the amount these customers will owe in future years, and these customers would never recover that amount. However, it will be easy to explain to customers that the first cycle is a partial year and the following cycles can be expected to perform in alignment with projections of annual savings.[898]

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[895] Exh. IOU-01 at 134:23-135:2.

[896] Exh. CSA-01 at 55:6-10.

[897] Exh. CSA-01 at 56:9-12.

[898] Exh. CSA-01 at 56:13-22.

10. Improving the Quality of Savings Estimates

In order to provide accurate savings estimates to customers, it is essential that DER providers have access to customer electricity consumption data for all billing intervals in a year (interval data). D.20-08-001 requires that all proposals for solar installations include savings estimates that use interval data.[899] However, that data can be difficult to obtain.

For customers that do not have enough computer skills to log onto their utility account, download the Green Button data, save it, and e-mail it to the contractor, the only viable and no-cost approach to obtaining the data needed to assist customers is to obtain a written authorization from the customer, request the data from the utility by email, and wait up to four weeks for the data.[900] This approach is not reasonable customer service.

CALSSA recommends that the utilities construct a portal to enable approved solar providers to upload a customer authorization form and download a file with customer interval data. Such access will reduce reliance on estimates that can be inaccurate and allow for timely customer service and better projections of savings data to be communicated to customers.[901]

The Joint IOUs responded in rebuttal testimony that the current process is the best they can do, stating that "a data portal would still require manual review" of the customer authorization form and that a portal "would offer no difference in timing" compared to processing requests via email.[902] To the extent the Commission agrees that manual review of each customer authorization form is necessary, even for contractors with proven track records, it is surely more efficient for utility personnel to verify a form within a portal step than to process

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899 D.20-08-001 at 19-21.

900 Exh. CSA-01 at 6-23.

901 Exh. CSA-01 at 57:25-58:2.

902 Exh. IOU-02 at 103:4-6.

the transaction via email and do the additional work of downloading and sending a data set. This is a high-volume activity that the utilities are handling in a low volume way. The Commission should order the utilities to improve this very important part of the solar contracting process.

11. TURN's Dispatch Requirements

TURN's dispatch requirements for solar-paired resources undermine the purpose of storage investments, endanger vulnerable customers, and cannot currently be implemented. TURN proposes "requiring any paired storage unit participating in the successor tariff to discharge during certain extreme system stress and emergency conditions in support of overall grid needs." [903] This requirement is unreasonable. Giving dispatch privileges to the utilities would discourage participation.[904] Customers are less likely to adopt storage if they are unable to control their resource and that control is instead in the hands of the utility.[905] A better program design would use price signals to influence behavior for the benefit of the grid. [906]

Giving the utilities dispatch privileges will mean that battery capacity could be partially or fully depleted before an outage or system emergency, during which customers like senior citizens and those with medical- or disability-related needs would be most vulnerable. [907] Such customers need sufficient battery capacity to allow critical medical equipment and other equipment reliant on electricity to continue operating throughout outages.[908] Failing to allow all

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[903] Exh. TRN-01 at 57:5-6.

[904] Exh. CSA-02 at 32:1-34:4 (discussing the Joint IOUs' STORE proposal, which includes a similar dispatch requirement).

[905] Exh. CSA-02 at 32:1-34:4.

[906] Exh. CSA-02 at 32:1-34:4.

[907] Exh. CSA-02 at 63:24-65:2.

[908] Exh. CSA-02 at 63:24-65:2 (citing See CPUC, Medical Baseline, https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/medical-baseline;

of a battery's capacity to meet these needs would not provide the support these customers need.[909]

When confronted with this issue in hearing, TURN's witness proposed an opt-out be created for medical baseline and some yet-to-be-defined group of customers.[910] However, Witness Chait also acknowledged the fact that "[i]n other jurisdictions, utilities are providing either incentives or DR-type payments to customers that have storage. And the amount that the utility can discharge is related to the size of the payment."[911] She further acknowledged that an opt-in scheme like this one "could" better protect customers that require batteries at full capacity during blackouts from the problem of accidental discharge than the opt-out scheme that TURN proposes.[912]

Last, TURN admitted it did not do all of its homework when proposing this requirement. Witness Chait was unaware if TURN had even asked the utilities if they are technically capable of implementing a remote dispatch requirement.[913] She also was unaware of testimony in a utility rate case stating the time is not yet ripe for programs that require remote dispatch.[914] While that testimony is not on the record in this proceeding, the dispatch requirement in the IOUs' STORE proposal in direct testimony in this case is telling. There, the Joint IOUs propose

Ready Nevada County, Public Safety Power Shutoffs, https://www.mynevadacounty.com/2878/Public-Safety-Power-Shutoffs-PSPS).

909 Exh. CSA-02 at 63:24-65:2.

910 9 Tr. 1534:5-1535:20 (TRN – Chait).

911 9 Tr. 1534:5-1535:20 (TRN – Chait).

912 9 Tr. 1535:10-20 (TRN – Chait).

913 9 Tr. 1535:21-1536:4 (TRN – Chait).

914 9 Tr. 1535:21-1536:4 (TRN – Chait).

that the dispatch program and other details be developed in the future, through a stakeholder process.[915]

If customers choose to participate in demand response or emergency reliability programs, their performance during grid events should be mandatory as required by the programs, but participation in those programs is voluntary. [916] If customers were required to participate in emergency reliability programs as a condition of taking service under NEM, it would discourage storage under net metering and thus undermine the benefits of having energy storage systems doing daily load shifting to shape state load during normal conditions. [917]

CALSSA is strongly in support of modifying demand response and emergency reliability programs to make better use of customer-sited resources. [918] However, doing that work within NEM policy is not a realistic administrative objective.[919]

12. Interconnection and Communications Requirements

The Joint IOUs propose that "interconnecting under the proposed default tariff would require certain communications and cyber security capabilities, for both PV solar and energy storage systems."[920] These requirements are under active consideration in other proceedings and should not be relitigated here. Cybersecurity policy is under development in the Smart Inverter Working Group, which reports to R.17-07-007 and has met nine times on the issue since June 2020.[921] The IOUs are planning to finalize a guidebook before the end of the year. Two

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915 Exh. IOU-01 at 165:3-6.

916 Exh. CSA-02 at 63:24-65:2.

917 Exh. CSA-02 at 63:24-65:2.

918 Exh. CSA-02 at 63:24-65:2.

919 Exh. CSA-02 at 63:24-65:2.

920 Exh. IOU-01 at 160:10-11.

921 Exh. CSA-02 at 65:6-10.

paragraphs in a NEM proposal should not circumvent the conclusions of a lengthy process on a highly technical and consequential subject.

The Joint IOU testimony also states, “The default IEEE 2030.5/CSIP requires information sharing at no additional cost[.]”[922] That is not true. IEEE 2030.5, and CPUC Resolution E-5000 that implements it for the California IOUs, require that DERs use equipment with a proven *capability* for communication, not that they actively share information. It is the customer’s obligation to pay for any interface that may be required but not for delivery of information.[923] Any California requirements to maintain active information sharing as a condition of interconnection would need to be considered carefully, and the Rule 21 or Grid Modernization proceedings are better venues for that debate than the NEM proceeding.

The Joint IOUs estimated the costs of some of these requirements to be $200 upfront and $150 per year, and for some of the requirements they had no estimate of the associated costs.[924] These costs were not included in modeling of cost recovery periods.[925] These costs need to be more carefully documented and studied before new requirements are approved.

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

1. Analysis of Legal Requirements and Guiding Principles

The Commission should adopt CALSSA’s successor tariff proposal, as it is consistent with each of the guiding principles established in D.21-02-007.[926] While many party proposals

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922 Exh. IOU-01 at 161:24.

923 Exh. CSA-02 at 65:13-19.

924 Exh. CSA-01 at 75-76, Table 11.

925 Exh. CSA-01 at 75:4-6.

926 D.21-02-007, Ordering Paragraph 1.

fail entirely to meet Public Utilities Code Section 2827.1's foundational requirement that the successor ensure sustainable growth, CALSSA's proposed successor tariff will achieve this mandate, while also effectively balancing other important directives from the Legislature and the Commission.

a. Guiding Principle (a).

Guiding principle (a) provides that "[a] successor to the net energy metering tariff should comply with the statutory requirements of Public Utilities Code Section 2827.1."[927] CALSSA's proposal is consistent with each of the relevant statutory criteria.

Sustainable Growth

First, CALSSA's proposed tariff will "ensure[] that customer-sited renewable distributed generation continues to grow sustainably."[928] As discussed in Section II.A, the plain meaning of the term "grow sustainably" and AB 327's legislative history, historical context, and statutory context confirm that this language refers to *sustained industry growth*—the tariff must ensure the continued growth of customer-sited distributed generation in the State.

CALSSA's proposal will ensure sustained growth of distributed generation through a tariff designed to achieve cost recovery periods for solar that customers find acceptable.[929] While cost recovery periods are generally longer than customers find acceptable on a purely economic basis for storage, they will improve if incentives are renewed, customers place value on the co-benefit of resilience, and/or if additional revenue sources are developed. CALSSA's proposed glidepath for export compensation, which will step export rates down based on the

927 D.21-02-007, Ordering Paragraph 1(a).

928 Cal. Pub. Util. Code § 2827.1(b)(1).

929 *See* Section III.B.1.

achievement of adoption targets, will ensure that changes are introduced at a pace the market can bear.[930]

The Commission should not adopt party proposals that clearly fail to prioritize this statutory objective. Notably, the following proposal elements would significantly diminish—or eliminate—distributed generation growth in the State:

- The Pro-Transmission Parties do not include any glidepath to their new, ACC-based export compensation values.[931] Dramatic reductions to export compensation from current export values—ranging from 68%-84% using non-levelized values from the 2021 ACC—would hit the market all at once.[932]
- To determine export compensation rates, the Pro-Transmission Parties essentially propose to use unlevelized, one-year avoided cost values, which would leave customers with excessive uncertainty about whether their investments will be worthwhile.[933]
- The Pro-Transmission Parties' proposed solar fees—which single out NEM customers for high fees based on their levels of self-consumption while customers who reduce their load through other means pay no such charges—would specifically disincentivize self-generation as compared to other forms of load management.[934] Adding the requirement that NEM customers take service under rate designs that include high fixed charges and/or a high TOU rate differential would further disincentivize self-generation.[935]

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930 *See* Section III.C.2.

931 *See* Section III.C.4.

932 Exh. CSA-02 at 47:10-15.

933 *See* Section III.C.2.b.

934 *See* Section III.C.5.

935 *See* Section III.C.5.

- Cal Advocates' and the Joint IOUs' proposals to establish a tariff with no set eligibility term would leave customers in the dark about the terms of their investment and their estimated savings, and thus would strongly deter customer investment.[936]
- The Joint IOUs and Cal Advocates' proposals to change to a system of instantaneous netting would prevent accurate solar savings estimates, chilling customer investment.[937]
- TURN's dispatch requirements for storage-paired resources would discourage storage investment.[938]

The Pro-Transmission Parties' payback period results—as presented in these parties' *own analyses*, the analyses conducted by E3, and in data presented by CALSSA—demonstrate that these proposals would significantly diminish the number of customers willing to invest in solar.[939] The Commission should not adopt proposals that, by all analyses in the record, would fail to ensure continued sustainable growth of customer-sited distributed generation.

Growth Among Residential Customers in Disadvantaged Communities

Second, CALSSA's proposal "include[s] specific alternatives designed for growth among residential customers in disadvantaged communities[,]" both for single-family and multifamily residential customers.[940] CALSSA proposes to (1) allow low-income customers in single-family homes to be eligible for a tariff that is equivalent to NEM-2, (2) credit exports from CARE and FERA NEM customers at the undiscounted otherwise applicable retail rate minus NBCs, (3) allow apartment buildings in low- and moderate-income census tracts and properties that would

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936 *See* Section III.C.6.

937 *See* Section III.C.7.

938 *See* Section III.C.11.

939 *See* Section III.B.1.b.

940 Cal. Pub. Util. Code § 2827.1(b)(1).

be eligible for the MASH and SOMAH programs to be eligible for a virtual net metering tariff that is equivalent to the structure under NEM-2, and (4) extend eligibility for the NEM-2 structure of export credits to community-owned solar projects.[941] These simple and relatively easy-to-implement proposals would maintain policies that encourage solar adoption among low-income customers and in lower-income census tracts, foster greater participation by customers taking service under the CARE and FERA programs, and address obstacles that have hindered solar growth for renters.

In contrast, the Pro-Transmission Parties' proposals would diminish low-income customers' access to distributed generation in a variety of ways:

- Low-income solar adopters and those who live in DACs would immediately be subject to greatly reduced export compensation and—for some or all low-income customers—new monthly fees as well.[942] The Joint IOUs', NRDC's, and Cal Advocates' fee exemptions and modifications would fail to protect many lower-income customers from the added burdens of the new fees.
- By eroding solar incentive project economics, the Pro-Transmission Parties' proposals would significantly harm the DAC-SASH and SOMAH programs. These programs rely on cost savings created through the NEM and VNEM tariffs, and potential customers will not be motivated to adopt solar without sufficient bill savings.[943]
- Proposals to limit subsidies and fee exemptions to only a subset of low-income customers would run counter to the Commission's equity goals and the goal of expanding access.[944]

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941 *See* Section III.C.1.

942 *See* Section III.C.1.c.

943 *See* Section III.C.1.d.

944 *See* Section III.C.1.e.

Tariff Based on Costs and Benefits of Renewable Electrical Generation Facility

Third, CALSSA's proposal ensures that the tariff "is based on the costs and benefits of the renewable electrical generation facility."[945] CALSSA modeled costs and benefits of systems in its payback period analyses, targeting payback periods that customers will find acceptable and that therefore will allow for sustainable growth. CALSSA's assumptions regarding system costs in its payback period analyses reflect best estimates of real-world pricing.[946] Certain parties' assumptions regarding the costs of distributed generation are highly inaccurate, such that their proposals fail to adhere to this statutory directive:

- The Joint IOUs, NRDC, TURN, and E3 use a theoretical cost of residential solar in their payback period modeling that does not reflect real-world pricing.[947]
- E3 and other parties to this proceeding are underestimating the costs of installing solar on commercial systems in their payback period modeling.[948]
- Cal Advocates uses theoretical solar price data in its dGen modeling that does not reflect real-world pricing.[949]

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945 Cal. Pub. Util. Code § 2827.1(b)(3).

946 Exh. CSA-01 at 63:7 to 71:3.

947 *See* Section III.B.1.c.

948 *See* Section III.B.1.c.

949 *See* Section III.B.1.d.

Approximately Equal Total Benefits and Costs

Finally, CALSSA's proposal ensures "that the total benefits of the . . . tariff to all customers and the electrical system are approximately equal to the total costs."[950] As discussed in Section II.A, this provision requires the total benefits and the total costs of the tariff to be reasonably balanced, although not necessarily exactly equal. In line with this directive, CALSSA's proposal achieves TRC and RIM values near or above 1.0.[951]

b. Guiding Principle (b).

Guiding principle (b) provides that "[a] successor to the net energy metering tariff should ensure equity among customers."[952] This principle's focus on equity should be understood in the context of Public Utilities Code Section 2827.1's equity mandate that the net metering tariff should ensure growth of distributed generation "among residential customers in disadvantaged communities."[953] In light of this statutory context and the Legislature's focus on expanding access, the equity goals embraced within guiding principle (b) should center on specifically prioritizing expanding access to distributed generation among disadvantaged communities[954] and low-income customers. True equity will be realized when all low-income and disadvantaged communities have demographically proportionate access to solar. Accomplishing that equity goal calls for making it easier for those with limited financial resources to go solar and overcome barriers to adoption.

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950 Cal. Pub. Util. Code § 2827.1(b)(4).

951 *See* Section III.B.2.b.

952 D.21-02-007, Ordering Paragraph 1(b).

953 Cal. Pub. Util. Code § 2827.1(b)(1).

954 "Disadvantaged communities include communities scoring in the top 25% of census tracts according to CalEnviroscreen, including those scoring in the top 5% for pollution burden without an overall score. They may also include tribal lands, low-income households, and low-income census tracts." Exh. PAO-03 at 1-3 n. 27.

Equity will not be achieved by constricting access to customer-sited renewable generation and leaving all lower-income customers and residents of underserved communities equally unable to participate in the clean energy transition. The Commission should also reject rhetoric that seeks to frame equity in terms of equal treatment between NEM participants and non-participants where the result is this form of false equity.[955] Proposals that reduce bill savings for low-income customers and residents of disadvantaged communities, thereby making it more difficult for them to adopt solar, should also be rejected.[956]

CALSSA's proposal will ensure equity among customers by offering targeted and easy-to-implement policies to accelerate DER adoption among low- and moderate-income customers. CALSSA's policy proposals for residential customers with income below 80% of AMI, customers on CARE and FERA rates, and customers residing in multifamily rental properties in low- and moderate-income locations are designed to increase access to DERs across a broad spectrum of low- and moderate-income customers with varying access barriers.[957] In addition, CALSSA proposes a community-owned solar policy under which solar projects and hybrid solar and storage projects that are community owned and controlled would receive NEM credits at full retail rates, minus non-bypassable charges, as under the NEM-2 tariff.[958] Accelerating adoption among these customer groups and through these different avenues is vital to both the State's

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955 *See* Exh. TRN-01 at 36:1-18; Exh. NRD-01 at 10:26-27.

956 *See* Exh. CSA-01 at 32:14 to 37:6; Exh. CSA-02 at 18:21 to 20:2, 20:11 to 21:11, 26:2 to 28:20; Exh. GRD-02 at 13:14 to 15:22.

957 *See* Section III.C.1. CALSSA proposes to (1) allow low-income customers in single-family homes to be eligible for a tariff that is equivalent to NEM-2, (2) credit exports from CARE and FERA NEM customers at the undiscounted otherwise applicable retail rate minus NBCs, and (3) allow apartment buildings in low- and moderate-income census tracts and properties that would be eligible for the MASH and SOMAH programs to be eligible for a virtual net metering tariff that is equivalent to the structure under NEM-2.

958 *See* Section III.C.1.

clean energy goals and to ensuring that the successor tariff structure equitably serves all California residents.

Rather than "ensur[ing] equity among customers[,]"[959] the Pro-Transmission Parties' proposals would actively undermine equity goals, as discussed at length in Section III.C.1 and summarized above in Section III.D.1.a.

Finally, while CALSSA urges the Commission to interpret guiding principle (b) consistent with the Legislature's focus on expanding access for low-income customers, CALSSA recognizes that equity goals can also be understood to refer to cost-effectiveness objectives. CALSSA's proposed step down of the export credit value for NEM for general market residential customers is designed to achieve cost-effectiveness from the perspective of both the TRC and the RIM test.[960] The proposal achieves cost-effectiveness according to the TRC, the test mandated as the primary cost-effectiveness test in this proceeding,[961] and the step-down structure increasingly improves the proposal's performance on RIM, which measures impacts to nonparticipating customers.[962]

c. Guiding Principle (c).

Guiding principle (c) provides that "[a] successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services."[963]

959 D.21-02-007, Ordering Paragraph 1(b).

960 *See* Section III.B.2.

961 D.21-02-007, pp. 35-36 and Finding of Fact 4.

962 Exh. CSA-01 at 127 n. 260.

963 D.21-02-007, Ordering Paragraph 1(c).

In Sections III.C.9 and III.C.10, CALSSA details proposed reforms regarding monthly billing and data access that will greatly improve customer experience with the NEM tariff and reduce the risk of regulatory uncertainty for these customers. These two measures, taken together, will significantly enhance consumer protection for NEM participants.

In addition, CALSSA's proposal to set an eligibility period of 20 years—meaning any customer that installs solar during a particular step will maintain that step for 20 years—will allow customers to have a reasonable expectation of stability, as well as the ability to calculate their expected savings over a set time period that reflects an estimate of system lifetime.[964] Without a set eligibility provision, customer understanding of the financial consequences of investing in solar would be low, and NEM customers would be subject to the rate volatility likely to result from frequent changes to the tariff.

CALSSA also strongly supports the Commission's existing precedent protecting NEM-1 and NEM-2 customers from changes to their tariffs that would undermine existing export compensation mechanisms set for 20 years.[965] Modifying eligibility terms retroactively would not only harm existing NEM customers—including lower income customers—and undermine the terms of their investments that the Commission had previously determined were set, but it would also cast doubt on the stability of the NEM program going forward.

The Pro-Transmission Parties' proposals would undermine the Commission's consumer protection goals in myriad ways:

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[964] *See* Section III.C.6.

[965] *See* Section IV. *See also* D.14-03-041, p. 2; D.16-01-044, pp. 100-101.

- The Pro-Transmission Parties' proposed solar fees are incredibly complex, difficult to understand, and likely to be volatile.[966]
- Cal Advocates' and the Joint IOUs' proposals to establish a tariff with no set eligibility term would mean that customers would have no way to reasonably educate themselves about the financial consequences of investing in solar. NEM customers would be subject to changes to the terms of their investment at any time, and the resulting rate volatility from those changes.[967]
- The Pro-Transmission Parties propose retroactive changes that would undermine customers' existing investments, including the investments of vulnerable customer populations.[968]
- The proposal from Cal Advocates and the Joint IOUs for instantaneous netting would make it difficult for contractors to provide accurate solar savings estimates to customers.[969]

d. Guiding Principle (d).

Guiding principle (d) provides "[a] successor to the net energy metering tariff should fairly consider all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1."[970] CALSSA's proposed tariff is consistent with this guiding principle, as all eligible technologies can participate in CALSSA's proposed tariff.[971]

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966 *See* Section III.C.5.f and Section III.C.5.g.

967 *See* Section III.C.6.

968 *See* Section IV.

969 *See* Section III.C.7.

970 D.21-02-007, Ordering Paragraph 1(d).

971 *See* Cal. Pub. Util. Code § 2827.1(a).

e. Guiding Principle (e).

Guiding principle (e) provides "[a] successor to the net energy metering tariff should be coordinated with the Commission and California's energy policies, including but not limited to, Senate Bill 100 (2018, DeLeon), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18."[972]

CALSSA's proposal is consistent with these State energy policies. The proposal is designed to achieve the pace of customer solar adoption that has been relied on in modeling by the Commission, the CEC, and the California Air Resources Board to determine how to meet SB 100 commitments.[973] The State will not be able to achieve its ambitious greenhouse gas goals without a strong solar market with the ability to facilitate the transition to widespread customer-sited energy storage. In the context of the level of interplay between these two technologies, and because meeting the State's greenhouse gas reduction goals through utility-scale renewables alone is not feasible, CALSSA's proposal prioritizes a step-down structure that will avoid major market disruption.

In addition, the CEC's Building Energy Efficiency Standards require solar on all new home construction.[974] Drastic modifications to the NEM tariff, or the rates NEM customers must pay, may undermine the CEC's ability to achieve its goals, and specifically the requirement that there be cost savings over the course of a 30-year mortgage.[975] CALSSA's proposal maintains

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[972] D.21-02-007, Ordering Paragraph 1(e).

[973] Exh. CSA-01 at 82:16-17.

[974] Exh. CSA-01 at 129 n. 267 (citing *2019 Building Energy Efficiency Standards for Residential and Nonresidential Buildings*, California Code of Regulations, Title 24, Part 6 § 150.1(c)14).

[975] Exh. CSA-01 at 129 n. 268 (citing *Building Energy Efficiency Measure Proposal to the California Energy Commission for the 2019 Update to the Title 24 Part 6 Building Energy Efficiency Standards, Rooftop Solar PV System*, pp. 39-40 and 44-46, Energy and Environmental Economics, Inc. (September 2017)).

cost recovery periods that ensure the installation of solar on all new homes does not financially harm the customers living in those homes.

Pro-Transmission Party proposals would significantly reduce customer adoption of solar and storage, to the point that the State may be unable to achieve its greenhouse gas goals and meet the CEC requirements regarding cost-savings associated with solar, including:

- The Pro-Transmission Parties' lack of any glidepath to export compensation derived from ACC values[976] and use of unlevelized, one-year avoided cost values to determine export compensation rates.[977]
- The Pro-Transmission Parties' unprecedented solar fee and rate requirement proposals.[978]
- Cal Advocates' and the Joint IOUs' proposals to establish a tariff with no set eligibility term.[979]
- The Joint IOUs and Cal Advocates' proposals to change to a system of instantaneous netting.[980]
- TURN's dispatch requirements for storage-paired resources.[981]

While each of these proposals would be damaging in isolation, it is important to note that even *just* adopting ACC-based export compensation values with no glidepath would devastate adoption rates, as shown in CALSSA's dGen modeling.[982] Adopting certain proposals together—for instance, a successor tariff with ACC-based export compensation and high solar

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976 *See* Section III.C.4.

977 *See* Section III.C.2.b.

978 *See* Section III.C.5.

979 *See* Section III.C.6.

980 *See* Section III.C.7.

981 *See* Section III.C.11.

982 *See* Section III.C.4.c.

fees—would create a tariff that simply would not be economically viable for customers. The Commission should reject proposals like this that would seriously jeopardize the State's greenhouse gas goals.

f. Guiding Principle (f).

Guiding principle (f) provides "[a] successor to the net energy metering tariff should be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities."[983]

CALSSA's proposal includes various elements to help ensure transparency and terms that will be understandable to customers:

- None of the reforms in CALSSA's proposal interfere with behind-the-meter consumption rights, and therefore the proposal does not disturb customers' current expectation and understanding that their behind-the-meter consumption is off-limits for utility interference and regulation.
- The proposed NEM successor tariff for general market residential customers will step down the export rate in predictable steps, and potential customers will have adequate notice of the timeline for these step downs.[984]
- To ensure transparency and avoid confusion, the proposal requires the utilities to track progress toward each step-down threshold and file a Tier 1 advice letter before the threshold is projected to be hit that establishes a firm date—at least three months after the advice letter is filed—for the transition to take place.[985]

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983 D.21-02-007, Ordering Paragraph 1(f).

984 *See* Section III.C.2.

985 *See* Section III.C.4.

- The proposal does not include additional elements such as the market transition credit proposed by E3, which would add an unnecessary layer of complexity and ratepayer risk to the NEM tariff.[986]
- The proposal's low-income and tenant policies are straightforward and clear. Rather than relying on complex rate structures or reforms, these proposals simply maintain the current NEM-2 structure for certain low-income and renter customers, and allow CARE and FERA customers to receive NEM credits at the same level as the non-discounted rates of their otherwise applicable rate schedule.[987]
- The proposal with respect to agricultural and commercial customers could not be more straightforward: CALSSA proposes no reform for these customers.[988]
- CALSSA's two consumer experience-related provisions are aimed at improving information and eliminating unexpected outcomes for customers on the NEM tariff.[989]

In contrast, Pro-Transmission Party proposals that would undermine transparency and customers' ability to understand the tariff terms include the following:

- The market transition credits proposed by TURN and NRDC would add unnecessary complexity and ratepayer risk to the NEM tariff.[990]
- The Pro-Transmission Parties' proposed solar fees are incredibly complex, difficult to understand, and likely to be volatile.[991]

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986 *See* Section III.C.4.d.

987 *See* Section III.C.1.

988 *See* Section III.C.3.

989 *See* Sections III.C.9 and III.C.10.

990 *See* Section III.C.4.d.

991 *See* Sections III.C.5.f and III.C.5.g.

- Cal Advocates' and the Joint IOUs' proposals to establish a tariff with no set eligibility term would mean that there are no set tariff terms for any guaranteed period. As a result, customers would be unable to predict or understand the financial consequences of investing in solar at the time they are making the investment.[992]

g. Guiding Principle (g).

Guiding principle (g) provides "[a] successor to the net energy metering tariff should maximize the value of customer-sited renewable generation to all customers and to the electrical system."[993]

CALSSA's proposal will effectively transition the DER market from standalone solar to solar plus storage. Energy storage will help maximize the efficiency of the existing grid, avoiding the continued overbuilding of the grid as we increase the portion of electricity that comes from renewable sources, at the same time that it provides resilience in an increasingly wildfire-prone state.[994]

The Pro-Transmission parties make claims that their proposals would boost energy storage, but the opposite is true. Fixed charges and solar fees, in particular, would harm the ability of customers to cost-effectively install solar plus storage, and abrupt changes with no glidepath would devastate the market. By reducing export compensation while avoiding monthly charges, CALSSA's proposal will maintain customer adoption of DERs while the glidepath increasingly pushes customers toward energy storage.[995]

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992 *See* Section III.C.6.

993 D.21-02-007, Ordering Paragraph 1(g).

994 Exh. CSA-01 at 6:5-9.

h. Guiding Principle (h).

Guiding principle (h) provides "[a] successor to the net energy metering tariff should consider competitive neutrality amongst Load Serving Entities."[996] CALSSA's proposal adheres to this guiding principle in that nothing in its proposal favors or would provide competitive advantage to certain LSEs over others.

Because CALSSA's proposal achieves and effectively balances these statutory directives and goals, CALSSA urges the Commission to adopt its proposal.

2. Implementation Issues and Timelines

The amount of time necessary for a transition period is directly proportional to both the degree of change the successor tariff represents in comparison to NEM-2 and the complexity of the new program overall.[997] Turnkey proposals like that from CALSSA provide relatively few changes to the existing structure, reducing implementation timelines; while those from the Pro-Transmission parties will take years to implement.

a. CALSSA's Proposal is the Quickest to Implement

CALSSA's residential customer proposal requires the shortest implementation period of all of the proposals in this case, maintaining most of the essential elements of NEM-2 and adjusting export rates to provide a cost-effective, multi-year glidepath to a new tariff endpoint.[998] CALSSA's proposal does not require further phases of this proceeding, the need for any working groups, the need for future Commission rulings, or the need to wait for decisions in other proceedings before this Commission or at the Federal Energy Regulatory Commission

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[996] D.21-02-007, Ordering Paragraph 1(h).

[997] Exh. CSA-01 at 120:12-18.

[998] Exh. CSA-01 at 120:12-18.

("FERC").[999] It does not require future calculation of specific values for export rates, fees, or credits.[1000] The advice letter process to implement CALSSA's tariff can begin on "day one" after approval of the decision.[1001] CALSSA's proposal can be implemented as soon as Q3 2022,[1002] based on the proposed timeline set forth in Table 18 in CALSSA's Direct Testimony.[1003] Interconnecting customers would go on NEM-3 if they submitted an interconnection application after the date when the final resolution is approved.[1004]

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[999] Exh. CSA-01 at 120-19:121-2.

[1000] Exh. CSA-01 at 120-19:121-2.

[1001] Exh. CSA-01 at 120-19:121-2. While the Tier 2 process may be sufficient for some components of CALSSA's proposal, such as the consumer experience provisions discussed in Sections III.C.9 and III.C.10, Tier 3 advice letters will be necessary to implement any new tariffs under the terms of General Order 96-B. *See* General Order No. 96-B, General Rules § 7.6.1 and Energy Industry Rules §§ 5.3.1-4.

[1002] Exh. CSA-01 at 120-19:121-2. The actual implementation date depends on the timing of the Commission's final decision in this proceeding, the deadline set for the utilities to file implementation advice letters, the speed with which Energy Division can issue a draft resolution, and the length of the Commission's deliberation on the draft resolution.

[1003] Exh. CSA-01 at 121, Table 18.

[1004] Exh. CSA-02 at 70:6-12. It should be noted that residential customers submit their solar installation contracts with the interconnection application.

Table 18. CALSSA Proposal Implementation Timeline

Event	Timing
Commission Decision	January 13, 2022[1005]
Utilities File Implementing Advice Letters	March 14, 2022 (Assuming decision includes 60-day deadline)
Protests and Responses Due	April 4, 2022
Draft Resolution Issued	June 2022
Comments on Draft Resolution Submitted	July 2022
Final Resolution Approved	August 2022

The suggestion from the utilities' witness that *any change to the NEM tariff* would take equally long to implement as all others is absurd.[1006] The idea that changing one component of the utilities' NEM tariffs will take as much time to implement as proposals that overhaul every component of that tariff, including new rate structures, new solar-specific customer charges, new netting mechanics, and new true-up cycles, undermines the IOUs' credibility. Indeed, contradicting her testimony during hearings, Witness Molnar states in her direct testimony that the parallels only apply to "any other NEM proposal *of similar complexity.*"[1007]

b. The Pro-Transmission Parties' Proposals Will Take Years to Implement.

The Pro-Transmission Parties' proposals are a stark departure from the *status quo*, including some combination of new solar fees to treat self-consumption like retail sales, requirements to use unproven new rates, new solar-specific customer charges, the application of

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[1005] *See* Scoping Ruling, p. 4, as amended by R.20-08-020, *Email Ruling Noticing April 22, 2021 Workshop and Revising Procedural Schedule* (April 8, 2021). The ALJ's April 8, 2021 Email Ruling set the last date for a proposed decision in this case as December 9, 2021. Thirty days after that meeting falls on January 8, 2022. The Commission's business meeting calendar for 2022 is not yet available on the Commission's website, but January 13, 2022 would be the first possible Thursday for a Commission meeting in which the proposed decision could be adopted.

[1006] 4 Tr. 650:9-14 (IOU – Molnar).

[1007] Exh. IOU-01 at 181:11-13.

new non-bypassable charges like the PCIA, new netting mechanics, and new true-up cycles, among other provisions.

Per the IOUs' testimony, the minimum that must be implemented for their proposal is the following:[1008]

- Addition of a solar fee
- New rate structures (for PG&E and SDG&E)
- Treatment of export compensation credits
- Modifications to netting logic based on TOU periods
- A monthly, rather than annual, true-up process
- Bill presentment of new line items; and
- Updating of existing bill management tools (e.g. rate analysis tools)

Making this complex situation worse, the testimony states, "PG&E is pursuing updates to our billing systems in the next few years," which could result in further implementation delays.[1009]

These delays significantly impact all aspects of the Joint IOUs and other Pro-Transmission Parties' proposals. For example, as IOU Witness Kerrigan admitted, the Commission will not know the actual export compensation rates, which rely on the Avoided Cost Calculator, until the 2022 or even 2023 version of the calculator is approved.[1010] As a result, the Joint IOUs' long implementation timelines mean customers, the Commission, and other stakeholders will not know the *actual* export compensation rates, cost-effectiveness scores, or payback periods of the tariff it adopts until *years* from now.

1008 Exh. IOU-01 at 181:2-9.

1009 Exh. IOU-01 at 181:10-26.

1010 *See* 4 Tr. 685:19-686:20 (IOU – Kerrigan).

Because the other Pro-Transmission Parties' successor tariffs are equally complicated, their implementation plans are equally problematic. Cal Advocates unwittingly believes the IOUs can file advice letters within three months of a Commission decision to implement the proposed policy reforms,[1011] suggesting implementation could be completed soon after. However, Cal Advocates Witness Ward admitted their proposal and the Joint IOUs' proposal are composed of similar key elements, including a new tariff with export compensation rates decoupled from the retail rate and set at avoided cost,[1012] a net billing structure with instantaneous netting,[1013] and a new fee to be imposed on NEM customers.[1014] In fact, as Witness Ward admitted during hearings, Cal Advocates' proposal includes other major elements beyond those in the IOUs' proposal, including (a) a new transition incentive program to encourage NEM-1 and NEM-2 participants to transition to the successor tariff,[1015] and (b) implementing an equity charge on residential NEM-1 and NEM-2 customers and successor tariff customers.[1016]

When asked to explain the discrepancy between the IOUs' two-year implementation timeline[1017] and Cal Advocates' four-month implementation timeline, Witness Ward could not do so credibly.[1018] He stated: "I can't speak to the IOUs' implementation time, but it would be

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[1011] Exh. PAO-3 at 6-1:13-14.

[1012] 5 Tr. 847:13-19 (PAO – Ward).

[1013] 5 Tr. 843:13-18 (PAO – Ward); 5 Tr. 848:24-26 (PAO – Ward); 5 Tr. 849:2-5 (PAO – Ward).

[1014] 5 Tr. 844:4-7 (PAO – Ward); 5 Tr. 849:6-15 (PAO – Ward).

[1015] 5 Tr. 849:25 to 850:3 (PAO – Ward).

[1016] 5 Tr. 851:21 to 852:4 (PAO – Ward).

[1017] 5 Tr. 853:8-13 (PAO – Ward).

[1018] 5 Tr. 854:14-18 (PAO – Ward).

the level of detail we include in our testimony that the Commission could adopt . . . ."[1019] However, it is not difficult to see that the IOUs include a similar level of detail in their proposal as Cal Advocates, if not more, laying bare the fallacy in Mr. Ward's statement.

These long implementation timelines will only be exacerbated by the placeholders for rates, Avoided Cost Calculator values, market transition credits, and other elements that the Pro-Transmission Parties leave to FERC, future Commission proceedings, later phases of the instant proceeding, or the advice letter process. First, *any proposal* seeking to include a solar fee based on transmission costs will require approval at FERC.[1020] The Joint IOUs proposal correctly states that "[t]ransmission rates are FERC jurisdictional,"[1021] and, in response to discovery, the IOUs explain that their fixed solar fees would not include a transmission component until they obtain FERC approval.[1022] The same would be true for the solar fees from the other Pro-Transmission parties, all of which include transmission components.

TURN admits an entire second phase of this proceeding is necessary for the key parts of its proposal, including the calculation of the market transition credits, its behind-the-meter production estimates, and the development of export credit methodology that relies on Avoided Cost Calculator values or CAISO day-ahead hourly market prices.[1023] For its solar fee alone, rules and methodologies need to be developed in a subsequent phase to address the estimation of self-consumption quantities and the determination of which components will constitute the NUS

1019 5 Tr. 855:13-19 (PAO – Ward).

1020 Exh. CSA-01 at Attachment 4 (Joint IOUs Response to CALSSA DR 4.23); Exh. CSA-02 at 66:18-23.

1021 Exh. CSA-01 at 121:11-122:2 (citing to the Joint IOUs Proposal at 45, n. 23).

1022 Exh. CSA-01 at Attachment 4 (Joint IOUs Response to CALSSA DR 4.23).

1023 9 Tr. 1517:15-26 (TRN – Chait); Exh. TRN-01 at 58:3-23; Exh. CSA-02 at Attachment 7 (TURN Response to CALSSA DR 4.08).

charge.[1024] During hearing TURN's witness also admitted that its market-based compensation option cannot be implemented until after the Commission implements a real-time pricing program.[1025] The IOUs agree, stating TURN's proposal is "not practical to implement" until "real time pricing rates are widely available."[1026]

TURN suggests collaborative working groups can accomplish its second phase in eight months.[1027] That is a long time period in and of itself, assuming it is correct: Witness Chait admitted during hearing that she does not have personal experience with estimating Commission timelines for implementation.[1028] Indeed, it is difficult to see how the collaborative process TURN suggests would not require hearings and fact-finding given the contentious nature of the instant proceeding.

Moreover, that process is not the end of the work to implement TURN's proposal. The utilities' two-year timeline for implementing complex proposals like TURN's will also be needed, suggesting the eight months TURN suggests is necessary to finish its proposal may be additive to the two years the IOUs will need. On the stand, Witness Chait suggested such work might happen in parallel, but she admitted during hearing that she had not consulted the IOUs on whether these two phases could occur in parallel and that implementation could last longer.[1029]

NRDC's proposed implementation timeline is much like the rest of its work in this case: incomplete and unsupported. NRDC's Question 25 asks for its own proposed "timeline for

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[1024] Exh. TRN-01 58:0-14; 9 Tr. 1585:18-19 (TRN – Chait).

[1025] 9 Tr. 1569:18-26 (TRN – Chait).

[1026] Exh. IOU-02 at 51:14-19.

[1027] Exh. TRN-01 at 58:25 to 59:21.

[1028] 9 Tr. 1572:20-28 (TRN – Chait).

[1029] 9 Tr. 1517:15-26 and 1574:22-26 (TRN – Chait).

implementation," but Mr. Chhabra does not answer his own question.[1030] Given the complexity and undeveloped nature of NRDC's proposal,[1031] and once those details are developed, its similarity to the Joint IOU's proposal, a three-year timeline for implementation is likely a good minimum estimate for NRDC's proposal.

Despite both the November 19, 2020 Scoping Memo and Judge Hymes's January 28, 2021 ALJ Ruling requesting parties submitting successor tariff proposals to identify their implementation plans, CUE's testimony does not provide one. A three-year implementation plan is likely necessary, assuming one can discern which components of which parties' testimony that CUE says it supports would constitute a CUE "proposal", including its proposal to transition all NEM-1 and NEM-2 customers to NEM-3 immediately.[1032]

If the Commission adopts any of the Pro-Transmission Parties' proposals, it is most likely committing to a two to three-year implementation timeline. The best solution to ensure faster reform of the existing tariff is not giving interim NEM-2 status to a set of NEM-3 customers, not holding a second phase of the proceeding, and not pretending implementation of complex proposals can happen faster than the IOUs say it can happen. If the Pro-Transmission Parties' interest is to close a gap between NEM-2 export compensation and measured avoided costs, they should value the benefit of implementing a first step away from NEM-2 sooner than would be possible with more complex changes.

[1030] *See* Exh. NRD-01 at 24:8 to 27:10.

[1031] *See* Section III.D.3.

[1032] CUE Direct Testimony at 17:10 to 20:2.

c. Keeping NEM-2 Open Until NEM-3 is Implemented Will Protect Customers.

The Joint IOUs and Cal Advocates suggest that the program be transitioned off NEM-2 after the *decision* in this case and *before* the implementation of NEM-3. Cal Advocates states that "the IOUs should be able to begin accepting new customers on the successor tariff by April 8, 2022," with zero transition for the industry to adjust to changes.[1033] This approach is not credible.

The Joint IOUs' direct testimony backs down slightly from their original, deeply unreasonable proposal to avoid any transition at all for solar customers and installers. The Joint IOUs now "recognize that there will need to be some limited transition time between the final decision and ending NEM 2.0 eligibility."[1034] However, their revised proposal makes the transition overly complex, using *four phases* to implement their successor,[1035] which itself is difficult to understand. These four phases would provide separate treatment to customers submitting interconnection applications (1) prior to the final decision; (2) after the final decision but before a NEM-2 eligibility deadline; (3) after the NEM-2 eligibility deadline but before the IOUs can finish upgrading their billing systems; and (4) after the successor tariff is operational.[1036]

In the second phase, the Joint IOUs add yet another layer of complexity between NEM-2 and NEM-3 customers. They create a "buffer period" limited to only "customers who are in the purchase process, or may be waiting on local permits near the time of the final decision, to

1033 Exh. PAO-03 at 6-1:13-23; Exh. CSA-01 at Attachment 6 (Cal Advocates Response to CALSSA DR 2.02).

1034 Exh. IOU-01 at 182:24-25.

1035 Exh. IOU-01 at 186, Table VI-42.

1036 Exh. IOU-01 at 186, Table VI-42.

submit an application for utility interconnection under NEM 2.0 before the deadline on which the Reform Tariff will take effect."[1037] In contravention of D.16-01-044, which ensures 20-year legacy treatment for NEM-2 customers,[1038] the NEM-2 customers caught in this buffer period will receive a different legacy timeline, with some legacy periods as short as three years (but the IOUs do not explain which customers will be subject to this treatment).[1039] This approach suffers from the same problems as the Joint IOUs' original transition proposal: it contravenes existing decisions, undermines customers' investment certainty, and risks widespread customer misunderstanding.

New net metering customers that had not submitted an interconnection request prior to the effective date of this decision would be enrolled in NEM-3 despite there being no tariff details for the program. [1040] Instead, they would be billed under NEM-2 until NEM-3 takes effect.[1041] To address the fact installers and customers have no details of the new tariff the IOUs suggest the filing of "an information-only Tier 1 Advice Letter to provide details of the Reform Tariff as directed in the Final Decision," followed a month later with a supplemental filing "containing rate factors based on the applicable revenue requirements and associated tariff sheets." [1042] The IOUs explain:

> This Tier 1 Information-only advice letter will summarize *our interpretation of how the NEM tariff will be structured* and provide indicative levels of price components. This will include information regarding pricing for the underlying net billing tariff as well as the export compensation rate. The level of information provided in the

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1037 Exh. IOU-01 at 183:3-6.

1038 D.16-01-044 at Conclusions of Law 14 and 15.

1039 Exh. IOU-01 at 184:1-6; Exh. IOU-02 at 100:22.

1040 4 Tr. 652:8-13 (IOU – Molnar).

1041 Exh. IOU-01 at 184:7-185:3.

1042 Exh. IOU-02 at 99:10-23.

> Tier 1 Information-only Advice Letter *should be sufficient to allow customers and solar providers to plan for and adjust to the Reform Tariff.*[1043]

Thus, the solar industry is supposed to rely on the IOUs' best guess of how the tariff is to be structured utilizing their interpretation of the Commission decision. When asked what would happen if parties disagreed with the IOUs' interpretation, IOU Witness Molnar stated "parties to the proceeding have a right to comment or protest what we file."[1044] That is, the terms of the tariff would be unsettled and unknown, *i.e.*, the Tier 1 Advice Letter would have little value.

As a result, solar company sales teams would need to explain a product to customers where the "kitchen-table conversation" conveys that a customer will take service under one tariff and, after that, be switched to a new tariff, the details of which are still being developed.[1045] The result would be a disastrous customer experience where the Joint IOUs would expect solar companies to be able to understand each aspect of the Commission's decision, guess at the implementation details that follow the decision, and then communicate those details to their customer relations teams.[1046]

Such a situation is untenable from a customer standpoint.[1047] A solar contractor cannot educate a customer about the mechanics of a tariff when the details of those mechanics do not exist.[1048] At best, it is an extremely risky decision for the customer to make; at worst, it is a consumer protection problem where implementation follows a different path than originally

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1043 Exh. IOU-02 at 13-18 (emphasis added).

1044 Tr. Vol. 4 (Joint IOUs- Molnar), p. 659, lines 8-10.

1045 Exh. CSA-01 at 44:7-46:16.

1046 Exh. CSA-01 at 44:7-46:16.

1047 Exh. CSA-01 at 44:7-46:16.

1048 Exh. CSA-01 at 44:7-46:16.

surmised by contractors that are doing their best to learn quickly and interpret policy language.[1049] The fact that the Joint IOUs are monopolies could not be clearer than from this suggested approach; no business without a guaranteed customer base would promote such an approach as a remotely workable strategy for a business to sell a product. [1050]

3. NRDC's Proposal is Not Supported by Substantial Evidence.

NRDC failed to support its proposal with substantial evidence, instead putting forward what amounts to an outline of tariff concepts for the Commission to fill in at a later date:

Export Compensation – NRDC's export compensation rate proposal consists of three bullets in its direct testimony. [1051] Mr. Chhabra provided no further detail, and no illustrative export rates, [1052] anywhere else on the record other than to suggest the average is "around 5 cents" in PG&E's service territory. [1053]

Rate Design – The record on NRDC's rate design proposal consists solely of a statement of which rates NRDC asked E3 to model and a general statement in support of time-of-use rates; no other detail is provided. [1054]

Solar Fee – As discussed in more detail in Section III.C.5, NRDC's testimony on its proposed solar fee consists almost entirely of a statement that it asked E3 to model a solar fee for its proposal using Cal Advocates' proposal.[1055] During cross examination,

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1049 Exh. CSA-01 at 44:7-46:16.

1050 Exh. CSA-01 at 44:7-46:16.

1051 Exh. NRD-01 at 15:13-16:7; 10 Tr. 1765:3-7 (NRD – Chhabra).

1052 10 Tr. 1765:18-22 (NRD – Chhabra).

1053 10 Tr. 1765:18-22; 1766:27-1767:7 (NRD – Chhabra).

1054 Exh. NRD-01 at 16:20-21; 10 Tr. 1767:11-1768:10 (NRD – Chhabra).

1055 Exh. NRD-01 at 18:11-13.

NRDC's witness admitted that "[w]e don't have a specific proposal for the Grid Benefits Charge."[1056]

Market Transition Credit – As discussed in more detail in Section III.C.4.d, despite being a "critical part of the NRDC successor tariff",[1057] NRDC's witness has not presented any illustrative example of what that credit would be, limiting the description of it to four bullet points in NRDC's direct testimony.[1058] E3's Comparative Analysis also does not include any illustration of what market transition credit was needed to achieve a ten-year payback under NRDC's proposal,[1059] and E3 was unable to complete the calculation correctly,[1060] meaning the record in this proceeding still has no details on NRDC's market transition credit.

Equity Fee Proposals – As discussed above in Section III.C.1, NRDC's proposal is not fully developed, and it is unclear how funds would be allocated.[1061]

Implementation – As discussed in Section III.D.2, NRDC has not put forward an implementation proposal in its testimonies.

[1056] 10 Tr. 1773:9-11 (NRD – Chhabra).

[1057] Exh. NRD-01 at 19:3.

[1058] 10 Tr. 1773:24-1774:9 (NRD – Chhabra).

[1059] Exh. CCS-01 at Attachment, E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020* (May 28, 2021).

[1060] *See, e.g.,* Exh. CSA-32, pp. 34-35 of E3's report (including payback periods of 8.0, 8.9 and 9.0 years and 6.6, 7.9 and 8.1 years).

[1061] *See* Exh. NRD-01 at 21:10-13 (proposing to provide clean energy benefits "such as through rooftop solar, electrification, and energy efficiency), 21:26 to 22:1 (discussing a future consultation process and new phase of this proceeding to determine how to spend funds); NRD-02 at 17:22-24 ("The arguments that NRDC's proposal would make solar unattractive to lower income customers forget that NRDC is proposing an equity fund that would completely buy down the cost of solar for lower-income Californians.").

Despite being given opportunity after opportunity to put forward a fully developed tariff proposal supported by substantial evidence, NRDC chose not to do so. If the Commission were to adopt any of NRDC's recommendations in this proceeding, the resulting decision would be susceptible to challenge under Public Utilities Code Section 1757, which requires such a decision to be "supported by the findings," with those findings "supported by substantial evidence in light of the whole record."[1062] The Commission cannot conclude certain tariff elements are reasonable by relying on inferences drawn from NRDC's testimony.

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

Three key improvements to VNEM should be adopted to improve the program overall. First, it is common for property owners to take over customer accounts when installing VNEM systems and to incorporate utility costs into rent. Currently, this results in CARE accounts losing their CARE status, discouraging solar adoption for low-income customers. An account should be eligible for CARE rates if the tenant meets CARE eligibility requirements even if they do not own the unit. If a property manager presents documentation that a tenant resides in a particular unit and is eligible for CARE, the utility should put that account on CARE rates even if the account is in the name of the property owner.[1063] The process for demonstrating CARE eligibility, including later reaffirmation, can be identical to the process for account holders.

Second, when a new tenant moves into a unit that previously received VNEM credits, the default should be that the new tenant receives the same VNEM credits as the previous tenant.

1062 *See, e.g.*, D.20-05-027, p. 6.

1063 Exh. CSA-01 at 26:9-27:6.

Currently, when a tenant moves out the credits start going to a backup account, which shifts benefits from tenants to property owners. The property owner has to add the new tenant during the next annual allocation update or pay a fee to do it outside of the annual update. Instead, new tenants should automatically get the same benefit as the previous tenant in the same unit.[1064]

Finally, the Commission should allow multiple solar arrays on one property to be treated as one generator, with credits allocated across the property. The NEM-2 VNEM tariff allows multiple solar arrays on one property, but each array can only serve a subset of customers on the property. Most apartment complexes have multiple buildings that require the use of separate roof surfaces and points of interconnection. It is inefficient to treat each array separately with its own subgroup of customer accounts. The tariff should allow the output of multiple solar arrays on one property to be combined into one generation total with a portion of that total assigned to participating customers.[1065]

1. The Joint IOUs' Proposals Are Unreasonable and Should Be Rejected.

The Joint IOU testimony states: "For some virtual tariffs, all the generation is exported to the grid and none of the generation directly serves the load of the aggregated accounts."[1066] The testimony also states, "Virtual NEM systems do not displace onsite load, and therefore does not provide the same distribution benefits as standard NEM."[1067] These statements are not true. There is an appearance of veracity from a billing perspective, because VNEM generation is treated separately from the load on customer accounts for billing purposes. A utility meter

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1064 Exh. CSA-01 at 27:7-12.

1065 Exh. CSA-01 at 27:13-20.

1066 Exh. IOU-01 at 154:15-17.

1067 Exh. IOU-01 at 156:18-19.

measures production and applies credits to benefitting accounts. From an electrical perspective, however, the electricity produced by solar systems behind the same service delivery point as concurrent customer load will serve that load without ever reaching the distribution feeder. It has the same grid benefits as energy efficiency.[1068]

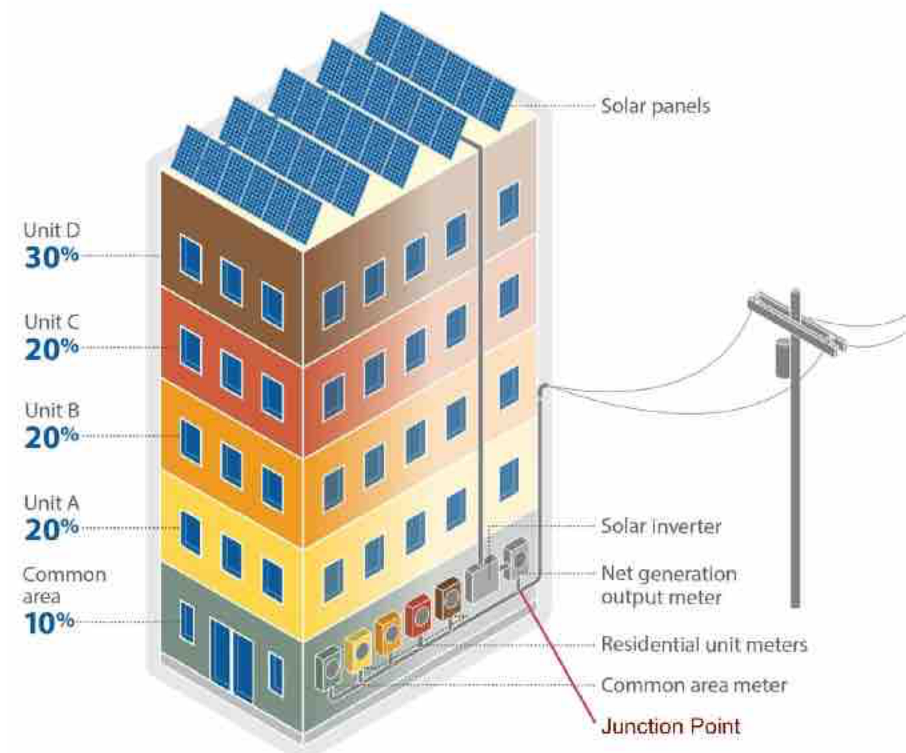
Figure 15 below from CALSSA's Rebuttal Testimony shows a common VNEM configuration.[1069] At the point marked as the "junction point," electricity flowing from the solar panels will go to customer meters if there is concurrent load. If generation exceeds load, it will flow to the distribution feeder. This is the same as any customer-sited solar system, which all have similar junction points. Although the wires between the generation meter and the customer meters are technically not "behind the meter," those wires are designed to handle the amount of current that the customer will draw, so having that current come from solar rather than the grid does not cause the utility to build or maintain the grid any differently. If the service transformer or the wire between the generation meter and the service transformer need to be upgraded, cost responsibility is the same as it is for a standard NEM customer. If the transformer serves only that customer, the customer pays to upgrade it. This will more often be the case for VNEM than for solar on single-family housing.[1070]

1068 Exh. CSA-02 at 71:20-26.

1069 Exh. CSA-02 at 72, Fig. 15.

1070 Exh. CSA-02 at 71:27-72:7.

Figure 15. VNEM Configuration



Joint IOU direct testimony further states, "VNEM generation is typically located at a different location on the grid from the load it serves."[1071] That is not true. CALSSA submitted a data request to the IOUs to determine the percentages of VNEM systems that are co-located with the load they serve. Only PG&E was able to provide data, and the other utilities stated they do not have such data readily available. The data shows that 77% of general-market VNEM customers and 41% of MASH and SOMAH VNEM customers are on the same transformer as the generator. *Ninety-eight percent* of all such meters are on the same distribution feeder. For NEM-A, a majority of systems have more than one transformer but 90% are on the same feeder, which can be seen in Table 11 below:[1072]

1071 Exh. IOU-01 at 154:14-15.

1072 Exh. CSA-02 at 73:5-9 and p. 73, Table 11.

Table 11. IOU Data Response on VNEM Generator Proximity to Load

Virtual NEM Type	% Benefiting Meters on Same Feeder	% Benefiting Meters on Same Transformer
All Virtual NEM	92%	48%
NEMA	90%	48%
NEMV	98%	77%
NEMV-MASH/SOMAH	97%	41%

2. Unjustified Changes to VNEM Must Be Rejected.

The Joint IOUs slipped three changes to virtual net metering rules into one paragraph of the direct testimony. These proposals would be harmful to customers, and no justification is provided.

a. System Owner

The Joint IOUs testimony states, "For both DG-ST-V and DG-ST-VSOM, the owner of the property must be the owner of the generating account."[1073] This declaration is made without context, history, or justification. It would limit customer options and prevent solar providers from assuming risk.

In one model of VNEM system management for multi-tenant business properties, the project developer installs a new meter on the customer's property for the generator and maintains it in their name. In this model, the project developer is responsible for collecting payments from participating customers, which takes financial risk away from the property owner. The project developer may choose to do this if the property owner is not willing to assume the risk of making

1073 Exh. IOU-01 at 158:12-13.

the investment and recovering costs over time.[1074] The Commission should reject this proposed new requirement that would disallow arrangements like this.

b. Grid Upgrade Costs

The Joint IOU testimony proposes, “For DG-ST-V, the owner is responsible for all interconnection costs.”[1075] Currently, all interconnecting customers pay for engineering review and interconnection facilities. Projects smaller than 1 MW do not pay for grid upgrades that are triggered by the project but also benefit other customers.[1076] Changing this interconnection cost responsibility would be a burden for VNEM projects, including those at moderate-income apartment buildings.[1077] The IOUs do not present any data on recent or projected costs for such facilities, and do not state any justification for the change.

c. NEM-A Billing

The Joint IOU testimony states, “the other major difference between the standard virtual tariff and the low income tariff is that the low income tariff would maintain the current credit allocation rules of the SOMAH program, while the standard tariff would allow the owner to freely determine allocations.”[1078] Currently, for VNEM projects the property owner assigns a percentage of generation to each benefitting account. For NEM-A projects the generation credits are assigned to each meter according to the percentage of combined load that is used by each meter.[1079] Accounts that use more power get more credits. This automated allocation

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1074 Exh. CSA-02 at 74:1-6.

1075 Exh. IOU-01 at 158:13.

1076 Exh. CSA-02 at 74:10-12.

1077 Exh. CSA-02 at 74:12-14.

1078 Exh. IOU-01 at 158:15-17.

1079 Exh. CSA-02 at 74:20-23.

mechanism ensures that credits are not stranded at meters that do not need them.[1080] The proposed change would be a new limiting factor. It is stated as if it were a benefit to require the property owner to pre-determine the allocations for each account, but it would be a setback for NEM-A systems. The Commission should reject the change.

The Joint IOUs state that a benefit of their proposal is that it "allows the customer/tenant to easily compare the value they receive from the allocation to the price they pay to the landlord for that allocation, whether increased rent or monthly payment."[1081] There is no reason such a comparison is not possible today.[1082] If the customer cannot easily see their credits on the bill and understand their savings, the utilities have a bill presentment problem that they should fix without reinventing how crediting works.

IV. RETROACTIVE CHANGES

In its Scoping Ruling, the Commission established seven issues, five of which were to be addressed in the current phase of the proceeding, and zero of which clearly encapsulate changes to the NEM-1 and NEM-2 tariffs.[1083] Despite that ruling, some parties included provisions related to those tariffs in their proposals. All of the following provisions are out of scope of this proceeding:

- CUE now has the most aggressive retroactive proposal, suggesting the Commission either *immediately* transfer all NEM-1 and NEM-2 customers to the successor tariff, or, similar to Cal Advocates, transfer NEM-1 and NEM-2 customers as they reach a poorly calculated payback period (but without the storage incentive Cal Advocates promises).[1084]

1080 Exh. CSA-02 at 74:23-24.

1081 Exh. IOU-01 at 159:10-12.

1082 Exh. CSA-02 at 75:5-6.

1083 *See* Scoping Ruling at 2-3.

1084 Exh. CUE-01 at 18:11-20:2.

- NRDC maintains its suggestion to create a fixed solar fee on existing NEM-1 and NEM-2 customers of $2.50/kW per month.[1085] NRDC also supports Sierra Club and Cal Advocates' retroactive proposals.[1086]
- Cal Advocates supports NRDC's fee and also suggests moving customers on these tariffs to the successor tariff five years after interconnection, with the possibility of receiving a rebate for an energy storage system, with the rebates funded via distribution charges.[1087]
- TURN suggests recovering 25-50% of its proposed market transition credit from NEM-1 and NEM-2 customers via a charge that it estimates to be $4-8/month.[1088]
- Sierra Club promotes placing existing NEM-1 and NEM-2 customers on specific electrification rates with high fixed charges eight years after interconnection, including rates that have yet to be approved by the Commission.[1089]

Adopting proposals that were not properly scoped violates the due process rights of NEM-1 and NEM-2 customers by to failing to apprise them "of the pendency of the action and afford them an opportunity to present their objections."[1090]

Beyond the proposals being out of scope, it would be either illegal or unreasonable for the Commission to adopt these proposals for the following reasons:

- Proposals from CUE, NRDC, Cal Advocates, and TURN subject NEM-1 customers to different rates than they would have otherwise been subject in violation of the Public Utilities Code;
- The proposals create a consumer protection nightmare, hurting many of the same vulnerable customer populations these parties seek to protect;
- Retroactivity damages customers relationships that are critical to achieving the State's policy goals, as well as to the continued growth of solar deployment;
- The fees are contrary to ratemaking principles intended to encourage long-term customer investments; and

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1085 Exh. NRD-01 at 21:15-24.

1086 Exh. NRD-01 at 23:6-24:5.

1087 Exh. PAO-03 at 3:55-4 to 3:61-20.

1088 Exh. TRN-01 at 6:10-14, 35:10-19, and 55:1-13.

1089 Exh. SCL-01 at 21:17-20 and 6:28-23:11; Exh. SCL-02 at 3:8-23:7.

1090 *Pacific Gas & Electric Co. v. Pub. Util. Comm'n*, 237 Cal. App. 4th 812, 859-60 (2015) (quoting *Mullane v. Cent. Hanover Bank & Trust Co.*, 339 U.S. 306, 314 (1950)) (emphasis added).

- They are based on a faulty premise that individuals make large asset investments simply to achieve cost recovery.

The Commission must reject these proposals.

A. Modifications to the NEM-1 and NEM-2 Tariffs Are Out of Scope.

Due process in California requires "notice reasonably calculated, under all the circumstances, to *apprise interested parties of the pendency of the action* and afford them an opportunity to present their objections."[1091] The California Supreme Court has ruled on the application of this standard in the context of the Commission, finding, "[d]ue process as to the commission's initial action is provided by the requirement of 'adequate notice to a party affected and an opportunity to be heard before a valid order can be made.'"[1092] Further, the California Supreme Court has recognized that, in determining the appropriate due process safeguards of a particular situation, "it must be remembered that 'due process is flexible and calls for such procedural protections as the particular situation demands.'"[1093] The extent to which due process relief is available "depends on a careful and clearly articulated balancing of the interests at stake in each context."[1094] This analysis should consider the private interest affected by the official action and the "risk of an erroneous deprivation of such interest through the procedures used, and the probable value, if any, of additional or substitute procedural safeguards," as balanced against any countervailing governmental interest.[1095]

1091 *Pacific Gas & Electric Co. v. Pub. Util. Comm'n*, 237 Cal. App. 4th 812, 859-60 (2015) (quoting *Mullane v. Cent. Hanover Bank & Trust Co.*, 339 U.S. 306, 314 (1950)) (emphasis added).

1092 *People v. Western Air Lines, Inc.*, 42 Cal. 2d 621, 632 (1954).

1093 *People v. Ramirez*, 25 Cal. 3d 260, 268 (1979) (citing *Morrissey v. Brewer*, 408 U.S. 471, 481 (1972)).

1094 *Id.* at 269.

1095 *Id.* The four relevant factors for determining whether a particular procedure comports with due process under the California Constitution, according to the California Supreme Court, are: "(1) the private

In opening and reply comments on the Order Instituting Rulemaking ("OIR") for this proceeding,[1096] several parties discussed issues relevant to the NEM-1 and NEM-2 tariffs and customers, offering representations of the purported cost shift from solar customers to non-solar customers,[1097] assertions of high costs and resulting rate increases,[1098] commentary on issues of equity from the standpoint of lower income customers,[1099] and arguments regarding the current NEM tariff's lack of compliance with AB 327.[1100] Relatedly, and relying on many of these contentions, a number of parties recommended that the Commission include issues associated with NEM-1 and NEM-2 within the scope of this proceeding. For instance, parties advocated for revisiting the legacy treatment of all NEM customers,[1101] ending enrollment in the NEM-2 tariff

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interest that will be affected by the official action, (2) the risk of an erroneous deprivation of such interest through the procedures used, and the probable value, if any, of additional or substitute procedural safeguards, (3) the dignitary interest in informing individuals of the nature, grounds and consequences of the action and in enabling them to present their side of the story before a responsible governmental official, and (4) the governmental interest, including the function involved and the fiscal and administrative burdens that the additional or substitute procedural requirement would entail." *Id.* The analysis under the federal Constitution is similar, but does not include the analysis of the dignitary interest in factor three. *See Mohilef v. Janovici*, 51 Cal. App. 4th 267, 287 n.18 (1996); *Gilbert v. Homar*, 520 U.S. 924, 931-32 (1997).

[1096] R.20-08-020, *Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering* (August 27, 2020) ("OIR").

[1097] R.20-08-020, *Joint Opening Comments of SCE, PG&E, and SDG&E on OIR to Revisit Net Energy Metering Tariffs Pursuant to D.16-01-044, and to Address Other Issues Related to Net Energy Metering*, p. 8 (October 5, 2020) ("Joint IOUs Opening OIR Comments"); R.20-08-020, *Comments of the Natural Resources Defense Council on the OIR to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering*, p. 7 (October 5, 2020) ("NRDC Opening OIR Comments").

[1098] R.20-08-020, *Comments of The Utility Reform Network on the Preliminary Scope and Schedule*, p. 3 (October 5, 2020) ("TURN Opening OIR Comments").

[1099] Joint IOUs Opening OIR Comments, pp. 4-5; R.20-08-020, *Opening Comments of the Public Advocates Office on OIR to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering*, pp. 6-7 (October 5, 2020) ("PAO Opening OIR Comments"); NRDC Opening OIR Comments, pp. 6-7.

[1100] TURN Opening OIR Comments, p. 2.

[1101] Joint IOUs Opening OIR Comments, p. 8; PAO Opening OIR Comments, p. 10 ("the first phase of this proceeding should also identify a reasonable timeline to shift customers on existing NEM tariffs to immediately,[1102] and, more generally, for the consideration of changes to existing NEM tariffs to be included within the proceeding's scope.[1103]

None of the issues in the Scoping Ruling clearly encompass any of the NEM-1 or NEM-2 issues discussed at length in parties' comments on the OIR. The Commission has thus considered and rejected the suggestion that these NEM-1 and NEM-2 tariffs, and customers' associated legacy treatment, should be open issues for litigation in this proceeding. Cal Advocates' statement that "[t]he Commission has not ruled that NEM 1.0 and 2.0 issues are out of scope" is absurd:[1104] the Commission determines issues to be *in scope* because listing all issues that are out of scope is not possible.

In their testimony and responses to discovery, Sierra Club, Cal Advocates and CUE list various scoping issues to try to capture existing NEM customers. When asked which scoping issues allowed it to raise changes to the NEM-1 and NEM-2 tariffs in this case, Cal Advocates initially cited Issues 2, 4, 5 and 7 in response to discovery,[1105] but then changed their minds and also relied on Issue 6 in their rebuttal testimony.[1106] Sierra Club also cited to items 2, 4 and 6,[1107]

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a new cost-effective and equitable NEM tariff."); TURN Opening OIR Comments, p. 8 (recommending that the scope include the "[t]erm of any 'grandfathering' for customers on current and future NEM tariffs"); R.20-08-020, *Reply Comments of the California Wind Energy Association on Proposed Decision on Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to D.16-01-044, and to Address Other Issues Related to Net Energy Metering*, p. 6 (October 13, 2020) ("CalWEA Reply OIR Comments").

1102 Joint IOUs Opening OIR Comments, p. 10.

1103 R.20-08-020, *Opening Comments of the Coalition of California Utility Employees on the OIR*, p. 7 (October 5, 2020) ("CUE Opening OIR Comments") ("All of the existing NEM related tariffs should be examined for possible modification in this proceeding. This includes the tariffs listed above, as well as the NEM 1.0 tariff."); CalWEA Reply OIR Comments, p. 6.

1104 Exh. PAO-02 at 4-17:17.

1105 Exh. CSA-02 at Exh. CSA-02 at Attachments 13 (Cal Advocates Response to CALSSA DR 2.04(f)-(i)).

1106 Exh. PAO-02 at 4-17:16 to 4-18:114.

1107 Exh. SCL-02 at 1:11-2:9.

and CUE focused on Issue 6 in its rebuttal testimony and during its cross examination of CALSSA Witnesses Heavner and Plaisted.[1108]

Issue 7 is not currently being addressed since the Scoping Ruling limits direct testimony to Issues 2-6, evidentiary hearings to Issues 3-6 and briefing to Issues 2-6;[1109] thus, the specious argument regarding Issue 7 can be dismissed out of hand. Issues 2, 4, and 5 can also be quickly dismissed based on the emphasized language below:

> 2. What information from the Net Energy Metering 2.0 Lookback Study should *inform the successor* and how should the Commission apply those findings in its consideration?[1110]
>
> 4. What program elements or specific features should the Commission include *in a successor* to the current net energy metering tariff? [1111]
>
> 5. Which of the analyzed proposals should the Commission *adopt as a successor* to the current net energy metering tariff and why? What should the timeline be for implementation? [1112]

NEM-1 and NEM-2 programs are existing programs. Scoping Items 2, 4 and 5 (and Item 7 for that matter) clearly distinguish between a "successor" and the existing NEM-1 and NEM-2 tariffs by utilizing the term "the current net energy metering tariff." None of these items can be relied upon to modify the terms and rates under which NEM-1 and NEM-2 customers take service.

That leaves Issue 6, which states:

> 6. Other issues that may arise related to current net energy metering tariffs and subtariffs,

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1108 6 Tr. 1030:26-1032-7 (CSA – Heavner and Plaisted); Exh. CUE-02 at 38:3-5.

1109 Scoping Ruling at 4.

1110 Scoping Ruling at 2 (emphasis added).

1111 Scoping Ruling at 3 (emphasis added).

1112 Scoping Ruling at 3 (emphasis added).

> which include but are not limited to the virtual net energy metering tariffs, net energy metering aggregation tariff, the Renewable Energy Self-Generation Bill Credit Transfer program, and the net energy metering fuel cell tariff. [1113]

CUE's testimony acerbically points out, and CUE's cross focused on the fact, that this scoping item includes the phrase "current net energy metering tariffs." [1114] However, the context of the rest of Issue 6 makes clear that this scoping item is addressing the other tariffs and sub-tariffs that exist in California beyond the main NEM tariffs. The phrase "current net energy metering tariffs" refers directly to the examples of current net metering tariffs listed later in the item, *i.e.*, the virtual net energy metering tariffs, net energy metering aggregation tariff, and the net energy metering fuel cell tariff. If the Commission intended to list examples of the "current net energy metering tariffs" that were in scope in this case, how could it miss listing the NEM-1 and NEM-2 tariffs?

Moreover, Issue 6 also includes the phrase "other issues that *may arise*", *i.e.*, issues that had not been raised or addressed in parties' comments on the OIR. The issue of retroactively revising the NEM-1 and NEM-2 tariffs, and the rates under which those customers take service, had been raised by numerous parties, as described above. The Scoping Order was issued "[a]fter considering the comments on the Order, replies to the comments, and discussion at the prehearing conference,"[1115] meaning those issues had already been taken into account and are not issues that "may arise".

Regardless of what the language in Issue 6 is supposed to mean, the real problem is that it is likely a reasonable, affected customer would have read the scoping items and determined their

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1113 Scoping Ruling at 3 (emphasis added).

1114 Exh. CUE-02 at 38:3-5.

1115 Scoping Ruling at 2.

existing investments were not at risk. The private interest and the "dignitary interest in informing individuals of the nature, grounds and consequences of the action" at issue in questions of due process are both high in this case.[1116] For many solar customers, their solar energy system is one of their most valuable assets, carrying a stature akin to home equity or a car, for example. Such customers may have intervened in the proceeding had they known certain parties to the docket would attack the viability of their investments despite the Scoping Ruling's focus on the successor tariff.

The fact is customers on the NEM-1 and NEM-2 tariffs were not put on clear notice that the value of their investments are at risk in this case, which violates their due process rights. If the Commission would like to adopt proposals that renege on its prior commitments to NEM customers, and reopen these tariffs or create new rates for them to take service under, it should go about it in a clear and transparent manner and not the backhanded manner these parties propose.

B. Applying an "Equity Fee" to NEM-1 Customers Violates the Law.

Equity fee proposals that apply to NEM-1 customers violate Section 2827(g) of the Public Utilities Code, which requires "each net energy metering contract or tariff" to "be identical, with respect to rate structure, all retail rate components, and any monthly charges, to the contract or tariff to which the same customer would be assigned if the customer did not use a renewable electrical generation facility."[1117] The "equity fee" proposals from TURN, CUE, Cal Advocates, and NRDC violate this safe harbor provision by assigning fees to those customers to

[1116] *People v. Ramirez* at 269.

[1117] Cal. Pub. Util. Code § 2827(g).

which the customers would not otherwise be subject but for their use of a rooftop solar system.[1118] Thus, assigning these fees to NEM-1 customers violates the law.

C. Moving NEM Customers to High-Fixed Charge Rates is Bad Policy.

Most Customers Will Soon Be on Time-of-Use Rates.

With regard to Sierra Club's proposal to move customers to certain TOU rates, Sierra Club observes that most customers still have not yet been transferred to a TOU rate.[1119] While it is true NEM-1 customers are not required to take service under a TOU rate, a majority of them will soon be on TOU due to the migration to residential default TOU rates.[1120] PG&E estimates that 66% of NEM-1 customers will not opt out of TOU. SCE finds that only 17% of NEM-1 customers opted out of TOU in the first wave of migration.[1121] Sierra Club proposes that these customers be *forced* to take the additional step of being on particular TOU rates, but the Commission should understand that most NEM-1 customers will be moved from tiered rates to TOU rates.

These Proposals are a Consumer Protection Nightmare That Has Not Been Sufficiently Studied and Will Undermine Trust in the Commission's Promises to Customers.

CUE, NRDC, Cal Advocates, TURN, and Sierra Club's proposals are a consumer protection nightmare. CUE, NRDC, Cal Advocates and Sierra Club use a variety of broad-brush reasoning to conclude that NEM-1 and NEM-2 customers have had sufficient opportunity to pay off their investments, regardless of the individual circumstances these customers might be

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1118 Exh. CSA-02 at 16:20.

1119 Exh. SCL-01 at 9:5-13.

1120 Exh. CSA-02 at 58:21-63:23.

1121 Exh. CSA-02 at Attachment 9 (Joint IOUs Response to CALSSA DR 2.07). SDG&E declined to investigate the TOU opt-out rate of NEM-1 customers.

facing.[1122] For example, Cal Advocates relies on average payback periods derived in the Lookback Study and the E3 white paper to conclude that its five-year trigger for a transition to NEM-3 "is reasonable because *the majority* of these systems would have paid for themselves at that time."[1123] The NEM-2 Lookback Study, however, undermines Cal Advocates' own position, suggesting NEM-2 paybacks take as long as 8-10 years.[1124]

CUE relies on *average* payback periods to justify transitioning NEM-1 and NEM-2 customers to NEM-3 immediately, or at the end of those payback periods, despite acknowledging in testimony that the "length of payback depends on the year of installation, geographical location, and other factors … ."[1125] TURN does not conduct any analysis of the impact of its proposal on existing customers other than to assert that "adding a modest surcharge to the monthly bills" NEM-1 customers "should not have a material impact on the overall payback periods" for those customers.[1126]

Equally problematic is that none of these parties have conducted any thorough analysis to attempt to determine the size of the pool of customers that will *not* have paid off their systems prior to the fees and changes these parties propose take effect, *i.e.*, the size of the "minority" implied in Cal Advocates' discussion of majorities. The record in this proceeding simply does not show that the customers, particularly low-income customers, are certain to emerge unscathed by their retroactive proposals.

1122 *See, e.g.,* Exh. NRD-01 at 22:9-23:5; Exh. SCL-02 at 13:9-23:7.

1123 Exh. PAO-3 at 4-3 to 7-16; *Public Advocates Office Amended Proposal for a Successor Tariff to the Current Net Energy Metering Tariffs*, p. 45 (April 7, 2021) ("Cal Advocates Proposal"); Exh. CSA-02 at Attachment 13 (Cal Advocates Response to CALSSA DR 2.04(d)-(e)).

1124 Exh. CSA-02 at 59:10-11 (citing to the NEM 2.0 Lookback Study, p. 85).

1125 Exh. CUE-01 at 18:11-20:2.

1126 Exh. TRN-01 at 35:16-19.

The risk these parties ask the Commission to take will affect *all* NEM-1 and NEM-2 customers, including the low-to-middle income customers these parties purport to benefit. As CUE's testimony highlights: "*CARE only protects households with incomes less than 200% of poverty, which for a family of 4 is currently $53,000 per year. You aren't in poverty if you are slightly above that income, but in California you sure aren't making ends meet without a struggle."*[1127] NRDC admits its fee would apply to customers with similar income levels that have installed solar,[1128] endangering their payback periods. Sierra Club makes a similar admission, *i.e.*, that its proposal would apply to customers with "income exceeding 80% of their area median income."[1129] Cal Advocates objected and did not answer the question of whether it "agrees that low-income and middle-income NEM customers would be subject to its proposal,"[1130] but states in direct testimony that it supports NRDC's fee, which does apply to these customers. The result of adopting these proposals would be a substantial consumer protection concern that is certain to harm the same populations it is intended to help.

Beyond harming those that have already gone solar, these proposals will discourage others from going solar by leading to poor customers experiences, where the Commission—in the circumstances where it is legal to do so—would undermine customers' expectations in the legacy treatment of their investments.[1131] The policy justifications underlying Sierra Club's and Cal Advocates' direct testimony are good ones: all parties to this proceeding agree electrification

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1127 Exh. CUE-01 at 2:6-9.

1128 *See* Exh. CSA-02 at Attachment 15 (Response to CALSSA DR 2.08(e)) (citing to p. 15 of NRDC's proposal, which states "*All* existing non-CARE and non-FERA residential customers, who continue under NEM 1.0 and NEM 2.0, will be required to pay an equity fee of $2.50 per kWdc of distributed generated capacity installed per month.") (emphasis added).

1129 Exh. CSA-02 at Attachment 14 (Sierra Club Response to CALSSA DR 1.01(e)).

1130 Exh. CSA-02 at Attachment 13 (Cal Advocates Response to CALSSA DR 2.04(j)).

1131 Exh. CSA-02 at 61:3-6.

is an important goal, customers should be encouraged to shift solar energy production to on-peak periods, and behind-the-meter storage is an important technology that must be encouraged. [1132] However, these parties' approaches sow distrust in Commission policies, treating customers like they are part of an investment scheme in which victims are encouraged to make an initial investment and then later told they need to make more investments in order to maintain the value of their initial investment. [1133]

Solar companies rely on solar customers recommending to friends and neighbors that they install distributed energy resources, including energy storage. [1134] Tellingly, neither NRDC nor Cal Advocates was willing to provide a responsive answer to the question of whether they believed adoption of their proposals would lead to positive customer experiences that may "lead to existing solar customers recommending to friends and neighbors that they install distributed energy resources" [1135] or to "to include energy storage" in their existing system. [1136] Sierra Club pointed to customer education efforts.[1137] All of these proposals certainly will lead to less customers wanting to invest in solar, and retroactive proposals like these do significant harm to the State's climate goals and the industry's ability to grow sustainably. [1138]

Also contributing to the reputational harm these proposals would create for the Commission's distributed generation programs is the fallacy that "payback" is the right metric to

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1132 Exh. CSA-02 at 61:3-62:6.

1133 Exh. CSA-02 at 61:3-62:6.

1134 Exh. CSA-02 at 61:3-62:6.

1135 Exh. CSA-02 at Attachment 15 (NRDC Response to CALSSA DR 2.08).

1136 Exh. CSA-02 at Attachment 13 and 15 (Cal Advocates Response to CALSSA DR 2.04(k) and NRDC Response to CALSSA DR 2.08).

1137 Exh. SCL-01 at 20:22-27; Exh. CSA-02 at Attachment 14 (Sierra Club Response to CALSSA DR 1.01(f)).

1138 Exh. CSA-02 at 61:3-62:6.

consider undermining existing investment values. For example, Sierra Club states that "[c]hanges to solar compensation should be gradual and should preserve sufficient bills savings for these customers to *recover the cost* of their investments."[1139] NRDC and CUE base their proposals on similar reasoning.[1140] Solar investments are major assets for customers, second only to perhaps their home and their vehicle. The funds encumbered by such assets could have been used for innumerable different investments, all of which provide competing rates of return. Thus, the right metric is not payback but whether customers are happy with their returns on their investments, whether they would consider recommending to others that they go solar, and whether the Commission is good investment partner or a bad one. There can be no question that adopting these proposals would put these important relationships at risk.

They also fly in the face of ratemaking principles intended to ensure rates cause customers to make informed long-term investments.[1141] The current legacy treatment for NEM tariffs provide "a uniform and reliable expectation of stability of the NEM structure" under which customers decide to invest in their customer-sited renewable DG systems.[1142] They "promote consistency" between tariffs,[1143] "promote fairness in the treatment of customers" under an existing NEM tariff and customers under a NEM successor tariff, [1144] they follow "a reasonable payback period as contemplated in AB 327, in that existing analyses show that customers of *all* customer classes are likely to achieve full payback for system installation costs

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1139 Exh. SCL-02 at 14:14-16.

1140 Exh. NRD-01 22:3-23:5; Exh. CUE-01 at 18:11-20:2.

1141 Exh. CSA-02 at 62:7-63:23 (citing to James C. Bonbright, *Principles of Public Utility Rates*, Columbia Univ. Press (1961)).

1142 D.16-01-044, *Decision Adopting Successor to Net Energy Metering Tariff,* p. 100 ("D.16-01-044").

1143 *Id.* at Conclusion of Law 14.

1144 *Id.* at Conclusion of Law 15.

in this timeframe,"[1145] and they are "consistent with the expected useful life of NEM PV systems as reflected in several contexts, including PPAs and financing agreements."[1146] As the Commission itself concluded at the time the transition period for NEM-1 customers was set, "[t]he Governor's message to the legislature when signing AB 327 encourages the Commission to protect customers for the expected life of their NEM-eligible systems."[1147] CUE, Cal Advocates, NRDC, TURN, and Sierra Club's proposals go against these long-standing principles.

Lastly, it is not possible to take a customer group as expansive as NEM-1 and NEM-2 customers and make sweeping conclusions regarding the "fairness" of individual investments.[1148] The parties making these proposals spill a lot of ink on cost-shift analysis that is inflated, as discussed in CALSSA's Rebuttal Testimony.[1149] Many NEM-1 customers took service under that tariff in the early 2000s when California's coincident peaks fell in the middle of the day, while other NEM-1 and NEM-2 customers take service after peaks had shifted to the later afternoon and evening hours.[1150] Some NEM customers were large electricity users that installed solar to reduce their bills; many other customers are small customers that installed solar because it was the right thing to do for the environment. Some NEM-1 and NEM-2 customers are located in disadvantaged communities and others in gated communities.[1151] The socioeconomic status,

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1145 D.14-03-041, *Decision Establishing a Transition Period Pursuant to Assembly Bill 327 for Customers Enrolled in Net Energy Metering Tariffs*, Finding of Fact 5 (emphasis added) ("D.14-03-014").

1146 *Id.* at Finding of Fact 6.

1147 *Id.* at Finding of Fact 4.

1148 Exh. CSA-02 at 62:7-63:23.

1149 Exh. CSA-02 at 34:5-36:9.

1150 Exh. CSA-02 at 62:7-63:23.

1151 Exh. CSA-02 at 62:7-63:23.

motivations for installations, avoided costs at the time each customer group began NEM, and geographies among all of these customers are quite different.[1152] It is overly simplistic to suggest one fixed solar fee applied to all such customers is a reasonable and equitable approach.[1153]

V. REQUEST FOR ORAL ARGUMENT AND ALL-PARTY MEETING

In accord with Commission Rule 13.14 (b), CALSSA requests that an oral argument in this proceeding be held before the full Commission. To render this oral argument most effective in their decision-making process, CALSSA requests that the oral argument be held subsequent to the issuance of the Proposed Decision and be structured to address specific points of interest to the Commissioners. Providing structure to the oral argument is the best means of ensuring that the Commissioners' points of interest are addressed.

In addition, prior to the issuance of the Proposed Decision, CALSSA requests that an all-party meeting be held. Such a meeting could be sponsored by any of the Commission offices but could be attended by all offices. Such a meeting could allow all Commission offices to become better versed in the key issues and parties positions earlier on in the deliberation process. Such knowledge could assist them in their review of the proposed decision.

VI. CONCLUSION

For the myriad legal and policy reasons discussed in detail in this Brief, CALSSA urges the Commission to adopt CALSSA's proposal and reject the Pro-Transmission Parties' Proposals. While this Opening Brief does not address every party's proposal, components of other parties' proposals align with those of the Pro-Transmission Parties. CALSSA does not agree with those components, which suffer from the same shortcomings as those proposed by the

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[1152] Exh. CSA-02 at 62:7-63:23.

[1153] Exh. CSA-02 at 62:7-63:23.

Pro-Transmission Parties, and CALSSA likewise urges the Commission to reject them for the reasons stated herein.

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Respectfully submitted,

Tim Lindl
Julia Kantor
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (510) 314-8385
E-mail: tlindl@keyesfox.com
jkantor@keyesfox.com

Attachment A

Acronym Table

TABLE OF ACRONYMS

Acronym	Description
A.	Application
AB	Assembly Bill
ACC	Avoided Cost Calculator
ALJ	Administrative Law Judge
AMI	Area Median Income
Cal Advocates	Public Advocates Office at the California Public Utilities Commission
CAISO	California Independent System Operator
CALSSA	California Solar and Storage Association
CalWEA	California Wind Energy Association
CARE	California Alternate Rates for Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CUE	The Coalition of California Utility Employees
D.	Decision
DAC	Disadvantaged Communities
DER	Distributed Energy Resources
FERA	Family Electric Rates Assistance
FERC	Federal Energy Regulatory Commission
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
GWh	gigawatt-hour
IOU	Investor-Owned Utility
Joint IOUs	Southern California Edison Company, Pacific Gas & Electric Company, and San Diego Gas & Electric Company
kW	kilowatt
kWh	kilowatt-hour
LCR	Local Capacity Requirements
MASH	Multifamily Affordable Solar Housing
MW	megawatt
MWh	megawatt-hour
NBC	Non-bypassable Charge
NEM	Net Energy Metering
NRDC	The Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
OIR	Order Instituting Rulemaking
PAC	Program Administrator Cost
PAO	Public Advocates Office
PCF	Protect Our Communities Foundation
PCT	Participant Cost Test
PG&E	Pacific Gas and Electric Company
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
R.	Rulemaking

RIM	Ratepayer Impact Measurement
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
SEIA	Solar Energy Industries Association
SOMAH	Solar on Multifamily Affordable Housing
TRC	Total Resource Cost
TWh	terawatt-hours
TURN	The Utility Reform Network
VNEM	Virtual Net Energy Metering
VS	Vote Solar