JOINT RECOMMENDATIONS OF THE INDEPENDENT PARTIES FOR A SUCCESSOR TARIFF TO THE CURRENT NET ENERGY METERING TARIFFS

The below groups, representing a diverse array of independent voices, provide the following set of Joint Recommendations to resolve the issues in Rulemaking (R.) 20-08-020. The groups recommend the California Public Utilities Commission (Commission) adopt these Joint Recommendations to effectively reform the current Net Energy Metering (NEM) tariffs. The Joint Recommendations span essential policies, export compensation, a Grid Benefit Charge, equity provisions, transition of legacy NEM 1.0 and 2.0 customers, and an interim tariff designed to make immediate progress on reducing the NEM cost burden until the successor tariff can be implemented in full.

The below groups recommend the Commission adopt the following sections of the Joint Recommendation.

Organization	**Support for Specific Sections of Joint Recommendations**
Public Advocates Office (Cal Advocates)	Sections 1-6
Natural Resources Defense Council (NRDC)	Sections 1-6
Coalition of California Utility Employees (CUE)	Sections 1-3, Sections 5-6
California Wind Energy Association (CalWEA)	Sections 1-3, Sections 5-6
The Utility Reform Network (TURN)	Sections 1-3, Sections 5-6
The Independent Energy Producers Association (IEPA)	Section 1-4, Section 5 Part 1 and Part 2a, Section 6

TABLE OF CONTENTS

Pages

SECTION 1 ESSENTIAL POLICIES FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision on the NEM successor tariff should include the following fundamental policies:

- Fairly compensate successor tariff customers for the benefits of clean energy without unduly raising electric bills for non-participating customers by valuing successor tariff customers' exported energy using the most current Commission-approved Avoided Cost Calculator. The successor tariff should utilize net billing, which means one bill that separates compensation for exports, using a value that differs from the retail rate, and charges for consumption.
- Require successor tariff customers to pay their fair share for grid use by implementing a Grid Benefits Charge (GBC) to recover costs for transmission, distribution, non-bypassable charges, and any other shared system costs.
- Support lower income customers by protecting them from undue cost burden as a result of the existing or successor tariffs. Provide lower income customers with assistance to overcome structural barriers to adopting distributed energy resources.
    - Any incentives should be prioritized for lower income customers and should be provided upfront to reduce the initial system cost.
    - Transparently identify any subsidies to successor tariff customers and collect them, to the maximum extent possible, from sources other than utility rates.
- Transition existing NEM 1.0 and 2.0 non-California Alternate Rates for Energy (CARE) and non-Family Electric Rate Assistance (FERA) customers in a way that quickly decreases and eventually eliminates the NEM cost burden while ensuring a payback of the NEM customer's system cost over a reasonable period of time.

When developing different components of the successor tariff, the Commission should ensure the components interact in a manner that satisfies the essential policies outlined here.

SECTION 2 EXPORT COMPENSATION FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision on export compensation for the NEM successor tariff should include the following:

- Instantaneous netting or, if that is not possible, hourly netting to determine the (1) monthly quantity of electricity exported from the customer's premise to the grid and (2) the time periods at which these exports are made.
- Exported electricity should be compensated based on avoided costs, as calculated by the Commission's Avoided Cost Calculator (ACC).
- Avoided cost-based export values should be updated annually on January 1
- To avoid potentially large swings in export compensation levels due to different ACC versions, export values should be based on the two most recent Commission-adopted ACC versions.
- Export compensation rates should be differentiated either hourly or, at a minimum, by Time-of-Use (TOU) period to provide appropriate compensation for exported electricity and thereby also incentivize paired storage systems operation to support grid needs (e.g., charge during off-peak and discharge during on-peak periods).
- Export compensation should be structured to provide customers with the option to obtain predictable values for a defined period of time. There are two ways to provide this certainty:

  (1) Develop export compensation based purely on the ACC. Customers get locked-in to a predictable avoided cost-based export compensation for a period of up to 10 years (based on the recommended methodology to provide a stable export compensation signal described below).

  (2) Lock-in all avoided cost values except avoided energy costs.[1] The avoided energy costs will be taken from the day-ahead or real time-market.

  - Explanation – Although the use of ACC energy cost forecasts will provide a more stable signal, tying a portion of export compensation to the day-ahead or real-time market would better align with observed avoided energy supply costs, and it would provide a more accurate signal and allow customers to receive higher payments during periods of supply scarcity (when electric prices are very high). Each method has its advantages. The joint recommendations are agnostic on which of these are chosen, i.e., tying the avoided energy cost component of the export compensation purely to the values in the ACC or to the day-ahead or real time market.
- To provide more certainty to customers considering installation of a behind the meter (BTM) generation system, the initial export compensation may be locked in for up to 10

[1] The avoided energy cost is a specific component of the ACC's avoided costs that is linked to the costs of procuring energy (kWh) from CAISO wholesale energy markets.

years.[2] After the lock-in period, export compensation rates should be updated annually on January 1 using the method described above.

- Because successor tariff customers may lock-in export values for several years, the export value should be based on the estimated ACC values for all years associated with the lock-in period.[3] If fixed levelized values are used rather than the forecast values for each future year in the ACC, the levelized values should not be based on forecasts beyond the next four consecutive years.[4]
- The lock-in export vintage should be determined by the calendar year that a customer submits a complete Interconnection Request. For example, a customer who submits a complete Interconnection Request in 2022 should receive the export rate adopted on January 1, 2022 (based on the 2020 and 2021 ACCs), even if the BTM system doesn't receive permission to operate until 2023.
    i. The lock-in period for each customer should start on January 1 of the calendar year in which they receive permission to operate. The lock-in period for customers who receive permission to operate on or after July 1 will begin January 1 of the following year. For example, assuming a five-year export compensation lock-in, a customer who interconnects on July 1, 2022, would receive the locked-in exports rates until December 31, 2027. This provision will ensure that all customers will have the opportunity of benefitting from the adopted lock-in period plus or minus six months.
- The TOU or hourly export values, with the possible exception of the avoided wholesale energy costs, should be fixed for the duration of the lock-in period.[5]
- When determining a lock-in period, the Commission should ensure the different components of export compensation interact with each other and other aspects of the successor tariff in a manner that satisfies the principles outlined in Section 1.

---

[2] Parties provide their recommendations for a specific lock-in duration (up to 10 years) in briefs.

[3] For example, if a customer joins the successor tariff in 2023, their export compensation rate in 2026 would be the 2022 version ACC forecast for 2026.

[4] For example, a peak TOU export compensation rate for a BTM generation system that completes interconnection in 2021 would be averaged using TOU peak avoided costs over 2022-2025 from the 2019 and 2020 versions of the ACC.

[5] For example, with a five-year lock-in period the TOU export compensation rates for a BTM generation system that submits an Interconnection Request in 2021 and receives permission to operate before July 1, 2021, would be based on the levelized avoided costs over 2021-2025 from the 2019 and 2020 versions of the ACC.

SECTION 3 GRID BENEFITS CHARGE FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision for the NEM successor tariff should include a Grid Benefits Charge (GBC) with the following aspects:

- Successor tariff customers should pay a GBC that includes transmission and distribution costs of service, as well as the non-bypassable charges (NBCs) described below, to fairly recover shared system costs that are currently unpaid by NEM customers.
- For GBCs that are denominated on a $/kW of installed BTM capacity basis, the final GBC amounts should fall within the following range:
    - Lower end of $6.37 – $8.32/kW.[6] Distribution and transmission components from Cal Advocates and certain NBC components from TURN; and
    - Upper end of $10.24 – $14.13/kW.[7,8] GBCs proposed by the joint IOUs that are estimated by valuing all BTM production at avoided costs.
- The GBC should be based on successor tariff customers' BTM system size, energy production or portion of production consumed onsite.
    - Since certain NBCs are required to be collected based on usage, all NBCs should be assessed on a volumetric basis. The NBC charges should apply to customers' total on-site electricity consumption, which is the sum of measured imports, using either instantaneous or billing interval netting, and the electricity simultaneously produced and consumed onsite, which is equal to total generation minus exports.
    - Successor tariff customers should be given two choices to measure BTM system generation: installation of a separate, utility-grade meter to track on-site generation during each billing cycle, or the use of an engineering estimate of the total monthly on-site generation of the customer's BTM system.
- The GBC should include the following NBCs, at a minimum:
    - Public Purpose Programs (PPP);
    - Wildfire Fund Charge;
    - Nuclear Decommissioning;
    - Competition Transition Charge (CTC);
    - Reliability Services (RS);
    - New System Generation Costs (NSGC);
    - Investor-Owned Utility (IOU) securitization costs relating to wildfires or other undercollections;
    - Energy Cost Recovery Account (for PG&E); and
    - PUC Reimbursement Surcharge.
- The GBC may include the additional NBC:

---

[6] The lower end should be $6.37/kW for San Diego Gas & Electric Company (SDG&E), $8.23/kW for Southern California Edison Company (SCE), and $8.32/kW for Pacific Gas and Electric Company (PG&E).

[7] The upper end should be $14.06/kW for SDG&E, $10.24/kW for SCE, and $14.13/kW for PG&E. From Joint IOUs Opening Testimony.

[8] These values do not include the Energy Resources Recovery Account costs or the PG&E wildfire securitization costs, which should also be added.

    - Power Charge Indifference Adjustment (PCIA).[9]
- The GBC for non-residential customers should include at least the NBCs listed above. The Commission should require the utilities to propose reforms in the next rate design phases of utility General Rate Cases (GRC2s) or Rate Design Window (RDW) proceedings to look specifically at GBCs for non-residential customers.
- Because all electricity generated by Virtual Net Energy Metering (VNEM) and Net Energy Metering Aggregation (NEM-A) systems is treated as exports to the grid, the GBC should not be levied on benefitting accounts in VNEM and NEM-A arrangements, except for any NEM-A residential account with generation behind the meter.
- Please refer to Section 4 for additional exemptions to the GBC.

[9] The PCIA includes the above-market energy and capacity costs of the utilities' generation portfolios, as well as costs of utility-owned-generation assets and of managing the utilities' generation portfolios, that were incurred on behalf of all customers including successor tariff participants. Adoption of distributed generation does not reduce any of these legacy procurement costs. It would be consistent with the principles of cost causation and equitable allocation of shared generation system costs to include the PCIA in the GBC.

SECTION 4 EQUITY PROVISIONS FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision for the NEM successor tariff should include the following provisions to ensure equity:

- Exempt California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) successor tariff customers from the GBC.
- Apply a monthly Equity Charge of \$3.41-3.81/kW[10] based on distributed generation capacity installed to all existing non-CARE/FERA residential NEM 1.0 and 2.0 customers.
    - New non-CARE/FERA residential successor tariff customers should not pay the Equity Charge until a period of ten years from distributed energy resource (DER) generation system interconnection. CARE/FERA successor tariff customers should not pay this charge.
    - The Commission should implement an inclusive process, with the input of representatives of disadvantaged communities, environmental justice groups, and consumer advocates, to decide how these funds should be spent. Below are some examples of how Equity Charge funds could be used promote equity in the Commission's DER policies.
        1. An up-front subsidy to CARE/FERA households to offset their costs of installation and address barriers to DER access, particularly in disadvantaged communities,
        2. Ensuring equity in payback periods between CARE/FERA and non-CARE/FERA successor tariff customers.[11] The Equity Charge can vary by IOU based on the amounts needed to ensure equity in payback periods, and
        3. Other DER programs that align with the Commission's Environmental Social Justice Action Plan.

[10] The Equity Charge should be \$3.41/kW for SCE, \$3.44/kW for SDG&E, and \$3.81/kW for PG&E. From Cal Advocates' Opening Testimony.

[11] Currently, CARE/FERA NEM customers receive less value than non-CARE/FERA NEM customers for the energy they produce, because net-metered credits are valued at their discounted retail electricity rate.

SECTION 5 TRANSITION EXISTING CUSTOMERS TO THE NEM SUCCESSOR TARIFF

The Commission's final decision for the NEM successor tariff should adopt the following policies to transition existing NEM customers to the successor tariff to reduce the cost burden on non-participating customers:

If at any point an existing NEM 2.0 customer voluntarily switches to the successor tariff[12] on or after January 1, 2023, and until December 31, 2027, they should be given a rebate for a paired storage system.[13,14]

- o The incentive level should start at a $0.20/Wh storage[15] rebate on January 1, 2023, then be stepped down 10% annually until December 31, 2027.

The Commission should also adopt a process to transition existing NEM customers who do not voluntarily switch:

- Part 1:
    - a) Switch existing non-CARE/FERA NEM 1.0 and 2.0 customers to a new underlying TOU rate five years from the date of interconnection of their BTM generation systems or as soon as practicable for the IOU thereafter.
        - i. This new underlying TOU rate must be non-tiered and have at least a 2:1 differential between summer weekday peak and weekday off-peak periods.[16] Eligible rates include:
            1. PG&E: EV2, E-ELEC (if adopted in PG&E's General Rate Case Phase 2 Proceeding[17]);
            2. SCE: TOU-D-PRIME; and

---

[12] If the Commission adopts an interim tariff, the customer should be transitioned to the successor tariff's end-state.

[13] NEM 1.0 customers should be excluded from this incentive program as they have received more years of payback for their BTM system. An existing NEM 2.0 customer should not be eligible for any incentive if they have already been mandatorily switched over to the successor tariff.

[14] Incented paired storage systems should follow rules already supplied by the Self-Generation Incentive Program to ensure the system maximizes grid benefits.

[15] The current SGIP Small Residential Storage incentive level is $0.20/Wh. See: https://www.selfgenca.com/home/program_metrics/ (accessed August 20, 2021). In 2020, the average incentive for residential general market customers to purchase and install storage through SGIP was $3,172.80. See "Real-Time Public Report," accessed March 5, 2021: https://www.selfgenca.com/home/resources/.

[16] Community Choice Aggregation (CCA) customers must switch to one of the eligible rates described in Part 1.a.i.

[17] See Application 19-11-019.

3. SDG&E must enact a non-tiered TOU rate that accomplishes the required 2:1 rate differential.[18] Until an applicable rate is adopted, customers should transition to DR-SES or EV-TOU/EV-TOU2.

ii. The IOUs should be required to perform a marketing and outreach campaign at least 3 months in advance of any rate switching. Customer marketing and outreach shall include information on technologies and available incentives that can improve system value such as heat pump water and space heaters, electric vehicles, and batteries. In addition to potential operational cost savings from electrification and load shifting technologies, materials shall also explain the climate benefits of electrification and how utilizing energy during periods of mid-day solar generation and limiting evening usage reduces climate and air pollution.

b) Rate switching shall begin no later than January 1, 2023, at which point all existing non-CARE/FERA NEM customers that interconnected in 2017 or earlier shall be moved to the new eligible TOU rate. Existing NEM customers that interconnected after 2017 shall transition to an eligible rate five years from the date of interconnection or as soon as practicable for the IOU thereafter.

- <u>Part 2:</u>
    a) Concurrent with Part 1, five years from the date of system interconnection or as soon as practicable for the IOU thereafter, apply the GBC to all non-CARE/FERA NEM 1.0 and 2.0 customers.
    b) Eight years from the date of system interconnection or as soon as practicable thereafter,[19] switch all non-CARE/FERA NEM 1.0 and 2.0 customers to the successor tariff.

The table below provides the Public Advocates Office's projected reductions in NEM cost burden of this two-part approach for the PG&E, SCE, and SDG&E territories. Part 1 was based on the simplifying modeling assumption that all NEM customers switch to TOU rates with 2:1 price differentials *in 2026*, whereas in reality many customers will be switched before then. The Part 1 estimate (9.0%) is a lower bound estimate of the cost burden reduction, and the actual reduction to the cost burden will be larger depending on how many customers switch to the new TOU rates.

---

[18] In Decision (D.) 20-03-003, the Commission directed SDG&E to propose in its next residential rate design application an opt-in, un-tiered residential TOU rate with a fixed charge that would be available to residential customers charging an electric vehicle, utilizing energy storage, or utilizing electric heat pumps for water heating or climate control. In D. 21-07-010 , the Commission specifically directed SDG&E to submit its proposal no later than September 1, 2021. This rate could potentially meet the requirements specified in the document.

[19] All NEM 1.0 and 2.0 customers will have already reached their payback period by this point.

Commission Policy Adopted	Cost Burden Savings (in net present value)	Cost Burden Reduction	Cumulative Cost Burden Reduction
No Reform for NEM 1.0 or NEM 2.0 customers.	$0 (out of a total $41.1 billion)[20]	0%	0%
Part 1: switching existing NEM customers to a new underlying rate five years from the date of system interconnection.	$3.71 billion[21]	9.0%	9.0%
Part 2a: applying a GBC to all existing NEM customers from the date of five years of system interconnection.[22]	$6.21 billion	15.1%	24.1%
Part 2b: switching all existing customers to the successor tariff from the date of eight years of system interconnection.	$9.51 billion	23.1%	47.3%
Offering an incentive for NEM 2.0 customers to switch to the successor tariff.	$11.97 billion[23]	29.1%	76.4%

[20] The total net present value of the cost shift over all existing customers' 20-year legacy period is $41.1 billion.
[21] This is a conservative estimate of savings as it assumes that all customers transfer to a new underlying rate in the last year of Part 1.
[22] All Part 2 modeling includes CARE and non-CARE NEM customers.
[23] This cost reduction estimate assumes that 100% of NEM 2.0 customers accept the storage rebate in first year that the successor tariff is implemented (2022). Because the share of NEM 2.0 customers accepting the incentive and the timing of the uptake are uncertain, actual reductions in the cost burden will likely be lower.

SECTION 6 INTERIM TRANSITION TO THE NEM SUCCESSOR TARIFF

Because implementing the details of the successor end-state tariff may take time, the Commission should adopt an interim successor tariff for new residential NEM customers. This interim tariff should be required for new residential NEM customers only until the end-state successor tariff rate is implemented. Within 30 days of the Commissions' final decision on a successor tariff, the IOUs should file Advice Letters to implement the interim tariff. The interim tariff should be required for new residential NEM customers within 90 days of the final decision. Key features of the interim tariff should include the following:

- Residential customers should be required to take service on an electrification rate.
- Export compensation is set at a defined percentage reduction to the Non-CARE "net" electrification retail rate at the time the interim successor tariff is enacted in 2022. The "net" electrification retail rate is the residential electrification retail rate net of the four nonbypassable charges recognized under NEM 2.0 and the Power Charge Indifference Adjustment.
- For PG&E and SCE, the percentage reduction to the 2022 Non-CARE net electrification rate is calculated to achieve an average Participant Cost Test (PCT) result of 1.2 over a 15-year timeframe for 2022 and 2023 installations. This approach achieves a discounted payback shorter than the 15-year interim successor tariff term proposed for PG&E and SCE.
- For SDG&E, the percentage reduction to the 2022 Non-CARE net electrification rate is calculated to achieve a discounted payback of 10 years, equal to the 10-year term proposed for the SDG&E interim successor tariff. The shorter payback period for SDG&E is due to the much higher average rates and the lack of a suitable electrification rate option.
- For both CARE and non-CARE customers, export compensation is fixed at the initial 2022 level, with no escalation over the interim successor tariff term (15 years for PG&E and SCE, 10 years for SDG&E).
- Netting period is instantaneous if practicable for the IOU. Otherwise, hourly netting should be performed.
- Customers should be allowed to remain on the interim successor tariff through the term of the interim successor tariff (15 years for PG&E and SCE, 10 years for SDG&E). The shorter duration for SDG&E is due to the accelerated payback period for these customers.
- Customers may voluntarily switch to the adopted end-state successor tariff at any point.
- For SCE and PG&E customers, the interim tariff is expected to yield fully discounted payback periods of 13-15 years and simple payback periods of 8-9 years. For SDG&E customers, the interim tariff is expected to yield fully discounted payback periods of 10 years and simple payback periods of 7.5 years. Details are shown in the tables at the end of this section.

The interim successor tariff should be required for new residential customers until the end-state successor tariff rate is implemented. The end-state successor tariff should be implemented as soon as practicable, and no later than January 1, 2024, once the IOUs have completed any necessary billing system modifications and both the Grid Benefit Charge and any authorized Market Transition Credits are able to be applied.

Modeling results for proposed Interim Successor Tariff

TURN used its cost effectiveness model to assess the impact of the proposed interim successor tariff on residential customers with both stand-alone solar and solar plus paired storage.[24] Sample results for SCE, PG&E and SDG&E customers are shown on the next page. In performing this analysis, TURN made the following assumptions:

- Residential customers take service on an electrification tariff and are assumed to be on a tariff with a baseline prior to adoption.
- Standalone renewable generator is assumed to be solar PV and is sized to serve 100% of first-year load.
- Export compensation is set at a defined percentage reduction to the 2022 Non-CARE net electrification rate, which excludes the following nonbypassable charges -- Competition Transition Charge, Public Purpose Programs, Nuclear Decommissioning Charge, Wildfire Fund Charge, and Power Charge Indifference Adjustment.
- The E3 SCE, SDG&E, and PG&E load shapes are assumed to be representative of average SCE, SDG&E, and PG&E residential customers prior to adoption.
- For SCE, and with assumptions noted, the percentage reduction to the net electrification rate for a 15-year PCT result of 1.2 is approximately 34% for non-CARE customers. With no reduction to the electrification rate, it is not possible to achieve a PCT of 1.2 for CARE customers under a 15-year PCT.
- For PG&E, and with assumptions noted, the percentage reduction to the net electrification rate for a 15-year PCT result of 1.2 is approximately 44.5% for non-CARE customers. With no reduction to the electrification rate, it is not possible to achieve a PCT of 1.2 for CARE customers under a 15-year PCT.
- For SDG&E, there is an 85% reduction to the net electrification rate, which yields exports-weighted compensation of $0.03 per kWh. While this rate is low, it is slightly higher than the export-weighted ACC over the 10-year interim successor tariff term ($0.027 per kWh). In addition, the basic charge, in 2021 dollars, is increased to $1.50 per day for Non-CARE customers and $0.40 per day for CARE customers. With no reduction to the electrification rate, it is possible to achieve a 10-year discounted payback for CARE customers with the change to the basic charge described above.
- Hourly netting is modeled.
- The SCE electrification rate is TOU-D-PRIME, the PG&E electrification rate is EV-2, and the SDG&E electrification rate is EV-TOU-5 (modified with an increase in the basic charge).

[24] TURN's entire model was admitted to the evidentiary record (Ex. TRN-5) and was shared with all parties several times during the proceeding.

- Modeling assumes TURN's capital & operating cost assumptions and financing via a lease. Note that PCT results incorporate only the lease repayments expected to be made through the assumed term of the interim successor tariff.
- All other relevant modeling parameters are the same as those identified in TURN's model and described in testimony.[25]
- The steps to calculate the defined percentage reduction to the 2022 net electrification rate for exports compensation are as follows:

    - <u>Step 1</u>: Calculate imports and exports by TOU period over the interim successor tariff term using the relevant E3 load profile and assuming the standalone renewable generator is sized to serve 100% of first-year load.
    - <u>Step 2</u>: Calculate the standalone renewable generator cost components used in the discounted payback calculation for 2022 and 2023 installations. Costs, including any tax benefits and incentives, are those incurred/received over the interim successor tariff term.
    - <u>Step 3</u>: Calculate the compensation for the E3 load shape assuming the Non-CARE electrification rate for consumption, the 2022 Non-CARE net electrification rate in all years for exports, and the following NBCs assessed on imports: Competition Transition Charge, Public Purpose Programs, Nuclear Decommissioning Charge, Wildfire Fund Charge, Department of Water Resources Bond-Charge, and Power Charge Indifference Adjustment from full electrification rate.
    - <u>Step 4</u>: Calculate the customer's annual bills prior to and post adoption over the term of the interim successor tariff. Export compensation is the export rate in each TOU period applied to exports in each TOU period. Calculate annual bill savings for 2022 and 2023 installations.
    - <u>Step 5</u>: Calculate discounted payback result.
    - <u>Step 6</u>: For each eligible standalone renewable technology (i.e., solar PV), goal seek on the Non-CARE and CARE customer discounts to the 2022 net electrification rate export compensation to achieve a discounted payback equal to the interim successor tariff term, on average, for 2022 and 2023 installations.

[25] Ex. TRN-1, pages 20-30, 60-63.

TABLE 1
SCE 15-yr Tariff Standalone solar results
34% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.127	$ 0.127	0.40	0.38	1.12	15	8.6	8.8%	$ 548
2022	Non-CARE	34.00%	$ 0.127	$ 0.084	0.40	0.35	1.19	13	8.3	10.2%	$ 580
2023	CARE	2022 export rate (0%)	$ 0.127	$ 0.127	0.40	0.37	1.12	15	8.6	8.9%	$ 574
2023	Non-CARE	2022 export rate (34.0%)	$ 0.127	$ 0.084	0.40	0.35	1.21	13	8.2	10.4%	$ 615

TABLE 2
SCE 15-yr Tariff Paired storage results assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.192	$ 0.192	0.59	0.58	1.00	18	11.5	6.3%	$ 471
2022	Non-CARE	34.00%	$ 0.192	$ 0.127	0.59	0.45	1.22	12	8.3	10.9%	$ 921
2023	CARE	2022 export rate (0%)	$ 0.192	$ 0.192	0.62	0.60	1.01	17	11.1	6.7%	$ 520
2023	Non-CARE	2022 export rate (34.0%)	$ 0.192	$ 0.127	0.62	0.47	1.24	11	8.1	11.5%	$ 978

TABLE 3
PG&E 15-yr Tariff Standalone solar results
44.5% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.141	$ 0.141	0.31	0.27	1.14	14	8.5	9.2%	$ 701
2022	Non-CARE	44.50%	$ 0.142	$ 0.079	0.31	0.26	1.19	13	8.5	10.1%	$ 696
2023	CARE	2022 export rate (0%)	$ 0.141	$ 0.141	0.30	0.26	1.15	14	8.4	9.4%	$ 702
2023	Non-CARE	2022 export rate (44.5%)	$ 0.142	$ 0.079	0.30	0.25	1.21	13	8.3	10.4%	$ 707

TABLE 4
PG&E 15-yr Tariff Paired storage results assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.232	$ 0.232	0.42	0.41	1.00	18	12.1	6.1%	$ 553
2022	Non-CARE	44.50%	$ 0.232	$ 0.129	0.43	0.30	1.31	10	7.6	12.7%	$ 1,250
2023	CARE	2022 export rate (0%)	$ 0.232	$ 0.232	0.44	0.41	1.01	17	11.6	6.6%	$ 581
2023	Non-CARE	2022 export rate (44.5%)	$ 0.232	$ 0.129	0.45	0.30	1.34	10	7.3	13.3%	$ 1,290

TABLE 5

SDG&E 10-yr Tariff Standalone solar results

85% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	10-year RIM	10-yr PCT	Discounted Payback	Simple Payback	10-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.197	$ 0.197	0.33	0.22	1.32	10	7.4	9.0%	$ 769
2022	Non-CARE	85.00%	$ 0.197	$ 0.030	0.33	0.22	1.33	10	7.4	9.3%	$ 777
2023	CARE	2022 export rate (0%)	$ 0.197	$ 0.197	0.33	0.21	1.35	10	7.1	9.6%	$ 835
2023	Non-CARE	2022 export rate (85%)	$ 0.197	$ 0.030	0.33	0.20	1.38	10	7.1	10.1%	$ 838

TABLE 6
SDG&E 10-yr Tariff Paired storage results assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	10-year RIM	10-yr PCT	Discounted Payback	Simple Payback	10-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.239	$ 0.239	0.52	0.42	1.03	15	11.2	1.4%	$ 613
2022	Non-CARE	85.00%	$ 0.239	$ 0.036	0.52	0.31	1.31	10	7.5	9.1%	$ 1,205
2023	CARE	2022 export rate (0%)	$ 0.239	$ 0.239	0.55	0.44	1.05	15	10.7	2.2%	$ 676
2023	Non-CARE	2022 export rate (85%)	$ 0.239	$ 0.036	0.55	0.31	1.36	9	7.2	10.0%	$ 1,293