**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 ADMINISTRATIVE LAW JUDGE'S RULING SETTING ASIDE SUBMISSION OF THE RECORD TO TAKE COMMENT ON A LIMITED BASIS

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OPENING COMMENTS OF THE CALIFORNIA SOLAR & STORAGE ASSOCIATION ON ADMINISTRATIVE LAW JUDGE'S RULING SETTING ASIDE SUBMISSION OF THE RECORD TO TAKE COMMENT ON A LIMITED BASIS

Pursuant to Administrative Law Judge Hymes' May 9, 2022 *Administrative Law Judge's Ruling Setting Aside Submission of the Record to Take Comment on a Limited Basis* ("Ruling") and June 2, 2022 Ruling, the California Solar & Storage Association ("CALSSA") submits these opening comments.[1]

CALSSA supports changing the customer generation tariff from net metering ("NEM") to net billing with vastly reduced export compensation over time. Net billing will cause increased payment of non-bypassable charges ("NBCs") due to its structure. CALSSA also recognizes that the California Public Utilities Commission ("Commission") is likely to approve mandatory electrification rates. These three factors represent major change, and the Commission should not additionally require any fee on behind-the-meter ("BTM") self-generation or an excessively sharp glidepath toward lower export compensation.

On legal grounds, the Commission should reject the proposal to collect NBCs on the gross consumption of net billing tariff ("Tariff") customers or any subset of these customers. The Commission lacks a clear statutory basis for extending its jurisdiction to the private BTM activity of Tariff customers. A Tariff that collects NBCs on customers' BTM consumption would also violate federal and state law for the same reasons as the Proposed Decision's ("PD")[2] Grid Participation Charge ("GPC"). Both mechanisms are designed to impose additional fees solely on Tariff customers with no cost-based rationale. While the Ruling's proposed mechanism would not collect the transmission and distribution costs included in the proposed GPC,[3] the potentially expansive set of NBCs that are now proposed would be assessed based on the amount that Tariff customers *reduce* their grid consumption by relying on onsite generation, or meet *new* load increases with self-generation—absent any evidence that Tariff customers cause incremental costs and that these charges are designed to recover such costs. This constitutes discriminatory treatment under federal and state law.

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[1] R.20-08-020, *Administrative Law Judge's Ruling Setting Aside Submission of the Record to Take Comment on a Limited Basis* (May 9, 2022) ("Ruling"); R.20-08-020, *Administrative Law Judge's Ruling Granting Motion to Limit Number of Pages for Responses to May 9, 2022 Ruling and Extend Deadline to File Reply Comments* (June 2, 2022).

[2] R.20-08-020, *Proposed Decision Revising Net Energy Metering Tariffs and Sub-Tariffs* (December 13, 2021) ("PD").

[3] *See id.*, pp. 125-127 (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."); Exh. PAO-01 at 3-24 to 3-25 (the Public Advocates Office's ("Cal Advocates") proposed charges include distribution and transmission costs).

If the Commission determines that low usage poses a problem under the current rate design, it must resolve the related cost-of-service questions on behalf of all ratepayers, utilizing a consistent methodology across all relevant customer classes and categories. As it has stated throughout this proceeding, CALSSA would not oppose a fixed charge applicable to all residential customers if it was designed to be consistent with the Commission's rate design principles. This kind of rate design reform—which may be furthered by currently pending legislation that would remove the cap on fixed charges for residential customers—is the correct way to approach this question of how to recover utilities' fixed costs equitably, on behalf of all ratepayers.[4]

Further, the Ruling is silent as to whether the Commission is considering expanding NBCs on Tariff customers *in addition to* imposing some kind of GPC as proposed in the PD. Using these mechanisms together would be wholly inappropriate, as such a proposal would result in the double-collection of the NBCs designed to be recovered by both mechanisms.[5] In light of this obvious double-collection that would occur through the imposition of both mechanisms, and the fact that the Sierra Club proposal on which the Ruling's proposal is based recommends *elimination* of the GPC in favor of NBCs on total energy use,[6] CALSSA responds to the Ruling's questions assuming that this NBC proposal would be applied *instead of* the GPC.

Ultimately, the Commission must balance the statutory requirements of maintaining sustainable growth of distributed generation and ensuring the costs and benefits of the Tariff are approximately equal.[7] The Commission has acknowledged that, to reach this balance, it must design a Tariff that achieves a reasonable payback period.[8] Practically, any GPC or charge on BTM consumption will simply translate to the Commission needing a higher Avoided Cost Calculator ("ACC") adder or Market Transition Credit ("MTC") in order to achieve the appropriate payback. CALSSA strongly opposes any additional fees on

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4 *See Department of Finance Trailer Bill Language*, State of California, https://esd.dof.ca.gov/trailer-bill/public/trailerBill/pdf/741. Pursuant to Rule 13.10, CALSSA respectfully requests that the Commission take official notice of this bill in this proceeding. This bill language would not need to pass in order for the Commission to impose a new fixed charge on all residential customers (the current statutory language caps fixed charges at $10, and current rates do not impose fixed charges up to this cap).

5 *See* PD, pp. 125-127 (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."); Exh. PAO-01 at 3-24 to 3-25 (Cal Advocates' proposed charges include NBCs like the Competition Transition Charge, Public Purpose Program Charge, Nuclear Decommissioning Charge, and Wildfire Fund Charge). *See also* Ruling, pp. 6-7 (listing the many potential NBCs to be collected based on gross consumption).

6 R.20-08-020, *Sierra Club Opening Comments on Proposed Decision Revising Net Energy Metering Tariff and Subtariffs*, pp. 10-13 (January 7, 2022) ("Sierra Club Opening Comments on PD").

7 Cal. Pub. Util. Code §§ 2827.1(b)(1), 2827.1(b)(4).

8 PD, Finding of Fact 48, Conclusion of Law 14.

Tariff customers, and submits that the appropriate balancing of these statutory mandates can be achieved without them, with a reasonable ACC adder.

I. Glide Path Approach

A. Question 1: CALSSA Supports the ACC Plus Residential Glidepath Approach.

A glidepath based on an ACC adder is preferable to the MTC approach because it would reflect the structure of net billing and be more understandable to customers and contractors during a period of enormous change. Net metering and net billing are tariff structures that compensate customers with onsite generation for the kWh of electricity exported from the customer site to the grid. Adjustments to that export compensation level can be explained more easily than an additional mechanism on top of export compensation. CALSSA believes that customers will be able to accept that exports have a certain value more readily than trying to understand different interpretations of the regulatorily determined value and a make-up credit that a state agency promises will last a certain amount of time (especially one that may have just broken its promises to NEM-1 and NEM-2 customers).

The primary goal of a glidepath is to maintain the state's capacity to expand clean onsite generation as we transition to a future based on energy storage. To get that future, we need to retain the expertise of the contractors and workers who explain options to customers and who design, finance, and install distributed energy resources. The overnight reduction in export compensation in the *first step* of CALSSA's recommended ACC Plus glidepath, detailed below, will shock the market at best. Changing the net metering tariff quickly but not too quickly is a difficult balance, and we can only hope that this level of change will not be so disruptive that it imperils our capacity to install customer energy systems. It should be acceptable to the Commission not to go farther than the CALSSA proposal, especially in the initial years of a new net billing tariff with major structural changes.

B. Question 2: ACC Plus Can Ensure That Distributed Generation Continues to Grow Sustainably.

When evaluating whether the glidepath will ensure that customer-sited renewable distributed generation continues to grow sustainably, the most important considerations are the length of the transition and the size of the first step. Any of the three structural options done with a more gradual trajectory is preferable to a different option with a sharper trajectory.

CALSSA maintains our position in briefs that a declining percentage of rates is the simplest option and that a straight line from rates to an end point derived from the ACC is a workable alternative. On the question of a $/kWh adder (ACC Plus) versus a $/kW credit (MTC), the ACC Plus would be more effective at achieving a steady market. Net metering is a tariff that sets export compensation rates. Basing the glidepath on export rates will make sense to customers and contractors.

The ACC adder and the corresponding total export compensation rate should be a constant value for 15 years, which the PD set as the term of current NEM tariffs and should therefore be expected to be the most common financing term.[9] CALSSA continues to urge the Commission to use 15-year levelized values from the ACC.[10] If we are going to use the ACC for rate setting, we need to trust the ACC, including its long range projections, and frontloading customer savings is better policy than creating a structure with savings that increase over time. If export compensation is a set dollar amount it will decline in real value due to inflation, but it will still be known and understandable.

C. <u>Question 3</u>: Customers Will Provide Value to the Electric Grid Under ACC Plus.

In any scenario, there will be higher export compensation in the peak hours and lower compensation in off-peak hours, and this will encourage systems to be designed and operated in ways that provide value to the grid. The Commission should not falsely presume that the values in the ACC are perfectly accurate. They are based on projections of future market conditions and stress on the grid. Averaging projected costs across time of use ("TOU") periods is standard practice in ratemaking. Moving to hourly export values immediately on implementation of NEM-3 would be confusing for customers and contractors, and would not provide the level of precision that some parties seem to imagine.

Value to the grid is also dependent on a large volume of adoption. That is the point of a glidepath. Maintaining current adoption rates will ensure that more clean energy is installed, and all of the NEM reforms under consideration will push customers toward grid-friendly behavior. A tariff that sends highly precise price signals that few people respond to would be less effective than a tariff that encourages basic evening-to-daytime load shifting that many customers adopt.

D. <u>Question 4</u>: A Multiplier Should Not Be Used Instead of a Fixed ¢/kWh Adder.

An adder that is an additional cents per kWh value would be much simpler than a percentage increase in the export compensation rate. A percentage adder would be more difficult to predict and could create unintended impacts because some hours are assigned a very high value and some are near zero or are negative.

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[9] PD, Ordering Paragraph 12.

[10] Exh. CSA-02 at 37:1-41:15.

E. Question 5: Adders for Solar and Solar + Storage Should Be Calculated Separately.

The Tariff should include separate values for solar and solar + storage systems. As shown in response to Questions 7-9 below, there are significant differences for the two technology types in the adder that is needed to achieve the target savings threshold.

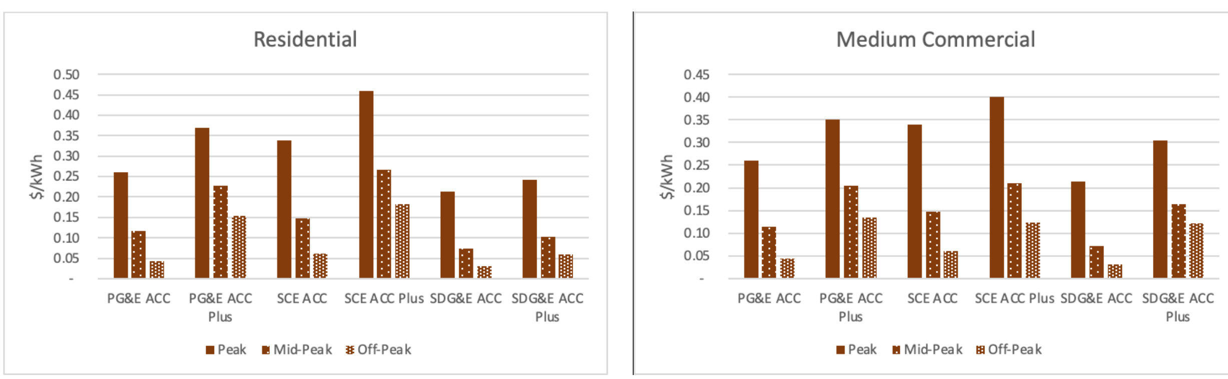
Interconnection applications already include very specific details of the equipment that is installed. It is important for technical reasons that the utilities know what equipment is installed. It would not present a challenge to use that information to assign a system the appropriate adder under the Tariff if there are separate glidepath values for solar and solar + storage.

F. Question 6: Net Billing with ACC Plus Compensation Will Encourage Good Battery Dispatch.

There will be a strong signal for grid-friendly battery dispatch with or without the adder. With an equal cents adder for each time period, the $/kWh differentials between periods are unchanged.

Figure 1 shows the differences in ACC and ACC Plus values grouped by TOU period, using the Step 1 adders recommended in response to Questions 7a and 9. The peak to off-peak differentials are $0.22/kWh for PG&E, $0.28/kWh for SCE, and $0.18/kWh for SDG&E. This is a sufficient differential to encourage grid-friendly dispatch.

Figure 1. 2023 ACC and ACC Plus Values Grouped by TOU Period



The amount of change from NEM-2 export rates to CALSSA's proposed Step 1 of the glidepath will fundamentally change the economics of solar and encourage customers seeking energy solutions to become solar + storage customers in the first place, and then to select a storage discharge pattern that limits mid-day exports. Table 1 shows the reduction in export compensation in the TOU periods with the greatest amount of annual solar production. This level of change is extremely dramatic and will shift the market. A smaller adder is not needed to impact customer decision making.

Table 1. Reduced Residential Export Compensation During High Solar Production Hours ($/kWh)

		NEM-2 Export	Glidepath Step 1	ACC	Pct of Annual Solar Generation
PG&E	Summer Off-Peak	0.32	0.15	0.04	29%
	Winter Off-Peak	0.27	0.14	0.03	51%
SCE	Summer Off-Peak	0.22	0.18	0.06	33%
	Winter Super-Off-Peak	0.21	0.16	0.04	55%
SDG&E	Summer Mid-Peak	0.33	0.10	0.07	33%
	Winter Mid-Peak	0.36	0.08	0.05	31%

G. Question 7a: Basis for the ACC Plus Adder Amount.

The first step of an ACC Plus adder for residential customers should be based on achieving 10% savings for a customer with a 15-year loan at 5% interest.[11]

The PD would reduce the eligibility term for current NEM tariffs to 15 years.[12] If that is the length of time that customers have a defined structure of net metering, we cannot expect lenders to offer financing for a longer period of time. Ten percent bill savings is a minimum threshold to motivate customer adoption.[13]

Financing brings solar and storage to low-income and moderate-income customers. The Commission should be careful to preserve financing options. It has been a positive development in recent years that lenders have been issuing unsecured loans for solar and storage installation and that solar loans have become a leading approach to installing solar for lower income households.[14]

Table 2 shows the adders that would be necessary to achieve the target level of savings for residential non-CARE customers, using the E3 "Net Billing Tariff PD Model." Achieving 10% savings equates to a simple payback period near 9 years.[15]

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11 This can be calculated within the E3 model by comparing the Bill Savings in the Results tab with a simple calculation of annual bill payment: value=PMT(5%,15,system cost).

12 PD, Ordering Paragraph 12.

13 9 Tr. 1093:24-28 (CSA – Plaisted).

14 Exh. CSA-01 at 34:19-35:3.

15 CALSSA maintains that a seven-year payback is the appropriate target to maintain full market activity, but models nine years in these comments as a backstop. *See* R.20-08-020, *Opening Brief of the California Solar & Storage Association*, pp. 18, 20, 22, 27, and 67 (August 31, 2021) ("CALSSA Opening Brief"). CALSSA's recommended edits to Findings of Fact and Conclusions of Law in the PD included "Seven to nine years." R.20-08-020, *Opening Comments of CALSSA on Proposed Decision Revising NEM Tariff and Subtariffs*, Appendix A, Finding of Fact 48 and Conclusion of Law 14 (January 7, 2022) ("CALSSA Opening Comments on PD").

SCE solar + storage cannot reach 10% bill savings through an adder alone because with an adder of $0.132/kWh for a non-CARE solar + storage customer in 2023 the customer bill equals the minimum bill plus the fixed charge in rates. A higher adder does not produce additional savings. Savings of 7% are the maximum achievable using an ACC adder alone. It is therefore necessary to have an MTC in addition to the adder.[16]

The adders in the first step of the glidepath for residential non-CARE customers should be the values in Table 2. These values are calculated for solar + storage systems with the E3 model issued with the PD, "Net Billing Tariff PD Model."[17] All default 2023 values were used except a solar cost of $3.52/W, elimination of a solar-specific fee, and TOU-averaged export compensation rates.[18]

Table 2. Residential Non-CARE Adders

	PG&E		SCE		SDG&E	
	Solar	S + S	Solar	S + S	Solar	S + S
ACC Adder ($/kWh)	0.103	0.118	0.117	0.125		0.029
Upfront MTC ($/kW)				200		
Payback Period (Years)	8.8	9.2	8.9	9.2	7.9	8.8
Year One Savings	10.0%	10%	10%	7%	13%	10%

The glidepath calculation should be based on a cost of solar that is truly available to customers. Even the $3.52/W value from CALSSA testimony is lower than the expected available cost in 2023. That value was based on the 2019 cost of $3.80/W as documented by Lawrence Berkeley National Laboratory ("LBNL"), with an assumption of a 5% cost reduction in each of the following two years and a 3% annual reduction thereafter.[19] In reality, those cost reductions since 2019 have not materialized. The values in these comments are based on the $3.52/W value because that was contained in CALSSA testimony, but the Commission should understand that a tariff based on that value will err on the side of reduced solar adoption.

More recent LBNL analysis shows that the 2020 cost of residential solar in California was $3.87/W.[20] California Distributed Generation Statistics shows that the cost trendline since 2020 has been

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16 A $200/kW upfront MTC is equivalent to a $1.92/kW monthly MTC, using a 5.5% nominal discount rate and 2.2% inflation.

17 One correction was made to the model. The published version of the model calculates October as a summer month for PG&E's existing electrification rate. This was changed to winter in cells O:102 to BJ:102 of the Import Rates tab.

18 TOU-based export rates are available in the E3 model on the Export Rate Averages tab and can be activated by entering "TOU Periods" in cell D:124 of the Dashboard tab.

19 Exh. CSA-01 at 66:1-12.

20 *Tracking the Sun*, "Summary Data Tables: State Comparison," Lawrence Berkeley National Laboratory (September 2021), https://emp.lbl.gov/tracking-the-sun.

flat.[21] Cost numbers in the LBNL analysis are lower than those in California DG Stats, but the trendlines track each other. Also, upward pressure on the cost of solar equipment has been widely reported throughout this year. We can therefore conclude that the right number to use for an accurate analysis for 2023 would be at least $3.87/W.

H. Question 7b: Timeframe and Step-Down for ACC Plus.

CALSSA maintains its position that the glidepath should have four steps.[22] The glidepath should move to the next step separately for residential and non-residential customers, with the threshold for each non-CARE residential step equivalent to twice the annual residential installation rate of the past five years, as shown in Table 3.[23]

Table 3. Residential Non-CARE Glidepath ($/kWh)

		PG&E		SCE			SDG&E	
	Thresholds	Solar	S+S	Solar	S+S Adder	S+S MTC	Solar	S+S
Step 1	0 GW - 1.7 GW	0.103	0.118	0.117	0.125	200	-	0.029
Step 2	1.7 GW - 3.4 GW	0.077	0.089	0.088	0.094	150	-	0.022
Step 3	3.4 GW - 5.1 GW	0.052	0.059	0.059	0.063	100	-	0.015
Step 4	5.1 GW - 6.8 GW	0.026	0.030	0.029	0.031	50	-	0.007

This glidepath is designed to last eight years.[24] The stepdown timing should be converted to a date certain as described in CALSSA testimony.[25]

I. Question 8: Glidepath for Low-Income Customers.

For CARE customers, an ACC Plus adder is not sufficient to achieve 10% savings, except for SDG&E customers without storage. For all other CARE customer types, savings are negative or less than 10% when the maximum impact of the adder is reached.[26] It is therefore necessary to use an MTC in addition to the ACC adder for CARE customers, as shown in Table 4. CALSSA recommends an upfront MTC rather than a monthly MTC, with the first step of the adder and upfront MTC at the levels shown in

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21 *Statistics and Charts*, California Distributed Generation Statistics, https://www.californiadgstats.ca.gov/charts/.

22 Exh. CSA-01, Table 5 at 40; Exh. CSA-02, Figure 11 at 48. What is described in testimony as "Step 5" is actually the end point after the glidepath.

23 Exh. CSA-01 at 39:12-15. CALSSA has also expressed support for all customer classes moving to the next step at the same time based on installation thresholds for the combined market. However, separate stepdowns would be more effective because the development cycle is far longer for non-residential projects and adjustment to tariff changes for one market segment does not equate to adjustment for another market segment. One segment may stall while the other does not.

24 *Id*. at 38-39.

25 *Id*. at 40:7-41:5.

26 As explained in response to Question 7a, the value of an adder is limited by the minimum bill and fixed charges in electrification rates.

Table 4.[27] These values are calculated with the E3 "Net Billing Tariff PD Model" with no solar-specific fee, no assessment of NBCs on BTM self-generation, and a solar cost of $3.52/W. Similar values should be calculated for FERA customers. The stepdown amounts can be set as shown in Table 5, but the timing cannot be determined at this time. ACC adders for CARE and FERA customers should only step down upon review within a Commission proceeding.

CALSSA recognizes that installation costs on average are higher for CARE customers due to building conditions and lengthier customer interactions. We are aware of and support recommendations submitted by GRID Alternatives, Vote Solar, and Sierra Club for a glidepath with similar structure and different values because those recommendations are based on CARE-specific solar installation costs.

Table 4. Residential CARE Adders and Credits

	PG&E		SCE		SDG&E	
	Solar	S + S	Solar	S + S	Solar	S + S
ACC Adder ($/kWh)	0.026	0.065	0.015	0.052	0.057	0.057
Upfront MTC ($/kW)	1300	1300	1500	1500	0	800
Payback Period (Years)	9.3	9.6	9.3	9.6	9.0	9.3
Year One Savings	10%	10%	10%	10%	10%	10%

Table 5. Residential CARE Glidepath

			Solar		Solar + Storage	
		Thresholds	Adder ($/kWh)	Upfront MTC ($/kW)	Adder ($/kWh)	Upfront MTC ($/kW)
PG&E	Step 1	Upon Review	0.026	1,300	0.065	1,300
	Step 2		0.020	975	0.049	975
	Step 3		0.013	650	0.033	650
	Step 4		0.007	325	0.016	325
SCE	Step 1	Upon Review	0.015	1,500	0.052	1,500
	Step 2		0.011	1,125	0.039	1,125
	Step 3		0.008	750	0.026	750
	Step 4		0.004	375	0.013	375
SDG&E	Step 1	Upon Review	0.057	-	0.057	800
	Step 2		0.043	-	0.043	600
	Step 3		0.029	-	0.029	400
	Step 4		0.014	-	0.014	200

J. <u>Question 9</u>: A Glidepath is Needed for Nonresidential Customers.

The numbers for small commercial customers are similar to those for residential customers, which is expected due to similar solar system sizing and similar rate design. The values in Table 6 are calculated

27 The equivalent monthly MTC values that correspond with upfront MTCs of $800/kW, $1300/kW, and $1500/kW are $7.69/kW/mo, $12.50/kW/mo, and $14.43/kW/mo, respectively.

with the E3 "Net Billing Tariff PD Model" with no solar-specific fee, no assessment of NBCs on BTM self-generation, and the assumption that is embedded in the model that the cost of a 10 kW small commercial solar system is 95.1% of the cost of residential solar.[28]

As with residential SCE customers, small commercial SCE customers installing solar + storage cannot achieve 10% savings with the ACC adder alone. An MTC is also needed, and CALSSA recommends an upfront MTC of $500 per kW.[29]

The small commercial glidepath should step down when the nonresidential market as a whole reaches the equivalent of twice the annual average installation rate over the past five years, as shown in Table 7.

Table 6. Small Commercial Adders

	PG&E		SCE		SDG&E	
	Solar	S + S	Solar	S + S	Solar	S + S
ACC Adder ($/kWh)	0.055	0.134	0.092	0.086	0.025	0.157
Upfront MTC ($/kW)				500		
Payback Period (Years)	8.9	9.3	9.1	9.4	8.7	9.1
Year One Savings	10%	10%	10%	10%	10%	10%

Table 7. Small Commercial Glidepath

		PG&E		SCE			SDG&E	
	Thresholds	Solar	S + S	Solar	S+S Adder	S+S MTC	Solar	S + S
Step 1	0 GW - 0.8 GW	0.055	0.134	0.092	0.086	500	0.025	0.157
Step 2	0.8 GW - 1.6 GW	0.041	0.101	0.069	0.065	375	0.019	0.118
Step 3	1.6 GW - 2.4 GW	0.028	0.067	0.046	0.043	250	0.013	0.079
Step 4	2.4 GW - 3.2 GW	0.014	0.034	0.023	0.022	125	0.006	0.039

For medium and large commercial customers, the E3 model is not sufficient to measure the level of glidepath needed because the model does not include demand charges, which are critical components of these customers' rate schedules. Because commercial solar customers cover their cost of service,[30] have lower mid-day rates,[31] and have lower solar adoption levels,[32] the Commission should create a glidepath for medium and large commercial customers that is based on a straight line transition that starts near a level based on current customer savings and ends at values derived from the ACC. The Commission can create ACC Plus adders that begin at a level that is derived from current volumetric rates but are hard numbers that decline to zero. The first step should be set to achieve year one savings for a typical customer

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[28] One correction was made to the E3 model for small commercial customers. The summer off peak rate on SCE Schedule B1 in April 2021 was 0.18066 instead of 0.15066.

[29] This is equivalent to a monthly MTC of $4.81 per kW.

[30] CALSSA Opening Brief, p. 104.

[31] Exh. CSA-01, Figure 2 at 17.

[32] Exh. PCF-15 (Lookback Study), Figure 3-2 at 25.

that are ten percent below the year one savings under NEM-2, and the final step should be consistent with how it is calculated for other customer classes. CALSSA recommends that the Commission adopt this methodology, with values to be determined via advice letter.

For illustrative purposes, Table 8 shows the level of ACC Plus adders that are needed to match current savings for a typical medium commercial customer.[33] Table 9 shows the stepdown glidepath. As stated in response to Question 2, CALSSA recommends that the adders be available to customers for the 15-year term of the tariff at the level of the step at the time of interconnection.

Table 8. Medium and Large Commercial Customer Savings and Adders

	PG&E		SCE		SDG&E	
	Solar	Solar + Storage	Solar	Solar + Storage	Solar	Solar + Storage
Pre-Solar Bill ($/yr)	132,493	132,493	111,144	111,144	156,353	156,353
NEM-2 Bill	57,855	45,515	48,236	38,402	78,966	60,017
NEM-2 Savings	74,638	86,978	62,908	72,742	77,387	96,336
ACC Bill	71,175	56,643	58,960	45,927	91,714	71,061
ACC Savings	61,318	75,850	52,184	65,217	64,639	85,292
Reduced Savings	13,320	11,128	10,724	7,525	12,748	11,044
ACC Adder to Produce Equivalent Savings ($/kWh)	0.091	0.091	0.065	0.060	0.090	0.091

Table 9. Medium and Large Commercial Glidepath

Thresholds		PG&E	SCE	SDG&E
Step 1	0 GW - 0.8 GW	0.082	0.056	0.082
Step 2	0.8 GW - 1.6 GW	0.061	0.042	0.061
Step 3	1.6 GW - 2.4 GW	0.041	0.028	0.041
Step 4	2.4 GW - 3.2 GW	0.020	0.014	0.020

II. Non-Bypassable Charges on Gross Consumption

A. <u>Question 10</u>: The Commission Should Not Collect NBCs on BTM Consumption for Any Subset of Tariff Customers.

The Ruling's NBC proposal must be rejected for all customers because it exceeds the Commission's jurisdiction and would violate federal and state anti-discrimination law. Like the GPC, this proposal would single out and penalize NEM customers for reducing their consumption, thus failing to

[33] This typical customer has a 250 kW solar system that offsets approximately 80% of consumption. The solar + storage customer has a 125 kW/375 kWh battery. Before installing solar the customer is on Schedule B-19 for PG&E, TOU-GS2-D for SCE, and AL-TOU for SDG&E. After installing solar or solar + storage, the customer is on B-19-R for PG&E, TOU-GS2-E for SCE, and DG-R for SDG&E.

remedy this fatal flaw in a PD that "despite its talk of modernization, is a throwback in time" that undermines California's flagbearer status on energy innovation.[34]

1. The Ruling's NBC Proposal Would Improperly Extend the Commission's Reach to Private BTM Activity.

The Ruling's NBC proposal presents a threshold legal question that is not raised by the PD's proposed GPC: does the Commission possess the authority to regulate private activities occurring in Californians' homes, beyond the jurisdictional water's edge at the utility's meter? There is no statutory basis for the Commission to assert this authority, and the Commission should decline to consider the proposal on this basis alone.

The Commission has jurisdiction to "supervise and regulate every public utility in the State" and do all things "necessary and convenient in the exercise of such power and jurisdiction."[35] These powers are liberally construed, and as long as the Commission's actions are cognate and germane to the regulation of public utilities, and not expressly barred by statute, they are upheld.[36] In statute, "public utility" is defined to include "electrical corporations[,]" but it does not cover "independent solar energy producers"—entities that are explicitly excluded from the "electrical corporation" definition.[37] Therefore, while the Commission clearly has broad authority to regulate public utilities, it does not have the authority to directly regulate independent solar energy producers.

Even so, the Commission's authority to supervise and regulate public utilities provides it with jurisdictional reach over many aspects of the provision of electrical service that impact retail customers, including independent solar energy producers. For example, when a retail customer is engaged in an activity that touches the regulated provision of electrical service—*i.e.*, the consumption of electricity from the electrical corporation's grid, interconnection to the electrical corporation's grid, or export of energy to be measured and netted at an electrical corporation's meter as part of a NEM program—the

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34 R.20-08-020, *Comments of Ahmad Faruqui on the PD Revising NEM Tariff and Subtariffs*, p. 5 (January 7, 2022).

35 Cal. Pub. Util. Code § 701. *See also* Cal. Const., art. XII, §§ 1, 6.

36 *See S. Cal. Edison Co. v. Peevey*, 31 Cal. 4th 781, 792 (2003).

37 Cal. Pub. Util. Code §§ 216, 218(e). Section 2868(b) of the Public Utilities Code defines "[i]ndependent solar energy producer" as "a corporation or person employing one or more solar energy systems for the generation of electricity for any one or more of the following purposes: (1) its own use or the use of its tenants. (2) The use of, or sale to, not more than two other entities or persons per generation system solely for use on the real property on which the electricity is generated, or on real property immediately adjacent thereto."

The Commission also has limited, non-ratemaking jurisdiction over other load serving entities in California such as community choice aggregators ("CCAs") and electric service providers ("ESPs"). Independent solar energy producers are neither CCAs nor ESPs. *See* Cal. Pub. Util. Code §§ 218.3(c), 331.1.

Commission's jurisdiction over the rates and practices of electrical corporations confers it with the authority to regulate these transactions.

There is no similar basis, however, for the Commission to extend its jurisdictional reach to the private, BTM activities of independent solar energy producers. An independent solar energy producer's BTM consumption of onsite generation does not involve any interaction with public utility service or the regulated portion of the grid. The customer is not drawing any energy or services from the grid, and its activities are entirely on private property and behind the utility's meter. This is therefore not an activity over which the Commission has jurisdiction as part of its broad authority to regulate public utilities.

While the Legislature has broad authority to confer additional jurisdiction on the Commission via statute,[38] there is no other statutory basis for the Commission to assert this authority to assess charges on the BTM activities of independent solar energy producers in Section 2827, Section 2827.1, or any other section of the Public Utilities Code. Given this limited reach of the Commission's jurisdiction over the private activities of independent solar energy producers, the Commission does not have the authority to apply the charges of jurisdictional retail electric service to Tariff customers' BTM consumption.

2. The Ruling's NBC Proposal Would Violate PURPA.

Assessing NBCs on BTM consumption would violate the Public Utility Regulatory Policies Act of 1978 ("PURPA") for the same reason the GPC violates PURPA. PURPA's regulations require rates for sales to customers with Qualifying Facilities ("QFs")[39] to be non-discriminatory.[40] A proponent of any additional fee on QF customers must establish a cost causation basis for imposing differential rate treatment and demonstrate that 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.[41]

The Ruling's NBC proposal would result in differential rate treatment for Tariff customers because non-Tariff customers would be charged NBCs based on the amount of energy they consume from the grid, while Tariff customers would be charged NBCs based on the amount of energy they consume from the grid *plus* the amount by which they reduce their grid consumption through self-generation. Non-Tariff

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38 Cal. Const., art. XII, § 5.

39 *See* CALSSA Opening Brief, p. 16 (NEM-eligible BTM solar facilities of 1 MW or less constitute QFs under PURPA. QF status automatically applies to onsite 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)).

40 18 C.F.R. § 292.305(a). *See also* 16 U.S.C. § 824a-3(c).

41 CALSSA Opening Comments on PD, n. 18.

customers who reduce their grid consumption through other measures—such as energy efficiency or demand response—would not pay NBCs on the degree of their reduced grid consumption. This approach would violate all three prongs of PURPA's anti-discrimination regulations.

First, the record in this proceeding 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 any additional charge on Tariff customers.[42] The Lookback Study cannot fill this role because it only compares residential NEM-2 customers' annual bills to those same customers' cost of service; 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. The Lookback Study's analysis actually shows that NEM-2 customers' cost of service is *lower* after they install solar, for both residential and commercial customers, undermining any claim that NEM customers cause incremental costs.[43] Finally, the fact that there is no record evidence suggesting the costs associated with the NBCs listed in the Ruling are incurred by the utilities based on gross load further demonstrates that these charges on BTM consumption would not be cost-based. In fact, many of these NBCs either recover costs that are fixed (*i.e.*, not dependent on consumption, either BTM or from the grid), or costs that are not incurred on behalf of BTM load.[44]

Even if the record contained any evidence that NEM customers cause incremental costs—which it does not—this additional charge on Tariff customers would need to be *designed to recover* such costs in order to comply with PURPA. Neither the Ruling, nor the Sierra Club's comments on which its NBC proposal is based, suggest that these charges would be designed to recover any such incremental costs caused by NEM customers.[45]

Second, the NBC proposal violates PURPA because it is designed to solve a problem conceptualized based on a lost revenue analysis, rather than on consistent system-wide costing principles.[46] The record does not contain any comprehensive analysis using consistent system-wide

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42 CALSSA Opening Comments on PD, n. 5.

43 Exh. CSA-01 at 97:10-12 n. 165 (citing NEM 2.0 Lookback Study, pp. 10-11, 95-97).

44 For example, the Public Purpose Program charge recovers fixed costs associated with certain low-income, clean energy, and energy efficiency programs. The Power Charge Indifference Adjustment, New System Generation, and Local Generation charges recover generation costs that are not incurred on behalf of BTM load, as future distributed generation adoption is incorporated into the utilities' load forecasts used to inform the associated procurement decisions. D.08-09-012, p. 23; D.12-12-010, pp. 5-6, Attachments A and C.

45 Ruling, pp. 5-7; Sierra Club Opening Comments on PD, pp. 12-13.

46 18 C.F.R. § 292.305(a)(2).

costing principles across all ratepayers to fairly determine the cost responsibility of QFs.[47] Instead, the Commission seems to be seeking an alternative to a GPC designed to claw back certain costs Tariff customers would otherwise avoid under volumetric rate design,[48] while ignoring the low revenues associated with other low usage customers.

Third, the Ruling's proposal violates PURPA because it would apply an additional set of charges on either all Tariff customers or some subset of Tariff customers,[49] and it would not be designed to apply to other customers with similar load or other cost-related characteristics. 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 onsite generation that reduce consumption via other means.[50]

Both the Ruling's NBC proposal and the PD's proposed GPC violate PURPA by failing to meet each prong of the analysis required by its anti-discrimination provision. The Commission cannot ignore these violations in the context of the NEM program, as urged by some parties, as PURPA's anti-discrimination provision concerning utility rates for sales to QFs applies to QFs participating in state NEM programs. Reliance on *MidAmerican*[51] or *SunEdison*[52] to argue to the contrary is misplaced because these

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47 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) (if, on the basis of "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 . . . principles.").

48 *See* PD, pp. 98-100; Sierra Club Opening Comments on PD, p. 13.

49 Ruling, p. 6.

50 CALSSA Opening Comments on PD, pp. 6-7 and nn. 34-35.

51 *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001). In *MidAmerican*, FERC held that the Iowa Board's order directing the utility to interconnect with three alternate energy facilities and offer net billing arrangements was not preempted by federal law (and specifically, the pricing requirements of the FPA or PURPA). FERC found the Iowa Board was not preempted from allowing flows of power from a customer to the utility from being measured on a net basis, and that no FERC jurisdictional sale to a utility occurred when a customer accounted for its dealings with the utility through the practice of netting. Therefore, compensation to customers under the net billing arrangement was not subject to federal pricing requirements, while net sales to utilities were required to be priced consistent with the requirements of PURPA or the FPA. *MidAmerican Energy Co.*, 94 FERC ¶ 61,340, 62,262-62,263 (2001).

52 *SunEdison LLC*, 129 FERC ¶ 61,146 (2009). *SunEdison* addressed a case in which the entities that owned the generating facilities were not the participants in the net metering program, but sold their output to the net metering program participants; SunEdison asked FERC to declare that, in these circumstances, there is no sale for resale. FERC agreed that "where the net metering participant (*i.e.*, the end-use customer that is the purchaser of the solar-generated electric energy from SunEdison) does not, in turn, make a net sale to a utility, the sale of electric energy by SunEdison to the end-use customer is not a sale for resale, and our jurisdiction under the FPA is not implicated." Under the holding of *MidAmerican*, where there is no net sale over the applicable billing period to the utility, there is no sale; accordingly, where there is no net sale over the applicable billing period to the

cases both involve the Federal Energy Regulatory Commission's ("FERC") jurisdiction over the pricing of *a customer-generator's transmission of power to a utility*, and affirm the holding that when there is no net sale to the utility over a billing period, no FERC jurisdictional sale occurs through the practice of netting. This precedent does not concern rates for sales to NEM customers or somehow limit the applicability of PURPA to rates for sales to NEM customers. Claims that this Commission has concluded that NEM arrangements are not subject to FERC jurisdiction are inaccurate for the same reasons.[53]

It is also incorrect to argue that Federal Power Act ("FPA") precedent regarding state jurisdiction to regulate and set retail rates somehow renders PURPA's rates for sales provisions obsolete or inapplicable.[54] While under the FPA, states retain jurisdiction to regulate and set retail rates, Congress

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utility by the end-use customer that is the purchaser of SunEdison's solar-generated energy, SunEdison was likewise not making a sale "at wholesale," *i.e.*, a "sale for resale." Therefore, SunEdison's sales of energy to end-use customers were not subject to FERC's jurisdiction under the FPA. *SunEdison LLC*, 129 FERC ¶ 61,146, 61,620-61,621 (2009).

[53] R.20-08-020, *Reply Comments of TURN on the Proposed Decision of Administrative Law Judge Hymes Revisiting NEM Tariffs and Subtariffs*, p. 2 n. 9 (January 14, 2022) ("TURN Reply Comments on PD"). This argument is based entirely on a citation to D.11-06-016 that does not support TURN's overly broad statement. In D.11-06-016's discussion of the Commission's authority to set a net surplus compensation rate, the Commission simply affirms *MidAmerican* and *SunEdison*'s central holding that, through the practice of netting, NEM customers are able to avoid FERC jurisdictional net sales to utilities. D.11-06-016, pp. 7-10. The Commission did not find, as TURN suggests, that *all* aspects of NEM programs operate outside of federal jurisdiction. Rather, it concluded that "the Commission should implement the NEM Program *pursuant to PURPA*[,]" recognizing that "[u]nder such a program, the Commission should establish [a net surplus compensation] rate that does not exceed the utility's full avoided costs." D.11-06-016, p. 10 (emphasis added). The Commission also noted in D.11-06-016 that "NEM customers can be considered QFs exempt from certification requirements at FERC." D.11-06-016, p. 11. The Commission has therefore recognized that NEM customers are QFs under PURPA—not, as TURN suggests, that PURPA does not apply to *any* aspect of the design of NEM programs.

[54] TURN Reply Comments on PD, p. 2; R.20-08-020, *Reply Comments of Cal Advocates on Proposed Decision Revising NEM Tariff and Subtariffs*, pp. 2-3 (January 14, 2022) ("Cal Advocates Reply Comments on PD"). TURN and Cal Advocates both cite to *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260 (2016). This case discusses the framework of the FPA, which authorizes FERC "to regulate 'the sale of electric energy at wholesale in interstate commerce,' including both wholesale electricity rates and any rule or practice 'affecting' such rates . . . But . . . places beyond FERC's power, and leaves to the States alone, the regulation of 'any other sale' — most notably, any retail sale — of electricity." *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 264-265 (2016). While the Supreme Court held that the FPA "places beyond FERC's power . . . the regulation of . . . retail sale[s]" (under 16 U.S.C. § 824(b)) it also clarified that "*a FERC regulation does not run afoul of §824(b)'s proscription just because it affects — even substantially — the quantity or terms of retail sales*." *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016) (emphasis added). FERC's regulations implementing PURPA provide that rates for sales to QFs must be "just and reasonable" and in the "public interest", and cannot discriminate against QFs, but they do not infringe on state authority to "specif[y] terms of sale at retail." *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 280 (2016). These PURPA regulations set parameters within which utilities must operate as they set rates for sales to QFs; while the regulations may therefore "*affect[]* . . . the . . . terms of retail sales[,]" they do not infringe on the state's authority to regulate and set retail rates. TURN also points to *FPC v. Conway*, 426 U.S. 271 (1976) for the proposition that FERC has no jurisdiction over retail rates. TURN Reply Comments on PD, p. 2. However, this case's holding that FERC "has no power to *prescribe* the rates for retail sales of power

has separately—and properly[55]—established federal standards in PURPA to encourage small power production, including standards that ensure utilities sell energy to QFs at non-discriminatory rates. Therefore, while the states retain jurisdiction to *regulate and set* retail rates, FERC has properly promulgated regulations pursuant to PURPA that establish a framework within which utilities must operate in setting rates for sales to QFs. This means that FERC cannot dictate retail rates, but it can determine that a utility has not conducted the proper analysis in setting those rates.

3. The Ruling's NBC Proposal Would Violate State Anti-Discrimination Law.

The Ruling's NBC proposal would also contravene state anti-discrimination law.[56] State law prohibits utilities from establishing "any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[57] As discussed above, there is no evidence on the record that NEM customers cause incremental costs as compared to non-NEM customers; that imposing NBCs on BTM consumption would recover any such cost of service difference; or that NEM customers' load profiles are significantly different from those of customers without onsite generation that reduce consumption through other means.[58] The Ruling's NBC proposal would result in a rate structure in which similarly situated customers with similar consumption patterns would be treated differently based on their status as a Tariff customer.[59] Self-generation, energy efficiency investments, and demand response measures are all forms of load management that allow customers to avoid grid consumption and can result in a reduction in utility revenues.[60] While other customers with similar load profiles that have reduced their demand through these other measures besides self-consumption are not charged NBCs on their demand reduction, Tariff customers that made a sizeable

companies" under the FPA neither precludes FERC from promulgating regulations pursuant to PURPA that set basic requirements utilities must follow in setting rates for sales to QFs, nor somehow nullifies FERC's PURPA regulations doing so. *FPC v. Conway*, 426 U.S. 271, 276 (1976) (emphasis added). PURPA's rates for sales provisions do not infringe on states' authority to regulate and set retail rates.

55 *See FERC v. Miss.*, 456 U.S. 742 (1982).

56 The Ruling's NBC proposal would violate state law for the same reasons as the GPC, as described in CALSSA's Opening Brief. *See* CALSSA Opening Brief, pp. 123-168 (imposing a GPC would violate state law because: 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)). CALSSA focuses in these comments on the violation of California's anti-discrimination statute, Cal. Pub. Util. Code § 453(c).

57 Cal. Pub. Util. Code § 453(c).

58 *See supra*, nn. 42, 50.

59 Exh. CSA-01 at 94:8 to 97:12.

60 *Id*. at 99:6-14.

private investment in self-generation would be under the Ruling's NBC proposal. This differential treatment would constitute an "unreasonable difference as to rates" that is discriminatory under state law.

B. Question 11: None of the Listed Charges Can Properly Be Applied to BTM Consumption.

For the reasons discussed in response to Question 10 above, none of the NBCs listed in Question 11 should be collected from Tariff customers based on their BTM consumption. Beyond the jurisdictional, PURPA, and state anti-discrimination legal issues, there is no evidence on the record supporting an expansion of the list of NBCs adopted in D.16-01-044—a fact that the Commission explicitly acknowledged in the PD.[61] While assessing any of these NBCs on BTM consumption would therefore be unsupportable, there are additional reasons why assessing the Power Charge Indifference Adjustment ("PCIA") on BTM consumption would be particularly problematic.[62]

The Commission adopted the PCIA to ensure that when investor-owned utility ("IOU") customers depart from bundled service *entirely*, and receive *all of their* electricity service from a non-IOU provider or IOU green tariff program, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[63] The PCIA is derived from the utility's Indifference Amount, which is updated annually in each IOU's ERRA proceeding. The Indifference Amount is the difference in the target year between the cost of the IOU's supply portfolio ("Total Portfolio Cost") and the market value of the IOU's supply portfolio ("Portfolio Market Value").

61 PD, Finding of Fact 114.

62 CALSSA focuses entirely on the PCIA in response to this question due to Judge Hymes' page limit constraints; CALSSA supports the Solar Energy Industries Association/Vote Solar's concurrently filed comments detailing the reasons why assessing many of the other NBCs on gross consumption would also be inappropriate.

63 R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (September 25, 2017); D.18-10-019, p. 3; Assembly Bill ("AB") 117 authorized the creation of community choice aggregators and clarified, with respect to these customers' cost responsibility, that it was "the intent of the Legislature to prevent any shifting of recoverable costs between customers." AB 117 (Cal. Pub. Util. Code § 366.2(d)(1)). It also specifically required that a cost-recovery mechanism be imposed on customers of the CCA "to prevent shifting of costs." AB 117 (adding Cal. Pub. Util. Code § 366.2(c)(5)). *See also* D.06-07-030, pp. 25-28; D.08-09-012; D.18-10-019; Cal. Pub. Util. Code §§ 365.2, 366.3.

Total Portfolio Cost includes capital investment recovery and fixed maintenance costs for utility owned generation ("UOG"), purchased power such as that from power purchase agreements ("PPAs"), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator ("CAISO") grid charges and revenues, net of any sales.[64] Portfolio Market Value is derived from total eligible generation multiplied by the Market Price Benchmarks ("MPBs"), an administratively determined set of proxy values that represents the market value of the IOU's resource portfolio.[65] The MPBs are estimates of the value per unit associated with the three principal sources of value in utility portfolios: non-RPS energy, RPS, and RA capacity.[66] Each MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value.

Each generation resource and departing customer subject to the PCIA is assigned a "vintage."[67] Generation resources are assigned a vintage based on when a commitment to procure each resource was made, and customers are assigned to a vintage according to the date they departed bundled IOU service.[68] Each vintage is assigned a separate Indifference Amount, and customers are responsible for the cumulative PCIA rates for their vintage.[69] The Indifference Amount and the year-end balance in the Portfolio Allocation Balancing Account, a rolling true-up between the forecasted costs and revenues used to determine the Indifference Amount and the actual costs and revenues an IOU realizes during the year, are added together to form the PCIA revenue requirement for each vintage. The PCIA revenue requirement is allocated among both bundled and unbundled customers based on their rate class as well as their vintage. Currently, there are not only 15 separate PCIA vintages (pre-2009 to 2022), there are different PCIA rates for each customer class within each of those vintages.[70]

The foundational statutes and decisions developing the PCIA are clear that departed load customers, for purposes of determining the applicability of the PCIA, are community choice aggregator ("CCA") and electric service provider ("ESP") customers—customers that are *fully* departed from utility

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64 D.11-12-018, pp. 8-9.

65 D.19-10-001, p. 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year.").

66 *Id*.

67 D.08-09-012, Ordering Paragraph 10.

68 Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage.

69 D.11-12-018, p. 9.

70 Exh. CSA-01 at Attachment 4 (Joint IOUs Response to CALSSA DR 4.06(b)).

generation service.[71] Customers that self-generate but continue to take generation service from their utility do not fall within this category.

While the Legislature specifically acted to ensure ratepayer indifference through a charge like the PCIA for CCA customers, it did not do so in the context of NEM customers. AB 117, which created a pathway for CCAs,[72] specifically required that a cost-recovery mechanism be imposed on customers of the CCA "to prevent shifting of costs."[73] AB 327 does not include such a requirement. In fact, the Legislature deliberated over language to "preserve nonparticipant ratepayer indifference"[74] in the context of AB 327, but ultimately removed this language from the draft bill, reflecting a clear legislative intent to eliminate this concept from the statute in favor of a set of requirements that aims to balance cost-effectiveness concerns and other key statutory goals.[75] For instance, AB 327 requires a balancing of the requirement that "the total benefits of the . . . tariff to all customers and the electrical system are approximately equal to the total costs"[76] with the requirement that the tariff ensures that customer-sited renewable distributed generation continues to grow sustainably.[77] Extending the PCIA to Tariff customers' BTM consumption would be akin to treating these customers like CCA customers, who operate under a statutorily imposed ratepayer indifference requirement; imposing this kind of strict ratepayer indifference standard via the PCIA would be contrary to AB 327's more nuanced legislative mandate.

Not only does the statutory context surrounding departed load customers and NEM customers differ, but there is also a significant difference between these two sets of customers from a ratemaking perspective. The Commission has already determined that, because the IOUs do not procure resources on behalf of customer generation departing load ("CGDL")—a category that includes NEM customers[78]—the PCIA should not be assessed on these customers.[79] While the utilities' load forecasts cannot

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71 Cal. Pub. Util. Code §§ 365.2, 366.2, 366.3; D.06-07-030, pp. 25-28; D.08-09-012. Note that while Green Tariff Shared Renewables ("GTSR") customers are also subject to the PCIA, this program was established pursuant to SB 43, which dictates that the program be implemented in a manner that ensures nonparticipating ratepayer indifference. D.15-01-051, pp. 20-21, Finding of Fact 99, Conclusion of Law 49; Cal. Pub. Util. Code § 2831(h). To ensure this statutorily mandated indifference standard, the Commission extended the PCIA to these customers as well. D.15-01-051, pp. 100-104, Finding of Fact 100. No statutorily mandated indifference standard exists for NEM customers.

72 AB 117 (adding Cal. Pub. Util. Code § 366.2).

73 *Id*. (adding Cal. Pub. Util. Code § 366.2(c)(5)).

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

75 CALSSA Opening Brief, pp. 10-13.

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

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

78 D.08-09-012, pp. 2-3 n. 6.

79 *Id*., pp. 18-26.

adequately predict departures for CCA or ESP service, and therefore the IOUs procure resources based on a load forecast that includes future CCA and ESP customers, future CGDL customers *are* captured by historical trends used to develop the load forecasts.[80] Because these CGDL departing loads have been forecasted and are not included in the load forecasts used to determine the need for utility resources, the utilities do not procure resources on behalf of this load; therefore, these customers' fair share of PCIA-related costs is zero once they "depart."[81] This reasoning from the Commission still holds true today, as forecasts of BTM generation adoption are still incorporated into the load forecasts on which utilities base their procurement.[82] Assessing the PCIA on the BTM consumption of Tariff customers would upset this prior determination of the Commission without any compelling justification.

Departed load customers and NEM customers also differ in terms of their contributions to the revenue requirements for PCIA-eligible resources. If the PCIA was not assessed on CCA or ESP customers' consumption, these customers would not contribute anything to the IOUs' revenue requirements for PCIA-eligible resources. Tariff customers, in contrast, will already contribute to these above-market generation costs, absent a PCIA charge on BTM consumption. NEM customers generally do not self-generate enough electricity to zero out their bills, and they continue to consume electricity from the grid. On average, residential NEM customers spend between $69 and $194 per month on their electricity bills.[83] Through these bills, bundled Tariff customers will contribute to the utilities' generation revenue requirements for PCIA-eligible resources based on the amount they consume, while unbundled Tariff customers will contribute to the PCIA revenue requirement based on the amount they consume.[84] There is no evidence on the record that Tariff customers' contributions to these above-market generation costs will be insufficient to cover their cost of service. Charging NEM customers these

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80 *Id.*, p. 20.

81 *Id.*, p. 23.

82 *See* CEC Docket No. 21-IEPR-01, *Adopted Final 2021 Integrated Energy Policy Report Volume IV California Energy Demand Forecast*, pp. 2-3 (February 17, 2022).

83 *See* CALSSA DR to Joint IOUs 14.2 (attached hereto in Appendix B). Pursuant to Rule 13.10, CALSSA respectfully requests that the Commission take official notice of these data responses in this proceeding. Using data provided in 2021 that does not account for recent rates increases, the average bill numbers are between $46 and $118. Exh. CSA-01 at Attachment 4 (CALSSA DR to Joint IOUs 7.01).

84 *See* PD, p. 128. Under the billing rules adopted in the PD, imports and exports will be calculated based on instantaneous netting, whereby all recorded net imports on the first meter channel are charged the retail rate and all recorded net exports on the second meter channel are compensated at the export compensation rate. This means that Tariff customers will pay all the same NBCs on all imports as any other retail customer (including the PCIA).

above-market costs based on their BTM consumption—in addition to their grid consumption—is therefore unwarranted.

Finally, extending the PCIA to Tariff customers' BTM consumption would also raise two significant rate design issues. First, to ensure that the PCIA revenue requirement is translated into PCIA rates accurately, the Commission would need to add BTM load, on a vintaged basis, back into the load forecast for purposes of PCIA ratemaking. This would be necessary because the load forecasts the utilities use to set PCIA rates net out both existing and forecasted distributed generation,[85] and PCIA rates are calculated utilizing billing determinants that are specific to each vintage.[86]

Adding BTM load back into the load forecast *on a vintaged basis*, and based on when the Tariff customer "departed" bundled service, would be complicated and administratively burdensome. PCIA vintage-specific billing determinants correspond directly with the forecast usage of all customers responsible for each vintage portfolio of resources. For example, if departed load customers in a utility's 2014 vintage total 7,335 GWh, the forecast billing determinants for the 2015 vintage portfolio of resources would be 7,335 GWh less than the 2014 vintage – the forecast system sales minus all customers departing prior to, and including, the 2014 vintage (*i.e.*, the forecast sales for everyone except those who left before the 2015 resources were procured).[87] If the PCIA is assessed on BTM consumption, the utilities would need to vintage every single customer's system, estimate each system's BTM usage, and then add that load back into the load forecast *only* for that vintage. Only this approach would ensure that the PCIA rates for each vintage of PCIA customer are calculated correctly, *i.e.*, utilizing only the billing determinants from BTM consumption from NEM systems "procured" in a particular vintage.[88]

Beyond vintaging the NEM resources themselves in order to correctly calculate PCIA rates, NEM *customers* would also need to be assigned a vintage. The problem is NEM customers that are also CCA or ESP customers would essentially be "double-departed" customers associated with two different vintages: one tied to the year the customer left bundled utility service for a CCA or ESP, and one tied to the year they installed their onsite generation. Since a customer can only have one PCIA rate associated

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85 *See, e.g.*, A.22-05-014, *SCE 2023 ERRA Forecast Testimony (SCE-01)*, pp. 19-20 (May 16, 2022). Pursuant to Rule 13.10, CALSSA respectfully requests that the Commission take official notice of this testimony in this proceeding.

86 D.19-10-001, pp. 43-46, Finding of Fact 33, Conclusion of Law 23.

87 *See* A.22-05-014, *SCE 2023 ERRA Forecast Testimony (SCE-01)*, pp. 130-131 (May 16, 2022) (using this same example for SCE's pre-2009 vintage).

88 System "procurement" could be determined as when a customer first installed their system or when they switched to the successor tariff from a different NEM tariff.

with one vintage, the rate eventually assigned will result in a lack of indifference for either the customer's distributed generation characteristics or their departed load characteristics.[89] For all of these reasons, both legal and practical, the "blunt instrument" that is the PCIA should not be applied to Tariff customers.

C. Question 12: The PD Already Dramatically Expands the NBCs to Be Collected from Tariff Customers' Imports, and Future NBCs Will Automatically Apply to Imports.

Under the billing rules adopted in the PD, Tariff customers will pay all the same NBCs on all imports as other retail customers, increasing total NBC collection compared to NEM-2.[90] Under net metering, exports produce kWh credits that offset imports and are converted to dollar values only at the end of the month if there are excess credits. Imports that are offset by credits would not be assessed NBCs but for the NEM-2 provision that applies four NBCs on those kWh imports. Under net billing, credits are never applied as kWh credits. Therefore, all NBCs are assessed on all imports, regardless of the amount of net billing credits that are later applied to customer bills.

If approved, the PD's billing rules will result in a substantial expansion of NBC collection from customer-generators. For example, if a customer self-generates 4,500 kWh per year and does not have net surplus compensation, the PD's expanded NBC collection would increase the annual NEM customer bill by approximately $250.[91] Under this tariff design, if the Commission were to impose additional electric program or securitization charges in the future through other proceedings, those charges would automatically apply to all imports of Tariff customers; no additional process would be required. The fact that the PD's Tariff design already expands NBC collection dramatically cuts even further against the need to reach behind the meter to impose additional fees on these customers.

As discussed throughout these comments, CALSSA strongly opposes a policy of assessing NBCs on Tariff customers' BTM consumption. However, if the Commission adopts this proposal for some subset of NBCs, it should only add new charges to this policy in cases where the utilities have established a cost-based rationale for imposing the NBC on BTM consumption in a formal proceeding. This would entail, for example, a cost of service study that analyzes all customers and demonstrates that the costs associated with the NBC are incurred based on gross load, and determines whether new fees should apply only to load previously served by the utility or also to new load such as electric vehicle purchases.

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89 *See* Exh. CSA-01 at 103:3-6.

90 *See* PD, p. 128.

91 Average residential NBCs for the three IOUs, including PCIA, are $0.05545/kWh. A typical customer with a 6 kW solar system that offsets 85% of annual load self-consumes about 4,500 kWh/yr, per CALSSA testimony workpapers.

III. Community Distributed Energy Resources

CALSSA has no objection to creating a new version of a low-income community solar program in place of CS-GT as long as: A) projects under development for CS-GT are allowed to continue; B) the new program is centered on community needs, developed with extensive stakeholder input, and administered by a non-IOU entity; and C) the Commission first orders improvements to the renter tariff and program that have proven track records but need attention: VNEM and SOMAH. Utilities have mismanaged VNEM crediting and should be ordered to correct their mistakes immediately.[92]

IV. Conclusion

CALSSA urges the Commission to adopt the recommendations herein to ensure an appropriate balancing of AB 327's statutory mandates.

Dated: June 10, 2022

Respectfully submitted,

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[92] Notably, the IOUs have failed to provide the required VNEM credits to low-income renters in contravention of a central provision of the SOMAH program, despite ample administrative funding for billing system solutions.

Appendix A
List of Acronyms

Acronym	Description
A.	Application
AB	Assembly Bill
ACC	Avoided Cost Calculator
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CALSSA	California Solar and Storage Association
CARE	California Alternate Rates for Energy
CCA	Community Choice Aggregator
CGDL	Customer Generation Departing Load
CPUC	California Public Utilities Commission
D.	Decision
ESP	Electric Service Provider
GTSR	Green Tariff Shared Renewables
GPC	Grid Participation Charge
GWh	Giga-watt hour
ERRA	Energy Resources Recovery Account
FERA	Family Electric Rate Assistance Program
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
IOU	Investor-Owned Utility
kW	Kilo-watt
kWh	Kilo-watt hour
LBNL	Lawrence Berkley National Laboratory
MPB	Market Price Benchmark
MTC	Market Transition Credit
NBC	Non-bypassable Charge
NEM	Net Metering
OIR	Order Instituting Rulemaking
PAO	Public Advocates Office
PCIA	Power Charge Indifference Adjustment
PD	Proposed Decision
PG&E	Pacific Gas and Electric Company
PPA	Power Purchase Agreement
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
R.	Rulemaking
RA	Resource Adequacy
RPS	Renewable Portfolio Standard
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SOMAH	Solar on Multifamily Affordable Housing

TOU	Time-of-Use
TURN	The Utility Reform Network
UOG	Utility-owned Generation
VNEM	Virtual Net Energy Metering
W	Watt

Appendix B
Data Responses From the IOUs

PACIFIC GAS AND ELECTRIC COMPANY
Net Energy Metering-Successor Tariff OIR
Rulemaking 20-08-020
Data Response

PG&E Data Request No.:	CALSSA_014-Q02		
PG&E File Name:	NetEnergyMetering-SuccessorTariffOIR_DR_CALSSA_014-Q02		
Request Date:	May 25, 2022	Requester DR No.:	014
Date Sent:	June 9, 2022	Requesting Party:	CALSSA
PG&E Witness:	Colin Kerrigan	Requester:	Tim Lindl

QUESTION 02:

Referring to CALSSA's Data Request to the Joint IOUs 7.01(b), please provide an updated response based on data from the most recent 12 months for which data is available.

ANSWER 02:

Please see the table below. As with the May 2021 response, the averages in this table exclude DA/CCA NEM customers. Also please note that due to the way electric bills are recorded in PG&E's database, neither response includes the effect of the California Climate Credit, which is currently -$78.06 per year (or -$6.55/month). For additional context, we are providing the average usage that corresponds to the average bills for both responses.

NEM Type	May 2021 Response		June 2022 Response	
	Average Bill ($)	Average Usage (kWh)	Average Bill ($)	Average Usage (kWh)
NEM 1	$95	428	$113	381
NEM 2	$58	223	$69	165

CALSSA DATA REQUEST
CALSSA-SDGE-DR-14
NET ENERGY METERING REFORM OIR – R.20-08-020
SDG&E RESPONSE
DATE RECEIVED: MAY 25, 2022
DATE RESPONDED: JUNE 9, 2022

2. Referring to CALSSA's Data Request to the Joint IOUs 7.01(b), please provide an updated response based on data from the most recent 12 months for which data is available.

SDG&E Response:
SDG&E's updated response is provided below

Time period	2021/05/01 - 2022/05/01

NEM v1

Average Payment/Month Range	Average Payments/Month	Count of Accounts	% of Accounts
$0-$10	$4	9,890	15.77%
$10-$50	$29	17,054	27.19%
$50-$100	$73	13,543	21.59%
$100-$500	$196	20,525	32.72%
$500-$1000	$661	1,026	1.64%
>$1000	$8,736	685	1.09%
Grand Total	**$194**	**62,723**	**100.00%**

NEM v2

Average Payment/Month Range	Average Payments/month	Count of Account	% of Accounts
$0-$10	$4	19,169	18.99%
$10-$50	$28	26,769	26.52%
$50-$100	$73	19,890	19.70%
$100-$500	$198	32,510	32.20%
$500-$1000	$661	1,431	1.42%
>$1000	$7,558	1,186	1.17%
Grand Total	**$185**	**100,955**	**100.00%**