FILED
08/31/21
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering.	R.20-08-020

OPENING BRIEF
OF THE PUBLIC ADVOCATES OFFICE

WAYNE A. PARKER
Attorney

for the Public Advocates Office
California Public Utilities Commission
300 Capitol Mall
Sacramento, CA 95814
Phone: (916) 823-4772 (ext. 31-54772)
E-mail: wayne.parker@cpuc.ca.gov

August 31, 2021

TABLE OF CONTENTS

Page

TABLE OF AUTHORITIES

Page (s)

LIST OF ACRONYMS

AB	Assembly Bill
AECA	Agricultural Energy Consumers Association
ALJ	Administrative Law Judge
CALSSA	California Solar
CARE	Californians for Renewable Energy
CCS	Coalition for Community Solar Access
CLC	Clean Coalition
COS	Cost of Service
CSE	Center for Sustainable Energy
CSI	California Solar Initiative
CUE	Coalition of California Utility Employees
CWA	California Wind Association
DER	Distributed Energy Resources
DG	Distributed Generation
EWG	Environmental Working Group
FWP	Foundation Windpower
IOU	Investor-Owned Utility
IVY	Ivy Energy
Kw	Kilowatt
LCOE	Levelized Cost of Energy
MW	Megawatt
MWh	Megawatt Hour
NEM	Net Energy Metering
NPV	Net Present Value
NRDC	Natural Resources Defense Council
OIR	Order Instituting Rulemaking
OLS	Ordinary Least Squares
PCF	Protect Our Communities Foundation
PG&E	Pacific Gas and Electric Company
PU Code	Public Utilities Code
PV	Photovoltaic
RAM	Renewable Auction Mechanism
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
SBUA	Small Business Utility Advocates
SCE	Southern California Edison
SCL	Sierra Club
SDG&E	San Diego Gas and Electric Company
SEIA	Solar Energy Industries Association
SPM	Standard Practice Manual
SVL	Silicon Valley Leadership Group
T&D	Transmission and Distribution
TOU	Time of Use

TRC	Total resource cost
TURN	The Utility Reform Network
VS	Vote Solar
WAL	Walmart

I. INTRODUCTION

Pursuant to the instructions of Administrative Law Judge (ALJ) Hymes, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits this Opening Brief. Cal Advocates' proposed successor tariff for net energy metering (NEM) satisfies the statutory requirements of the California Public Utilities Code (Pub. Util. Code), including § 2827.1, and ensures customer-sited renewable distributed generation will continue to grow sustainably.[1] In addition, Cal Advocates' proposals and the Joint Recommendations attached hereto in Appendix A address the growing and inequitable cost burden that adversely impacts non-NEM customers under the current NEM tariff structure while also strengthening efforts to reach California's climate and equity goals. Hence, Cal Advocates' proposed adjustments to the successor tariff will create a more cost-effective, fair and balanced successor tariff that aligns with the relevant statutes and the California Public Utilities Commission's (Commission) guiding principles.

II. SUMMARY OF RECOMMENDATIONS

The following is a summary of Cal Advocates' recommendations. These recommendations are consistent with those found in the Joint Recommendations in Appendix A. The Commission should make the following updates to NEM:

1. Create a NEM successor tariff that compensates NEM participants through net billing at the avoided cost value for their exported energy rather than at the retail rate so as to reasonably and fairly compensate the customer for the actual value of their exported energy to the system (Section 2, Joint Recommendations);
2. Establish a Grid Benefits Charge to ensure NEM participants pay their fair share for grid services including distribution, transmission and public program costs (Section 3, Joint Recommendations);
3. Provide incentives, including a battery storage rebate, to encourage current NEM participants to transition to the successor

[1] Pub. Util. Code § 2827.1(b)(1).

tariff and thereby maximize grid benefits while minimizing unintended rate burdens under the current tariffs (Section 5, Joint Recommendations);

4. Exempt lower income customers from the proposed Grid Benefits Charge to create a substantial value proposition for behind-the-meter (BTM) adoption for lower income customers (Section 4, Joint Recommendations);
5. Establish an Equity Charge to be paid by certain NEM program participants to fund programs focused on increasing distributed energy resources in disadvantaged communities (Section 4, Joint Recommendations); and,
6. Establish an Interim Rate for residential customer who install behind the meter (BTM) generation until such time that the end-state successor tariff rate is implemented (Section 6, Joint Recommendations). This interim rate may be necessary to immediately address some of the essential polices issues that could arise (described in Section1 of the Joint Recommendations) after the Commission issues its decision in this proceedings.

III. APPLICABLE LAW AND PROCEDURAL BACKGROUND

Assembly Bill (AB) 327 (2013 Perea), codified as Pub. Util. Code § 2827.1, instructed the Commission to develop a successor tariff/standard contract to the original NEM tariff (NEM 1.0) by December 31, 2015. In AB 327, the Legislature directed the Commission to develop a structure to replace the NEM 1.0 tariff that would align costs with benefits while allowing sustainable growth in the distributed renewable industry. The Commission thereafter issued Decision (D.) 16-01-044 creating the NEM 2.0 tariff structure that remains in effect today.

Pub. Util. Code § 2827.1 details the requirements for a NEM successor tariff. These requirements include:

1. Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities.

2. Establish terms of service and billing rules for eligible customer-generators.
3. Ensure that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility.
4. Ensure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs.[2]

Pub. Util. Code § 2827.1 further requires that "[a]ny rules adopted by the [C]ommission shall consider a reasonable expected payback period based on the year the customer initially took service under the tariff or contract authorized by Section 2827."[3] The statute also directs that participants be provided electric service at just and reasonable rates.[4] Pub. Util. Code § 451 mandates that rates be just and reasonable for all customers, which includes non-NEM participants.[5]

In D.16-01-044, the Commission further committed to reviewing the NEM 2.0 tariff to consider necessary adjustments. On August 27, 2020, the Commission initiated Rulemaking (R.) 20-08-020 to develop a successor to the existing NEM 2.0 tariff. On November 19, 2020, Assigned Commissioner Martha Guzman Aceves and ALJ Hymes issued a Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles (Scoping Memo).[6] The Scoping Memo, among other things, set forth the issues to be determined:

1. What guiding principles (including those related to Assembly Bill 327 (2013, Perea), equity, environmental goals, and social justice) should the Commission adopt to assist in the development and evaluation of a successor to the current net

---

[2] Pub. Util. Code § 2827.1(b)(1)-(4).

[3] Pub. Util. Code § 2827.1(b)(6).

[4] Pub. Util. Code § 2827.1(b)(7).

[5] See Pub. Util. Code § 451: "All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable."

[6] *Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles*, November 19, 2020 ("Scoping Memo").

energy metering tariff?

2. What information from the Net Energy Metering 2.0 Lookback Study should inform the successor and how should the Commission apply those findings in its consideration?
3. What method should the Commission use to analyze the program elements identified in issue 4 and the resulting proposals, while ensuring the proposals comply with the guiding principles?
4. What program elements or specific features should the Commission adopt as a successor to the current net energy metering tariff?
5. Which of the analyzed proposals should the Commission adopt as a successor to the current net energy metering tariff and why? What should be the timeline for implementation?
6. Other issues that may arise related to the current net energy metering tariffs and subtariffs [sic], which include but are not limited to virtual net energy metering tariffs, net energy metering aggregation tariff, the Renewable Energy Self-Generation Bill Credit Transfer program, and the net energy metering fuel cell tariff.
7. What additional or enhanced consumer protections for customers taking service under net energy metering and/or successor to the current net energy metering tariff should be adopted by the Commission?[7]

ALJ Hymes subsequently released two studies outlining the issues to be considered in these proceedings: the Verdant Associates, LLC's *Net Energy Metering 2.0 Lookback Study* (Lookback Study), which examines the performance of the NEM 2.0 program and its impacts, and the *Whitepaper by Energy and Environmental Economics, Inc. (E3) and Verdant* (Whitepaper), which offered policy options for a NEM successor tariff.[8]

On February 17, 2021, the Commission issued D.21-02-007 providing guiding

[7] Scoping Memo, pp. 2-3.

[8] See, January 21, 2021, Administrative Law Judge Email Ruling "R-20-08-020 Email Ruling Presenting Final Verdant Study and Instructing Parties to Respond." See also, January 28, 2021, Administrative Law Judge Email Ruling, "R.20-08-020 Email Ruling Introducing Whitepaper, Noticing Workshop, and Providing Instructions on Successor Proposals."

principles for the development of the NEM successor tariff in response to the first issue described in the Scoping Memo.[9] Evidentiary hearings were held from July 26, 2021, through August 11, 2021, on the remaining issues detailed in the Scoping Memo. Testimony on these issues was limited to information specifically applicable to the NEM successor tariff proposals, i.e. Scoping Memorandum issues #3-6.[10] At the conclusion of the evidentiary hearings, ALJ Hymes instructed all parties to submit Opening Briefs by August 31, 2021, and specifically, to respond to issues 2-6 of the Scoping Memo in their respective Opening Brief.

---

[9] *Decision Adopting Guiding Principles for the Development of a Successor to the Current Net Energy Metering Tariff* (D.21-02-007), R.20-08-020 (February 17, 2021), pp. 45-46. The decision provides eight guiding principles for this proceedings:

(a) A successor to the net energy metering tariff should comply with the statutory requirements of Public Utilities Code Section 2827.1;

(b) A successor to the net energy metering tariff should ensure equity among customers;

(c) A successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services;

(d) A successor to the net energy metering tariff should fairly consider all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1;

(e) A successor to the net energy metering tariff should be coordinated with the Commission and California's energy policies, including but not limited to, Senate Bill 100 (2018, DeLeon), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18;

(f) A successor to the net energy metering tariff should be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities;

(g) A successor to the net energy metering tariff should maximize the value of customer-sited renewable generation to all customers and to the electrical system; and

(h) A successor to the net energy metering tariff should consider competitive neutrality amongst Load Serving Entities.

[10] Scoping Memo, pp. 3-4.

IV. DISCUSSION

A. The Lookback Study and Other Studies Provide Ample Data Proving the Current NEM Tariff is Not Cost Effective and Unreasonably Burdens Non-NEM Customers

The evidence in this case proves the current NEM policies result in a significant cost shift to non-NEM customers.[11] The parties in this case have provided different estimates of the cost shift amounts and have used different calculation methods. But the only reasonable conclusion one can draw from the record is that tying compensation for customer-sited generation at a rapidly increasing retail rate has resulted in higher bills for customers who have installed solar.[12] As further explained below, these burdens are felt disproportionately by low income households and those in disadvantaged communities (DACs).[13]

In its Rebuttal Testimony, Cal Advocates demonstrated that the Commission should rely on the findings and data described in the Lookback Study.[14] These findings and data clearly show the NEM 2.0 tariff is cost-ineffective and unreasonably burdens non-NEM customers. The Lookback Study specifically details the NEM 2.0 tariff's exacerbation of the cost burden, NEM participants' underpayment relative to their cost of service, lagging NEM program adoption in DACs, and the low number of NEM installations paired with battery storage. The Lookback Study illustrates these important negative trends and uses the 2020 Avoided Cost Calculator (ACC) in its calculations to reach its findings.

---

[11] Exh. PAO-03 pp. 2-18 to -19. Exh. TRN-01 p. 9. Exh. CUE-01 p. 2. Exh. IOU-01 pp. 64. E3, "Updated: Cost Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020," June 15 2021, pp. 7, 19, 21, 23-25.

[12] Exh. PAO-03 p. 2-18 to 2-19, 2-39 to 2-44. Exh. TRN-01 pp. 9, 20-31. Exh. CUE-01 p. 2. Exh. IOU-01 pp. 64, 73-75.

[13] Exh. PAO-03 p. 2-32

[14] Exh. PAO-02, p. 1-1.

The Whitepaper by E3 and Verdant[15] shows similar trends in the increasing cost burden and finds that steps are needed to alleviate that burden that are similar to those highlighted in the Lookback Study. The Commission should also examine and take into account the findings detailed in E3's *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020* (Cost-effectiveness Study),[16] which uses the updated 2021 ACC, as ALJ Hymes also ruled E3's Cost Effectiveness Study would be relied on to perform the cost effectiveness of proposals.[17]

As described in the White Paper, meeting the requirements of AB 327 requires a rate mechanism that prevents shifting non-avoidable fixed costs to nonparticipating customers.[18] The Lookback Study clearly shows the NEM 1.0 and 2.0 tariffs create equity concerns due to the misalignment between costs and value. This misalignment creates revenue under-collections (i.e., costs)[19] that must be recovered from nonparticipating customers. Under the volumetric rate structure and NEM 2.0 policies, average residential NEM 2.0 customers pay only 18% of their total annual cost of service for PG&E, 9% for SCE and 9% of SDG&E.[20] NEM 1.0 customers pay for even less of their cost of service because they are not required to take service on time of use (TOU) rates and are exempt from non-bypassable charges.[21]

E3's Cost Effectiveness Study describes the low Ratepayer Impact Measure (RIM) scores for the current NEM 2.0 tariff and CALSSA's proposed tariff as compared to Cal

---

[15] E3 and Verdant, *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California* (Whitepaper), January 28, 2021.

[16] E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020* (Cost-effectiveness Study), May 28, 2021.

[17] April 8, 2021, Administrative Law Judge Email Ruling "R.20-08-020 Email Ruling Noticing April 22, 2021 Workshop and Revising Procedural Schedule (Email 2 of 2)."

[18] Whitepaper, p. 8.

[19] The costs are in the form of customer bill savings that exceed the value that NEM customers' on-site generation provides to the system. This creates revenue under-collections that must be collected from non-participants.

[20] Lookback Study, pg. 12.

[21] The NEM 2.0 decision defined four non-bypassable charges that customers are not allowed to net their exports against.

Advocates' proposed successor NEM tariff.[22] Cal Advocates' proposed successor tariff results in a score of less than 1.0 because it balances the cost burden with other statutory requirements, i.e., encouraging sustainable growth of distributed energy resources by providing substantial bill savings for customers considering adding rooftop solar.[23]

B. The Commission Should Use the 2021 ACC and the RIM Test to Analyze the Program Elements Cal Advocates' Proposes in Section C Below

Pursuant to D.16-06-007 and D.19-05-019, all proceedings evaluating a distributed energy resource (DER) must use the most recently adopted version of the ACC for determining cost effectiveness.[24] The Commission adopted the 2021 ACC in Resolution E-5150 on June 28, 2021.[25] The 2021 ACC incorporates the most recent data and modeling from the Integrated Resource Planning proceedings (R.16-02-007), including load forecasts from the 2019 California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR), an updated gas price forecast, and updated resource costs for renewable generation and storage. Thus, the 2021 ACC is the most accurate means of determining the cost effectiveness of any successor NEM tariff proposal.[26] Accordingly, all party proposals in these proceedings must be evaluated utilizing the 2021 ACC.

---

[22] Exh. PAO-01, p. 5-3, Table 5-1.

[23] The substantial bill savings from the Cal Advocates proposal would also provide a reasonable payback period for NEM customers. Exh. CSA-21 p. 4, Exh. PAO-02 p. 3-13.

[24] In D.19-05-019, the Commission stated that, "D.16-06-007 found that the Avoided Cost Calculator is used in determining the cost-effectiveness of resources across many Commission proceedings and that it is reasonable to require that all Commission proceedings focused on the approval, evaluation, or cost-effectiveness evaluation for other purposes of a distributed energy resources use the most recent version of the adopted Avoided Cost Calculator." D.19-05-019, p. 5 (cites to D.16-06-007, Finding of Fact 4: "It is reasonable to require that all Commission proceedings focused on the approval, evaluation, or other purpose of a distributed energy resource should use the adopted avoided cost calculator, as specified in this decision.")

[25] See, Resolution E-5150, *Adopting Updates to the Avoided Cost Calculator for use in demand-side distributed energy resource Cost-Effectiveness analyses*. California Public Utilities Commission. Issued June 28, 2021. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K955/389955728.PDF

[26] Resolution E-5150, p. 37 ("We believe that the proposed 2021 ACC is a vastly improved calculator that includes the most current data and most accurate modeling available.").

The ACC provides the most mathematically robust estimation of the value that "unplanned" DERs provide to the grid. "Unplanned" here refers to DER adoption that is consequent to customer choice rather than specific grid planning efforts. The value these DERs bring to the transmission and distribution systems, as well as their contribution towards reducing greenhouse gas (GHG) emissions and reducing the need for utility procurement of Renewable Portfolio Standard (RPS) resources is reflected in the output of the ACC and shown down to an hourly basis.[27]

The Commission should use the RIM test to evaluate the cost-effectiveness of the various proposals because it ensures the most accurate cost-effectiveness analysis for any proposed tariff for NEM customers' solar photovoltaic (Solar PV) systems. The RIM test is the only test that captures the cost burden for non-participants caused by NEM and therefore tests for compliance with the guiding principle of equity.[28] Cost-effectiveness and calculations for NEM must use the 2021 ACC to reflect the most recent cost data available while maintaining consistency with supply side resource planning. Cal Advocates notes the Commission-approved Standard Practice Manual (SPM) requires including on-site consumption when conducting a RIM test analysis.[29]

Cal Advocates also addressed issues associated with using the total resource cost (TRC) test as a tool in analyzing the NEM tariffs currently in place. As noted in Cal Advocates' Prepared Testimony, the TRC test does not capture alterations in NEM tariff design nor does it address equity concerns.[30] The TRC tests cannot account for equity as it does not account for any costs passed on to NEM non-participants it does not differentiate between non-participants and participants.

As discussed in more detail in Section B, Cal Advocates proposes the Commission use the ACC values to determine net billing compensation. A benefit of utilizing the ACC values for net billing compensation is that it is a dynamic tool that provides the

[27] Exh. PAO-01, pp. 3-8, 3-9.

[28] Exh. PAO-01, p. 5-6.

[29] Exh. PAO-02, p. 3-2.

[30] Exh. PAO-01, 5-5.

most up to date valuation of the benefits provided by DERs. The Commission updates the underlying data, makes minor changes on an annual basis and evaluates the need for major updates to the tool on a bi-annual basis in the Integrated Distributed Energy Resource (IDER) proceedings (R.14-03-003). Accordingly, setting net billing at avoided costs is the best mechanism by which to accurately and fairly compensate customers for their systems' contributions to the grid.

As explained further below, the ACC sufficiently values the benefits provided by BTM generation through the avoided cost values of GHG emissions, transmission capacity, distribution capacity, energy, and system generation capacity.

1. Avoided Cost Values of GHG Emissions

The avoided cost of GHG emissions estimated by the ACC is calculated by determining both the avoided *amount* of emissions from the electric grid and the *value* of those emissions that would be associated with a given DER measure. The value is based on the GHG shadow price, which represents the cost of reducing an additional unit of GHG emissions in each year.[31] To best reflect the value of GHG reductions over the next decade, the 2030 GHG shadow price from the Renewable Energy Solutions Model is discounted for 2020-2029 based on the utility weighted average cost of capital.[32] The amount of emissions, or the actual impacts on emissions output from DERs measures, is calculated through a two-step approach that first derives marginal emissions and then rebalances the portfolio so annual GHG intensity targets are met.[33] The approach the ACC uses to calculate avoided GHG emission costs is similar in concept to both the fuel substitution test used for energy efficiency and the CEC Title 24 building standards.

---

[31] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, pg. 21. Available at https://www.cpuc.ca.gov/General.aspx?id=5267

[32] The Renewable Energy Solutions Model is a publicly available resource planning model created by E3 that is used in the IRP proceedings. This model is used to create the final Reference System Plan (RSP). The models, inputs, and results are available here: https://www.cpuc.ca.gov/General.aspx?id=6442464143

[33] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, p. 24.

2. Avoided Cost Values of Transmission Capacity

The ACC provides a quantification of transmission avoided capacity costs to represent the estimated cost impacts on utility transmission investments due to peak load reductions.[34]

Because the ability to avoid transmission investment projects is dependent on a variety of specific factors, the avoided cost values are not associated with any "specified" transmission deferral projects. Those projects that provide specified benefits are evaluated in the California Independent System Operator's (CAISO) Transmission Planning Process and the Commission's transmission permitting process and are not incorporated into the ACC.[35] The "unspecified" transmission avoided cost values within the ACC represent the value provided by a DER if the peak load reductions can be obtained in the right amount, right location, and with sufficient dependability to avoid or defer a transmission investment.[36] These avoided costs are calculated through the marginal cost of transmission, which is derived from either the Investor Owned Utilities' (IOUs) General Rate Case (GRC) Phase 2 proceedings or information obtained through data requests.[37] Transmission marginal costs are based on the capacity-driven projects for each utility's transmission plan incorporated into the respective GRC filings, and estimated using the Discounted Total Investment Method.[38]

---

[34] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, p. 36.

[35] CAISO has integrated Non-Wires Alternatives into their Transmission Planning Process. As stated in CAISO's 2019-2020 Transmission Planning Process Final Study Plan issued on April 3, 2019, if reliability concerns are identified during the initial transmission assessment CAISO will perform additional assessments in order to determine if demand response or energy storage could act as a potential mitigation measure. *Decision Adopting Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values.* Decision (D.) 20-03-005, R.14-08-013, filed March 18, 2020, p. 7.

[36] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, p. 36.

[37] PG&E provides transmission marginal capacity costs in its GRC filings, SCE provides its transmission marginal capacity costs through data request responses to Energy Division. SDG&E's transmission marginal capacity costs are calculated with IEPR load forecasts. See the 2021 ACC documentation for more detail, p. 43. See: https://www.cpuc.ca.gov/general.aspx?id=5267.

[38] SCE's transmission marginal capacity costs additionally use the LNBA method for the Aberhill project.

(continued on next page)

The 2021 ACC utilizes the same inputs and methods as the 2020 ACC for valuing the avoided cost of transmission capacity. Under Cal Advocates' proposed successor tariff, NEM systems would not be exempt from the Transmission Access Charge as their benefits to the transmission system would be accounted for with the ACC. Transmission owners' capital costs and operation and maintenance (O&M) costs should be socialized across all ratepayers since all energy users benefit from the transmission system. Any successor tariff should utilize the prevailing ACC to account for the avoided costs of transmission investments that can be attributed to BTM generation.

3. Avoided Cost Values of Distribution Capacity

Similar to the transmission capacity avoided costs, the avoided costs for distribution capacity in the ACC represent the value of deferring or avoiding investments in distribution infrastructure through reductions in distribution peak capacity needs and represent "unspecified" deferral or avoidance values. The costs are derived through a system-average approach and are based on data from the utility's Distribution Deferral Opportunity Report, Grid Needs Assessment, and GRC filings.[39]

The avoided cost values for distribution capacity adopted by the Commission in D.20-04-010 are modeled to capture the long-term value that BTM generation can provide in deferring distribution system upgrades. The method is adjusted to fit the distribution needs of each IOU (based on their respective Grid Needs Assessments) and is vetted in the Distributed Resource Plan proceedings.[40] The Commission-approved 2021 ACC retains the avoided distribution capacity costs from the 2020 ACC. The ACC accurately values the benefits of unspecified deferred or avoided distribution system

See the 2021 ACC documentation for more detail, p. 46. See: https://www.cpuc.ca.gov/general.aspx?id=5267.

[39] For detailed descriptions of the avoided distribution cost methodologies, see the 2020 ACC documentation at https://www.cpuc.ca.gov/General.aspx?id=5267

[40] The 2021 calculator maintains the same approach as 2020, though the secondary distribution costs from the calculation of PG&E's long-term avoided distribution costs has been removed. See the 2021 ACC documentation for more detail: https://www.cpuc.ca.gov/general.aspx?id=5267

investments that can be attributed to BTM generation in both versions of the calculator. Any successor tariff should utilize the 2021 ACC.

4. Avoided Cost Values of Energy Generated

The ACC uses the Strategic Energy Risk Valuation Model[41] to project energy prices until 2030. The model simulates the wholesale price of energy based on projected generation portfolios and weather forecasts. The modeling scenario used for the ACC assumes no new BTM generation, thus giving an estimate of the marginal impact of a new DER.[42] These values are used to estimate the dollar value of energy generated by a DER and are an essential component of estimating the avoided costs of energy. Any successor should utilize the 2021 ACC for valuing energy from BTM generation.

5. System Generation Capacity

System generation capacity includes a DER's contribution to avoided grid peak capacity costs. The ACC uses E3's Renewable Energy Solutions Model to estimate the Net Cost of New Entry of a 4-hour battery storage resource with optimal dispatch according to the CEC Solar + Storage Model. These Cost of New Entry values are subtracted from the levelized fixed costs of the battery to generate the Net Cost of New Entry. The value of this dispatch is allocated to the hours of the year with the highest system capacity need according to the E3 Renewable Energy Capacity Expansion model, which results in allocation of these values to evening hours in late Summer and early Fall.[43] Any successor tariff should utilize the 2021 ACC.

C. The Commission Should Adopt a Successor Tariff that Will Fairly Compensate Customers with BTM Generation without Unreasonably Burdening All Customers

Consistent with its guiding principles the Commission must approve a successor tariff that includes the following components: Net billing at avoided costs, a Grid

---

[41] 2021 ACC documentation for more detail: https://www.cpuc.ca.gov/general.aspx?id=5267, p. 5.

[42] 2021 ACC documentation for more detail: https://www.cpuc.ca.gov/general.aspx?id=5267, p. 11.

[43] 2021 ACC documentation for more detail: https://www.cpuc.ca.gov/general.aspx?id=5267, p. 41.

Benefits Charge with appropriate exemptions for low-income customers, an incentive for storage systems to encourage legacy customers to switch to the successor tariff, and an equity charge to address the low penetration rates of BTM generation in disadvantaged communities. The Joint Recommendations, as supported by a wide range of parties (as described in Appendix A), are consistent with all these components.

1. Net Billing at Avoided Cost

Under the NEM 2.0 tariff, Solar PV exports are compensated at levels that are 3.8 to 5.4 times higher than the benefits they provide to the electrical system in the form of avoided costs.[44] This disparity creates a cost shift that creates upward pressure on non-NEM participant rates and frustrates electrification goals. The disparity will likely continue to grow over time, as retail rates are increasing faster than avoided costs.[45]

Compensating NEM exports at the avoided costs value of Solar PV, will ensure that exports are compensated based on the benefits they provide to the system thereby reducing the cost shift. An important benefit of net billing is that it disassociates export compensation from the retail rate and thereby provides a more objective and transparent method that prices BTM solar excess generation (exports) at its value to the electricity system.[46] Also, aligning net billing with ACC values will support the grid planning efforts of the IRP and distributed resource planning proceedings and aligns exports treatment with the Whitepaper's proposals.[47]

Net billing with exports priced at avoided costs creates strong incentives for customers to maximize their annual bill savings by electrifying transportation and building end uses. By setting exports compensation at the avoided costs level, Cal Advocates' proposal results in very low price of 6-9 cents/kWh for additional self-

[44] Exh. PAO-03, p. 2-21, Table 2-3 and ln. 10-12.

[45] Exh. PAO-03 pp. 5-39 to 5-40.

[46] Whitepaper, pg. 16.

[47] Whitepaper, pg. 15.

consumption of PV associated with electrification technologies.[48] The low price of self-consumption results in large annual operating costs differentials (bill savings) between electrification technologies and gas-fired technologies.[49] Thus, Cal Advocates' proposal provides NEM customers an opportunity to reduce their combined gas and electric bills if the increased electricity consumption is due to switching from gas to electric appliances or purchasing an electric vehicle.[50] For example, Cal Advocates' proposal would cut the payback for a heat pump water heater by two-thirds.[51] This is less than the heat pump's useful lifespan of 13 to 15 years and would provide customers ample opportunity to realize net savings over the heat pump's lifespan. In short, Cal Advocates proposal aligns the successor tariff price signals with the economics of electrification technologies.

Net billing at avoided costs also incentivizes greater self-consumption of solar PV electricity by NEM customers. Greater self-consumption of solar PV benefits grid operations by ameliorating conditions that give rise to the "duck curve," reducing curtailment by CAISO, promoting greater integration of utility-scale renewables, and reducing the need for fast-ramping gas-fired generation that is required to meet evening ramps in net load.[52]

The Commission should adopt Cal Advocates' proposal to compensate NEM exports at avoided costs in the following manner:

- The avoided cost values should be aggregated based on the underlying TOU periods of the customer's retail rate schedule to improve rate stability and minimize confusion.

---

[48] Under Cal Advocates' proposal, the price of additional self-consumption of PV generation is the exports compensation rate plus the non-bypassable charges (NBC) portion of the grid benefits charge, because NBCs are assessed based on a customer's total self-consumption of PV (kWh) during each billing cycle. Exh. PAO-02 pp. 3-19, 5-35.

[49] The cost of additional self-consumption of PV under Cal Advocates' proposal is the exports price plus the non-bypassable charges (NBC) portion of the GBC, which typically totals 6-9 cents/kWh. Exh. PAO-02 pp. 3-19, 5-32, 5-35.

[50] Exh. PAO-02 p. 3-19.

[51] Using SCE's current rates, the payback for a heat pump water heater would be reduced from a span of approximately 20 to 22 years to under 7 years. See, Exh. PAO-02, p. 5-37.

[52] Exh. PAO-02, pp. 4-15 to 4-16.

- The avoided costs should be weighted by solar PV production for each period during non-evening TOU periods so that NEM exports are properly compensated for the value they provide.
- The export compensation rates (ECR) for any TOU period that begins at 4 PM or later and ends at midnight or earlier should be based on a simple average of avoided costs to encourage adoption of battery storage.
- The avoided cost values should be averaged based on a going forward four-year average of the two most recent Commission-approved versions of the ACC to provide stability.

Cal Advocates' net billing proposal could reduce the cost shift by 36% per year while also providing stability and a simpler exports compensation structure that will help customers better understand their rates.[53] Averaging the avoided costs across the two most recent Commission-adopted ACCs dampens the effect of regulatory changes on customers' exports compensation when going from one version of the ACC to the next and produces consistent, stable changes in exports compensation over time.[54] Because a customer's exports compensation lock-in would reset after four years, there would never be more than four export vintages in place at any point in time for a given utility.[55] Thus, Cal Advocates' approach would provide administrative simplicity and there would be a much smaller number of vintages than in other vintaging structures that the utilities have successfully implemented, such as the Power Charge Indifference Adjustment (PCIA).[56]

Cal Advocates proposes the hourly avoided cost be aggregated, in accordance with the TOU period configuration of the underlying rate schedule on which a customer is

[53] Exh. PAO-02, 5-4 to 5-5.

[54] The expected year-to-year changes in exports compensation under Cal Advocates' proposal are also within the ordinary range of changes that residential customers experience in retail rates, which additionally promotes familiarity and customer acceptance. Exh. PAO-02, pp. 5-5 Figure 5-1, 5-6 to 5-7.

[55] For instance, in 2027 all the customers who are part of the 2023 exports vintage would have their exports compensation reset to the next four-year cycle based on the 2027 vintage of export compensation rates.

[56] The PCIA has a different vintage every year.

enrolled.[57] This will promote simplicity and customer understanding; customers will avoid having to interpret different TOU period configurations for the energy they draw from the grid versus the energy they export to the grid.

To ensure that TOU aggregated avoided costs compensate solar PV production accurately, the hourly avoided cost during non-evening TOU periods should be based on a solar PV production weighted average using a single location for each utility and the default settings in the National Renewable Energy Laboratory's (NREL) public PV Watts tool. As discussed in Cal Advocates' Prepared Testimony, solar PV production is highly variable with production ramping up in the morning, peaking in the middle of the day and then falling off in the evening hours before completely disappearing at night.[58] Because solar production is not constant hour to hour within each TOU period, it would be inaccurate to aggregate hourly avoided costs based on a simple average. Taking a simple average will overstate the value of solar production because it would create an analytical fiction of a flat generation profile and ignore that solar generation output is highest in the middle of the day when energy costs are lowest.[59]

On the other hand, Cal Advocates proposes to set the ECR based on a simple average of hourly avoided costs (rather than the solar production weighted average) during the evening TOU periods to encourage technologies that can produce high levels of energy exports[60] for multiple evening hours and provide high generation capacity value.[61] The evening hours are also the period when the grid's marginal GHG emissions intensity (or quantity of GHGs emitted per kWh of incremental load) is highest due to the dispatch of the oldest, most polluting combustion turbine peaker plants.[62] Encouraging evening exports would maximize the benefits of new distributed generation to the system

---

[57] Exh. PAO-03, p. 3-15.

[58] Exh. PAO-01, p. 3-34.

[59] Exh. PAO-03, p. 3-20 Table 3-2.

[60] Energy is valued in Kilowatt-Hours (kWh).

[61] Exh. PAO-02 pp. 3-17 to 3-18.

[62] Exh. PAO-02 p. 3-18.

and to all ratepayers in the form of avoided capacity costs, which could reduce the need for additional, expensive capacity procurement in the long run – and reductions to the system's GHG emissions by reducing the operation of highly-polluting peaker plants.

Switching to compensation based on avoided costs rather than retail rates will also encourage deployment of paired solar and storage systems because it creates large price differentials between battery charging (avoided costs) and discharging (generally, compensated at full retail rates of the highest price, evening TOU periods). After the Hawaii Public Utilities Commission adopted two updated net billing rates with exports compensation set at far below retail rates in October 2017, the percentage of new PV installations that are paired with BTM storage increased from 0.9% in 2016 to 23.9% in 2017, and further increased to 74.8% by 2019.[63]

2. The Commission Should Establish a Grid Benefits Charge to Ensure NEM Customers Pay Their Fair Share for Grid Services

Simply updating the NEM tariff with net billing with exports compensated at avoided costs would not collect enough revenue to ameliorate the cost burdens imposed on non-NEM customers. NEM customers enjoy the benefit of having a maintained grid available to serve them with energy after the sun sets, as well as taking their surplus energy when their on-site demand is less than their Solar PV system's production.

NEM customers' underpayments relative to their cost of service and their over-compensation relative to the value of their generation result in their paying 82-91% less on their annual bills than their annual cost of service.[64] A well designed and equitable rate would ensure all customers pay their cost of service to ensure a just and reasonable allocation of the utility's costs among customers.[65] The Commission should establish a Grid Benefits Charge (GBC) to ensure NEM customers pay their fair share for grid services (See Joint Recommendations, Section 3 of Attachment A).

---

[63] Exh. PAO-02, pp. 5-11 to 5-13.

[64] Exh. PAO-01, p. 3-28.

[65] Cost of service is the total costs to the system of providing electrical service to a group of customers.

Beginning in the late 1970's, the Commission adopted a marginal costs-based approach to revenue allocation (cost of service) and rate-setting.[66] Under a marginal costs-based approach to cost of service, the Commission determines customer groups' cost of service by calculating the theoretical marginal costs their usage imposes on the system.

However, because total marginal costs rarely match the utility's revenue requirement, the Commission assigns the system's total system costs above marginal costs – what Cal Advocates refers to herein as the system's fixed costs – among customer groups using the equal percent of marginal cost (EPMC) approach. Applying the EPMC approach, the Commission scales all customer groups' marginal costs by the same EPMC multipliers[67] so that total system marginal costs equals the Commission-approved revenue requirement.[68] Because the EPMC approach assigns the system's fixed costs to all customer groups in proportion to the incremental costs their usage imposes on the utility, the Commission has repeatedly found the EPMC approach to be a fair, equitable way to assign the revenue requirement (system marginal and fixed costs) among customer groups.[69]

NEM customers pay only a small fraction of their total cost of service, which shifts their EPMC (fixed)[70] costs responsibility onto other customers. NEM customers tend to be larger than average users prior to installing an on-site generator and, even after installing on-site generation, they continue to impose high levels of peak period usage and customer demand (kW) on the system.[71]

---

[66] D.18-08-013, p. 12.

[67] Each utility has a single EPMC multiplier applied to all marginal distribution costs and a single EPMC multiplier applied to all marginal generation costs.

[68] The Commission has employed a marginal costs approach to revenue allocation using the EPMC approach since the early 1980's. D.18-08-013 pp. 13-15 and p. 17 citing D.89-12-057, p. 220.

[69] D.18-08-013, p. 14, p. 15 citing D.82-12-113 p. 131, p. 16 citing D.86-08-083 p. 26 and D.87-05-071, COL 3.

[70] Cal Advocates uses the terms EPMC costs and fixed costs interchangeably to refer to all system costs that do not vary with marginal cost drivers. Exh. PAO-03 p. 3-25 fn., 256.

[71] Exh. PAO-01, p. 3-29, Table 3-7.

The Lookback Study reports that average *pre-interconnection* annual consumption of residential NEM 2.0 customers is considerably higher than typical residential single family homes' annual consumption.[72] Solar PV mostly generates during the middle of the day and provides very little distribution system value.[73] These customers continue to impose high peak period usage and customer demand levels (kW) on the system even after installing on-site generation.[74] The Lookback Study showed large shortfalls in NEM 2.0 customers' annual bills from their cost of service responsibility for all three IOUs. The Lookback Study's cost of service analysis includes all components of the Commission's revenue allocation (cost of service) process.[75]

NEM customers' bill savings are much larger than the benefits provided by their on-site generation, because the avoidance of full residential volumetric retail rates compensates NEM customers for many costs that their on-site generation does not avoid. Residential rates are designed to recover residential customers' total cost of service while considering various customer-specific factors. These residential rates were not designed to produce accurate compensation at full retail rates for customers who install PV systems. This design flaw results in an inequitable shift of costs from NEM to non-NEM customers under the NEM 1.0 and 2.0 tariffs.[76] Therefore, a monthly GBC is necessary to address these gaps and to reduce the cost burden further.

A GBC should include a NEM customers' responsibility for fixed distribution system costs – or the total costs of the system that are above marginal costs – as well as transmission costs. The costs above marginal costs include costs to maintain and replace aging distribution capacity[77] and to provide sufficiently reliable and safe electric service.

---

[72] Average NEM 2.0 pre-interconnection consumption is 7,824-10,513 kWh while single family home consumption is 7,450-7,701 kWh. Lookback Study, p. 30.

[73] Exh. PAO-01, p. 3-33.

[74] Exh. PAO-01, p. 3-28.

[75] Verdant, "NEM 2.0 Lookback Study," p. 98; see also, Exh. PAO-01, p. 3-31, Table 3-9.

[76] Exh. PAO-01, p. 3-33, ln. 3-12.

[77] The unavoidable or fixed costs of service include the equal percent of marginal cost (EPMC) scalar in the Commission's rate making terminology. EPMC revenues equal the different between system-level

(continued on next page)

Most distribution and transmission costs are fixed and therefore do not change with a customer's usage level. Both the California Solar and Storage Association (CALSSA) and Solar Energy Industries Association (SEIA) fail to demonstrate how various expenditures related to fixed distribution and transmission costs are avoided when customers install solar PV. For example, when asked about the undergrounding of distribution lines CALSSA's witness admitted that NEM customers would also require undergrounding of their distribution lines.[78] Similarly, SEIA's witness admitted that the costs of wildfire hardening of existing facilities cannot be avoided by urban NEM customers.[79] If these costs are not adequately covered by NEM customers, non-NEM customers are forced to pay more towards these costs even though, as SEIA's witness noted, "reducing wildfires is something that is in everybody's best interest."[80]

Fixed distribution and transmission are critical components of cost of service that should be included in a GBC because they benefit all ratepayers and are unaffected by customers' participation in NEM.

There are also significant non-bypassable charges (NBCs) that do not change when customers add on-site generation. NBCs cover the costs of public programs that serve broad societal purposes and benefit all ratepayers. Examples of costs covered by

---

marginal cost revenues and the utility's approved revenue requirement. The EPMC scalars scale the marginal cost revenues to the full revenue requirement. The Commission has repeatedly stated its preference for EPMC scaling of marginal costs, which assigns costs to customer groups in proportion to the marginal costs they impose on the system. The Commission has stated that rates based on EPMC scaled marginal costs are cost-based rates and that EPMC scaling is the preferred way to achieve *fair, equitable* rates. Therefore, when NEM customers do not pay their EPMC-scaled marginal costs (cost of service), it violates the Commission's definition of fair, equitable rates. D.18-08-013. pp. 14, 18, 19.

[78] "Q: And would that suggest that if other distribution lines were being undergrounded, that the distribution lines serving these net meter customers would also be undergrounded as well? A: The individual local adoption of net metered solar would still require the undergrounding and would not alter the utility's plan for undergrounding." Testimony of Brad Heavner, Hearing Transcript, Vol. 7, p. 1131, ln. 13-21.

[79] "Q: Wildfire mitigation costs which typically involve grid hardening of existing facilities. A: Yeah, I'm not talking about hardening existing facilities. I don't think that those can be avoided." Testimony of Thomas R. Beach, Hearing Transcript, Vol. 7, p. 1352, ln. 10-15.

[80] Testimony of Thomas R. Beach, Hearing Transcript, Vol. 7, p. 1168, ln. 5-11.

NBCs include funding for the California Alternate Rates for Energy (CARE) program,[81] the costs of decommissioning nuclear generators (Nuclear Decommissioning Charge), the costs for legacy electricity contracts (Competition Transition Charge), and wildfire mitigation costs (Wildfire Fund Charge).[82] Installation of on-site generation does not reduce the need or the costs of these programs, nor does it provide any reason to exempt NEM customers from their responsibility to equitably pay for these program costs. Cal Advocates' proposal would ensure that such costs are truly non-bypassable.

Therefore, Cal Advocates proposes a monthly GBC to address these gaps and to reduce the cost burden further. A minimum bill would not fairly or accurately address the shortfall in cost of service on an individual customer basis, because it would apply a flat charge for all customers[83] despite the fact that customers with larger PV systems are likely to exhibit larger shortfalls in their fixed costs responsibility – and should contribute more to ensure they pay their fair share of system costs.[84] In addition, a minimum bill would be regressive in regards to customers' usage level, meaning it would impact smaller users more than larger users. This could tilt adoption of PV even further away from smaller customers and toward large customers.[85]

Importantly, Cal Advocates' proposal does not include a distribution or transmission component for *non-residential* NEM customers.[86] Non-residential GBCs would be constructed only the nine NBCs identified in the Joint Recommendations and

---

[81] Testimony of Brad Heavner, Hearing Transcript, Vol 7, p. 1167, ln. 14-25. A non-CARE customer who contributes to funding the CARE program benefits from "general public welfare" even if the non-CARE customer does not receive CARE discounts. Additionally, Mr. Heavner testifies that there's a long-term benefit to electrification for all society, and that's the benefit when asked what services a non-EV customer receives when subsidizing electric vehicle charging stations. Hearing Transcript, Vol 7, p, 1168, ln. 1-4.

[82] Nuclear generation provides consistent day and nighttime baseload generation for the benefit of all customers, so the NDC is an NBC and is allocated widely across all customers on the basis of sales.

[83] The charge would only be applied during billing cycles in which their bill is below the minimum bill threshold.

[84] Testimony Mohit Chhabra, Hearing Transcript Vol. 10, p. 1864, ln 10-28, & p. 1865, ln. 1-16.

[85] Testimony Mohit Chhabra, Hearing Transcript Vol. 10, pp. 1864, ln 17 - 1865.

[86] Exh. PAO-01, p. 3-45.

would reflect the NBCs that are current at the time the improved successor tariff is implemented.[87]

The GBC proposed by Cal Advocates would be a monthly GBC based on the size of the customer's generator[88] to address distribution and transmission costs, and based on their monthly gross consumption of on-site generation[89] for the nine NBCs.[90] The transmission and distribution components of the GBC should be set at $4.73 and $1.34 per kW, respectively, for PG&E customers, at $3.48 and $0.72 per kW for SCE customers, and at $3.40 and $1.58 per kW for SDG&E customers, assuming that the improved successor tariff is implemented in 2022.[91] These values should be escalated at the same rate as the annual change in the residential average rate during every year from 2022 onward.[92] For example, if the PG&E residential average rate increases by 4.0% from 2022-2023 and by 4.0% from 2023-2024 and if the Commission directs PG&E to implement the successor tariff by January 1, 2024,[93] then the transmission and distribution components of the GBC as implemented on January 1, 2024 should be $5.12 per kW and $1.45 per kW, respectively.[94] Finally, the GBC should include the nine

---

[87] Exh. PAO-01, p. 3-25. See also, Appendix A, Joint Recommendations of the Independent Parties, p. 4.

[88] GBC associated with the size of the BTM generation system would be calculated as dollars per installed kilowatt ($/kW)

[89] GBC associated with the monthly gross consumption would be a charge calculated based upon the energy consumed ($/kWh).

[90] Exh. PAO-01, p. 3-15. The Joint Recommendations include an illustrative valuation of all components (transmission, distribution and NBCs) converted to $/kW for comparison. See, Appendix A, Joint Recommendations, p. 4

[91] Exh. PAO-03 pp. 3-26, 3-44. See also, Appendix A, Joint Recommendations of the Independent Parties, p. 4.

[92] Escalation at the same rate as retail rates ensures that the GBC continues to collect the same amount of costs on a proportional basis of a customers' total bill savings. This mitigates increases in the cost burden as retail rate increases continue to rapidly outpace inflation. Exh. PAO-03 p. 3-45.

[93] This scenario could occur if the Commission adopts the Interim Tariff that is put forth in the Joint Recommendations - which states the improved successor tariff should be implemented no later than January 1, 2024. See, Appendix A, Joint Recommendations of the Independent Parties, p. 11.

[94] $4.73 * 1.04^2 = $5.12. $1.34 * 1.04^2 = $1.45.

NBCs that are included in the Joint Recommendations to ensure fair recovery of the costs of public programs that benefit all customers.[95]

Cal Advocates' proposed GBC is smaller than the fixed and grid access charges proposed in the Whitepaper and, even after inclusion of the GBC, customers would be able to realize annual bill savings of $213.34 to $230.74 *per kW* assuming no changes from current NEM 2.0 levels of self-consumption – or significantly higher annual savings of $286.08 to $339.01 per kW if customers increase their self-consumption of PV, such as by adopting electrification technologies.[96] Since the GBC reduces NEM customers' shortfall in system fixed costs recovery while still allowing customers to experience substantial bill savings by adopting PV, it fulfills the statutory requirement that distributed generation continues to grow in a way that is sustainable for all customers.[97]

---

[95] Appendix A, Joint Recommendations of the Independent Parties, p. 4.

[96] Compare Whitepaper, p. 24 with Exh. PAO-01, pp. 3-25, 3-47. Exh. CSA-21, p. 4 row 7 of Excel spreadsheet. Even after inclusion of the GBC, customers would also have a significant opportunity to hedge against future increases to retail rates. Assuming average annual rates increase of 4% per year, customers would see increase in their annual bill savings of 1.8% to 3.5% per year. Testimony of Benjamin Gutierrez, Hearing Transcript Vol. 11, p. 1988, ln 4-9.

[97] Pub. Util. Code § 2827.1(b)(1).

3. Exempting Lower Income Customers from the Proposed Grid Benefits Charge Will Encourage These Customers to Adopt BTM Generation Technologies

The Commission should exempt California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) customers from paying the GBC in order to address one of the historical barriers to lower income customers' access to BTM generation.[98] Under current NEM tariffs, CARE and FERA customers with rooftop solar have had lower internal rates of return on their Solar PV investments because NEM compensation for these customers is tied to retail rates that are reduced by the CARE and FERA discounts.

Exempting CARE/FERA customers from paying the GBC would increase their annual bill savings.[99] The GBCs are expected to increase at the same annual rate as retail rates. As CARE/FERA customers would remain exempt from these charges, they will see increased annual bill savings relative to non-CARE/FERA customers' bill savings. This will produce greater parity between low income and higher income customers' system compensation over time.[100]

Under Cal Advocates' proposal, CARE customers' average annual compensation ranges from $62 less than non-CARE (assuming an SDG&E NEM customer that exports less energy than a typical NEM customer[101]) to $0 difference from non-CARE (assuming a PG&E NEM customer that exports less energy than a typical NEM customer).[102]

---

[98] Exh. PAO-01, p. 3-52.

[99] Cal Advocates identified annual bill savings of $91.92 per kW of interconnected PV capacity for PG&E customers, $69.12 per kW per year for SCE customers, and $73.68 per kW per year for SDG&E customers in the first year the successor tariff is implemented (2022). Exh. PAO-01, p. 3-52.

[100] For a comparison of CARE and non-CARE customers' annual compensation (annual bill savings) per kW under the NEM 2.0 tariff and Cal Advocates' proposed successor tariff averaged over the years 2022-2030, see Exh. PAO-01, p. 3-52, Table 3-18.

[101] This is not a fixed lower limit on exports. Customers' annual net exports percentages generally follow a normal distribution that gradually tails off at the lower and higher ends. There will be a small and gradually declining percentage of customers whose annual exports are less than the lower bound estimate.

[102] CARE customers' annual compensation per kW may be higher than non-CARE under Cal Advocates' proposal, because CARE customers are exempt from paying the GBC and they receive the same export

(continued on next page)

Successor tariff customers are likely to size their systems in such a way as to reduce exports and maximize self-consumption. This will increase their annual compensation per kW and thereby reduce their payback periods.[103]

Cal Advocates' GBC proposal and the exemption for CARE/FERA customers would greatly reduce the structural disparity and bring greater alignment in payback periods between low-income and high-income NEM customers. The GBC would also address other structural barriers in access to BTM generation that low-income customers face.

4. Providing Storage Incentives Will Encourage Current NEM Customers to Transition to the NEM Successor Tariff

As the Lookback Study confirms, the current NEM tariffs do not encourage customers to pair storage with their Solar PV systems. Only 6% of NEM systems interconnected in 2019 were paired with energy storage.[104] Paired Solar PV with storage would maximize the benefit of solar energy production by allowing the generation to be provided to the grid when it is most valuable.[105] As explained in Section 2 above, NEM 1.0 and 2.0 customers currently avoid many of the grid costs from which they benefit and thereby create a large and growing cost burden for non-NEM customers. Additionally, current payback periods for solar PV installation range from 3-8 years,[106] an

---

compensation as non-CARE, so their relative compensation to non-CARE customers depends on what proportions of their total annual production they consume on-site or export to the grid.

[103] By increasing onsite consumption, customers reduce their exports. Although the low exports scenario provides a lower bound estimate and in reality, most customers' exports will likely fall somewhere in between the upper and lower bounds. Cal Advocates calculated payback periods to reflect this possibility as the "low exports scenario." Payback periods based on the "low exports scenario" are reflected in the "lower" columns of the pay back ranges provided in Exh. PAO-03, Tables 3-25 and 3-26 on pp. 3-69 and 3-70. Additionally, Cal Advocates provided savings estimates in Table 3-19 on p. 3-54 using the low exports scenario for each IOU.

[104] Lookback Study, p. 27. Figure 3-4.

[105] "More than 90% of all megawatts (MW) of customer-sited solar capacity interconnected to the grid in the three large investor-owned (IOU) territories (PG&E, SCE, and SDG&E) in California are on NEM tariffs." See: https://www.cpuc.ca.gov/NEM/.

[106] Exh. PAO-01, p. 4-34, Attachment 4-A.

unreasonably short payback period for NEM 2.0 customers in light of the benefits they provide the grid. It speaks volumes that even SEIA's expert witness testified that the current payback periods in California are too short.[107] The relevant statute requires "reasonable" payback periods.[108] As outlined in the Joint Recommendations in Appendix A, Cal Advocates proposes storage incentives to encourage NEM 2.0 customers to move to the NEM successor tariff, which should have a more reasonable payback period, from January 1, 2023, to December 31, 2027.[109] Five years after the date of interconnection, NEM 1.0 and 2.0 customers should be moved to a new underlying TOU rate that is non-tiered and has at least a 2:1 TOU price differential between summer weekday peak and weekday off-peak periods. The GBC should also be applied to all non-CARE/FERA NEM 1.0 and 2.0 customers at that time. By the eighth anniversary of the date of interconnection, all non-CARE/FERA NEM 1.0 and 2.0 customers should be transitioned to the NEM successor tariff. Cal Advocates also proposes the Commission design the successor NEM tariff to encourage NEM customers to adopt paired storage systems.

Without paired storage, increased renewable energy from solar can have a minimal or negative value where the solar generation added does not align with system needs.[110] The Whitepaper explains paired storage can shift solar generation from the lower-value midday hours to the higher-value evening hours.[111] The most recent report on the Self-Generation Incentive Program (SGIP) also demonstrates paired storage can maximize the benefits of BTM generation by allowing generated energy to be used at times when it is

---

[107] "I think that all parties for this case, as far as I know, have agreed that paybacks should be longer in California, that they're too short." Testimony of Thomas R. Beach, Hearing Transcript, Volume 8, pp. 1282-1283.

[108] Pub. Util. Code, § 2827.1(b)(6).

[109] Appendix A, Joint Recommendations, Section 5. Cal Advocates further detailed the structure of a potential storage rebate program in its Opening Testimony. See Exh. PAO-01, p. 4-1 thru 4-9.

[110] See the growing annual rates of energy curtailment by CAISO: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[111] Whitepaper p. 11.

more valuable to the grid, to meet peak grid demand, and reduce GHG emissions.[112] If storage is dispatched to maximize grid benefits, it also has the potential to increase resiliency, support reliability during periods of system and local peak demand, and improve customer bill savings.[113] As evidenced by low adoption rates, energy storage is a more nascent industry compared to stand-alone rooftop solar. Cal Advocates' paired storage incentive policy proposal can aid its growth.

Statutory mandates also require the Commission to establish transition periods so that NEM customers can remain on their current NEM tariff for "a reasonable expected payback period based on the year the customer initially took service under the tariff."[114] D.14-03-041 established a 20-year transition period, beginning when the system was interconnected for NEM 1.0 customers.[115] Similarly, the NEM 2.0 Decision established a 20-year transition period for NEM 2.0 customers.[116] In order to create the reasonable payback periods required by statute, the Commission should encourage existing residential NEM customers to switch over to the successor tariff by offering rebates on paired storage systems.

Storage rebates would compensate customers for switching to the new tariff with BTM systems that enhance grid benefits compared to stand-alone rooftop solar. Current NEM residential customers taking service on NEM 1.0 and 2.0 tariffs either have already paid off their systems with their utility bill savings, or they will within three to eight years.[117] The storage incentive would only be offered for a five-year period, after which

---

[112] ITRON, 2018 SGIP Advanced Energy Storage Impact Evaluation (January 29, 2020), p. 1-10. See https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIP%20Advanced%20Energy%20Storage%20Impact%20Evaluation.pdf.

[113] 2018 SGIP Advanced Energy Storage Impact Evaluation, p. 4-14.

[114] Pub. Util. Code § 2827.1(b)(6).

[115] *Decision Establishing a Transition Period Pursuant to Assembly Bill 327 for Customers Enrolled in Net Energy Metering Tariffs*, D.14-03-041 (March 27, 2014), p. 2.

[116] D.16-01-044, p. 100.

[117] A NEM 2.0 system can on average pay for itself in only three years for SDG&E customers, five years for PG&E customers, and eight years for SCE customers. Cal Advocates data requests IOUs: PGE-4, SDGE-5, SCE-6. See Exhibit 4-A of this Testimony.

the GBC should be applied to all non-CARE/FERA NEM customers who remain on NEM 1.0 and 2.0 tariffs.

Notably, other than SCE NEM 2.0 customers with systems installed after 2018, all existing NEM customers will have already reached their system payback within this 5-year program window.[118]

Cal Advocates proposals for implementing a battery storage rebate would create the reasonable payback periods required by statute.[119] This would greatly reduce the NEM cost burden on non-participants. Cal Advocates' proposal would also reduce the net present value of NEM 1.0 and 2.0 cost burdens over all of the remaining years of customers' 20-year transition periods to $24.79 billion (a $16.27 billion or 39.6% reduction), resulting in significant cost savings to general ratepayers.[120] There is also support from other parties for this proposal, as exemplified by the testimony of SEIA's expert witness.[121] This proposal would also have the additional benefit of lowering GHG emissions.[122]

5. The Commission Should Establish An Equity Charge on Program Participants To Fund Programs that Encourage Adoption of Distributed Energy Resources in DACs

A variety of independent parties have identified the need for the Commission to address the inequities inherent in the BTM generation programs. The Joint Recommendations includes some principles the Commission should include in considering the appropriate mechanism for implementing an Equity Charge (See Section 4 of Appendix A).

[118] See: https://www.californiadgstats.ca.gov/charts/. Accessed June 7, 2021.

[119] Pub. Util. Code § 2827.1(b)(6).

[120] Exh. PAO-01, p. 4-17 to 4-21.

[121] Testimony of Thomas R. Beach, Hearing Transcript, Volume 8, p. 1284, ln. 15-28.

[122] Exh. PAO-01, p. 4-3.

Cal Advocates supports the Joint Recommendations which builds upon the Natural Resources Defense Council's (NRDC) proposed Equity Charge.[123] This Equity Charge would provide meaningful benefits to historically under-represented customers among NEM participants. The Commission should impose an Equity Charge on all residential NEM 1.0 and 2.0 customers beginning on the effective date of the successor tariff, with exemptions for CARE and FERA NEM customers. Customers who take service on the improved successor tariff should be subject to the Equity Charge 10 years after the date of their system interconnection.

The Equity Charge should have two components. The first component is designed to collect a sufficient subsidy to ensure equity in payback periods between CARE and non-CARE customers. CARE/FERA customers would be exempted from the GBCs proposed by Cal Advocates. However, there would still be some disparity in payback periods based on Cal Advocates' internal modeling.[124] A modest fee of $0.26 - $0.66/kW per month on NEM 1.0 and 2.0 customers would generate the funds necessary to provide an up-front subsidy for CARE/FERA customers to ensure equity in payback periods.[125]

The second component would be a monthly equity fee of $3.15/kW of installed capacity on all non-CARE/FERA NEM 1.0 and 2.0 customers.[126] 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 to address barriers to adoption in DACs.[127] This component should

---

[123] Exh. PAO-01, p. 3-55.

[124] Cal Advocates' internal modeling concluded that CARE customers would save $33-76/kw-year less than non-CARE customers so their payback periods are longer.

[125] Exh. PAO-01, p. 3-56, Table 3-20.

[126] See Exh. PAO-01, fn 330. According to responses from a data request to the IOUs, there were 4,994,615 kW of non-CARE NEM rooftop solar as of September 2020. A $3.15/kW monthly charge on these installations would generate $189 million in funds for the equity fee. Response to Cal Advocates Data Request #DR-03, received November 16, 2020.

[127] See Pub. Util. Code § 2827.1(b)(1): "Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

be initially calibrated to collect, over the next decade, roughly the same amount that CARE customers have paid for NEM subsidies over the last decade.[128] This calibration would result in a collection of at least $200 million per year.[129] These funds should be collected in a balancing account from which funds can be disbursed to programs designated by the aforementioned process.[130]

In total, Cal Advocates' recommended Equity Charge is $3.15/kW plus $0.26-$0.66 for a total $3.41 - $3.81/kW charge per month. This is a modest enough charge that more affluent NEM customers can afford it while being sufficient to increase participation in NEM programs by customers living in DACs.

D. Cal Advocates' Proposal Best Balances Equity Concerns and the Need to Provide Sustainable Growth to BTM Generation in California

Cal Advocates' proposed successor tariff would substantially decrease the cost burden on non-NEM customers, address the current NEM design's cost-effectiveness deficiencies, and create fair treatment between residential and non-residential DER customers. This will ensure overall sustainable growth for DERs, including a healthy solar industry, and better align California's DER incentives with other states experiencing similar DER growth. As detailed below, Cal Advocates' proposed successor tariff would

[128] The average PG&E, SCE and SDG&E non-NEM CARE customer paid $106, $67, and $128 more on their annual bills in 2019, respectively, due to NEM according to p. 28 of "Designing Electricity Rates for an Equitable Energy Transition." This means that the three million CARE customers without rooftop solar pay approximately $384 million per year to NEM customers, who tend to be far wealthier than the average customer (Lookback Study, p. 33). This does not include payments by FERA-eligible customers, so the true amount paid by lower income customers is likely higher.

[129] CARE customers have paid $1.9 billion for NEM tariffs. This assumes that the CARE customer NEM cost was zero in 2010, the cost in 2020 was $384 million, and that the increase in this cost was linear while the number of CARE customers stayed the same (approximately 3.1 million). To collect this amount over the next ten years would require ~$192 million per year. This has been rounded up to account for the fact that there was a cost burden to CARE customers before 2010 and for the fact that this value does not include FERA customers.

[130] Each utility would independently collect the Equity Charge revenues and track them in a utility-specific balancing account. Expenditures for equity programs within a utility's service territory would be booked to the Equity Charge balancing account for that utility.

protect all utility customers from unreasonably high rates driven by the large NEM cost burden.

Cal Advocates' Proposals, detailed in Section C above, would substantially lower the cost burden on non-NEM customers by creating a successor tariff that is aligned with state equity and climate goals. Cal Advocates' proposals would lower the total annual cost burden of the successor tariff by $1.81 billion per year[131] in 2030 compared to a continuation of the current NEM 2.0 rate structure.[132] In addition, when calculating the net present value (NPV) of the annual cost burden over all the years remaining beyond 2021 of NEM 1.0 and NEM 2.0 customers' transition periods,[133] Cal Advocates' proposals would reduce the total NPV of the NEM 1.0 and NEM 2.0 cost burden by $16.3 billion[134] creating significant savings for ratepayers and helping to alleviate the unsustainable upward pressure on electric rates.[135] Reforming NEM through the combined changes detailed above will save non-NEM participants between $158 and $237 per year by 2030.

Cal Advocates' proposed successor tariff would enhance program cost-effectiveness, while other parties' proposals would not. As explained in Cal Advocates' Prepared Testimony, E3's RIM scores for Cal Advocates proposals were much higher than the score for CALSSA's proposed successor tariff for all three of the IOUs.[136] Cal Advocates' proposed successor tariff received the higher score because it better balances

---

[131] All of Cal Advocates' annual cost burden estimates are in real dollars (2021 dollars), meaning that Cal Advocates has backed out the effects of inflation. Thus, Cal Advocates' estimates only show growth in the annual cost burden that is caused by growth in total interconnected kW of distributed generation and assumed annual retail rate increases that exceed inflation. Exh. PAO-03, p. 1-27 fn 44, p. 2-43.

[132] Exh. PAO-01, p. 5-2.

[133] NEM 1.0 and 2.0 customers currently are allowed to continue to take service on their NEM tariff for 20 years from when they interconnected (20-year transition period). For instance, a customer who interconnected their PV system in 2016 would have approximately 15 years remaining of their 20-year transition period after 2021. The net present value (NPV) is the sum of the future stream of discounted annual cost burdens using a discount rate of 1.7% (the most recent 10-year rate of inflation). Exh. PAO-03 pp. 4-2, 4-12.

[134] This figure is in real dollars (2021 dollars).

[135] Exh. PAO-03, pp. 4-23 to 4-24.

[136] Exh. PAO-01, p. 5-3.

lowering the cost burden with other statutory requirements,[137] including encouraging sustainable growth of DERs and providing a reasonable payback period.[138] Across all scenarios, the Cal Advocates' proposal results in a more significant increase in RIM values and a large decrease in the first-year cost burden compared to current NEM 2.0 tariff and CALSSA's proposed successor tariff.[139] Cal Advocates' proposed successor tariff results in a significant decrease in the cost burden with a reasonable increase to the payback period. Cal Advocate's proposal also incentivizes solar paired with storage through a shortened payback period compared to stand-alone storage.[140]

Cal Advocate's proposal would also reinforce the sustainability of renewables growth, and in particular growth in solar production, in California. Title 24, section 6 of the California Energy Code, also known as the California Solar Mandate, mandates solar panels on all newly constructed residential buildings up to three stories,[141] guaranteeing a steady customer stream for the solar industry. This mandate could drive 74,000[142] to 100,000[143] solar installations, and the addition of 444 to 600 MW[144] of residential rooftop capacity each year. Prior to this mandate going into effect, approximately 143,000 homes

[137] Pub. Util. Code § 2827.1(b)(1). See also, Pub. Util. Code § 2827.1(b)(6).

[138] Exh. PAO-01, p. 5-3 and Figure 5-1.

[139] Cost-Effectiveness Study, p. 2.

[140] Cost Effectiveness Study, pp. 34-35. Cal Advocates proposal results in a payback period of 12.5, 16.5, and 9.1 years for PG&E, SCE and SDG&E respectively for 2023 Non-CARE Residential Solar and a shortened payback period of 10.2,10.5, and 6.8 respectively for 2023 Non-CARE Residential Solar paired storage.

[141] California Energy Code, Title 24 Part 6.

[142] E3's report to the CEC estimated 74,000 units per year, but only includes single-family homes, thus underestimating the total number of qualifying units. Measure Proposal Rooftop Solar PV Systems from the CEC's Title 24, Part 6, Building Energy Efficiency Standards Rulemaking, p. 48.

[143] The Federal Reserve Bank of St Louis indicates that 109,800 units were approved for construction in 2019 in California. It does not allow users to identify how many units are in buildings with four or more stories, thus providing an upper bound of around 100,000 qualifying units. 2019 was chosen as the reference year because the COVID-19 Pandemic may make 2020 non-representative of the norm. "New Private Housing Units Authorized by Building Permits for California." Federal Reserve Bank of St. Louis. See: https://fred.stlouisfed.org/series/CABPPRIVSA#0.

[144] DGStats indicates that the average solar installation in 2019 was approximately 6 kW. 74,000 * 6kW = 444 MW. 100,000 * 6kW = 600 MW. https://www.californiadgstats.ca.gov/

installed rooftop solar in 2019,[145] so the mandate could drive up to 70% growth[146] in the number of solar rooftops in California. With this mandate, the solar industry in California will see significant guaranteed sales over the coming years, ensuring sustainable growth in solar penetration.

The Title 24 Mandate is subject to cost-effectiveness evaluations, which Cal Advocates' proposal will pass. The CEC uses a 30-year cost-effectiveness test that compares the present value of bill savings to the present value of customer costs, applying a 3% discount rate. Any proposal with discounted bill savings greater than discounted costs over 30 years will pass this test.[147] To fail the CEC's cost-effectiveness tests, a successor tariff customer therefore, would require a discounted payback period longer than 30 years.

Cal Advocates calculated the discounted payback period using a 2.76% discount rate, and found payback periods between 7 and 11.4 years, depending on the percentage of generation that is exported.[148] While Cal Advocates' analysis uses a slightly lower discount rate than the CEC's analysis, it is unlikely that the CEC would find a discounted payback period greater than 30 years for any IOU customer under Cal Advocates' proposal. The Commission therefore runs no risk of endangering the Title 24 Rooftop Solar Mandate in IOU territories: customers will recoup their costs in far less than 30 years.

The Coalition for Community Solar Access (CCSA) has proposed an alternative community solar tariff.[149] While CCSA's proposal requires refinement to ensure the program costs are reasonable, the proposal is worthy of further evaluation by the

[145] Distributed Generation Stats. https://www.californiadgstats.ca.gov/. 2019 was chosen as the comparison year because 2020 may not be a valid comparison due to economic disruption by the COVID-19 pandemic.

[146] If most of the 143,000 installations in 2019 were not on newly constructed homes, the 100,000 annual installations will increase the number of annual BTM residential solar installations by 70%.

[147] Exh. PAO-07, p. 8. "Excerpt from Rooftop Solar PV System Report: prepared by E3 for the 2019 Standards update."

[148] Exhibit PAO-02, p. 3-21.

[149] Exh. CCS-01, pp. 31-45, Figure 5-3.

Commission because it could be a way to meet the Title 24 mandate in a more cost-effective manner than existing alternatives.

Modeling using the National Renewable Energy Lab's Distributed Generation Market Demand (dGEN) tool indicates that the solar industry would see continued growth under Cal Advocates' proposed successor tariff. Results from dGEN indicate that more than 5.6 GW of residential renewable capacity could be installed by 2030 under this proposed tariff.[150] This does not account for installations driven by the California Solar Mandate. The dGEN tool results show the solar industry would continue to see growth under Cal Advocate' proposed successor NEM tariff, indicating that the Commission can implement Cal Advocates' proposals and achieve the State's goals.

E. The Current NEM Tariff Creates Barriers to California's GHG Goals Targeting Electrification of Buildings and Transportation

The cost burden attributable to NEM is increasing average electric rates for all ratepayers. The increase in average electric rates threatens California's goal of achieving GHG reductions via beneficial electrification of transportation and buildings. High customer electric rates discourage customers from electrifying their household by switching to electric-fueled appliances or purchasing an electric vehicle.[151] Ongoing increases in the cost burden and in rates will undermine California's policy objectives of reducing GHG through electrification of buildings and transportation because making the switch to electric fuels will become less economically beneficial.

1. NEM is Less Cost-Effective Than Other Renewable Energy Procurement Strategies

A significant factor in the rise of electric rates is the growing cost burden imposed by the current NEM tariff. This cost burden of generating renewable energy through the

---

[150] This simulation used the same GBC values as those submitted for evaluation in E3's *Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking R.20-08-020*. Cal Advocates' GBCs as proposed in this document are slightly higher, but should not dramatically impact the results. Annual export compensation rates used the 2021 avoided cost calculator, and the analysis used PV prices from the NREL Annual Technology Baseline.

[151] Exh. PAO-02, p. 5-31.

current NEM tariff is much higher than the cost of Renewable Portfolio Standard (RPS) renewable energy procurement contract prices. This means that customer dollars collected from non-NEM participants to pay for the cost burden induced by the current high retail rate compensation structure of NEM 1.0 and 2.0 could be avoided through policies and investments in more cost-effective ways to procure renewable electricity and achieve the states' climate goals.[152]

As electricity rates continue to climb and RPS contract costs decline, the excess cost burden required to pay for NEM generation continues to grow. Pursuant to Pub. Util. Code § 913.3(a)(1)-(2) and (b), the Commission releases data annually on the costs of renewable energy resources that are utility-owned or under power purchase agreements. From 2018 to 2019, the average price of an executed RPS contract dropped 26% from $0.0381 to $0.0282 per kWh.[153] From 2019 to 2020 the average cost of an RPS contract increased to $0.035 per kWh hour due to "more diversified procurement of renewable generation from technologies such as bioenergy, geothermal, small hydro, and wind, and are higher in price compared to solar PV."[154]

By comparison, in November 2020, the average residential retail electricity rate for California was $0.2226 per kWh, a 10.7% increase from November 2019 when it was

[152] RPS contracts renewable energy resource contracts' eligibility is defined by Section 399.12(a).

[153] Adjusted into 2021 dollars this value would be roughly $0.0287/kWh. 2020 Padilla Report (costs and costs savings for the RPS Program), published May 2020, (Padilla Report) pp. 2, 10-11. See: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2020%20Padilla%20Report.pdf?__ac_lkid=2a14-b0f6-39ef-d2f417268072d07. These values are for contracts above 3MW. From 2007 to 2019 the average cost of a contract for all technologies decreased 12.7%, with wind and solar technologies together accounting for 87.4% of IOU's collective RPS generating technology.

[154] 2021 Padilla Report Costs and Cost Savings for the RPS Program (Pub. Util. Code § 913.3), published May 2021.

$0.2011 per kWh.[155] The Commission forecasts that the average residential retail rates of energy will continue to increase at a rate of about 4% per year.[156, 157]

Renewable electricity purchased through an RPS contract is significantly less expensive than the cost burden imposed by the NEM structure for compensating BTM generation. The Commission and IOUs use RPS contracting to procure diversified renewable energy generation that better meets the grids' needs. Non-dispatchable NEM policy essentially prioritizes incentives for rooftop solar PV at the expense of non-NEM participants. The current NEM tariff is an unnecessarily costly way to reach the state's renewable electricity procurement and climate goals compared to available alternatives such as RPS contracted renewable energy. This costly approach exacerbates upward pressure on electric rates and threatens EV adoption and increased electrification of homes and businesses.

2. Electric Vehicle Adoption Rates Are Threatened by Slow Renewables Adoption

The Legislature has found that widespread transportation electrification is needed to achieve the goals set forth in the Charge Ahead California Initiative and to reduce emissions of statewide GHGs "to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050."[158] As part of these goals, the state has set a target of 5 million zero emission vehicles on the road in California by 2030.[159] The Legislature has

---

155 EIA, Average Price of Electricity to Ultimate Customers by End Use Sector, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a, accessed on February 7, 2021.

156 D.20-08-001 Decision Adopting Standardized Inputs and Assumptions for Calculating Estimated Electric Utility Bill Savings from Residential Photovoltaic Solar Energy Systems, p. 17.

157 EIA, Average Price of Electricity to Ultimate Customers by End Use Sector, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a, accessed on May 21, 2021. From February 2020 to February 2021 the residential rates in California increased from 21.70 cents/kWh to 22.53 cents/kWh, a roughly 4% increase.

158 Pub. Util. Code § 740.12(a)(1).

159 Governor Brown Executive Order B-48-18. Office of Governor Edmund G. Brown, "Governor Brown Takes Action to Fund Zero-Emission Vehicles, Fund New Climate Investments," January 26 2018, accessed April 13 2021 at https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html

further found widespread transportation electrification requires electrical corporations to increase access to the use of electricity as a fuel.[160]

To achieve this ambitious goal, the Commission should incentivize adoption of electric vehicles (EVs) by minimizing increases in electric rates paid by ratepayers. Low electric rates are an important tool in encouraging EV adoption.[161] At the Commission's February 24, 2021 "En Banc on Energy Rates and Costs," David Rapson, Director of the Davis Energy Economic Program at the University of California, Davis, presented that "[e]ach $0.10/kWh increase in electricity prices" results in a "15% decrease in EV demand" (in terms of EV miles driven).[162] Rapidly escalating electricity prices therefore hinders the state's goal of achieving widespread EV adoption and EV miles driven.

Unfortunately, electric prices have been increasing faster than natural gas or gasoline prices in recent years.[163] In the last decade (between January 2010 and January 2020), the average price for a gallon of gasoline in California increased by 14%. Over the same period, PG&E's, SCE's, and SDG&E's residential average rates increased by 41%,[164] 22%,[165] and 60%[166] respectively. In short, it is increasingly challenging for Californians to adopt EVs based on the economics of fueling the vehicle.

---

[160] D.20-08-045, p. 7. The Legislature also found that "[a]dvanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse gas emissions reductions goals."

[161] Exh. PAO-01, p. 2-25.

[162] Slide 36, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Rates%20En%20Banc_PANEL%201_Updated.pdf.

[163] See: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMM_EPM0_PTE_SCA_DPG&f=A

The average price per gallon of gasoline (all grades) in California was $3.66/gallon in January 2014 and $3.49/gallon in January 2020. This period coincides with the significant uptake in residential solar PV adoption and excludes any months during which the California's COVID-19 shelter in place order was in effect.

[164] AL 3518-E and AL 5661-E.

[165] 1-22-19_CPUC Affordability Workshop_Materials and AL 4116-E-A.

[166] AL 2135-E and AL 3487-E.

Though low electric rates are an important tool in encouraging EV adoption, simply discounting certain EV or electrification rates to get around high average electric rates can exacerbate the existing equity issues caused by NEM. Assuming customers charge their EVs in a manner that is aligned with grid conditions,[167] additional EV load over the next decades presents the opportunity to place downward pressure on all customers' rates by allowing the utilities to spread their fixed costs across a larger sales base.[168] However, many residential and commercial EV rates have large portions or all of the rates set at marginal costs to provide adequate opportunity for fuel cost savings vis-à-vis fossil fuels and to promote EV adoption. When EV rates are set significantly below cost basis, there is less recovery of fixed costs; when rates are set at marginal costs, there is no recovery of fixed costs.[169] Put another way, there would be no resulting downward pressure on other customers' rates. It also means other customers are subsidizing the participation of customers on these EV or electrification rates because the Commission-approved revenue requirement, including those fixed costs, must still be recovered.

The Commission has deemed it necessary to discount EV rates at below full cost basis in order to promote EV adoption and provide sufficient opportunity for fuel cost savings in the initial years while charger utilization rates remain low.[170] It is unclear, however, when it will be possible to bring EV rates closer to cost basis and provide the expected benefits of EV load to all ratepayers if electric rates continue to grow at their unsustainable pace. The NEM cost burden also impacts when EV rates can be brought in

---

[167] Two examples of charging that is aligned with grid conditions are when customers manage their total maximum customer demand (kW) in order to avoid placing high stress on localized distribution infrastructure and when customers charge their EVs in accordance with TOU price signals.

[168] This can result in reductions in the average $ per kWh costs for all customers, assuming EV customers do not receive large, ongoing discounts in their rates from cost basis as is discussed further below.

[169] This is because rates that are set at marginal costs theoretically only recover the marginal costs to serve the customers' demand, but there is no recovery of costs beyond marginal costs (fixed costs).

[170] See D.20-12-023 discussing the need to provide a declining rate discount over 10 years in the SDG&E's Electric Vehicle Higher Power (EV-HP) charging rate. The Decision also discusses the need to set EV-HP rates at marginal costs for the first 3 years in order to provide an adequate opportunity for fuel cost savings vis-à-vis conventional fuels and to account for low charger utilization due to the COVID-19 pandemic. D.20-12-023, pp. 13-14.

alignment with cost basis, because the NEM cost burden is a major factor in the unsustainable rise of residential electric rates. If left unchecked, the NEM cost burden may create the need for large ongoing discounts to EV rates, creating another form of inequitable cost burdens, and preventing ratepayers from experiencing the benefits of rate stabilization that EV load can provide.[171]

3. Electrification of Homes and Businesses is Burdened by the Current NEM Tariff's Adverse Impacts on Electric Rates

Rising electricity rates also make the value proposition of fuel switching or electrifying household end-uses less attractive to customers. Reforming the NEM tariffs is necessary to lower non-NEM customers' average electricity rates and move rates closer to the actual costs to serve NEM customers. This would result in more economically efficient (and accurate) electricity pricing and improve the economic case for fuel switching without requiring ongoing distortions to the cost basis in rates. Reducing the existing subsidies to NEM customers is the best solution to improve equity, economic efficiency, and create benefits to all ratepayers while ensuring EV adoption and electrification are properly incentivized.

4. NEM Program Reform in Other States Has Advanced Further than in California

California's rooftop solar policy is lagging behind other states that have successfully implemented equity reform to NEM policies. Despite a multitude of states transitioning away from programs that compensate solar at full retail rates, solar represented the highest share of new capacity additions to the US electricity generation in 2020, more than any other resource.[172]

---

[171] In this case, the cost burden would be that EV customers would avoid paying their fixed costs responsibility-which would be paid for by other customers-and ratepayers would not experience the benefits of downward pressure from additional EV load.

[172] Solar Market Insight Report 2020 Year in Review, https://www.seia.org/research-resources/solar-market-insight-report-2020-year-review

DSIRE Net Metering June 2020 https://www.dsireusa.org/resources/detailed-summary-maps/

For example, the Arizona Corporation Commission eliminated its retail rate (NEM) compensation structure for new rooftop solar customers in a December 2016 decision.[173] For new solar customers, the Arizona Commission replaced net metering with a Value of Solar tariff. The Value of Solar for each Arizona utility is decided through individual rate cases,[174] and can be set using a Five-Year Avoided Cost methodology, a Resource Comparison Proxy methodology or a combination of the two.[175]

Subsequent to the changes adopted in Arizona, residential solar installations have continued at the same and even higher rates than prior to 2016.[176] Indeed, in the 4th Quarter of 2020, Arizona surpassed its record for quarterly volumes of residential sales.[177] Thus, reforming NEM with respect to ECR at the avoided cost can still lead to sustainable growth of the DER industry.

Kentucky, too, embraced the need for NEM reform. In May 2021, the Kentucky Public Service Commission issued an order approving a new ECR for NEM customers based on avoided costs (including the costs of generation, distribution and transmission capacity, energy, and ancillary service costs and avoided environmental costs), resulting in a compensation rate of $0.09746/kWh.[178]

However, the current state of NEM in California and its associated cost burden cannot be remedied by simply adopting other states' approaches to NEM reform. The cost burden in California from NEM is amplified due to the substantially larger scale of

---

[173] Exh. PAO-01, p. 5-12, fn. 526 (citing Arizona Corporation Commission, Decision No. 75859, Docket E-00000J-14-0023, *In the matter of the Commission's Investigation of Value and Cost of Distributed Generation* (Arizona Decision 75859). https://docket.images.azcc.gov/0000176114.pdf, accessed September 26, 2019.)

[174] Exh. PAO-01, p. 5-12, fn. 526 (citing Arizona Decision 75859, p. 176).

[175] Exh. PAO-01, p. 5-12, fn. 526 (citing Arizona Decision 75859, p. 177).

[176] Arizona, SEIA https://www.seia.org/state-solar-policy/arizona-solar, accessed 8/25/2021 (SEIA Arizona)

[177] Exh. SVS-10, "Wood Mackenzie US Solar Market Insight Executive Summary", p. 10.

[178] News Release PSC Issues Order on Net Metering Tariff in Kentucky Power Rate Case, pp. 1-2. https://psc.ky.gov/agencies/psc/press/052021/0514_r01.pdf

NEM installations and California's comparatively high retail rates.[179] Due to the cost burden's magnitude and severity in contributing to inequity in California, there is a need to accelerate NEM reform in California that cannot be compared to the prolonged transition glidepaths used by other states. If the Commission finds it necessary to implement an interim rate for NEM customers, Cal Advocates supports the interim rate described in the Joint Recommendations attached in Appendix A below.

V. JOINT RECOMMENDATIONS

As communicated to ALJ Hymes in a written communication on August 20, 2021, Cal Advocates and a number of independent parties have prepared a set of Joint Recommendations for ALJ Hymes' and the Commission's review. The independent parties met on several occasions to discuss the issues in these proceedings. After several meetings, the parties could not reach a settlement agreement. Instead, they developed the Joint Recommendations to narrow the list of recommendations for the NEM successor tariff and related issues. Attached as Appendix A hereto is a list of the Joint Recommendations that each of those independent parties will affix to their Opening Briefs in these proceedings.

VI. CONCLUSION

For the reasons stated here, Cal Advocates' proposals should be adopted.

Respectfully submitted,

/s/ WAYNE A. PARKER

WAYNE A. PARKER
Attorney

Public Advocates Office

[179] Wood Mackenzie, pp. 8-10. California is the number one ranking state for solar PV installs by over 3 times as many MWdc installed of the second ranked state (Texas). California set record quarterly residential sales in Q4 2020. There has been a surge of interest in solar sales following the October 2019 fires, which the continuation of these events Wood Mackenzie predicts will continue to "drive customer interest in solar and solar-plus-storage, with knock-on effects in other markets."

California Public Utilities Commission
300 Capitol Mall
Sacramento, CA 95814
Telephone: (916) 823-4772 (ext. 31-54772)
E-mail: wayne.parker@cpuc.ca.gov

August 31, 2021

APPENDIX A

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)	Sections 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

[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.

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 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.

---

[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.

- 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.

[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;

---

[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.

- 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:
  - 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

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]

- 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]);

---

[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.

2. SCE: TOU-D-PRIME; and
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.

- Part 2:

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

[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.

burden reduction, and the actual reduction to the cost burden will be larger depending on how many customers switch to the new TOU rates.

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 <u>Non-CARE</u> 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.

[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.

- 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).
- 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:
    - Step 1: 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.
    - Step 2: 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.
    - Step 3: 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.
    - Step 4: Calculate the customer's annual bills prior to and post adoption over the term of the interim successor tariff. Export compensation is the

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

export rate in each TOU period applied to exports in each TOU period. Calculate annual bill savings for 2022 and 2023 installations.

- Step 5: Calculate discounted payback result.
- Step 6: 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.

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