**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 COMMENTS OF THE CALIFORNIA SOLAR & STORAGE ASSOCIATION ON PROPOSED DECISION REVISING NET ENERGY METERING TARIFF AND SUBTARIFFS

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On behalf of the California Solar & Storage Association

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OPENING COMMENTS OF THE CALIFORNIA SOLAR & STORAGE ASSOCIATION ON PROPOSED DECISION REVISING THE NET ENERGY METERING TARIFF AND SUBTARIFFS

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the California Solar & Storage Association (CALSSA) submits these opening comments on Administrative Law Judge (ALJ) Hymes' *Proposed Decision Revising Net Energy Metering Tariff and Subtariffs* (PD).[1] The PD's attempt to navigate the stormy waters of this proceeding sinks well short of the shore, let alone reaching any kind of safe harbor that would constitute a balanced and measured approach to reforming net energy metering (NEM). The Grid Participation Charge (GPC) violates state and federal law, in particular the Public Utility Regulatory Policies Act of 1978 (PURPA). Each part of the PD's package of a GPC; complex and changing export rates; uncertain retail rates with high fixed charges; instantaneous netting; and a tepid and ill-conceived Market Transition Credit (MTC) challenges the commercial viability of the PD's tariff for *both* the mainstream market and low-to-moderate income (LMI) customers; but the combination of those parts overwhelms any hope of viability. As a result, the PD will cause a severe contraction of the State's solar industry, with CALSSA's smallest members and their workers hit hardest (the PD fails to even mention its outsized impact on small companies with little access to energy storage systems).[2]

If the PD is adopted, it will be a potent weapon in the hands of utilities across the country seeking to snuff out customer-sited solar. It rewrites *California's* climate change policy to one aimed at *slowing down* the pace of rooftop solar installations—a seismic shift where California treats customers with distributed energy resources (DERs) with more adversity than states like Alabama and Wyoming, where few customers have installed solar.[3] The PD breaks a promise the Commission made to NEM-1 and NEM-2 customers by modifying their legacy periods without having given them any real notice it might do so.

The PD's aspiration to "proceed in a measured fashion" is a sound objective,[4] and Appendix A to these comments demonstrates the substantial corrections necessary to fulfill that aim: eliminate the GPC; replace the MTC with a true glidepath for export rates; lock in tariff components for the full financing

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[1] R.20-08-020, *Proposed Decision Revising Net Energy Metering Tariffs and Sub-Tariffs* (Dec. 13, 2021) (PD); R.20-08-020, *Administrative Law Judge's Ruling Partially Granting the Coalition for Community Solar Access' Requests for an Extension of Time to File Comments and For an Increase in Page Limits for Opening and Reply Comments* (Dec. 17, 2021) (extending the deadline for opening comments on the PD to Jan. 7, 2022).

[2] Exh. CSA-06; 1 Tr. 122:4-124:6 (IOU Tierney); *see also* R.20-08-020, *Opening Brief of the California Solar & Storage Association*, pp. 111-112 (Aug. 31, 2021) (CALSSA Opening Brief).

[3] *See* CALSSA Opening Brief at 165-168 (showing solar fees like those in the PD are exceptionally rare and would be the highest, or among the highest, in the country); Exh. CSA-01 at Attachments 12 and 13.

[4] PD at 90-91, Findings of Fact (FOF) 48, 88.

term; simplify export rates and revise them to account for long-term benefits; and honor the 20-year legacy period for NEM-1 and NEM-2 customers.

I. THE GPC PLAINLY VIOLATES STATE AND FEDERAL LAW.

The GPC is an additional fee imposed solely on net billing customers with no cost-based rationale.[5] CALSSA focuses here on two of the many legal errors the PD commits by adopting the GPC:[6] (1) the GPC violates PURPA's regulations requiring that rates for sales to customers with Qualifying Facilities (QFs)[7] be non-discriminatory,[8] and (2) the GPC effectively nullifies customers' right to self-generate by imposing additional fees on behind-the-meter consumption that render self-generation uneconomic.

A. The GPC Violates PURPA.

The PD misstates and then dismisses CALSSA's position on the GPC.[9] CALSSA demonstrated *both* that such charges are not "just and reasonable"[10] *and* that they violate PURPA's anti-discrimination provision.[11] Pursuant to PURPA's regulations, a proponent of any additional fee on QF customers must

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5 The record is devoid of any cost-of-service study comparing the cost to serve NEM and non-NEM customers on which the Commission can properly rely. CALSSA Opening Brief, pp. 128-132. The record does not contain any cost-of-service studies in SCE's or SDG&E's service territory comparing NEM and non-NEM customers. While the Joint IOUs and Cal Advocates referenced testimony in PG&E's most recent Phase II general rate case proceeding (A.19-11-019) as providing support for a cost-of-service difference between NEM and non-NEM customers, the Commission specified in the final decision in that proceeding that it was adopting PG&E's proposed cost-of-service methodology "for use in this proceeding only." D.21-11-016, Conclusion of Law (COL) 25; *id.*, Ordering Paragraphs (OP) 12 and 13 (ordering PG&E to complete additional analysis to support the inclusion of received loads in its methodology in subsequent proceedings). Further, the record does not contain any cost-of-service study showing a cost-based rationale for imposing a charge on *successor net billing* customers (whose cost-of-service compared to that of non-net billing customers has not been assessed).

6 *See* CALSSA Opening Brief, pp. 123-168 (imposing a GPC would violate state law: the GPC (1) is not just and reasonable under state law because it is not based on cost-of-service (violation of Cal. Pub. Util. Code § 451), and (2) is discriminatory under state law and would disincentivize self-generation, contrary to state law (violations of Cal. Pub. Util. Code §§ 453(c), 2801)). The PD also errs by implicating FERC jurisdiction. The only detail the PD provides on the costs intended to be recovered by the GPC is its finding that "Public Advocates Office's calculation method [is] reasonable." PD at 125-127. That method was aimed, in part, at recovering transmission costs. Exh. PAO-01 at 3-24 and Line 2 of Table 3-6; PD at 125. As the Joint IOUs conceded on the record, transmission revenue requirements and associated rates fall under federal jurisdiction and must be approved by FERC. 16 U.S.C. § 824; 16 U.S.C. § 824d; Resolution E-3930, p. 4 and Finding 2 (May 26, 2005); Exh. CSA-01 at Attachment 4 (IOUs Response to CALSSA DR 4.23).

7 *See* CALSSA Opening Brief, p. 16 (NEM-eligible behind-the-meter solar facilities of 1 MW or less constitute QFs under PURPA. QF status automatically applies to on-site solar generators up to 1 MW, including those on net metering tariffs. 18 C.F.R. §§ 292.203(d), 292.204(b); FERC Order No. 732, 130 FERC ¶ 61,214, 2010 FERC LEXIS 507 (2010)). The same status would apply to customers on the PD's net billing tariff.

8 18 C.F.R. § 292.305(a). *See also* 16 U.S.C. § 824a-3(c).

9 PD at 99.

10 *See* CALSSA Opening Brief, pp. 125-134.

11 *See id.*, pp. 137-142.

analyze and justify this differential rate treatment.[12] The Commission commits a clear error of law in adopting differential rate treatment without even *mentioning* these federal requirements, let alone conducting the required analysis under PURPA.

Regardless, the Commission cannot legally adopt the GPC because the utilities and their allies have failed to justify the charge in a manner that meets the Federal Energy Regulatory Commission's (FERC) standard. FERC's regulations have two general requirements relevant to rates for sales to QF customers: they must be both (i) just and reasonable and (ii) non-discriminatory.[13] These protections are "perhaps the most fundamental cornerstone of the Section 210 [of PURPA] scheme"—a scheme "designed to remove the barriers inherent in the monopoly/monopsony position of most electric utilities to the development of economically appropriate levels of cogeneration or small power production and to 'encourage' such production."[14]

In addition to violating PURPA's just and reasonable requirement,[15] the GPC contravenes its requirement that rates for sales to QFs "[s]hall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility."[16] This anti-discrimination provision prohibits differential treatment for QFs as compared to other similarly situated customers from a cost causation perspective, *i.e.*, a rate cannot discriminate without a cost causation basis for doing so.[17] Specifically, FERC Order No. 69, implementing this requirement, prohibits differential treatment of QFs

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[12] 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) ("FERC Order No. 69") ("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*" except "if, 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, the utility may base its rates for sales upon those data and principles.") (emphasis added).

[13] 18 C.F.R. § 292.305(a)(1)(i) and (ii).

[14] *Alcon (Puerto Rico) Inc.*, 32 FERC ¶ 61,247, 61,581 (1985) (Stalon, dissenting); *Alcon (Puerto Rico) Inc.*, 38 FERC ¶ 61,042 (1987) (granting rehearing in part and reversing in part 32 FERC ¶ 61,247, referencing the reasoning in Stalon's dissent).

[15] A charge that is not based on cost-of-service—*i.e.*, not designed to account for any incremental cost to the utility of providing service to NEM customers, as compared to comparable non-generating customers—is not "just and reasonable." *See* CALSSA Opening Brief, pp. 125-134. This violation of the "just and reasonable" standard is also a violation of state law (Cal. Pub. Util. Code § 451). Not only does the PD make clear that the GPC is not designed to account for any such incremental costs, but further, such a design would not be *possible* based on the record of this proceeding. *See* PD at 98-101 (failing to cite to any cost-of-service study showing any incremental costs caused by NEM customers or explain how the fee is designed to recover such costs); *see also* n. 5, *supra*. The GPC therefore imposes rates for sales that are not just and reasonable.

[16] 18 C.F.R. § 292.305(a)(1)(ii).

[17] *See* FERC Order No. 69, 45 Fed. Reg. 12,214, 12,228 ("[t]his section contemplates formulation of rates on the basis of traditional ratemaking (*i.e.*, cost-of-service) concepts").

unless a utility can demonstrate this cost-based rationale and establish the rate: (1) is based on accurate data, (2) is established using consistent system wide costing principles, and (3) applies to the utility's other customers with similar load or other cost-related characteristics.[18] A violation of *any single* prong of this test would be sufficient to show a failure to adhere to FERC Order No. 69.[19] The GPC violates all three.

Prong 1: Accurate Data Demonstrating Cost-of-Service Difference.

The first prong of this test requires a showing, with accurate data, of a cost-based rationale—*i.e.*, a cost-of-service study demonstrating that QF customers have a higher cost-of-service than non-QF customers, or cause specific incremental costs as compared to non-QF customers—that justifies disparate treatment.[20] The Arizona Corporation Commission (ACC) recently reinforced this standard in striking down a $0.93/kW-dc grid access charge applicable to residential solar customers, finding that the charge violated PURPA because the record "[did] not contain any evidence of specific costs imposed by DG solar customers on APS's system; nor ha[d] APS attempted to quantify such costs."[21]

Similarly, in this proceeding, the record does not contain any cost-of-service study comparing the cost to serve QF and non-QF customers—and finding incremental costs imposed by QF customers—on which the Commission can properly rely in order to design such a charge.[22] While the PD finds that current NEM customers cause costs associated with certain grid services and policy mandates, and cause costs even when not directly importing from the grid,[23] these are not the relevant questions under PURPA; rather, the question is whether they cause *incremental* costs *as compared to* non-NEM customers.

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18 FERC Order No. 69, 45 Fed. Reg. 12,214, 12,228; 18 C.F.R. § 292.305(a)(2). *See also* 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) (providing guidance regarding how to interpret PURPA's anti-discrimination provision and FERC Order No. 69 in the context of a challenge to the Alabama Public Service Commission's approval of rates for back-up services for QFs, stating: 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.'") (Commissioner Joint Statement).

19 Commissioner Joint Statement, p. 2; 18 C.F.R. § 292.305(a)(2).

20 *See* ACC Docket No. E-01345A-19-0236, Decision No. 78317, pp. 357-358 (Nov. 9, 2021) (ACC Decision); *In re: Mr. and Mrs. Gregory Swecker v. Midland Power Cooperative*, 2000 Iowa PUC LEXIS 1528, **161-163, 184, 188-192 (March 28, 2000) (in interpreting PURPA's antidiscrimination provision, the Iowa Utilities Board 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).

21 ACC Decision, pp. 357-358.

22 *See* n. 5, *supra*.

23 PD at 98-100.

In the absence of any such comprehensive studies, the PD appears to assume that the Lookback Study's flawed cost-of-service analysis addressing NEM-2 customers is sufficient to impose the GPC.[24] However, the Lookback Study does not provide a basis for differential treatment of QF customers under PURPA because the study's analysis only compares residential NEM-2 customers' annual bills to those same customers' cost of service.[25] Focusing solely on NEM customers' contributions 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 that cost responsibility, while ensuring equitable treatment for similarly situated customers. Many customers, particularly residential customers, do not cover their full cost of service.[26] PURPA prohibits charges that single out QFs for differential treatment without a showing they cause *incremental* costs relative to other customers in the same class.

Importantly, not only is the Lookback Study's analysis not designed to assess whether NEM customers impose any incremental costs as compared to non-NEM customers, but its findings comparing the cost of service of NEM customers pre- and post-installation actually suggest that the *opposite* of the required finding under FERC Order No. 69 is true. Namely, the study finds that NEM-2 customers' cost of service is *lower* after they install solar, for both residential and commercial customers,[27] suggesting that NEM customers on average impose *less costs* than non-NEM customers once they go solar.

Even if the record contained any evidence that NEM customers cause incremental costs—which it does not—the GPC would need to be *designed to recover* such costs in order to comply with PURPA. Neither the parties advocating for the GPC nor the PD itself even *suggest* that these charges are designed to recover any such incremental costs caused by NEM customers.[28] Rather, the PD is clear that the GPC is designed to address a cost shift the PD concludes exists as a result of flawed rate design.[29] Because it is not designed to recover incremental costs caused by NEM customers based on a quantification of those costs using accurate data, the GPC violates PURPA.

Prong 2: Consistent System Wide Costing Principles.

The GPC violates the second prong of the analysis because it was not established using consistent system-wide costing principles. FERC Order No. 69 provides that if, on the basis of "consistent system-

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24 *Id*. at 47, 98-100.
25 Exh. PAO-03 at 3-32:13-19.
26 *See* Exh. CSA-01 at 99:6-14.
27 Exh. CSA-01 at 97:10-12 n. 165 (citing NEM 2.0 Lookback Study, pp. 10-11, 95-97).
28 CALSSA Opening Brief, pp. 125-128.
29 PD at 98-100.

wide costing principles, the utility demonstrates that the rate that would be charged to a comparable customer without its own generation is not appropriate, the utility may base its rates for sales upon those . . . principles."[30] This provision mandates the use of consistent cost-of-service ratemaking principles across all ratepayers to fairly determine the cost responsibility of QFs; only if such consistently applied costing principles demonstrate that QF customers cause specific, incremental costs may a utility impose an additional charge based on this showing.[31] The record contains no such comprehensive analysis using consistent system-wide costing principles. Instead, the PD seeks to claw back certain costs that would otherwise be avoided under volumetric rate design.[32] The GPC therefore was designed based on a lost revenue analysis, rather than on consistent system-wide costing principles.

Prong 3: Applies to Customers with Similar Cost-Related Characteristics.

Finally, the GPC violates the third prong of this test because it applies solely to residential NEM customers,[33] and it is not designed to apply to other customers with similar load or other cost-related characteristics. Two FERC Commissioners recently made clear in a challenge to the Alabama Public Service Commission's approval of rates for back-up services for QFs: to establish an additional fee on QFs, the record must "sufficiently demonstrate[] 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])"; "[i]f QF customer usage patterns are comparable to those of customers without on-site generation who reduce volumetric consumption through other means," the charge may be discriminatory.[34]

The record in this proceeding does not contain any comprehensive data demonstrating that NEM customer load profiles are different from those of customers without onsite generation, nor does it demonstrate that NEM usage patterns are incomparable to those of customers without on-site generation

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30 FERC Order No. 69, 45 Fed. Reg. 12,214, 12,228.

31 *See* ACC Decision, p. 358 ("Under . . . federal law, a utility may not discriminate against DG solar customers, and it must justify any difference in treatment based on accurate data and consistently applied cost-allocation principles, including that charges applied to DG customers also apply to non-DG customers with similar load characteristics." The record contained "no evidence of any specific and unique costs that DG solar customers impose on APS's system" to justify treating solar customers differently, and the proposed charge therefore was rejected.).

32 *See* PD at 98-100.

33 *Id*. at 127.

34 Commissioner Joint Statement, p. 2. On March 31, 2021, the Southern Environmental Law Center petitioned FERC to enforce the requirements of PURPA in Docket No. EL21-64-000. As is customary, FERC determined not to bring an enforcement action, clearing the way for the petitioners to challenge the legality of the charge under PURPA in federal court. The federal district court for the Middle District of Alabama is currently considering the legal challenge in Case No. 2:21-CV-00469-MHT-SMD.

that reduce consumption through other means.[35] Further, the PD did not even *address* the issue of NEM customer load profiles as compared to those of non-NEM customers,[36] instead focusing solely on the ability of the current rate design to "accurately calculate all of a customer's energy and grid usage, *with respect to net energy metering customers*."[37] While the PD briefly addresses the difference between self-consumption and certain conservation practices, referencing a difference in the associated load profiles, it does not include any data analysis and does not take on more than this narrow issue.[38] The PD's finding that NEM customers "cause costs even when not directly importing energy from the grid" because "the grid must be always prepared for the intermittent decrease and increase of usage" also fails to address this deficiency in the PD's analysis.[39] The question of whether self-generation customers cause *any* costs when not importing is not the relevant question under PURPA; rather, the relevant question is whether those costs are the result of distinct usage patterns of power from the grid that are not comparable to those of customers without onsite generation who reduce volumetric consumption through other means.

The GPC violates PURPA by failing to meet each prong of the analysis required by its anti-discrimination provision.[40] To equitably approach this issue in line with federal law, 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 QF customers.[41]

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[35] CALSSA Opening Brief, pp. 128-132 (demonstrating that the Joint IOUs' efforts to distinguish demand patterns of NEM customers relied on minimal and unrepresentative data (discussing the Joint IOUs' claims in Exh. IOU-02 at 63:10-12)); Exh. PAO-03 at 3-31:9 to 3-32:6 (Cal Advocates provides limited data derived from data requests that do not appear to be on the record, comparing certain usage characteristics of NEM and non-NEM customers (data provided only for SCE and SDG&E customers; timeframe associated with data not disclosed in testimony)). Further, these data do not compare NEM usage patterns to those of customers that reduce consumption through other means. *See also* CALSSA Opening Brief, pp. 125-134 (no party 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 that difference).

[36] *See* PD at 97-101.

[37] *Id*. at 100 (emphasis added).

[38] *Id*. at 99.

[39] *Id*. at 100.

[40] 18 C.F.R. § 292.305(a); Commissioner Joint Statement, pp. 1-2 (citing 18 C.F.R. § 292.305(a)(2)). FERC Order No. 69 makes clear that a QF "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." FERC Order No. 69, 45 Fed. Reg. 12,214, 12,228. Thus, to the extent that the Commission considers cost avoidance achieved through self-generation to be a "subsidy" to NEM customers, the GPC rate design violates FERC Order No. 69 in singling out NEM customers to lose this subsidy, while other customers reducing their demand through other means would maintain this subsidy.

[41] CALSSA would not oppose a fixed charge applied to all residential customers if it is consistent with the Commission's rate design principles.

B. The GPC Infringes on Customers' Right to Self-Generate.

Customers have a right to self-generate their own electricity, which is rooted in both state and federal law.[42] In particular, this right is implicit in PURPA's regulations addressing a QF's right to sell energy to its host utility, which grant a QF customer the ability to determine exactly how much energy the customer would like to use on-site.[43] The GPC would effectively nullify a net billing customer's right to self-supply by imposing $8/kW fees on behind-the-meter consumption that would deny customers the full economic benefits of self-generation.[44] Preserving those economic benefits is one of the primary legislative intents underlying PURPA's Section 210 scheme, which encompasses the right to self-generate. As articulated by FERC, "the whole point of the Section 210 scheme" is to provide QF customers the assurances necessary to encourage them to install QFs "to reduce their energy costs."[45] Congress established PURPA's regulatory scheme to ensure customers have the ability to realize the economic benefits of self-generation. The GPC infringes on customers' right to self-generation by clawing back those benefits.

II. THE PD'S NET BILLING TARIFF IS NOT COMMERCIALLY VIABLE.

The PD aims for balance between various policy objectives and legal requirements,[46] but the proposed net billing tariff falls well short of that goal. The PD buys into the falsehood propagated by parties like NRDC, TURN, and Cal Advocates that sudden and extreme changes to NEM can ensure "customer-sited renewable distributed generation continues to grow sustainably."[47] This conclusion relies on numerous errors in law and fact to settle on an uneconomic successor tariff that effectively would stop the market for customer-sited, exporting DERs in its tracks. Few customers would adopt, and few banks would finance, systems under the PD's tariff due to the following defects:

- Little investment certainty over the lifetime of the system;

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42 *See* CALSSA Opening Brief, pp. 143-146 (demonstrating the right to self-generate is implicit under (1) common law property principles, (2) Cal. Pub. Util. Code § 2801, and (3) PURPA, in light of the explicit rights granted to QFs under PURPA (under FERC's regulations, QFs may "provide energy as the [QF] *determines such energy to be available for such purchases*." 18 C.F.R. § 292.304(d)(1) (emphasis added). This language grants a QF customer the ability to determine (a) exactly how much energy the customer would like to use on-site, and (b) exactly how much energy the customer would like to sell to the utility.)).

43 18 C.F.R. § 292.304(d)(1).

44 *See* CALSSA Opening Brief, p. 143; PD at 127.

45 *See Alcon (Puerto Rico) Inc.*, 32 FERC ¶ 61,247, 61,581 (1985) (Stalon, dissenting); *Alcon (Puerto Rico) Inc.*, 38 FERC ¶ 61,042 (1987) (granting rehearing in part and reversing in part 32 FERC ¶ 61,247, referencing the reasoning in Stalon's dissent).

46 *See, e.g.*, PD at 50-51, 57, 126, 130, and FOFs 48, 55, 149, 160, 180, and 207.

47 Cal. Pub. Util. Code § 2827.1(b).

- Almost no chance of realizing the ten-year payback on which it is based, or realizing savings on financed systems, which the PD did not even attempt to measure despite much discussion of the importance of monthly bill savings;
- Nearly 576 different export rates over the course of a single year for a single customer, all of which undervalue the long-term benefits their systems provide;
- An ill-conceived and short-lived MTC that does not come close to softening the impact of other harmful tariff components;
- Instantaneous netting that is impossible to model for customers considering solar investments;
- Benefits for LMI customers that are overwhelmed by the PD's other shortcomings;
- Little chance of economic viability for DERs for nonresidential customers; and
- The elimination of opportunities for renters and farmers to go solar under VNEM and NEMA.

The attached Appendix includes the substantial revisions necessary to address these shortcomings.

A. The PD's Proposed Tariff Is Complex, Open-Ended and Difficult to Predict.

Prior Commission NEM decisions have emphasized the need for customers to have a reasonable expectation of stability in their investment and transparency into the savings from that investment over 20 years.[48] Under NEM, that analysis considered one variable to ensure a project would provide sufficient return over its lifetime: retail rates carrying over a century of historical performance to foster consumer and investor confidence. The PD gives lip service to investment certainty,[49] but then opts for a tariff relying on four variables that are difficult to predict, making financing risky and lifetime savings estimates extremely difficult to convey.

The PD dismisses substantial record evidence to the contrary in order to conclude an ACC-based export rate will be a stable and reliable ratemaking device.[50] The major cause of ACC volatility is that, unlike other Commission mechanisms where inputs like fuel costs are simply updated each year, the ACC *methodology itself* is subject to regular updates that are hotly litigated.[51] Even IOU Witness Morien admitted to the difficulty for solar customers in predicting the degree of future changes to the ACC at the time they invest in solar: "I think it's really difficult to say because we don't know what major updates or

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48 D.14-03-041, p. 2, FOFs 4-6, and COL 2; D.16-01-044, pp. 100-101 and COL 14; *see also* D.14-03-041, COL 7 (emphasizing the importance of installers disclosing to 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.").

49 *See* PD at 128.

50 PD at 90, FOFs 82, 84-87.

51 *See* CALSSA Opening Brief, pp. 90-92.

minor updates are going to be made to the [ACC]."[52] When asked about how much the avoided cost-related components might change over the course of ten years, she admitted: "I don't think anybody has a forecast of what the ACC is going to be in 10 years."[53]

ACC outcomes can change radically based on seemingly small factors, such as the policy decision determining the 20-45 hours in each year the ACC uses to assign capacity value based on outage risk.[54] In just this past year, the 2021 ACC dropped 60% to 66% in the 25-year levelized value of solar and 74% in the single-year 2030 value of solar as compared to the 2020 version.[55] The bungled, contentious process leading to the 2021 ACC underscores these concerns, where even the Commission admitted in D.21-11-035 that the Energy Division did not follow the process it prescribed for changes to the ACC.[56]

While the market likely can tolerate a slow transition to ACC-based compensation, as discussed in more detail below, combining the PD's overnight transition to ACC-based export rates with the other variable tariff components the PD adopts overwhelms the potential for investment certainty. While customers taking service on the successor tariff will be assessed the $8/kW "initial" GPC for 10 years, the solar fee will be "updated" to the then-current charge 10 years later.[57] There is no guarantee an "updated" GPC would not be much higher than a customer's initial GPC, extending the customer's payback period, or undermining the investment altogether. In contrast, the MTC is much smaller than the GPC, especially for customers installing after the first year of the net billing tariff, and the MTC will be gone or nearly gone when GPC fees potentially rise.[58]

The PD then adds to these variables a requirement for customers to go on rates with fixed charges for SDG&E and SCE, and the likelihood of a future fixed charge rate for PG&E.[59] The PD states it is maintaining a five-year legacy period that exists for NEM customers;[60] however, that legacy treatment

52 *See* 3 Tr. 465:18-21 (IOU – Morien) (stated with regard to the expected degree of change in the ACC component of the IOUs' proposed solar fee).

53 *See* 3 Tr. 466:9-11 (IOU – Morien).

54 Exh. CSA-02 at 41:20-24.

55 Exh. CSA-01 at 81:11-12 (citing to *2021 Distributed Energy Resources Avoided Cost Calculator Documentation For the California Public Utilities Commission*, pp. 7-8, Figure 4 (May 3, 2021)).

56 D.21-11-035 at 4 (admitting the Commission's "failure to send out a list of proposed minor changes" before a 2020 workshop to consider those changes, but nonetheless determining stakeholders were still "afforded legally sufficient notice and opportunity to be heard.").

57 PD at 127.

58 *Id*. at 119 and Figs. 3-5.

59 *Id*. at 123-124 ("As was the case with the NEM 2.0 tariff, customers of the successor tariff will have a five-year legacy period for the time-of-use rate they take service on upon interconnection.").

60 *Id*.

only applied to TOU periods, which are no longer volatile. As a result, the five-year legacy period for retail rates for customers on the successor tariff adds no certainty.

These variables are complex and numerous, as evidenced by the PD's own *ordering paragraph* failing to understand the different mechanics. Ordering Paragraph 3 concludes the net billing tariff's elements will be available to "an enrolled customer" for "a period of ten years from interconnection date," except for "the import rate itself."[61] However, under sub-part (a), the ACC-based *export* rate for these customers is only fixed for five years and then floats.[62] Only the GPC and MTC are fixed for ten years. If the PD gets its own tariff wrong, customers cannot be expected to understand it.

Parties explored the problems with open-ended proposals like the PD's in detail on the record. Like Cal Advocates' and the IOUs' proposals, the PD gives customers no way to know the degree of a potential increase in the GPC ten years in the future, the ACC values for export compensation beyond Year 5, or the eventual level of unavoidable fixed charges beyond Year 5.[63] 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.[64] If the customer does make the investment, consumer protection concerns result: subsequent changes to these components could result in a substantial loss of value no contractor could have predicted.[65] This uncertainty also makes it virtually impossible to comply with the spirit of D.20-08-001, which requires solar providers to present accurate savings estimates to customers.[66] Further, the uncertainty is a major barrier to financing, which is the main way that the majority of customers – particularly moderate-income customers, public entities and non-profits – adopt energy systems.

The PD attempts to resolve this uncertainty by relying on the flawed, extra-record analysis of payback discussed in the next section. However, even if the PD could demonstrate a specific payback based on reasonable assumptions, uncertainty about whether long-term benefits could be undermined by

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61 *Id*. at 128 and OP 3.

62 *Id*. at 114-115, Ordering Paragraph 3(a) ("Following the five-year lock-in period, export compensation will be based on averaged monthly avoided cost values, as previously described, but calculated by the version of the Avoided Cost Calculator adopted as of January 1.").

63 *See* 3 Tr. 480:19-482:25 (IOU–Morien); 6 Tr. 925:14 to 927:2 (PAO–Gutierrez); Exh. CSA-01 at 20:2-4.

64 6 Tr. 925:14 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); *see also* Exh. CSA-01 at 20:2-4.

65 *See* CALSSA Opening Brief, pp. 90-106, 149-158, 193-195.

66 D.20-08-001, pp. 8-10.

factors like large increases in the GPC in Year 10 is likely to sink an investment before it is even made. Moreover, uncertainty is equally problematic for commercial customers as residential customers, and the PD does not even attempt to reduce this problem with a transition mechanism for commercial customers.

B. The PD's Extra-Record Payback Analysis is Flawed.

During the payback, or cost recovery period, customers are at a financial loss.[67] The PD cobbled different components together to assert it achieves a 10-year payback for customers that install storage-paired solar systems,[68] despite even the Commission's own E3 whitepaper including a target cost recovery period of 7.5 years.[69] Record evidence from NREL data shows that with a seven-year cost recovery period, solar can reach 40% of the market, while at a 10-year payback only 25% of the market will adopt solar, with paybacks of 20 years only reaching five percent of the market.[70]

The Commission's analysis used a fictional solar cost to conclude mainstream market solar-only customers can achieve a payback ranging between 7.4 and 16.5 years, and paired systems can achieve payback between 7.8 and 11.2 years.[71] However, abundant record evidence—from parties beyond just CALSSA[72]—shows that the theoretical and unrealistic values used in that analysis constitute a foundational error in fact. First, the PD uses a $2.19/W cost of solar.[73] Few, if any, California customers will pay this amount because that figure is based on the bare minimum components and labor for the easiest possible installation, rather than average real-world costs.[74] Simply replacing the $2.19/W cost with a more realistic 2023 solar cost of $3.37/W based on LBNL's analysis of actual market prices results in solar paybacks with the MTC of 18.4 years and 18.2 years for PG&E and SCE's territory, respectively.[75] The payback for CARE solar customers is 14.6 years and 14.4 years for SCE and PG&E customers with

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

68 PD at 67, 130, FOF 48, and COL 14.

69 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 (Jan. 28, 2021)).

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

71 PD at 130.

72 *See id*. at 70.

73 This is the capital cost for 2023 in the E3 Net Billing Tariff PD Model, which corresponds to the cost of $2.34/W in 2022. E3 adds operating costs to get to the $2.59/W figure reported in Appendix B of the PD.

74 PD at Appendix B, p. B1; Exh. CSA-01 at 63:7-67:10. NREL itself recognizes that there are costs that lie between the ideal costs and the true costs. Exh. CSA-01 at 63:7-67:10 (citing to NREL, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020*, pp. 24-25)); *See also* 3 Tr. 444:12-25 (IOU – Morien) ("Q: Okay. Thank you. So the cost recovery period the IOUs calculated will be shorter than systems that use financing; right? Because you assumed cash was used. A: All else equal? Q: All else equal, yes. A: Yes.").

75 The 18-year figures are derived by using a 2023 value of $3.37/W, expressed in 2021 dollars. *See* CSA-01 at 67, Table 7. This assumes generous cost reductions between the 2019 LBNL cost of $3.80/W and a 2023 cost. For SDG&E, the payback is about 11 years.

the MTC. The solar plus storage payback with the MTC is 12.7 years for PG&E and SCE for both CARE and non-CARE customers, *far longer* than the 10-year payback which the PD claims to achieve.[76]

The Commission should rerun its payback analysis with these more accurate assumptions, and put the model and the corresponding results on the record.[77] In addition to simple payback period, another output of the model is first year bill savings. The Commission should run the model to determine whether or not a customer financing a solar and storage system is receiving electricity bill savings that are at least 10% greater than loan payments within the first year of the system being deployed, consistent with the monthly bill savings metric that the PD endorses as valuable to analyzing a tariff's viability.[78] Monthly savings is simply another side of the same coin as payback, but it is a critical metric for LMI and public sector customers that depend on financing.[79] Running that analysis shows that monthly bills savings for solar and storage under the PD are 14% *less than* a loan payment, on average, for both PG&E and SCE, showing again that the PD's tariff is not viable. For solar without storage, savings are 40% and 39% less than loan payments.[80]

C. The PD's Tariff Results in Almost 10,000 Different Export Compensation Rates Statewide—None of Which Account for the Long-Term Benefits of a 25-Year Asset.

The PD's export compensation scheme adds excessive uncertainty and complexity.[81] The PD points to the importance of rate mechanisms that are "user-friendly",[82] but it then discards that approach when setting export rates based on averaged monthly ACC values for each hour, differentiated between weekday and weekend and each of the State's 16 climate zones.[83] The result is a tariff where a single customer will need to determine export compensation based on 576 different export rates each year; statewide contractors will need to manage 9,216 different rates each year among the State's 16 different

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76 For SDG&E, it is 10.4 years.

77 While the PD states this "same model was used previously in this proceeding to analyze the proposals discussed in Section 6 of this decision[,]" as ALJ Hymes noted, that model was never sponsored by a witness, moved into the record, or subject to discovery or cross examination. PD at 129; R.20-08-020, *Procedural Email Providing Guidance on Party Testimony* (May 21, 2021). The most recent run was not served on the service list until after the PD was issued. R.20-08-020, *Publication of Model Used in Appendix B of PD (Revising Net Energy Metering Tariffs and Subtariffs)* (Dec. 20, 2021).

78 PD at 64-67, FOFs 45 and 48, and COL 14.

79 Exh. SVS-04 at 48: "almost 80% of residential solar systems are financed."

80 Exh. PCF-15 (Lookback Study) at 75: average loan characteristics are 18 year term at 5% interest. This produces an annual loan payment of $1726 for the 4.73 kW PG&E system in the E3 model and $1599 for the SCE 4.38 kW system.

81 *See* Cal. Pub. Util. Code § 451.

82 PD at 78, FOF 142 (discussing the MTC).

83 *Id*. at 113, 115-116, and Ordering Paragraph 3(a).

climate zones.[84] Tracking these over the lock-in period of the first five years multiplies this to 46,000 export values. As discussed above, these rates will change substantially over the lifetime of the system as both ACC inputs and the ACC methodology itself changes every year. This compensation scheme is so complex the PD does not have a handle on the actual compensation rates that would result on day one, instead requiring the IOUs to "coordinate to standardize the method of deriving export compensation rates" based on the ACC.[85] Stakeholders will not know the actual export rates until 100 days after the decision is finalized, and there may also be major updates to the ACC shortly thereafter.

Moreover, the values set in the PD ignore the long-term values the ACC provides. The PD finds that "using single years' avoided cost values, instead of averaged costs, brings the cost of the tariff closer to its value."[86] However, solar energy systems are a 25-year resource,[87] and the ACC has a levelization period as a primary input.[88] By using a five-year schedule of values and then an annual ACC value without a lifetime levelization, the Commission is ignoring the long-term avoided transmission and distribution benefits DERs provide.[89] The amount of grid infrastructure avoided by twenty years of DER installations represents a completely different level of savings compared to one-year deferrals of upgrades that have already been planned and are nearing construction.

D. The MTC Fails as a Glidepath.

The PD correctly finds a glidepath is essential "to balance the multiple requirements the tariff is required to meet,"[90] but then it fails to provide a meaningful mechanism to serve that role. The PD's aim for the MTC is to provide certainty for the industry during the transition, create gradual rate reform, and enable a reasonable payback period for customers investing in onsite renewable generation.[91] In reality, the only thing it provides is a small discount to the new solar fee for PG&E and SCE customers.

While, "at its foundation, the credit is meant to provide an incentive to customers to install customer-sited renewable distributed generation,"[92] basic math shows this will not be the case. The PD's

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84 (24 hourly export rates) * (2 day types) * (12 months) = 576 different rates. (576 different rates) * (16 climates zones) = 9,216. The 9,216 figure is likely 9,792 since there are two different versions of Climate Zone 10.

85 PD at 116.

86 *Id*. at 114-115 and FOF 136.

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

88 *Id*. at 37:3-4.

89 Exh. CSA-01 at 84:9-86-10.

90 PD at 73 and FOF 55.

91 *Id*. at 102, 104, 116-118 and Table 5.

92 *Id*. at 116-117.

tariff imposes new fees of $500 per year for a typical residential solar customer, plus fees within rates of $144 per year for SCE and $192 per year for SDG&E.[93] It would reduce the value of NEM credits by 80%,[94] reducing the value of exported energy to about $250 per year for typical residential customers.[95] The PD gives PG&E early adopters $100 per year and SCE early adopters $225 per year in MTCs.[96] Simple arithmetic shows that customers with DERs would be better off without using this tariff.[97]

The problem with the MTC is that targeting a specific payback period requires ascertaining elements of payback that are constantly in flux. Solar and storage costs increase and decrease, as do the underlying rates that form customer bill savings.[98] Predicting those figures is difficult in the near-term, and adopting a revised MTC at the five-year mark is both far too late, since the MTC expires after four years, and will be fiercely litigated.[99] The PD errs in adopting it and should be revised to adopt a meaningful glidepath.

The glidepath recommended by Sierra Club is a middle ground approach. To truly meet the Commission's objective of "a balanced approach to promoting the continued adoption of solar,"[100] the PD could set the first step lower than the Sierra Club recommendation and have fewer steps, while maintaining the step trigger of each GW of solar adoption. Although 1 GW is less than one year of solar adoption according to recent trends, a capacity-based stepdown is preferred because it would protect against a stalled market being exacerbated by step-downs during a period of low market activity. The transition should end no lower than the avoided cost values using a levelization period equal to the term of tariff eligibility.[101]

Commercial customers were not included in Sierra Club's proposal, but a glidepath is also needed for commercial customers. Because current commercial energy rates are far lower than residential, the

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93 All calculations use a typical residential system size of 6 kW-DC/5.2 kW-AC. ($8/kW/month) x (5.2 kW) x (12 months) = $499. 5.2 kW-AC is used in the calculation since the $8/kW is assessed on AC capacity.

94 Exh. CSA-02 at 50, Table 8 (the PD's export rates are similar to the 2021 Levelized ACC values in Table 8).

95 Exports of 5,000 kWh/yr * 0.05 $/kWh = $250/year.

96 5.2 kW-AC * $1.62/kW-AC/mo = $101/yr for PG&E; 5.2 kW-AC * $3.59/kW-AC/mo = $224/yr for SCE.

97 For PG&E: $500 GPC is greater than $250 in NEM credits + $100 MTC. For SCE, $500 GPC + $144 monthly charges in rates is greater than $250 in NEM credits + $250 MTC; for SDG&E, $500 GPC + $192 monthly charges in rates is greater than $250 in NEM credits.

98 10 Tr. 1774:10-1777:5 (NRD – Chhabra).

99 PD at 117 and Ordering Paragraph 3(b).

100 *Id*. at 67.

101 *See* Exh. CSA-02 at 44, Table 7 for 25-year levelized values from the 2021 ACC. Levelization periods of 15 or 20 years would produce lower values.

starting point should be at or near NEM-2 export rates. The step-downs can happen at the same time as for residential customers, when the combined market reaches each GW of adoption.

E. The PD's Negative Impacts Outweigh the Benefits of Its Low-Income Provisions.

The PD asserts an intention to expand solar access in low-income and disadvantaged communities,[102] yet despite its efforts to address these inequities, it weakens the solar value proposition for these customer groups by adopting many of the same harmful program elements for these customers as it does for general market customers. The PD would adopt the same export compensation rate for low-income customers as for general market customers, while moving to instantaneous netting and leaving customers exposed to potential further harmful changes.[103] The PD attempts to overcome these negative changes with an MTC aimed at achieving a 10-year payback for solar and storage for CARE customers who install at the start of the net billing tariff. The PD misses that mark, largely because it uses a fictitious solar cost as detailed above. But even if it were to correct this problem, a 10-year payback has not proven successful for CARE customers. The E3 July model shows that solar paybacks for CARE customers under NEM-2 are 10.0 years for PG&E, 11.1 years for SCE, and 6.7 years for SDG&E.[104] Because these paybacks have not been sufficient for CARE customers previously, we should not expect that to change under the successor tariff, especially as the MTC would step down to zero over a short period. The PD therefore errs in concluding that its low-income customer policies will advance the Commission's equity goals and "increase participation by households in disadvantaged communities."[105]

The PD's Equity Fund would not remedy these hits to the solar value proposition for these customers. The PD establishes no guardrails or direction for the Equity Fund, punting on almost all the significant details of this policy solution until after an April 2022 stakeholder workshop.[106] CALSSA supports creation of an Equity Fund and recommends directing it to battery rebates for CARE customers and preferably other low- and moderate-income customers as well.[107] Adopting this change in the PD should not be expected to carry the market, but it would help provide storage to customers in need.

The PD's attempt to achieve the Commission's equity goals would be severely undermined by its suite of successor tariff policies and its underdeveloped Equity Fund proposal. To remedy these deficiencies in the PD, in addition to the changes urged herein, CALSSA supports the equity-related

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102 PD at 136.
103 *Id*. at 136-137. Specific elements of the subtariff could be reduced after a five-year evaluation. *Id.* at 137.
104 E3 Residential Bill Model, June 15, 2021, using an upfront capital cost of $3.37/W.
105 PD at 76, 136.
106 *Id*. at 138-139.
107 *Id*. at 138.

proposals advanced by GRID Alternatives, Vote Solar, and Sierra Club in their concurrently filed opening comments. In particular, the PD's definition of "low-income customers" should be expanded. In the Environmental and Social Justice (ESJ) Action Plan adopted in February 2019, the Commission identified ESJ communities and provided definitions for "low-income households" and "low-income census tracts."[108] Those categories and median-income-based definitions should be incorporated for the reasons discussed by GRID Alternatives, Vote Solar, and Sierra Club.

F. The Analysis of the Nonresidential Tariff is Contradictory and Erroneous.

The PD's discussion of nonresidential tariffs is riddled with legal error and internal contradictions. First, while the PD correctly acknowledges that D.19-05-019 designated the TRC as the primary cost effectiveness test,[109] and that the Lookback Study found that the nonresidential sectors of the NEM-2 tariff had TRC and PCT results of 1.0 or better,[110] it concludes that the nonresidential NEM-2 tariff is not cost-effective.[111] In doing so, it allows the results of the RIM test alone to trump the other cost-effectiveness test results, contradicting not only D.19-05-019[112] but also *the PD's own conclusions* elsewhere that: the cost-effectiveness tests "should not be used individually or in isolation but, instead, allow for the consideration of the tradeoffs between the tests,"[113] and the Commission should "not strive for perfection in one test but rather a balance of the value and tradeoffs between the tests."[114]

Second, the PD's reasoning to support its decision to adopt the equal export rate treatment between nonresidential and residential customers, thus "ensuring equity" among customers,[115] is deeply faulty. Applying the same policy to differently situated customers is not necessarily equitable and, even if it was, the PD violates this very principle 29 pages later by providing a MTC to residential customers and denying one to commercial customers.[116] The PD correctly finds "[i]nclusion of a glide path is essential to balance the multiple requirements the tariff should meet" but fails to offer any transition mechanism for non-residential customers.[117] The PD requires commercial, industrial, government, school, nonprofit, and

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108 Exh. CSA-35 at 9-10 & nn. 6-7. The definition could also explicitly include multifamily households.

109 PD at 10-11.

110 *Id*. at 43.

111 *Id*.

112 D.19-05-019, p. 24 and COL 2 ("Hence, we find it reasonable to designate the TRC as the primary cost-effectiveness test, except where expressly prohibited by statute or Commission Decision . . . RIM and PAC test results should only be considered supplemental to the TRC test results").

113 PD at 56 and FOFs 28, 30-31.

114 *Id*. at 57 and FOFs 28, 30-31.

115 *Id*. at 93 and FOF 90.

116 *Id*. at 122.

117 *Id*. at 160, FOF 55.

agricultural customers to transition overnight from export rates based on the retail rate to export rates at avoided cost. The PD states the MTC was set "as defined in the Commission modeling,"[118] but the E3 Net Billing Tariff PD Model contains no analysis of medium or large commercial customers. The only commercial analysis looks at a customer with 17,000 kWh/yr of usage, which is about the size of two homes, *using rate schedules without demand charges*. The PD's decision to cut export rates with no glidepath for commercial customers should be reversed.

G. The PD Undermines the Viability of VNEM and NEMA by Ignoring Netting.

The PD would eliminate the viability of VNEM (largely used by multi-family properties) and NEMA (largely used by farmers and farmworkers). With no behind-the-meter savings, no project would be viable with ACC-based credits only. The PD states that it is adopting "revisions to the VNEM tariff that align with the adopted successor tariff."[119] However, the two tariffs are not aligned. NEM allows customers to generate their own power and gives export credits only to the portion of generation that is not used onsite. VNEM under the PD would treat all generation as exports even though much of it is used onsite. The PD claims it is creating ***net*** billing for the virtual ***net*** energy metering tariff, but it would not allow customers to "net" anything.

To align the successor tariffs, the Commission should allow interval netting, giving kWh credits to customers for the generation that is concurrent with onsite consumption within the interval, while giving dollar credits based on export compensation rates for generation that exceeds concurrent consumption within the interval. If the Commission does not choose to make that change within this decision, it should delay changes to all VNEM and NEMA tariffs rather than only for the VNEM tariff specific to the SOMAH and MASH programs.[120] That review should be expanded to include all of VNEM and NEMA.

H. Current NEM Paired Storage Rules Must Be Extended to New Tariff.

The PD states, "To distinguish this tariff from the two prior net energy metering tariffs, we break from the previous nomenclature and do not refer to this tariff as NEM 3.0 but rather refer to it as the Net Billing tariff."[121] This change calls into question whether previous decisions ordering changes to net energy metering tariffs also apply to the new net billing tariff. The most important of these decisions is D.19-01-030 on NEM Paired Storage. That decision established conditions under which solar systems

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[118] *Id*. at 122.
[119] *Id*. at 142.
[120] *Id*. at FOF 177 (stating "It is prudent to delay any changes to low-income subtariffs of VNEM until review in this proceeding of additional findings from the affordability proceeding and the SOMAH evaluation.").
[121] PD at 110.

with energy storage qualify for net metering, ordering the utilities to submit an "advice letter modifying their respective net energy metering tariffs and interconnection agreement forms, as applicable, to implement the power control-based options."[122] CALSSA would invite the opportunity to revisit and streamline the storage pairing rules in the near future, but the starting point should be the current rules. It would be greatly disruptive not to incorporate storage pairing rules in the new net billing tariff.

III. OTHER LEGAL AND FACTUAL ERRORS AND OMISSIONS.

The PD falls short in numerous other areas:

- Without providing them notice,[123] the PD breaks promises made to NEM-1 and 2 customers to give them "a *uniform and reliable expectation of stability* of the NEM structure under which they decided to invest."[124] The PD states "these customers will continue to experience monthly bill savings from the successor tariff"[125] without evidence of such savings for financed systems.
- Instantaneous netting was excluded from E3's payback analysis, cannot be estimated and conflicts with the hourly generation projection required in D.20-08-001.[126] The PD states the utilities shall include both channels of data in their energy usage data portals to allow customers to have the most accurate data possible;[127] but a customer only has readings in one channel before installing solar. Including both channels of data will not enable accurate estimates of solar savings.[128]
- The PD should clarify that a customer can add a battery to a NEM-2 system without losing NEM-2 status. This is the practice under NEM-1. Failing to continue the practice would greatly discourage adoption of energy storage.[129]
- If a GPC is adopted, the final decision should state the GPC is not additive to the minimum bill.[130]
- The PD is unclear on whether there is a solar fee if a NEMA arrangement contains both commercial and residential accounts.

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122 D.19-01-030, Ordering Paragraph 4.

123 *See* CALSSA Opening Brief, pp. 222-227.

124 D.16-01-044 at 100.

125 PD at 149.

126 D.20-08-001 at Attachment A, p. 7 ("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." (emphasis added)).

127 PD at 107.

128 Exh. ASO-01 at 6:15-17.

129 *See* PG&E Schedule NEM2, Special Condition 8.b.

130 The PD states, "a minimum bill is no longer necessary" (p. 105), but the current minimum bill was created by D.15-07-001 rather than the NEM-2 decision and will continue unless it is explicitly struck.

- The PD is correct to exclude the SOMAH and MASH Programs, but should acknowledge that the Commission must provide more sufficient protection to those customers to ensure those tariffs provide the statutorily mandated "economic benefits" to LMI customers in multi-family housing that the GPC would eliminate on its own.[131]
- Suggesting certain societal benefits from DERs cannot be determined in this proceeding because other resources might provide those benefits is a disingenuous reading of Commission precedent.[132] Similarly, the PD should not decline to consider societal benefits from land conservation and avoided long-term transmission costs beyond those included in the ACC,[133] as the way that NEM systems impact those benefits is unique to NEM systems.
- The cutoff point between NEM-2 and NEM-3 is not clear, with the PD alternately referencing "submitting interconnection applications" and "signing an installation, lease or PPA contract."[134] The most clear and fair process would be to consider a "complete interconnection application," defined as an application that is free of deficiencies but may not yet have the post-inspection notification from the local building department.[135]
- Ordering Paragraph 11 violates General Order 96-B by failing to require a Tier 3 Advice Letter.[136]
- The PD misrepresents CALSSA's position in numerous places.[137]

IV. CONCLUSION

CALSSA urges the Commission to adopt the recommendations herein and in Appendix A.

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[131] Cal. Pub. Util. Code § 2870(g)(2).

[132] PD at 60-61 and FOFs 38-40.

[133] *Id*. at 60; Exh. CSA-01 at 84:9-86-10.

[134] PD at 153.

[135] Exh. CSA-02 at 70:6-71:11.

[136] Tier 3 advice letters are 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.

[137] PD at 145-146 (CALSSA's scoping and due process arguments are not "disingenuous" because they addressed NEM-1 and NEM-2 customers, not CALSSA or its members (CALSSA Opening Brief, pp. 222-227)); PD at 49 (misquotes CALSSA's briefing and suggests CALSSA argued that the "sustainable growth" statutory requirement should receive preference over others, when CALSSA simply argued that the Commission has interpreted Section 2827.1 to refer to the *continued growth* of DERs (CALSSA Opening Brief, p. 8)); PD at 17-18 (omitting the fact CALSSA's proposal targeted <u>single-family</u> households with income below 80 percent" and "census tracts with income less than <u>100</u> percent of AMI <u>and properties eligible for the MASH and SOMAH programs</u>" (Exh. CSA-01 at 23:6-8, 24:19-22)).

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Appendix A

Proposed Changes to Findings of Fact, Conclusions of Law, and Ordering Paragraphs

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, CALSSA offers the following index of recommended changes to the *Proposed Decision Revising Net Energy Metering Tariff and Subtariffs*, including proposed changes to the Proposed Decision's Findings of Fact, Conclusions of Law and Ordering Paragraphs. CALSSA's proposed revisions appear in underline and strike-through.

Findings of Fact

1. The evaluation of NEM 2.0 tells us whether the tariff is or is not performing as required.
2. The evaluation of NEM 2.0 establishes a foundation for creating a successor tariff.
3. The Lookback Study does not tell a complete story but informs the Commission on ~~how the successor tariff should be revised~~ potential issues with the NEM 2.0 construct.
4. A disagreement on an assumption in the Lookback Study does not equate to a flaw in that assumption, but rather a dispute about its accuracy.
5. The cost-effectiveness analyses in the Lookback Study have been conducted in accordance with prior Commission decisions.
6. The Lookback Study ~~is a sound~~ provides an analysis of the NEM 2.0 tariff.
7. ~~By producing and consuming energy behind the meter, NEM 2.0 tariff customers bypass infrastructure and other service costs embedded in volumetric rates by decreasing grid imports~~.
8. ~~The bypassed infrastructure and other service costs embedded in volumetric rates by NEM 2.0 participants over the course of the 20-year legacy period are shifted to non-participant ratepayers~~.
9. The Lookback Study indicates NEM 2.0 negatively impacts non-participant ratepayers based on the assumptions used therein.
10. ~~The precise financial impact of NEM 2.0 on nonparticipant ratepayers depends on the Avoided Cost Calculator values used.~~
11. ~~PCF's analysis and estimate of the financial impact of NEM 2.0 is incorrect.~~
12. The financial impact of NEM 2.0 on non-participants is caused by ~~more than the simple bill savings from net energy metering customer energy consumption.~~ the difference between the current export compensation rate and the value of the resource exported.

13. Without changes to the current tariff structure, the financial burden on the shrinking pool of nonparticipants implicated in the Lookback Study ~~is unsustainable and~~ could fall disproportionately on lower-income customers.

14. The Lookback Study finds that the commercial, industrial, and agricultural customer segments of the NEM 2.0 tariff generally pass the TRC test and pay rates that fully cover their costs of services.

15. No party disputes the cost-effectiveness results of the commercial, industrial, and agricultural segments of the NEM 2.0 tariff.

16. The Lookback Study followed the directives of prior Commission decisions regarding the methods for cost-effectiveness analysis.

17. While the Lookback Study found commercial, agricultural, and industrial sectors of the NEM 2.0 tariff had TRC and PCT results of 1.0 or better, the results of the RIM test ~~showed a cost/benefit ratio of were~~ less than 1.0.

18. ~~The Lookback Study indicates the nonresidential sectors of the NEM 2.0 tariff are not cost-effective.~~

19. The Lookback Study finds the NEM 2.0 tariff is not cost-effective for the residential customer segment based on the assumptions used therein.

20. ~~Lower-income customers are burdened with the additional expense of a portion of the 82 to 91 percent of the cost of service bypassed by NEM 2.0 customers whose bill payments only cover nine to 18 percent of their cost of service~~.

21. The Lookback Study indicates that the NEM 2.0 tariff may disproportionately harm~~s~~ low-income customers not participating in the tariff.

22. The Lookback Study indicates that the NEM 2.0 tariff disproportionately benefits non-CARE residential NEM 2.0 tariff based on the assumptions used therein. ~~customers while all other customers, including those with lower incomes, bear the addition of 82 to 91 percent of the cost of service bypassed by these tariff customers.~~

23. Parties have varying interpretations of the phrase "grow sustainably" and what that means for the successor tariff.

24. In D.16-09-036, the Commission stated it was not placing a greater emphasis on achieving sustainable growth over other statutory obligations, and nothing in the record of this proceeding leads the Commission to stray from this position.

25. Any proposed change to the net energy metering tariff should consider the impact on the growth of the net energy metering market.

26. The net energy metering tariff has and should continue to assist California in meeting its energy and climate goals.

27. The Commission considered and adopted estimates of transmission and distribution costs and greenhouse gas reductions~~, and system resiliency and reliability~~ in D.20-04-010.

28. The Standard Practice Manual states that the cost-effectiveness tests should not be used individually, but instead consider the tradeoffs between the tests.

29. D.19-05-019 ~~directs the use of~~ designates the TRC as the primary test for evaluating the cost-effectiveness of distributed energy resources ~~and recognized the importance~~ but stated the Commission should require the review and consideration ~~that~~ of the PAC and RIM tests.

30. Each cost-effectiveness test has value. ~~and together the tests tell a complete story.~~

31. Consideration of all the cost-effectiveness tests allows us to consider the values and tradeoffs between the tests.

32. ~~Application of the Societal Cost Test is premature because the evaluation to determine the final details of the test has not been completed.~~ Behind the meter solar provides societal benefits that should be taken into account when considering the cost-effectiveness of the resource.

33. D.20-04-020 concluded that consideration of the benefits of grid services provided by specific distributed energy resources should be addressed in resource-specific proceedings.

34. D.20-04-020 ~~considered SEIA/Vote Solar's proposals for avoided~~ found that reliability and resiliency ~~costs and found the benefits described could only be attributable to storage and storage plus solar~~ were not an avoided cost to be included in the ACC.

35. ~~D.20-04-020 found the SEIA/Vote Solar proposal for avoided reliability and resiliency costs did not show any deferred or avoided costs to utility ratepayers but indicated ratepayers using these technologies receive additional participant benefits~~.

36. ~~Neither~~ SEIA/Vote Solar ~~nor~~ and PCF provide convincing evidence that the examples of resiliency benefits offered are more than individual benefits that should be considered in assessing the cost effectiveness of BTM resources.

37. ~~Examples given by SEIA/Vote Solar and PCF are either private or highly speculative and limited to unique circumstances~~.

38. The proposed societal benefits of an updated social cost of carbon metric, land conservation, a reduced methane leakage multiplier, and avoided transmission costs are ~~not solely~~ applicable to net energy metering.

39. ~~Other distributed energy resources could reduce methane leakage and avoid future transmission costs~~.

40. Methane leakage and updated cost of carbon can be attributable to ~~resources other than~~ net energy metering resources.

41. Out-of-state methane leakage, incremental greenhouse gas reduction, and land conservation and use are not accounted for in the Avoided Cost Calculator.

42. ~~Allowing for an additional value for societal benefits associated with social cost of carbon metric, land conservation, a reduced methane leakage multiplier, and avoided transmission costs would result in the double counting of these benefits.~~

43. Parties agree to differing degrees that the Commission should consider the length of time for a customer's payback period when determining the reasonableness of the successor tariff.

44. Analysis of the successor tariff requires balancing multiple legislative requirements and guiding principles~~, and the needs of participants and nonparticipants.~~

45. The 2013 and 2017 NREL studies show that consumers look at monthly bill savings when making an economic decision on adopting solar.

46. Payback periods are <u>one</u> ~~not the predominant~~ factor for customers when considering solar adoption.

New Finding. <u>Payback periods and monthly bills savings are closely related.</u>

New Finding. <u>Monthly bills savings are important to low-to-moderate-income customers that rely on financing to invest in onsite generation.</u>

47. We find it reasonable to consider <u>both monthly bill savings and</u> the length of time for a customer's payback period when determining the reasonableness of the successor tariff.

48. <u>Seven to nine</u> ~~Ten~~ years to payback <u>for solar + storage installations</u> in combination with the monthly bill savings presents a balanced approach to promoting the adoption of paired solar.

49. ~~The increased number of years to payback will alleviate cost shift in the successor tariff.~~

50. The number of years to payback should reflect all <u>realistic</u> costs of solar and paired storage adoption, including maintenance costs<u>, based on observed market prices</u>.

51. ~~Only CALSSA disputes the NREL estimate of $2.34 per watt as the cost of solar.~~

52. The ~~NREL~~ <u>LBNL</u> estimate is the best estimate of the cost of solar available in this proceeding.

53. Any proposed change to the tariff should consider the impact on the growth of the net energy metering market.

54. The White Paper proposed that preservation of a viable market is likely to require a glide path including both a gradual rate reform and an external transitional support mechanism designed specifically to enable a reasonable payback period for customers investing in onsite generation.

55. Inclusion of a glide path is essential to balance the multiple requirements the tariff should meet.

56. ~~The magnitude and severity of cost shift requires immediate action by the Commission.~~

57. The glide paths proposed by CALSSA and SEIA/Vote Solar are inadequate, but the type of glidepath proposed by Sierra Club is a middle ground approach.

58. The equity issue in this proceeding cannot be addressed solely by revising the NEM 2.0 tariff ~~reducing the cost shift.~~

59. Disadvantaged communities should not continue to be left behind with respect to clean energy options, including electrification and storage.

60. The Commission's adopted Environmental and Social Justice Action Plan ~~The record is sufficient to~~ establishes a ~~different~~ low-income eligibility definition that is appropriate to use in this decision.

61. ~~Continuation of the cost shift feeds into higher electricity rates, which discourages the adoption of electrification measures~~.

62. The objectives of the Lookback Study were to examine the impacts of the NEM 2.0 tariffs and to compare how different metrics have changed following the transition from the NEM 1.0 tariff to the NEM 2.0 tariff.

63. Electricity consumption patterns are not discussed in the key takeaways of the Lookback Study.

64. ~~Energy consumption patterns included in the study contain insufficient data to make the assertion that the current structure of net energy metering promotes electrification.~~

65. The Lookback Study contains incomplete data regarding change in consumption for SCE customers.

66. ~~Without complete data and more in-depth analysis on electricity consumption patterns, assertions regarding the promotion of electrification cannot be made or relied upon in this decision~~.

67. ~~The Lookback Study does not indicate that the current structure of net energy metering promotes electrification goals~~.

68. The Commission has consistently conveyed the message that net energy metering systems should be sized to load.

69. Policy messages regarding sizing net energy metering systems to load were conveyed prior to the contemplation of the electrification policy.

70. D.06-01-024, D.06-07-028, D.11-06-016 and D.14-11-001 do not address the policy of electrification.

71. SEIA/Vote Solar's proposal to allow customers to oversize their loads by 50 percent, with ~~the modification to compensate the~~ compensation for net surplus generation set at avoided costs ~~the current net surplus compensation rate,~~ will promote electrification.

72. ~~There is no reason to revise the net surplus compensation rate currently set at the Default Load Aggregation Point price~~.

73. The Lookback Study found that the TRC benefit-cost ratio is consistently higher for solar photo voltaic systems when compared to solar + storage systems.

74. The addition of storage provides greater benefits to both the customer and the grid.

75. The current cost of storage not only creates cost-effectiveness concerns, but also presents a barrier to widespread adoption.

76. It is the policy of the Commission to encourage paired storage with the benefits and costs in mind.

77. ~~Continuing to base export compensation on retail rates conflicts with the guiding principles~~.

78. Retail rates do not reflect the actual costs of the exports or ~~the~~ all of the benefits the exports provide to the utilities and the grid.

79. The Commission needs to know ~~export actual~~ all the costs and benefits of exports in order to ensure they are approximately equal pursuant to Section 2827.1

80. Basing export rates on current retail rates has resulted in compensation levels ~~3.8 to 5.4 times~~ higher than the benefits they provide to the electrical systems in the form of avoided costs.

81. ~~Using~~ A gradual glide path to long-term levelized avoided cost values ~~instead of~~ from ~~the~~ retail rate brings the cost of the successor tariff closer to its value, which will ensure equity among customers and maximize the value of the resource to all customers and to the grid.

82. Export compensation based on hourly Avoided Cost Calculator values ~~sends more~~ adds excessive uncertainty and complexity with no discernible improvement in the accuracy of ~~accurate~~ price signals ~~and promotes paired storage~~.

83. Ensuring the growth of customer generation is not the Commission’s only concern.

84. ~~Using~~ A gradual glide path to the long-term levelized values from the Avoided Cost Calculator ~~approach~~ will ensure the costs and benefits are approximately equal, as instructed by the Legislature.

85. ~~Using~~ A gradual glide path to long-term levelized values from the Avoided Cost Calculator ~~approach~~ should lead to positive outcomes for customers and nonparticipating ratepayers.

86. ~~With the exception of the 2020 version of the Avoided Cost Calculator, the calculator has consistently reflected the value of exported energy from year to year.~~

87. A gradual glide path to long-term levelized Avoided Cost Calculator values to set export rates will ensure export compensation is based on the benefits they provide to the system and will reduce the cost shift found in the Lookback Study.

88. The Commission can use other elements and tools to ensure a smooth transition to the successor tariff in a measured fashion.

89. There are multiple pieces to the export compensation rate, which can lead to confusion for customers

90. ~~Requiring the same~~ Including an export compensation rate glide path for all net energy metering customers will maintain equal treatment between nonresidential and residential customers, ensuring equity among customers.

91. ~~Adopting similar export rates for new nonresidential net energy metering customers is reasonable.~~

92. The Lookback Study found the above-1.0 TRC and PCT scores for the nonresidential sector of NEM 2.0 was most likely due to the federal Investment Tax Credit.

93. Without the federal Investment Tax Credit, most TRC values for nonresidential NEM 2.0 are lower than 1.0.

94. There is nothing in the record of this proceeding that would lead us to know whether the federal Investment Tax Credit will be extended beyond the current expected sunset date of December 31, 2023.

95. The Lookback Study highlighted that most nonresidential NEM 2.0 customers have high fixed charges, minimum bills, and demand charges, which tend to lower the potential savings with solar systems.

96. ~~If the Commission would find the NEM 2.0 structure compliant with guiding principles for the nonresidential customer sector, a change in demand charges or high fixed charges in another proceeding could lead to furthering the cost shift in net energy metering that could be challenging to unwind.~~

97. Requiring successor tariff customers to take service on highly differentiated time-of-use rates will improve the price signal to these customers.

98. Requiring successor tariff customers to take service on highly differentiated time-of-use rates will incentivize these customers to divert energy usage to lower-priced hours when the solar system is producing or deploying storage.

99. Highly differentiated time-of-use rates are closer to the energy prices required to run the grid.

100. Requiring successor tariff customers to take service on highly differentiated time-of-use rates maximizes the value of the generation to all customers and to the electrical system and ensures equity among all customer

101. Highly differentiated time-of-use rates encourage electrification and help California reach its greenhouse gas emissions reduction goals.

102. Requiring successor tariff customers to take service on highly differentiated time-of-use rates will meet several guiding principles in this proceeding.

103. ~~No evidence has been provided indicating that creating a highly differentiated time-of-use rate that is specific to net energy metering customers could discourage the adoption of multiple distributed energy resources~~.

104. ~~The current design of retail rates no longer provides the ability to accurately calculate a customer's energy and grid usage, with respect to net energy metering customers.~~

105. Net energy metering customers intermittently reduce usage depending upon the performance of the solar system, but the Lookback Study shows most customers reduce their cost of service by installing solar.

106. The grid must always be prepared for the intermittent decrease and increase of ~~a~~ all customers' usage, and the record does not indicate net energy metering customers cause incremental costs due to their usage patterns.

107. ~~Net energy metering customers cause costs even when not directly importing energy from the grid.~~

108. ~~Retail rates were created before the emergence of the two-way street of imports and exports.~~

109. ~~A grid participation charge in combination with the retail rate will provide improved accuracy for considering the grid usage of net energy metering customers.~~

110. ~~The addition of a grid participation charge will decrease the cost shift created by the inaccuracies related to having both imports and exports~~.

111. The addition of a grid participation charge will lead to ~~just and reasonable~~ rates that are not just and reasonable for ~~all~~ customers on the successor tariff.

New Finding. The grid participation charges advanced by parties (1) are not based on accurate data, (2) are not established using consistent system wide costing principles, and (3) do not apply to the utility's other customers with similar load or other cost-related characteristics.

New Finding. A grid participation charge will deny a customer the full economic benefits of generating their own electricity.

New Finding. A grid participation charge based on Public Advocates Office's proposal would recover transmission costs.

112. T~~he addition of a grid participation charge will ensure the successor tariff is accurately based on the generator's costs and benefits to the system as a whole and will ensure equity among customers~~.

113. D.16-01-044 determined the nonbypassable charges to be assessed on NEM 2.0 customers are the public purpose program charge, nuclear decommissioning, competition transition charge, and the Department of Water Resources bond charge.

114. Parties provided no evidence regarding why the list of nonbypassable charges adopted in D.16-01-044 should be expanded.

115. ~~The examples provided by CALSSA do not indicate the~~ A Market Transition Credit is ~~too~~ difficult to administer.

116. The Market Transition Credit proposals from TURN and NRDC are incomplete.

117. ~~The TURN, NRDC and E3 proposals for Market Transition Credit provides the Commission options for creating a Market Transition Credit.~~

118. ~~The Market Transition Credit provides flexibility to ensure ratepayer equity and ensures that customer-sited renewable distributed generation can continue to grow sustainably.~~

119. The Market Transition Credit does not provide the best approach for a glide path in the successor tariff.

New Finding: An export compensation rate step down provides the best approach for a glide path in the successor tariff.

120. In D.15-07-001, the Commission adopted a minimum bill standard for residential customers on the non-generation portion of their monthly electric bill.

121. In D.15-07-001, the Commission established a minimum bill of $5 for CARE customers and $10 for non-CARE customers.

122. ~~It is not necessary to adopt~~ There is no basis to change the minimum bill ~~because we are adopting a grid benefits charge.~~

123. Reducing the netting interval exposes more of the customers' imports and exports to net billing.

124. Instantaneous netting cannot be estimated and conflicts with the PV Watts solar generation projection required in D.20-08-001 ~~is more consistent with cost-based compensation and will maximize the value of customer-sited renewable generation to all customers and to the grid~~.

New Finding. Providing customers with data from both import and export channels of utility meters before they install solar will not inform them of their expected level of instantaneous exports after installing solar.

125. Allowing monthly billing and annual true-ups will help California reach its environmental objectives but not at the unnecessary financial burden of nonparticipating customers.

126. ~~Annual true-ups~~ Export compensation rates derived from the Avoided Cost Calculator allow generation to be credited for ~~exactly what it is valued based upon the rate~~ a projection of the value for that ~~hour~~ time period.

127. Annual true-ups do not undermine greenhouse gas emissions objectives.

128. Hourly Avoided Cost Calculator values for export rate compensation complicate the bill structure.

129. Averaging the Avoided Cost Calculator values across days in a month or time-of-use periods acknowledges the general trends in differences between hours and months and ~~results in accurate values~~ would smooth hourly spikes.

130. Averaging the Avoided Cost Calculator values yields ~~more accurate~~ signals for customer generators to reduce imports from the grid and for battery storage to dispatch during ~~hours~~ time periods that were projected to be most valuable to the grid.

131. Averaging the Avoided Cost Calculator values across days in a month or time-of-use periods ~~does not add~~ would reduce the false precision of potentially inaccurate forecasts of a specific hour's weather and other conditions.

132. ~~Using averaged monthly Avoided Cost Calculator values for export compensation ensures the tariff is based on the generator's true costs and benefits to the grid and leads to equity among all ratepayers while maximizing the value of the generation to all ratepayers and to the grid~~.

133. Like all forecasts, the Avoided Cost Calculator forecast values get increasingly uncertain further away from the present.

New Finding. Long-term avoided transmission and avoided distribution values are far higher than short-term avoided transmission and avoided distribution values.

New Finding. Basing export compensation rates solely on one-year or five-year forecasts fails to include long-term avoided transmission and avoided distribution values.

134. Basing the Avoided Cost Calculator values on a ~~five~~ twenty-year schedule of values will enable solar providers to predict customer savings and provide financing.

135. The certainty of a twenty~~five~~-year lock-in rate helps to ensure that customer-sited renewable distributed generation continues to grow sustainably, enhances customer protection measures, and provides transparency to customers.

New Finding. A twenty-year lock-in period is particularly important for commercial customers, who often install solar and storage with extremely small margins.

New Finding. An open-ended tariff that allows for key components to be significantly revised within five or ten years of initial operation undermines investment certainty.

136. ~~Using single year avoided cost values, instead of averaged costs, brings the cost of the tariff closer to its value~~.

137. ~~Using single year avoided cost values aligns with requirements to ensure the tariff is based on the costs and benefits of the customer generator and ensures the benefits are approximately equal to the total costs.~~

138. The purpose of the export rate step down as described in this decision is to ensure customer-sited renewable distribution generation continues to grow sustainably.

139. ~~Limiting the Market Transition Credit to a small subset of customers would not ensure customer-sited renewable distribution generation continues to grow sustainably.~~

140. The Commission does not intend the growth of the market to be focused solely on low-income customers.

141. ~~The Market Transition Credit is meant to ensure the continued growth of the market but also provide an incentive to customers to install customer sited renewable distributed generation~~.

142. ~~A dollar per kilowatt credit (of the generator's installed capacity) for the Market Transition Credit is a user-friendly calculation~~.

143. ~~Allowing for a discrete line on the customer's bill for the Market Transition Credit will provide customer transparency.~~

144. ~~Allowing the Market Transition Credit to be applied to future bills will prevent unnecessary energy usage by customers~~.

145. ~~The design of the Market Transition Credit will provide a more transparent and uniform incentive to successor tariff customers~~.

146. ~~The Market Transition Credit is a glide path that improves certainly over time for the industry.~~

147. TURN's Market Transition Credit proposal does not provide certainty for the industry.

148. TURN's Market Transition Credit proposal is unnecessarily complicated and inconsistent in terms of the inputs.

149. ~~In combination with other elements of the successor tariff, ratepayer funding of the stepped-down to zero dollars approach of the Market Transition Credit appropriately balances tariff requirements~~.

150. The transition to the successor tariff will require customers to make substantial investments in storage, as well as solar, with longer payback periods.

151. Net energy metering customers are more likely than other customers to choose critical peak pricing and real time pricing rates, which will help the grid during critical peak days.

152. Customers should be provided the opportunity to elect to choose critical peak pricing, ~~or~~ peak day pricing, or real time pricing rates on any rate option they select.

153. A grid participation charge does not enable~~s~~ the Commission to create a successor tariff based on cost causation for participating customers. ~~that ensures equity among customers and is accurately based on the costs and benefits of the generation~~.

154. ~~The name "grid participation charge" sends a clear message to the customers they are paying to use the grid.~~

155. Most nonresidential customers already have fixed and demand charges included in their rates.

156. The Joint Utilities' proposal to require bill credits be applied to charges in the same time-of-use period is overly prescriptive.

157. The successor tariff makes great strides in addressing the cost shift found in the Lookback Study~~, thus addressing one element of the equity issue.~~

158. The Equity Fund helps to address~~es~~ the statutory requirement of expanding access to disadvantaged communities.

159. ~~The Market Transition Credit assists the Commission in addressing the equity issue while also addressing the statutory requirement that customer-sited renewable distributed generation continues to grow sustainably.~~

160. The successor tariff balances the requirements of the statute and the guiding principles adopted previously in this proceeding.

161. Low-income households have financial challenges and barriers to adoption of behind-the-meter resources.

162. The successor tariff is required to meet many objectives other than expanding access to low-income households.

163. The Lookback Study found that low-income customers who participate in NEM 2.0 receive lower bill savings benefits and experience longer payback periods.

164. Installation of distributed generation is less frequent in low-income households and disadvantaged communities.

165. The inability to achieve higher bill savings and reasonable payback periods are barriers to increased participation by ~~low-income~~ ESJ customers.

166. Adopting the same net billing tariff structure for all income households does not meet~~s~~ the equity requirement in guiding principle b.

167. Providing ~~discounts on certain~~ separate elements of the tariff structure for eligible households will assist the Commission in meeting the objectives of improved equity and increased participation in low-income households and disadvantaged communities.

168. Low-income households have challenges with certain time-of-use rates and electrification costs.

169. The combination of an ~~Market Transition Credit~~ ESJ Adder that will achieve the intended payback period for ESJ customers and an equity fund could assist the Commission in meeting the requirement to ensure specific alternatives designed for growth among residential customers in disadvantaged communities.

170. It is reasonable to ~~use the cost shift savings generated through the reform of the successor tariff~~ establish tariff elements that make it more economical to install solar and storage to improve the low adoption rate of distributed generation in low-income households.

171. A guiding principle in this proceeding is to ensure equity in the successor tariff.

172. We stated in the Order Instituting Rulemaking that this proceeding would coordinate with other relevant proceedings.

173. There is a current proceeding assessing the affordability of utility services (R.18-07-006) and information gathered in the affordability proceeding could be helpful in providing a more complete record with respect to the VNEM tariff.

174. An evaluation of the SOMAH program has been conducted, pursuant to D.17-12-022.

175. A report of the SOMAH evaluation has been made public and the information in the evaluation could be useful in determining future changes to the tariff.

176. The SOMAH evaluation is not in the record of this proceeding.

177. It is prudent to delay any changes to ~~low-income subtariffs of~~ all VNEM and NEMA tariffs until review in this proceeding of additional findings from the affordability proceeding and the SOMAH evaluation and further analysis of the impact of the successor tariff on those tariffs.

178. One of our objectives in this proceeding is to ensure the successor tariff aligns with the costs and benefits of customer generation.

179. Basing export compensation on retail rates in the long term does not meet the objective of aligning costs and benefits of customer generation.

180. ~~Aligning the VNEM tariff with the successor tariff balances the multiple and competing objectives in this proceeding.~~

181. Renters have no ability to install storage and have less ability than homeowners to install load-shifting smart devices.

182. Ivy Energy has demonstrated there is onsite consumption of energy that is generated at multifamily buildings interconnected under VNEM; Joint Utilities do not dispute this claim in briefs.

183. It is reasonable to affirm that VNEM provides benefits to the grid similar to that of the NEM 2.0 tariff.

184. VNEM is for multifamily buildings designed to facilitate a virtual metering billing arrangement.

185. NEMA is available to a single customer that has a generating facility or facilities on adjacent or contiguous properties and allows for aggregation as if on one site.

186. VNEM and NEMA serve separate purposes and generally have separate customer bases: VNEM for multi-family customers and NEMA for agricultural customers and farmworkers.

187. The current VNEM tariff allows multiple arrays but requires each array to serve a subset of customers on the property

188. Joint Utilities point to no engineering or policy reason why multiple solar arrays on one property should not be treated as one generator on the VNEM tariff, with credits allocated across the property.

189. Many apartment complexes contain more than one building and often require the use of separate roof surfaces and points of interconnection for VNEM.

190. Treating multiple solar arrays on one property as one generator is reasonable and efficient.

191. There are aspects of community solar that are being discussed or considered in other proceedings.

192. It is the intention of the Commission to conduct workshops in this docket to ~~consider~~ finalize development of a Net Value Billing Tariff to build upon the record established in this docket. ~~aspects of community solar that are being discussed or considered in other proceedings.~~

193. It is premature to adopt a Community Solar tariff or subtariff at this time.

194. In D.16-01-044, determinations regarding the NEM 2.0 tariff were made at a transitional moment without the advantage of a quantitively informed basis.

195. The Commission now has the data to make an informed decision on a successor tariff.

196. Based on the assumptions used therein, ~~the~~ Lookback Study found that NEM 2.0 is not cost-effective for residential customers, has negatively impacted non-participant ratepayers, and has disproportionately harmed low-income customers.

197. ~~The estimated cost shift from the NEM 2.0 tariff ranges between $1 billion and $3.4 billion.~~

198. ~~The changes made to the net energy metering tariff in Section 8.5 above do nothing to tackle the cost shift; the changes only attempt to prevent or limit additional cost shift from new customers enrolling in the successor tariff.~~

199. While NEM 1.0 and NEM 2.0 are in the scope of Issue 6, the language in Issue 6 is unclear, no customers were given notice beyond that language that NEM 1.0 and 2.0 were in scope, and, as a result, few existing solar customers are likely to have understood their interests were at stake in this proceeding.

200. In D.16-01-044, the Commission established a legacy period of 20 years from a customers' interconnection date as a reasonable period over which the customer should be eligible to continue taking service under the NEM 2.0 tariff.

201. ~~Our choice regarding changes to NEM 1.0 and NEM 2.0 result in an inequity to one of two groups: nonparticipant ratepayers or legacy customer ratepayers~~.

202. Public Utilities Code Section 2827.1 and our guiding principles do not rank the requirements for the successor tariff and tell us whose needs should come first: the needs of a particular group of customers, the environment, or the grid.

203. Determining whether to revise NEM 1.0 and NEM 2.0 tariffs requires balancing various and competing requirements, and impacts participants, nonparticipants, the grid, and the environment.

204. ~~Remaining~~ Low- and medium-income residential NEM 1.0 and NEM 2.0 tariff customers may have higher financial burdens than other customers.

205. Once transitioned to the successor tariff, not all NEM 1.0 and NEM 2.0 customers will continue to experience monthly bill savings from the successor.

206. Revising the NEM 1.0 and NEM 2.0 tariff legacy periods to 15 years for existing residential customers ~~will continue to ensure these~~ will prevent some customers from having ~~have~~ reasonable payback of their investment.

207. ~~Shortening the legacy period of existing residential NEM 1.0 and NEM 2.0 tariff customers balances the needs of nonparticipants with the needs of participants~~

New Finding. Allowing customers on a NEM 2.0 system to add a battery without losing their eligibility for that tariff will comport with the current practice for NEM 1.0 customers and encourage the adoption of energy storage.

Conclusions of Law

1. The Commission should use the Lookback Study as a foundation to create a successor tariff that continues the elements that resulted in positive outcomes but corrects or replaces elements that resulted in negative outcomes.
2. ~~The Commission should affirm the NEM 2.0 tariff negatively impacts nonparticipant ratepayers~~.
3. The Commission should develop a revised net energy metering tariff that corrects the cost shift found in the Lookback Study, to the extent possible, while balancing the eight guiding principles.

4. The Commission should affirm the NEM 2.0 tariff is ~~not~~ cost effective for the commercial, industrial, and agricultural customer segments.

~~5. The Commission should affirm the NEM 2.0 tariff is not cost effective for the residential customer segment.~~

~~6. The Commission should affirm the NEM 2.0 tariff disproportionately harms low-income customers.~~

7. The Commission should ensure the growth of the net energy metering market does not come at the undue and burdensome financial expense of nonparticipant ratepayers.

8. The Commission should not grant the request to replace the Avoided Cost Calculator with the Lookback Study cost of service analysis.

9. The Commission should align its analysis in this proceeding with prior guidance from the Standard Practice Manual and consider the value of the TRC, PCT, and RIM cost-effectiveness tests, as well as the tradeoffs between the tests.

10. The Commission should ~~not use the Societal Cost Test~~ consider societal benefits in its analysis of the successor tariff.-

11. The Commission should ~~not~~ ascribe a resiliency adder for net energy metering customers.

12. The Commission should ~~not adopt proposed~~ consider societal benefits of an updated, social cost of carbon metric, land conservation, a reduced methane leakage multiplier, or avoided transmission costs.

13. The Commission should not rely on one single method of analysis to be the determinant of the final successor tariff.

14. The Commission should consider monthly bill savings and ~~ten~~seven to nine years to payback for paired storage as part of the successor tariff.

15. The Commission should use the ~~NREL~~ LBNL estimate ~~of $2.34~~ $3.80 per watt as the cost of solar in 2019 for general market residential customers .

16. The Commission should adopt a glide path as part of the successor tariff to minimize the cost shift, to ensure equity among all customers, and also to encourage the growth of the market~~, but not at the undue and burdensome financial expense of nonparticipant ratepayers.~~

17. The Commission should address equity in the successor tariff through increased participation by disadvantaged communities and combatting the cost shift found in the Lookback Study.

18. The Commission should conduct an evaluation of the equity elements adopted in this decision to determine whether they are sufficient or need to be revised.

19. The Commission should adopt a successor tariff that addresses the cost shift found in the Lookback Study to ensure equity. ~~but also to encourage adoption of electrification measures~~.

20. The Commission should adopt SEIA/Vote Solar's proposal to allow customers to oversize their loads by 50 percent, while ~~maintaining~~ modifying the current net surplus generation compensation rate to avoided costs, to promote electrification.

21. The Commission should continue to encourage paired solar in the successor tariff with both the benefits and costs in mind.

22. Continuing to base export compensation on retail rates in the long term does not comply with Public Utilities Code Section 2827.1.

23. Subsequent to the export compensation step down described in this decision, the Commission should base export compensation on values derived from the Avoided Cost Calculator.

24. The Commission should ensure customers can understand the export compensation rate structure to be able to make an informed decision on whether to purchase a solar system.

25. The Commission should adopt the same type of export compensation rate step-down ~~structure~~ for residential and nonresidential customer sectors.

~~26. The Commission should adopt a successor tariff that requires customers to take service on an existing highly differentiated time-of-use rate available to all customers.~~

27. ~~The Commission should adopt a successor tariff that includes~~ A grid participation charge is not based on cost causation and is not just and reasonable.

28. The Commission should adopt a successor tariff that includes a ~~Market Transition Credit~~ export compensation rate step down as a glide path for both residential and non-residential customers.

New Conclusion. An open-ended tariff that allows for key components to be revised within five or ten years of initial operation will not allow for sustainable growth of distributed energy resources.

29. The Commission should not adopt instantaneous netting in the successor tariff because it conflicts with the PV Watts solar generation projection required in D.20-08-001.

30. The Commission should allow monthly billing and annual true-ups for customers in the successor tariff.

31. Subsequent to the step down in the export compensation rate set forth in this decision, the Commission should set export compensation rates at monthly values for each hour, differentiated between weekday and weekend.

32. ~~The Commission should adopt Avoided Cost Calculator values based on a five-year schedule of values for each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the new successor tariff customer's interconnection date~~.

33. The Commission should adopt separate export compensation rate stepdown schedules for non-residential customers, low-income residential customers, and market rate residential customers as described in this decision. ~~ratepayer-funded, stepped-down to zero, Market Transition Credit that is available to all successor tariff customers who enroll in the tariff over the next five years~~.

New Conclusion: The Commission should adopt Avoided Cost Calculator values based on a schedule of levelized values from the most recent Avoided Cost Calculator for use as the export compensation rate at the conclusion of the export rate stepdown.

34. The Commission should permit customers to adopt critical peak pricing or peak day pricing as part of their highly differentiated time-of-use rates.

35. The Commission should not adopt a grid participation charge for residential net energy metering customers as part of the successor tariff.

New Conclusion: Adopting a grid participation charge without record evidence establishing the charge is based on accurate data, is established using consistent systemwide costing principles, and applies to the utilities' other customers with similar load or other cost-related characteristics would violate the law.

New Conclusion. A grid participation charge that denies a customer the full economic benefits of generating their own electricity infringes on the customer's right to self-generation.

New Conclusion. A grid participation charge based on Public Advocates Office's proposal implicates FERC jurisdiction.

36. The Commission should not adopt a requirement to apply credits only to charges during the same time-of-use period.

37. The Commission should adopt the successor tariff.

38. ~~The Commission should not maintain the NEM 2.0 tariff for low-income households~~.

39. ~~The Commission should adopt the same successor base tariff for all income levels~~.

40. The Commission should not decrease export compensation credits by applying the CARE and FERA discounts received by low-income households.

41. The Commission should not apply ~~the~~ a grid participation charge and should allow any time-of-use rate for ~~low-income~~ environmental and social justice (ESJ) ~~households~~ customers enrolled in the successor tariff.

42. The Commission should establish an equity fund to address the low adoption rate of distributed generation in low-income households.

43. The Commission should maintain the current structure of ~~the low-income~~ all VNEM and NEMA tariffs until review of findings in the affordability proceeding, ~~and~~ the SOMAH

evaluation, <u>and the analysis of the changes to VNEM and NEM are</u> ~~is~~ conducted in this proceeding.

44. The Commission should not require VNEM and NEMA customers to take service on highly differentiated time-of-use rates, but rather require these customers to take service on the time-of-use rates of their choice.

~~45. The Commission should adopt the same net billing structure for VNEM and NEMA, at this time.~~

46. The Commission should affirm that VNEM provides benefits to the grid similar to that of NEM 2.0.

47. The Commission should maintain separate VNEM and NEMA subtariffs.

48. The Commission should allow multiple solar arrays on one property to be treated as one generator in the VNEM subtariff.

<u>**New Conclusion**. New tenants in a housing unit that previously received VNEM credits should receive those credits upon opening a utility account unless otherwise requested.</u>

<u>**New Conclusion**. Public Utilities Code Section 2870(g) requires the Commission to ensure that electrical corporation tariff structures affecting the low-income tenants participating in the Multifamily Affordable Housing Solar Roofs Program continue to provide a direct economic benefit from the qualifying solar energy system.</u>

49. The Commission should not adopt a community solar tariff or subtariff at this time.

50. The Commission has the authority to amend previous decisions pursuant to Public Utilities Code Section 1708.

~~51. The Commission should revise non-CARE and FERA residential NEM 1.0 and NEM 2.0 tariffs for existing customers while considering the multiple impacts.~~

~~52. The Commission should require existing residential NEM 1.0 and NEM 2.0 tariff customers to transition to the successor tariff no later than 15 years after the date of interconnection.~~

53. ~~The Commission should revise the legacy period of new residential NEM 2.0 customers to 15 years~~.

54. ~~The Commission should revise the legacy period of customers taking control of a residential system to 15 years~~.

<u>**New Conclusion**. Because this decision changes the name of the customer generation tariff from net energy metering to net billing, previous decisions ordering changes to net energy metering tariffs should also apply to the new net billing tariff.</u>

<u>**New Conclusion**. Utilities should establish a clear two-step application process for residential interconnections to create a fair and transparent cutoff point for NEM-2 eligibility.</u>

Ordering Paragraphs

~~1. The following findings from the Lookback Study are affirmed:~~

~~(a) the NEM 2.0 tariff negatively impacts non-participant ratepayers;~~

~~(b) the NEM 2.0 tariff is not cost-effective for the commercial, industrial, and agricultural customer segments;~~

~~(c) the NEM 2.0 tariff is not cost-effective for the residential customer segment; and~~

~~(d) the NEM 2.0 tariff disproportionately harms low-income customers.~~

2. For the purposes of this decision, ~~a~~ ~~low-income~~ environmental and social justice (ESJ) ~~household is~~ customers are defined as residential customers ~~eligible for California Alternate Rates for Energy (CARE) and the Family Electric Rates Assistance (FERA) programs, resident-owners of single-family homes in disadvantaged communities (as defined in Decision (D.) 18-06-0127), or residential customers who live in California Indian Country (as defined in D.20-12-003) and take service on either the standard successor tariff or aggregated net energy metering subtariff~~ in Disadvantaged Communities located in the top 25% of communities identified by Cal EPA's CalEnviroScreen; residential customers who live on all Tribal lands; customers with household incomes below 80 percent of the area median income; and customers in census tracts with household incomes less than 80 percent area of state media income.

3. A net billing tariff is adopted. ~~With the exception of the import rate, the adopted~~ All elements below will be available to an enrolled customer for a period of ~~ten~~ twenty years from interconnection date. Imports and exports will be calculated based on ~~instantaneous~~ hourly netting of consumption and production for residential customers and 15-minute periods for commercial customers and will be trued-up on an annual basis. Bill credits will be applicable toward import charges from any time of use time period. The net billing tariff contains the following adopted elements:

(a) Export Compensation Rates based on a gradual glide path to 20-year levelized ~~hourly~~ Avoided Cost Calculator values ~~averaged across days in a month, differentiated by weekdays and weekends. For the first five years after system interconnection, export compensation rates will be based on a five-year schedule~~

~~of values for each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the customer's interconnection date. Following the five-year lock in rate, export compensation rates will be based on averaged hourly avoided cost values from the most recent Avoided Cost Calculator, adopted as of January 1~~.

~~(b) Market Transition Credits, as a glide path, based on a dollar per kilowatt installed amount. The adopted Market Transition Credit, as indicated in the table below, will be reviewed during a five-year evaluation of portions of the net billing tariff, conducted by the Commission. The Market Transition Credit will remain constant for a customer for 10 years from the customer's interconnection date.~~

~~Adopted Market Transition Credits~~			
~~Customer Segment~~	**~~PG&E~~**	**~~SDG&E~~**	**~~SCE~~**
~~Residential~~	~~$1.62./kW~~	~~$0/kW~~	~~$3.59/kW~~
~~Low-Income~~	~~$4.36/kW~~	~~$0/kW~~	~~$5.25/kW~~
~~NonResidential~~	~~$0/kW~~	~~$0/kW~~	~~$0/kW~~

~~The credit will decrease by 25 percent annually, as measured by the first-year credit rate until the credit reaches zero. The monthly credit will be a discrete line on the customer's utility bill, will apply to all charges, and will apply to future bills until the credit is used. Funding for the credit will be provided by all ratepayers through the Public Purpose Program charge.~~

(c) ~~Highly differentiated time-of-use rates as provided in the following table. These rates are available to enrolled customers for a period of five years from the customer's interconnection~~

~~date. Additional eligible rates may be added by utility request through submittal of a Tier 3 Advice Letter~~.

~~**Eligible Time Of Use Rates by Utility**~~			
	~~**PG&E**~~	~~**SDG&E**~~	~~**SCE**~~
~~**Eligible Rate**~~	~~EV2-A~~	~~EV-TOU-5~~	~~TOU-D-PRIME~~

~~(d) Grid Participation Charges, as shown in the following table, applied only to residential customers. The Grid Participation Charge will be reviewed as part of the five year evaluation of affordability and equity elements of the net billing tariff.~~

~~**Monthly Grid Participation Charge for Net Billing Customers**~~			
~~**Customer Segment**~~	~~**PG&E**~~	~~**SDG&E**~~	~~**SCE**~~
~~Residential~~	~~$8.00/kW~~	~~$8.00/kW~~	~~$8.00/kW~~
~~Low-Income~~	~~$0/kW~~	~~$0/kW~~	~~$0/kW~~
~~NonResidential~~	~~$0/kW~~	~~$0/kW~~	~~$0/kW~~

(e) ~~Low-income~~ Environmental and social justice (ESJ) customers (as defined in this decision) may also participate in the net billing tariff. For such participants, the CARE and FERA discount will not be applied to the export compensation rate. Eligible customers ~~will be exempt from the grid participation charge and~~ may take service on any time-of-use rate. Customers interconnecting within the five years from implementation of the net billing tariff will not experience changes in the elements (except for the import rate) for a period of ten years from the customer's interconnection date. The ~~low-income~~ ESJ subtariff of the net billing tariff will be reviewed during the five-year evaluation of affordability and equity elements of the net billing tariff.

~~4. Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company shall track the number of successor tariff applications and jointly submit a Tier 2 Advice Letter, annually, no later than July 1, to propose maintenance of the Market Transition Credit reduction trajectory or any specific changes to it~~.

5. Energy Division is authorized to conduct a five-year evaluation of the affordability and equity elements contained in the net billing tariff adopted in Ordering Paragraph 2 above. A future decision will consider the results of the evaluation to determine if changes are needed.

6. An Equity Fund is established to address the low adoption rate of customer-sited distributed generation in low-income households and households in disadvantaged communities. We establish an annual cap of $150 million~~, with funding provided through the cost shift savings generated by the reforms adopted in this proceeding~~. Additional details will be finalized in a future decision, following a workshop and party comment.

7. No later than April 30, 2022, Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company shall conduct one or more workshops to solicit stakeholder input on a) ~~use of the Equity Fund adopted in Ordering Paragraph 6, including the potential expansion and improved~~ alignment of existing low-income programs and new programs; and b) use of the Storage Evolution Fund, adopted in Ordering Paragraph 15.

8. The Virtual Net Energy Metering (VNEM) tariffs for ~~low-income eligible households~~ all customers shall remain unchanged until review of additional findings in Rulemaking 18-07-006, ~~and the~~ evaluation of the Solar on Multifamily Affordable Housing program, and further evaluation of potential changes to VNEM.

9. ~~The Virtual Net Energy Metering (VNEM) general tariff shall adhere to the same changes as the successor net energy metering tariff we adopt in Ordering Paragraph 2 above, with one distinction: VNEM customers shall take service on the time-of-use rates of their choice. Further,~~ T~~t~~he VNEM tariff is revised to allow multiple solar arrays on one property to be treated as one generator, with credits allocated across the property. New tenants in a housing unit that previously received VNEM credits shall receive the same level of credits unless otherwise requested. Other than these changes, all VNEM ~~for low-income customers remains~~ tariffs remain unchanged until further notice.

10. The Net Energy Metering Aggregation tariff shall ~~adhere to the same changes as the successor net energy metering tariff we adopt in Ordering Paragraph 3 above.~~ remain unchanged until further notice.

11. Implementation of the changes adopted in the previous ordering paragraphs of this decision shall occur via Tier 3 Advice Letter to be filed within 90 days of the date of this decision.~~in the following steps:~~

~~(a) Step 1: Within 30 days of the adoption of this decision Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company (Joint Utilities) shall each submit an information-only Tier 1 advice letter to provide the details of the net billing tariff, conforming to the elements adopted in Ordering Paragraph 3.~~

~~(b) Step 2: Within 45 days of the adoption of this decision, Joint Utilities shall each submit a supplemental advice letter containing rate factors based on the applicable revenue and associated tariff sheets. Joint Utilities shall ensure the tariff language is standardized across all three utilities.~~

~~(c) Step 3: No later than 100 days after the adoption of this decision, the Commission's Energy Division should dispose of the advice letters from Steps 1 and 2.~~

~~(d) Step 4. No later than 120 days after the adoption of this decision, the Commission will implement a tariff sunset on the prior net energy metering tariff, known as NEM 2.0, after which time, no additional customers will be permitted to take service under the NEM 2.0 tariff. Any delay in Step 3 above, will result in an equal, day-for-day, extension of time in the tariff sunset date. Customers signing contracts after this sunset date will take service and be billed on the NEM 2.0 tariff and transitioned to the net billing tariff, once it is operationalized.~~

~~(e) Step 5:~~ No later than 12 months following adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company will complete alignment of related necessary billing systems and transition to full implementation of the net billing tariff.

12. The original Net Energy Metering tariff, referred to as NEM 1.0, and its successor, referred to as NEM 2.0, are revised ~~as follows:~~

~~(a) Existing non-California Alternate Rates for Energy (CARE) residential customers on these two tariffs shall transition to the tariff we approve in Ordering Paragraph 3 above no later than 15 years after the customer's interconnection date.~~

~~(b)~~ to allow ~~E~~existing NEM 2.0 tariff customers who voluntarily transfer to the net billing tariff adopted in this decision, within four years from its inception, are eligible to receive a $0.20 per watt hour storage rebate. The storage rebate is available for a total of four years but will decrease by 25 percent a year over the subsequent four years. Customers are eligible for the storage rebate in the year they transition to the successor tariff. Customers must claim the rebate within three years of their transition to the net billing tariff by submitting proof of an energy storage system installation.

~~(c) Immediate replacement of the 20-year legacy period with a 15-year legacy period for all future NEM 2.0 tariff customers, including residential customers who take service under NEM 2.0 after the adoption of this decision, as well as customers taking control of (i.e., owning, leasing, or paying a power purchase agreement for) a residential system, other than when the subsequent customer is the legal partner (i.e., spouse or domestic partner) of the original customer.~~

~~13. No later than five business days after the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company (Joint Utilities) shall submit Tier 1 Advice Letters revising the legacy period for residential non-California Alternate Rates for Energy (CARE) customers on the current net energy metering tariff (NEM 2.0) and the previous net energy metering tariff (NEM 1.0) from 20 years to 15 years, with an effective date of five days after the advice letter submittal date. Joint Utilities shall inform solar providers of the change on the date that they submit these advice letters. Each of the Joint Utilities shall email and send an automated phone call to all solar providers who submitted an interconnection application in the three years preceding this date, and for whom the utilities have the requisite contact information. The Joint Utilities shall each mail a letter to all solar providers who submitted an interconnection application in the year preceding this date.~~

~~14. No later than 15 days from the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company shall notify customers of the original net energy metering tariff, NEM 1.0, and the current net energy metering tariff, NEM 2.0, of the changes in the tariff, as directed in Ordering Paragraph 12.~~

15. A Storage Evolution Fund is established and will be funded through the distribution charges of Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company.

16. No later than 30 days following the workshop directed in Ordering Paragraph 7, Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company shall file an implementation proposal for the Storage Evolution Fund. No later than 14 days following the filing of the Storage Evolution Fund implementation proposal, parties shall file comments on the proposal; replies shall be filed seven days thereafter.

17. Rulemaking 20-08-020 remains open to address issue seven in the Scoping Memo and continuing matters related to this decision.

Appendix B
List of Acronyms

Acronym	Description
A.	Application
AB	Assembly Bill
CALSSA	California Solar and Storage Association
CPUC	California Public Utilities Commission
D.	Decision
GPC	Grid Participation Charge
FERC	Federal Energy Regulatory Commission
IOU	Investor-Owned Utility
Joint IOUs	Southern California Edison Company, Pacific Gas & Electric Company, and San Diego Gas & Electric Company
MTC	Market Transition Credit
NBC	Non-bypassable Charge
NEM	Net Energy Metering
OIR	Order Instituting Rulemaking
PAO	Public Advocates Office
PCIA	Power Charge Indifference Adjustment
PD	Proposed Decision
PG&E	Pacific Gas and Electric Company
PURPA	Public Utilities Regulatory Policy Act
QF	Qualifying Facility
R.	Rulemaking
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
TURN	The Utility Reform Network