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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	)))))	Rulemaking 14-07-002 (Filed July 10, 2014)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING PARTY PROPOSALS FOR THE SUCCESSOR TARIFF OR CONTRACT

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Southern California Edison Company's (U 338-E) Response to the Administrative Law Judge's Ruling Seeking Party Proposals for the Successor Tariff or Contract

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Southern California Edison Company (SCE) respectfully submits the following proposal in response to the California Public Utilities Commission's (Commission's) June 4, 2015 Administrative Law Judge (ALJ) Ruling (1) Accepting into the Record Energy Division Staff Papers on the AB 327 Successor Tariff or Contract; (2) Seeking Party Proposals for the Successor Tariff or Contract; (3) Setting a Partial Schedule for Further Activities in this Proceeding, as well as the July 20, 2015 ALJ Ruling Providing Further Instructions for Parties' Proposals and Accepting into the Record Certain Updates to the Public Tool (SCE's Proposal).

EXECUTIVE SUMMARY

Achieving California's progressive energy and environmental policy goals will require a 21st century power system that promotes the deployment of distributed energy resources, encourages technological innovation, and fosters customer choice. SCE believes it has a critical role in modernizing the power grid to enable these advancements to support its customers' energy needs and the State's goals.

SCE's customers are increasingly installing renewable distributed generation (DG) systems—and particularly rooftop solar photovoltaic (PV) systems. Today, customers installing these systems are served under the Net Energy Metering (NEM) tariff. This tariff, coupled with dramatically decreasing solar PV costs, has led to a strong, vibrant solar industry in California, which continues to lead the nation with more than a third of the nation's total DG capacity.[1]

To ensure that DG continues to grow sustainably, the Legislature passed AB 327, and the Commission opened this rulemaking to develop a successor to NEM. Given the improving economics of solar PV systems, and to reduce the cost shift to customers without DG systems, SCE proposes to succeed the NEM tariff with a structure that charges participating customers suitable rates for electricity purchased from the utility, pays participating customers fair prices for exported electricity, and transparently conveys the cost of using the grid.

The key elements of SCE's Proposal are: (1) participating customers first consume their self-generated energy onsite with no payment to the utility; (2) participating customers purchase additional energy they need from the utility at their usual retail rate; (3) the utility fairly compensates participating customers for self-generated energy exported to the grid; and (4) the utility collects a small monthly charge based on the DG system's size to recover fixed costs associated, in part, with providing access to the grid for exports and power quality services.

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1 U.S. Energy Information Administration, Monthly Electric Utility Sales and Revenue Report with State Distributions (Form EIA-826), December 31, 2014.

SCE proposes that eligible residential customer-generators continue to first serve their onsite load with generation produced by the DG system and to receive a full retail rate offset for the electricity generated and consumed onsite. The DG system must be sized not to exceed the customer's annual historical onsite load. SCE proposes to serve these customers on their otherwise applicable tariff (OAT) rate for all electricity they import from the grid.

To compensate eligible customer-generators for exports of electricity generated by their DG systems but not consumed onsite, SCE agrees to pay eligible customer-generators an "Export Compensation Rate" (ECR) of $0.08/kWh by an on-bill credit to offset the eligible customer-generators' total bill. The ECR includes: (1) the Public Tool's levelized utility avoided cost estimate[2] of $0.07/kWh, and (2) a $0.01/kWh premium[3] for the renewable attributes of the exported generation, assuming it counts towards SCE's Renewable Portfolio Standard (RPS). If the compensation for exports exceeds the customer's bill in a month, the customer can carry credits over to future bills.

SCE further proposes to assess eligible residential customer-generators a monthly $3.00/kW-month "Grid Access Charge" (GAC) based on the installed AC nameplate capacity of the DG system. The GAC recovers a portion of SCE's (1) fixed transmission and distribution (T&D) costs associated with serving these customers, and (2) non-bypassable charges associated with the energy displaced by the DG system.

To further reduce the cost shift and ensure that eligible customer-generators receive fair compensation based on DG costs and the renewable energy market, SCE recommends that the Commission reassess the ECR and T&D portion of the GAC every three years (concurrent with the 2021 General Rate Case (GRC) Phase 2) to allow the Commission to further mitigate cost shifts over time as the market continues to mature. The Commission should reassess the non-

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[2] For the purpose of this proceeding only, SCE agrees to use the Public Tool's approximate levelized avoided cost calculation for purposes of establishing an ECR. SCE does not concede, however, that the Public Tool's avoided cost figure accurately calculates SCE's actual avoided costs.

[3] *See* Platts Electric Power Megawatt Daily reports (http://www.platts.com/products/megawatt-daily).

bypassable charge portion of the GAC only when it changes. The updated ECR will be calculated on a 20-year levelized basis and applied to customers interconnecting under that new vintage. To reduce uncertainty on customers' bills, the ECR would be "locked in" over a 20-year life of the system.

SCE proposes to serve eligible non-residential customer-generators, including over 1 MW systems, on SCE's rates applicable to commercial and industrial customers for electricity purchased from the utility. Generation consumed onsite will be offset at the OAT, and exports will be compensated at the ECR. Instead of a GAC, SCE will recover T&D costs from these customers through demand and customer charges, and non-bypassable charges through an updated Schedule for Departing Load Non-bypassable Charges (DL-NBC).[4]

SCE's Proposal meets the statutory criteria in AB 327 by striking the appropriate balance between: (1) mitigating the cost shift caused by the NEM program by ensuring that the benefits of the new standard tariff to all customers and the system approximately equal its costs, and (2) ensuring sustainable growth of customer-sited renewable DG. SCE's Proposal meets its interpretation of AB 327 criteria under all cases, and the Staff's criteria under all cases except for the implied payback period for customer DG systems. Because SCE believes that the bookend cases are unrealistic and inconsistent with economic forecasts, SCE modeled its proposal against its own "SCE case," which aligns more closely with economic forecasts and regulatory policy goals. SCE also modeled the three residential rate design options (two-tier and Time of Use (TOU) cases) for all cases, resulting in a total of nine model runs.[5]

Finally, SCE recommends that the Commission consider the outstanding issues of provisions for customers that have paired storage and multiple generators on a single meter.

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[4] SCE proposes to update Schedule DL-NBC to include the DWR Bond Charge and New System Generation Surcharge (NSGC).

[5] As discussed in SCE's July 22, 2015 email with Energy Division staff and E3, SCE did not model results for non-residential customers due to the low sample size and billing assumption errors that were not fully resolved in the Public Tool, which produced unrealistic results.

I.

BACKGROUND

SCE supports California's long-term energy and environmental policy objectives, and recognizes that achieving the State's progressive decarbonization goals will require a 21st century power system that promotes the deployment of distributed energy resources, such as rooftop solar PV systems, electric vehicles, energy storage, and energy efficient technologies; encourages technology innovation, and fosters customer choice. SCE believes it has a critical role in modernizing the power grid to enable customer choice in the energy technologies they wish to use. SCE intends to partner with agencies and industry stakeholders to facilitate distributed energy resources and encourage customer value and choice.

SCE's customers are increasingly installing renewable DG systems, and particularly rooftop solar under the NEM tariff. The existing NEM tariff was designed to encourage the installation of rooftop solar at a time when it was very expensive to do so, and has contributed greatly to the growth of solar DG that has resulted in California's strong and vibrant solar industry.[6] But NEM has also had the unintended consequence of allowing NEM customers to avoid paying for the power network that all customers use. As a result, the benefits that customers in the NEM program receive come, in part, at the expense of non-participating customers.

The NEM tariff structure has provided substantial support to the rapid growth of customer-sited DG in California by offering economic incentives for the installation of customer-sited DG systems. Those incentives allow participating customers[7] to: (1) bypass costs associated with grid services that the utility provides to the customer-generator; and (2) receive

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[6] California continues to lead the nation with more than a third of the nation's total DG capacity U.S. *See* Energy Information Administration, Monthly Electric Utility Sales and Revenue Report with State Distributions (Form EIA-826), December 31, 2014.

[7] For the purposes of this filing, "participating customers" refer to customers with eligible customer-sited renewable DG systems who are served by the NEM tariff.

bill credit at the customers' full retail rate for generation that is not consumed onsite and is exported to the utility grid. This retail rate credit includes the utility's full costs for generation (energy and capacity), transmission, distribution, and non-bypassable charges. NEM allows customer-generators to avoid paying these costs to the extent their exported electricity offsets their energy purchases from the utility. The utility is then forced to collect those unrecovered costs by billing non-participating customers at incrementally higher rates. In other words, participating customers can shift certain costs to non-participants.

Today's renewable DG market's high growth rate and technological advances have dramatically reduced the cost of customer-sited DG systems.[8] This trend, combined with generous State and Federal incentive programs,[9] has made the installation of renewable DG systems economically desirable for customers and DG companies. As a result, customer-sited DG has transformed from a nascent technology market into a vibrant and thriving industry.

Given this market transformation, the generous NEM structure is no longer needed to sustain the DG market, and it is not fair to continue such incentives as the burden on non-participating customers increases. SCE's analyses of the future cost of renewable DG and the impact of the present NEM structure show growing cost shifts of up to $16.7 billion[10] among SCE residential customers alone. Updating the current program is essential for enabling continued DG growth while reducing, if not ultimately eliminating, the shift of the utilities' costs to non-participants. To that end, the Legislature passed AB 327, a reform bill that requires the Commission by December 31, 2015, to develop a new standard contract or successor tariff to the

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8 CSI Annual Program Assessment findings noted that, "between the last quarter of 2008 and the last quarter of 2014, the average cost of installed residential systems has decreased 53 percent… In the same time period, non-residential system costs have decreased 62 percent."

9 Including, but not limited to, the California Solar Initiative incentive programs and the Federal Investment Tax Credit (ITC).

10 SCE's results from the E3 Public Tool – Ratepayer Impact Measure – All-Generation test assessing Net Present Value of cost shift under current NEM structure.

NEM tariff. The relevant provisions of AB 327 are codified in California Public Utilities Code Section 2827.1[11]

II.

SCE'S PROPOSAL FOR THE SUCCESSOR TO THE NEM TARIFF

SCE proposes to succeed the current NEM tariff with a standard successor tariff that will govern residential and non-residential[12] customers who install eligible DG systems. SCE's Proposal: (1) eliminates netting and decouples the compensation for exported energy from the participating customers' OAT rate for energy purchases; (2) allows renewable DG customer-generators to first serve their onsite load with generation produced by the renewable DG system; (3) compensates customers for exports of excess electricity not consumed onsite; and (4) assesses a small grid access charge to recover a portion of certain fixed costs that are not avoided by the customers' installation of renewable DG systems. A structure that eliminates netting and decouples exported energy from the participating customers' OAT is critically important because it mitigates the cost shift, supports sustainable growth, makes the incentives transparent, and is easy for customers to understand and for the utilities to administer and implement.

SCE's Public Tool input scenarios for its proposal are provided in the Excel Workbook submitted concurrently with this filing.[13] In addition, a selection of relevant results are also provided throughout the body of this filing to justify SCE's proposal based on the AB 327 criteria codified in Section 2827.1. Due to sample size and issues with the final version of the Public Tool, SCE did not model its non-residential proposal.[14]

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[11] Unless otherwise specified, all future Section references are to the Public Utilities Code.

[12] For the purposes of this filing, "non-residential" refers to small and medium commercial, large commercial, industrial, and agricultural customers.

[13] Public Tool inputs are separately submitted via email to Energy Division staff.

[14] As discussed in SCE's July 22, 2015 email with Energy Division staff and E3, SCE did not include the modeling results for non-residential customers because the low sample size and billing assumption errors that were not fully resolved in the final version of the Public Tool produced unrealistic results that are inconsistent with these customers' behavior.

As instructed in the ALJ's June 4 and July 20 Rulings, SCE modeled its residential proposal under nine different scenarios.[15] These scenarios include the two bookend cases, as well as a third case that SCE believes to be a more accurate representation of California's environmental and economic future (SCE's case), the inputs of which are described in Attachment 1. Each of these three cases was modeled under the three different rate structures described in the July 20 ALJ Ruling, representative of the Commission's recently adopted Decision (D.) 15-07-001 in the Residential Rate Design Rulemaking (R.) 12-06-013.

A. Linking Public Tool Results to Statutory Criteria Set Forth in Section 2827.1

SCE's Proposal is based primarily upon the modeling results of SCE's case. The assumptions in SCE's case represent the most realistic forecast of the economic market and regulatory policy future of California. Using SCE's case, the results in the body of these comments, unless otherwise stated, depict the effect of SCE's Proposal, as compared to California's current NEM program. Those modeling results demonstrate that SCE's Proposal meets the statutory criteria in Section 2827.1 under both SCE's and the Staff Paper's statutory interpretation in most cases.

Although SCE's Proposal does not eliminate the current cost shift, it substantially reduces it and strikes the appropriate balance between: (1) ensuring that customer-sited renewable DG continues to grow sustainably, and (2) mitigating or eliminating the cost shift caused by the existing rate design and the NEM program by ensuring that the benefits of the new standard tariff—to all customers and the system—approximately equal its costs. SCE's Proposal also provides for a three-year reassessment cycle for the ECR and GAC to provide the Commission with the ability to further mitigate or eliminate the cost shift over time.

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[15] *See* ALJ Ruling (1) Accepting into the Record Energy Division Staff Paper on the AB 327 Successor Tariff or Contract; (2) Seeking Party Proposals for the Successor Tariff or Contract; (3) Setting a Partial Schedule for Further Activities in the Proceeding. June 4, 2015.; and, ALJ Ruling Providing Further Instructions for Parties' Proposals and Accepting into the Record Certain Updates to the Public Tool. July 20, 2015.

The results of modeling SCE's Proposal in the Public Tool meet the Staff's criteria under the bookend cases, except for the implied payback period for customer DG systems. The implied payback period, however, is not an appropriate metric to implement AB 327's statutory directive. Instead, the Commission should use a Ratepayer Impact Measure (RIM) test as the primary metric for evaluating the directives, as discussed further below.

In addition, because SCE believes that the bookend cases are unrealistic and inconsistent with economic forecasts, SCE also modeled its proposal against SCE's case. SCE's case selects the most realistic inputs based on SCE's understanding of economic forecasts and regulatory policies, including inputs from the high and low cases, and inputs that differ from either case. Because it represents the most realistic view, the Commission should apply SCE's case in this proceeding. As previously noted, the inputs of SCE's case are provided in Attachment 1. For reference, below is an excerpt of the bookend cases from the Staff Paper:[16]

Bookend Cases:		
	High Renewable DG Value Case	**Low Renewable DG Value Case**
Policy Inputs		
2030 RPS Goal	33%	50%
Marginal Generation Capacity Avoided Cost Treatment	Renewable DG Generation is vintage	Renewable DG Generation is not vintaged
Electric Vehicle (EV) Selection	Default – Base EV Penetration (4.227 million EVs and 2.528 million fuel cells)	Default – Base EV Penetration (4.227 million EVs and 2.528 million fuel cells)
Electric Vehicle Charging Scenario	More Daytime Charging (35% of all EV charging occurs between 9 am-4 pm)	Less Daytime Charging (10% of all EV charging occurs between 9 am-4 pm)
Zero Net Energy (ZNE) Homes Policy Scenario	ZNE Not Implemented	ZNE Implemented

16 Highlighted selections indicate the inputs used in SCE's case, as justified in Attachment 1, and reflect SCE's estimate of a realistic mid-case between the two bookends.

Renewable Energy Credit (REC) Scenario[17]	NEM reduces RPS via bundled sales reduction	NEM reduces RPS via bundled sales reduction
Avoided Cost Inputs		
Natural Gas Price	Default Value	Default Value
RPS PPA Costs	Default Value	Default Value
Carbon Market Costs	High Value	Base (Default) Value
Resource Balance Year	2017	Model will Calculate
Ancillary Service Costs	1% Market Energy Purchases	1% Market Energy Purchases
Marginal Avoided Transmission Costs	No Value	No Value
Marginal Avoided Energy Cost Locational Multiplier	100%	100%
Marginal Avoided Subtransmission Cost Multiplier	100% (SCE: $23.29/kW-year)	No Value
Marginal Avoided Distribution Cost Multiplier[18]	100%	100%
Utility Distribution Capital Expenses		
PG&E	Default Value 100%	Default Value 100%
SCE[19]	Default Value 100%	Default Value 100%
SDG&E	Default Value 100%	Default Value 100%
DER Costs		
Solar Cost Case	Low Cost	High Cost
NEM Successor (post 2017) DER Program Costs Paid By[20]	Differs by Illustrative Successor Tariff/Contract Proposal	Differs by Illustrative Successor Tariff/Contract Proposal
Assumed Utility Rate Escalation (nominal)	5%	5%
Compensation Tax Treatment	Tax Exempt	Tax Exempt
Discount Rate Inputs		
Participant Nominal Discount Rate	9%	9%
Utility Nominal Discount Rate[21]	7%	7%

[17] Although SCE argues that NEM *should* be counted towards the RPS goal; in its model runs, SCE did not select "NEM reduces RPS via bundles sales reduction" because the associated value that the Public Tool calculated for the renewable premium far exceeded SCE's estimated value of the REC. Instead, as described in SCE's Proposal, SCE input its own ECR (rather than allowing the tool to calculate the 8 cents), which used a 1 cent/kWh value assigned as a REC premium within the 8 cent total for the ECR, as supported in SCE's Proposal description.

[18] As indicated and explained further in Attachment 1, SCE indicated "No Value" rather than the 100% High or Low Case for Avoided Distribution Costs Multiplier, as increasing customer-sited renewable DG has an associated net cost to the utility (not an avoided cost).

[19] As noted above, SCE only modeled SCE customer inputs.

[20] SCE selected: Participating Customers pay Successor Tariff under SCE Proposal.

[21] SCE selected: 7.9% as indicated in Attachment 1, as it represents SCE's most recent Weighted Average Cost of Capital.

Societal Nominal Discount Rate	**5%**	**5%**
Inflation	**2%**	**2%**

As discussed in more detail below, SCE's Proposal meets its interpretation of AB 327 criteria under all cases, and the Staff's criteria under all cases except for the implied payback period for customer DG systems criterion.

1. Metrics for Satisfying the Statutory Mandate that the Successor Tariff Ensure that Customer-Sited Generation Continues to Grow Sustainably (Section 2827.1(b)(1)[22]

SCE agrees in principle with the Staff Paper's interpretation of the phrase "continues to grow sustainably" as "preserving and fostering sufficient market conditions to facilitate robust adoption of customer-sited renewable generation while minimizing potential costs to non-participants over time."[23] SCE, however, emphasizes that continuing growth need not be "robust," as the Staff Paper suggests,[24] to satisfy the statute. "Sustainable" should be defined as "pertaining to a system that maintains its own viability."[25] The Staff Report agreed, stating: "[w]hile 'continues to grow' appears to imply maintaining a certain level of growth, 'sustainably' implies the creation of a self-sufficient market that doesn't negatively impact the infrastructure and services upon which it depends."[26]

Since AB 327 was signed into law, the cost of PV systems has continued to decline as solar adoption accelerates. The recent growth rates are no longer sustainable, and the

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22 SCE interpretation of this statutory provision has not changed. *See* SCE Comments on ALJ Ruling Seeking Comment on Policy Issues Associated with Development of Net Energy Metering Successor Standard Contract or Tariff, March, 16, 2015, at pp. 7; SCE Reply Comments on ALJ Ruling Seeking Comment on Policy Issues Associated with Development of Net Energy Metering Successor Standard Contract or Tariff, March 30, 2015, at pp. 3-6.

23 Energy Division Staff Paper on the AB 327 Successor Tariff or Contract: Staff Paper Demonstrating how to use the Public Tool to Evaluate Options for a Successor to Net Energy Metering (NEM) Tariffs in Compliance with AB at pp. 1-4 (Staff Paper).

24 *Id*. at pp. 1-4.

25 Dictionary.com definition of "sustainable," available at: http://dictionary.reference.com/browse/sustainable?s=t

26 Staff Paper at pp. 1-8.

impact on non-participating customers cannot be reconciled with the incentives that participants are receiving. The statute therefore does not say that the successor tariff shall sustain the *current* "robust" growth. Instead, it says that the successor tariff shall ensure that customer-sited renewable DG continues to grow sustainably. The present "robust" growth has been achieved in a manner that conflicts with the Staff Paper's interpretation of the statute, and is the result of business models that depend upon both generous government incentives, as well as incentives reflected in the Investor-Owned Utilities' (IOUs') current rate design for residential customers, which have caused a significant shifting of costs from participating customers to non-participating customers. Such a model is unsustainable. The successor tariff should ensure that growth continues in a manner that does not perpetuate this significant cost burden for current and future non-participating customers.

Likewise, the successor tariff should not merely "minimize" the cost shift over time. Instead, the successor tariff should be subject to periodic assessments and adjustments that will allow the Commission to *significantly reduce* or *eliminate* the cost shift over time. For growth to be truly sustainable, the successor tariff should result in customer-generators paying for the services they receive, while being fairly compensated for the energy they export. Incentives, while they continue, should be transparent and eliminated over time, as the customer-sited renewable DG market reaches competitive maturity.

For that reason, SCE agrees with the Staff Paper's reliance on the results from the RIM tests and the non-participant benefit/cost ratio as appropriate metrics to assess all AB 327 directives, including sustainable growth. Of the metrics relied upon by the Staff Paper,[27] the RIM test is the most important metric for assessing whether the successor tariff ensures that

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[27] To evaluate the illustrative tariff proposals' potential for sustainable growth, the Staff Paper relied upon a number of economic analyses, including: (1) results from the Standard Practice Manual (SPM) Participant Cost Test (PCT), and the implied payback period for participating technologies; (2) RIM test results and the ratepayer impact as a percent of the total revenue requirement; and (3) a forecast of participating customer adoption from 2017-2025. *See* Staff Report at pp. 1-5.

customer-sited renewable DG continues to grow in a sustainable manner. Specifically, the Commission should measure the total Net Present Value (NPV) of cost shifts with both the "all generation" and "export only" RIM tests, which will enable the Commission to set a reasonable starting point to measure the cost shift, and support sustainable growth by instituting a gradual decrease in that cost shift over time, eventually reaching a zero or a near-zero cost. The Commission should also assess the benefit/cost ratio to non-participating customers to determine whether growth under the successor tariff is self-sustaining.

Use of the RIM test is appropriate because it measures the impact of a program – in this case the successor tariff – by looking at how changes in utility revenues and operating costs caused by the program affect customer bills and rates.[28] It measures (1) the change to non-participating customers' rates and bills resulting from the participating customers' renewable DG system, and (2) renewable DG's beneficial value to the grid. Beneficial value to the electrical system or grid is measured by the costs the utility and its customers avoid as directly reflected in the utility's authorized revenue requirement, such as avoided generation capacity and energy purchases, avoided or deferred T&D upgrade costs, and avoided system losses. The DG's benefit/cost value to the grid also depends upon the facility's location, availability and generation profile to ensure that the facility's attributes are valued according the needs of the grid.

Under the RIM test, if the NPV of the benefits is less than the NPV of the cost of the renewable DG system, the non-participating customers will bear costs from the renewable DG system. These costs include administrative costs incurred by the utility or program administrators, utility integration and interconnection costs due to the renewable DG system, the price per kWh for any portion of the customer-generator output that is stipulated by the standard contract or tariff, and any utility revenue lost due to customer bill savings and incentives from the renewable DG system that would be shifted to non-participating customers. As stated in the Commission SPM, "[u]nder many conditions, revenues lost from … programs must be made up

[28] Commission October 2001 SPM at pp. 13.

by ratepayers. The RIM test is the only test that reflects this revenue shift with the other costs and benefits associated with the program."[29]

Within RIM, SCE believes the "all-generation" RIM test is the appropriate test for measuring cost impacts to non-participating customers because the electric grid must support the entire DG system size and output, not just the portion attributable to exports. Consumption from onsite DG does not permanently reduce a customer's load like energy efficiency so that the utility can account for that reduction in its system planning. Renewable DG operates intermittently under certain optimal conditions, such as when the sun is shining in the case of PV systems or when the wind is blowing for wind turbines. As a result, to ensure uninterrupted electrical service, eligible customer-generators require the use of the utility's grid to back-up the generator, sometimes at a moment's notice. The utility must therefore carefully balance the distribution grid with standby capacity to support the customer-generator when their system is not operating. Although SCE prefers the "all generation" RIM test as the criteria metric for assessing AB 327 directives, SCE assessed its Proposal from both an "all generation" and an "export only" perspective. SCE's results in the Public Tool meet the RIM test criteria under both of these perspectives.

As discussed in SCE's Policy Comments,[30] SCE maintains that using a MW or percentage growth target for adoption is not an adequate indicator of whether DG systems are self-sustaining, and that "sustainable growth" should neither be defined as a prescribed adoption rate of DG systems, nor be measured with an adoption rate metric. The Staff Paper appropriately acknowledges that adoption rate is an inferior metric to tie to sustainable growth because "forecasting adoption is very difficult and uncertain" and affected by numerous factors that are outside the Commission's control.[31] To determine if growth produced by a proposed successor is sustainable, Commission should rely instead primarily on the results of the RIM test.

[29] *Id*. at p. 14.
[30] *See* SCE Policy Comments at pp. 7.
[31] Staff Report at pp. 1-9.

As demonstrated in the Public Tool results set forth in Tables II-1 and II-2 below, which are based on the RIM test benefit/cost ratio and total NPV of the cost shift compared to NEM, SCE's Proposal satisfies SCE's and the Staff Paper's interpretation of sustainable growth because growth will continue in a manner that is not predicated and reliant upon a significant cost shift to non-participating customers.[32]

SCE's Proposal will reduce the current NPV cost shift, under SCE's case, from an all-generation perspective, by 78-83%; that is, from a cost shift of $15.3-$16.7 billion under the current NEM structure to $2.8-$3.1 billion under SCE's Proposal. From an export-only perspective, SCE's Proposal reduces the NPV cost shift under SCE's Case by 99% (*i.e.*, from $14.6-15.1 billion to approximately $200 million).

SCE's Proposal also represents a dramatic improvement in the benefit/cost ratio to non-participating customers as compared to NEM under SCE's case. From an all-generation perspective, SCE's Proposal will increase non-participants' benefit/cost ratio from a ratio of 0.28-0.30 under NEM to 0.50-0.54 under SCE's Proposal. From an export-only perspective, the non-participant benefit/cost ratio improves from a range of 0.18-0.22 to approximately 0.87 under SCE's Proposal.

Although SCE's Proposal results in a dramatic improvement in the benefit/cost ratio—almost doubling it, as compared to NEM—the costs to non-participants will continue to outweigh benefits, as demonstrated by the less than 1 benefit/cost ratio because of the remaining. For this reason, SCE proposes periodic assessment of the components of the successor tariff so the Commission can further reduce or eliminate the cost shift over time.

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32 *See* the Excel Workbook inputs submitted concurrently to assess full results.

Table II-1
RIM Test Results for SCE Residential Customers - SCE Proposal Using SCE's Case

	Two Tier	TOU (2-8 PM)	TOU (4-8 PM)
Benefit / Cost for Non-Participants (All Generation)	0.54	0.50	0.53
Benefit/Cost for Non-Participants (Export Only)	0.87	0.87	0.87
NPV ($) Cost Shift (All Generation)	$2.8 Billion	$3.3 Billion	$3.1 Billion
NPV ($) Cost Shift (Exports Only)	$200 Million	$200 Million	$200 Million

Table II-2
RIM Test Results for SCE Residential Customers – Existing NEM Using SCE's Case

	Two Tier	TOU (2-8 PM)	TOU (4-8 PM)
Non-Participant Benefit/Cost (All Generation)	0.29	0.28	0.30
Non-Participant Benefit/Cost (Export Only)	0.22	0.18	0.20
NPV ($) Cost Shift (All Generation)	$16.7 Billion	$15.3 Billion	$15.3 Billion
NPV ($) Cost Shift (Exports Only)	$15.1 Billion	$14.6 Billion	$14.9 Billion

In addition to significantly reducing the cost shift under SCE's case, the results of SCE's Proposal also satisfy the RIM test metrics under the high and low bookend cases. Under the low bookend case, SCE's Proposal reduces the NPV cost shift to a range of $2.6-$3.1 billion from an all-generation perspective, and to approximately $200 million from an export only perspective. The non-participant benefit/cost ratio is 0.43-0.46 from an all-generation perspective, and 0.83-0.84 from an export-only perspective.

Under the high bookend case, SCE's Proposal reduces the NPV cost shift to a range of $1.2-$1.6 billion under an all-generation perspective, and to approximately -$200 million from an export-only perspective (indicating a net benefit to non-participants). The benefit/cost ratio is 0.68-0.73 from an all-generation perspective, and 1.28-1.31 from an export-only perspective. Thus, under any of the three DG-value cases, SCE satisfies AB 327's "sustainable growth" mandate by substantially decreasing the cost shift, and providing much higher non-participant benefit/cost ratios as compared to NEM.

Even though adoption is an inadequate indicator and inferior metric for measuring sustainable growth, SCE's Proposal satisfies that metric under SCE's case, as well as either bookend, by either doubling or tripling SCE's current capacity of DG, depending on the case selected. As Table II-3 below demonstrates, the Public Tool forecasts that SCE's Proposal using SCE's case will result in an estimated incremental 2,713-2,815 MW residential soDG adoption in SCE's service territory from 2017 to 2025. These results demonstrate that customer-sited DG will continue to grow at a significant rate, and, more importantly, in a manner that significantly reduces cost shifts to non-participants and improves non-participant benefit/cost ratios.

To provide real world context, the added 2,713-2,815 MW of incremental adoption under SCE's case is estimated to more than triple the current 1,204 MW capacity[33] of customer-sited renewable generation in SCE's service territory by 2025.[34] Under the low and high cases, SCE's Proposal still results in significant incremental adoption, between 1,745-2,080 MW in SCE's territory. This range of adoption indicates a more than doubling of the current level of capacity adoption under the bookend cases with SCE's Proposal.

Table II-3
Adoption Using SCE's Proposal

Adoption MW	**Two Tier**	**TOU (2-8 PM)**	**TOU (4-8 PM)**
SCE's Case	2,713 MW	2,783 MW	2,815 MW
Low DG Value Case	1,980 MW	2,080 MW	1,957 MW
High DG Value Case	1,745 MW	1,768 MW	1,758 MW

33 Capacity for both residential and non-residential DG installed in SCE territory.
34 SCE Advice 3245-E Information Only Advice Letter Southern California Edison Company's Report on Progress Towards the Net Energy Metering Transition Trigger Level as of June 30, 2015. Filed July 10, 2015.

2. Metrics for Satisfying the Statutory Mandate that the Successor Tariff Be "Based on the Costs and Benefits of the Renewable Electrical Generation Facility" (Section 2827.1(b)(3))[35]

As discussed in SCE's prior comments, SCE agrees with the Staff Paper's conclusion that, overall, AB 327 directs the Commission "to perform a balancing act between maintaining or expanding the current levels of customer-sited renewable DG growth and addressing the costs of achieving that growth."[36] SCE and the Staff Paper, however, differ in their interpretation of Section 2827.1(b)(3). Specifically, as SCE discussed in its prior comments, SCE interprets AB 327 as requiring the Commission to base the standard contract or tariff on a cost-benefit analysis[37] and strike an appropriate balance between (1) mitigating or eliminating the cost shift caused by the existing rate design and the NEM program by ensuring that the benefits of the new standard contract or tariff to all customers and the system approximately equal its total costs, which are currently borne by non-participating customers,[38] and (2) ensuring that customer-sited DG continues to grow sustainably,[39] meaning that it continues to grow in a self-sustaining manner that eventually is not dependent on shifting costs to non-participants.

To that end, Section 2827.1(b)(3) and (4) set forth a two-step process. First, Section 2827.1(b)(3) establishes the cost-benefit analysis framework upon which the Commission must "base" the successor tariff or contract. Once the statute establishes that the Commission must predicate its development of the successor tariff or contract on the outcome of a cost-benefit analysis, the next provision in the statute, Section 2827.1(b)(4), then instructs the Commission to "[e]nsure that the total benefits of the standard contract or tariff to all customers

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35 SCE previously discussed this statutory provision in its comments. SCE 3/16/15 Comments at pp. 10-11; SCE 3/30/15 Reply Comments at pp. 7-9.
36 Staff Report at pp. 1-8.
37 Section 2827.1(b)(3).
38 Section 2827.1(b)(4).
39 Section 2827.1(b)(1).

and the electrical system are approximately equal to the total costs." Stated differently, the first provision establishes the required analytic framework, *i.e.*, the cost-benefit analysis, and the second instructs the Commission on how to apply the outcome of that analysis in its development and implementation of a successor tariff or standard contract.

The costs and benefits referred to Section 2827.1(b)(3) are thus the same costs and benefits referred to in Section 2827.1(b)(4). As a general matter, SCE measures costs with the "all generation" RIM test, which includes utility integration and interconnection costs, administration costs, customer bill savings (utility revenue loss), and utility incentives. The relevant benefits are those that: (1) can be quantified; and (2) directly reduce the utility's revenue requirement, such as avoided costs.

The Staff Paper adopts a different approach to Section 2827.1(b)(3). The Staff Report "evaluated the costs and benefits of the renewable generating facility from the perspective of the participating customer using the results from the [PCT] and the implied payback period."[40] SCE believes that this interpretation is inaccurate. AB 327's provisions represent the Legislature's efforts to rectify an existing unsustainable and unfair system of rates and NEM incentives that need to be updated. Rules of statutory construction require that, if ambiguity exists, the statute should be read holistically with the reform theme in mind.[41] SCE's interpretation of Section 2827.1 reads Sections 2827.1(b)(3) and (b)(4) in harmony.

SCE therefore continues to recommend that the Commission use the all-generation RIM test to measure the costs and benefits referred to in both Sections 2827.1(b)(3) and (b)(4) because those costs and benefits are the same. Given that the Staff Paper disagrees

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[40] Staff Paper at pp. 1-5, 1-10. According to the Staff Report, "the PCT compares the installation and maintenance costs of the renewable generation facility against the length of time required to recover the cost of an investment." *Id*. at p. 1-10.

[41] *Panama Ref. Co. v. Ryan*, 293 U.S. 388, 439 (1935) (Cardoza, J., dissenting) ("[T]he meaning of a statute is to be looked for, not in a single section, but in all the parts together and in their relation to the end in view.")

with only using the all-generation RIM test,[42] as demonstrated above, SCE modeled both the export-only and all-generation RIM tests. SCE's Proposal met the metrics for both tests under all nine scenarios modeled. Although SCE disagree that Section 2827.1(b)(3) should be measured differently than (b)(4), SCE can accept using the PCT as a secondary indicator of whether the proposed successor tariff should be adopted, as it demonstrates the value proposition for participating customers in installing DG. As depicted below, SCE's Proposal meets the PCT criteria under all cases modeled.

Although SCE can accept the PCT criteria for evaluating proposals, SCE strongly disagrees with the Staff Paper that a change of less than two years in the implied payback period, when compared to current NEM, is an appropriate metric for evaluating the costs and benefits of the successor tariff. Payback period is becoming an increasingly irrelevant and misleading metric for analysis, particularly for participating customers that enter into $0-down agreements with third parties who own the systems (Third-Party Owned (TPO) systems) and therefore experience immediate bill savings upon installation. Regardless, assuming the Commission adopts the Staff Paper's PCT value of greater than 1 as a metric for evaluating the benefits and costs of the renewable DG system,[43] SCE's Proposal, using SCE's case, satisfies that metric by providing a PCT benefit/cost ratio of approximately 2.

Table II-4
SCE's Proposal Residential Customer PCT Results Using SCE's Case

	Two Tier	**TOU (2-8 PM)**	**TOU (4-8 PM)**
PCT Benefit/Cost Ratio	2.01	2.11	1.96

42 Staff Paper at pp.1-10 ("To the extent that NEM enables the economics of the installation, an all-generation RIM test may be the appropriate approach… With that said, to the extent that the deployment of customer-sited renewable generation is a preferred approach to reduce onsite consumption from a policy perspective, using the export-only RIM test to estimate the cost impacts directly attributable to specific successor tariff/contract designs may be appropriate.")

43 SCE may be willing to accept the Staff Paper's proposed PCT value of greater than one if the Commission makes it clear that it has prioritized the RIM test results over the PCT value in its consideration of the merits of the various successor tariff proposals.

Using the bookend cases, SCE's Proposal still satisfies this metric under both the low and high cases. Under the low case, SCE's Proposal results in a PCT that ranges from 1.00-1.06, and under the high case, SCE's Proposal results in a PCT ranging from 1.90-2.04. As all of these results provide values equal to or greater than 1.00, SCE's Proposal satisfies the Staff's proposed PCT metric even under the bookend cases.

In addition to assessing the PCT as a metric, *if* the Commission decides to also adopt the implied payback period metric as an appropriate consideration, the Commission should look at whether the *total* payback period falls within an acceptable range, as opposed to scrutinizing the difference between the existing NEM and successor tariff proposal payback periods, as the Staff Paper recommends. As previously demonstrated in Table II-2 above, continuing NEM would perpetuate NPV cost shifts to non-participating customers of up to $16.7 billion, and benefit/cost ratios as low as 0.18. Accordingly, NEM payback period is not an appropriate baseline for comparison, and comparing the difference in the NEM payback period to SCE's Proposal payback period is not a meaningful measure of benefits and costs.

In R.12-06-013 (the Residential Rates Rulemaking), the California Solar Energy Industries Association (CALSEIA), which represents the interests of participating customers and DG market participants, testified that 7.5-13.3 years is an appropriate implied payback range.[44] If the Commission is inclined to adopt a payback range in this proceeding, it should adopt the range identified by the industry that markets and installs such systems. In any event, as demonstrated in SCE's Table 5 below, using SCE's case, SCE's Proposal meets the Staff Paper's criteria for the difference between SCE's Proposal's and NEM's implied payback periods.

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44 CALSEIA 9/15/14 R.12-06-013 Testimony at Table A-2.

Table II-5
SCE's Proposal's Residential Customer Implied Payback Period under SCE's Case

	Two Tier	**TOU (2-8 PM)**	**TOU (4-8 PM)**
Implied Payback Period (Total Years)	6.2	5.9	6.3
Difference in Payback Period Compared to NEM (Δ Years)	1.9	1.9	1.9

While SCE's Proposal does not meet the payback period under the bookend cases, it does meet the payback period range CALSEIA advanced. Under the low case, SCE's Proposal results in a difference in payback period of 5.8-6.0 years; and under the high case, SCE's Proposal results in a difference in payback period of approximately 2.2 years. If the Commission accepts CALSEIA's *total* implied payback period range of 7.5-13.3 years, SCE's Proposal's payback period falls within the acceptable range. Specifically, SCE's Proposal would result in a payback period between 9.8-10.4 years under the low case, and 6.2-6.6 years under the high case.

Finally, as SCE stated in prior comments, SCE agrees with the Staff Paper's decision to exclude the Total Resource Cost (TRC) and Societal Cost Test (SCT) from its evaluation of the successor tariff proposals because neither test is affected by retail rates or the successor tariff structure and thus cannot measure impacts on non-participants as required by the statute.[45]

3. Metrics for Satisfying the Statutory Mandate that the "Total Benefits of the Successor Tariff to All Customers and the Electrical System Are Approximately Equal to Total Costs" (2827.1(b)(4))

SCE interprets ensuring that "the successor tariff's total benefits to all customers and the electrical system approximately equal its costs" to mean that the successor tariff will ensure that costs are not being unreasonably shifted from participating to non-participating

[45] Staff Paper at pp. 1-12.

customers. As SCE recommended in its prior comments, to accomplish this goal, the Commission should use SPM's RIM test. If the RIM test benefit/cost ratio to non-participants is less than 1, the statute would require the Commission to adjust the standard contract terms or tariff over time so that the benefits and costs eventually approach or equal 1, *i.e.*, the ratio is, or approximates, 1:1.

As discussed above, SCE also recommends using the total NPV of the cost shift from non-participating customers to participating customers to evaluate the benefits and costs to all customers and the electrical system. SCE recommends that the Commission compare the total cost shift under the current NEM structure to the cost shift under the proposed successor tariff to determine the change in actual customer costs over time. A proposed tariff that reduces the total NPV of cost shift conveys greater benefits to all customers and the electrical system, as well as a reduction in costs to non-participants. The results from modeling SCE's Proposal under these metrics are depicted in Table II-1, above.

As demonstrated in SCE's RIM test results, referred to above, SCE's Proposal substantially increases the benefit/cost ratio to non-participants and reduces, but does not eliminate, the NPV cost shift as compared to NEM. To further mitigate or eliminate the cost shift over time, the Commission should periodically examine and adjust the tariff components on the schedule described below.

B. Details About the Proposed Tariff Components

The overall structure and components and Public Tool results as applied to the Section 2827.1 framework are set forth above in the Executive Summary and Section II.A. Set forth below are additional details about SCE's Proposal.

1. SCE Proposes a Commission-Approved Tariff Structure

SCE's Proposal should be adopted and implemented as a Commission-approved tariff. A tariff is the traditional method by which utilities offer services to their end-use customers, and is the most straightforward and efficient option for the IOUs, their customers, and the Commission from an operational and administrative standpoint. The rationale for recommending a tariffed service over a standard contract is as follows: a tariff (1) keeps the authority to resolve disputes with the Commission, (2) retains the ability to modify rates, terms and conditions over time, as necessary, through the established and familiar advice letter and GRC Phase 2 processes, (3) builds on existing customer familiarity with having service provided through Commission-approved tariffs, and (4) reduces the costs and administrative effort on the part of the utilities to implement and manage the program since tariffed services apply uniformly to all customers served under a specific tariffed option. The successor tariff should include the following standard key sections:

- **Applicability**: List of participant eligibility criteria.
- **Territory:** Limit of availability of the tariff to SCE's service territory.
- **Rates**: The specific rates that participants will be charged or credited with a description of their components.
- **Billing**: How participating customers will be billed.
- **Required forms:** Lists forms that participants are required to complete and submit, such as interconnection agreement, application, etc.
- **Metering requirements**: Requirements for metering participants.
- **Special conditions**: As needed, such as a "definitions" section, enrollment clarification, term, concurrent participation with other programs, consumer protections, etc.

2. The DG System Will Serve Onsite Load First and Imports Will Be Charged at the Customers' OAT

SCE proposes to continue to allow eligible customer-generators to serve their onsite load first with coincident generation produced by the renewable DG system and to receive a full retail rate offset for the electricity generated and consumed onsite. The renewable DG system must be sized to meet, and not exceed, the customer's annual historical onsite connected load. SCE proposes to serve residential eligible customer-generators on their OAT rate for all electricity the eligible customer-generator imports from the utility grid. SCE proposes to serve eligible non-residential customer-generators, including those with systems over 1 MW, on SCE's commercial industrial rates, in the same manner.

3. SCE's Proposal Pays Participating Customers a Fair ECR

As noted above, SCE proposes to pay all eligible customer-generators an ECR of \$0.08/kWh for electricity produced by the renewable DG system that is not consumed onsite and exported to the grid via an on-bill credit to offset the customer's bill.

The ECR includes: (1) the Public Tool's levelized utility avoided cost estimate[46] of \$0.07/kWh, and (2) a \$0.01/kWh premium[47] for the renewable attributes of the exported generation, assuming it counts towards SCE's RPS.

While customer-sited DG that is exported to the grid should be treated as supply and entitled to RPS credit, because such exports are wholly dependent upon how much generation the customer consumes onsite, the exported energy does not provide the predictable and full benefits associated with utility scale generation that is devoted to supplying the grid with renewable energy. Specifically, because all customers are entitled to just and fair utility rates,[48] the Commission should ensure that the price for utility scale energy and capacity – not the utility's retail rates – represents the outer limits of the ECR for renewable DG customer-generator exports under the successor tariff. Any value of the ECR that exceeds this outer limit represents a cost shift. This cost shift should be transparent and subject to periodic review and updated in the GRC Phase 2 proceeding.

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[46] For the purpose of this proceeding only, SCE agrees to use the Public Tool's approximate levelized avoided cost calculation for purposes of establishing an ECR. SCE does not concede, however, that the Public Tool's avoided cost figure accurately calculates SCE's actual avoided costs.

[47] *See* Platts Electric Power Megawatt Daily reports (http://www.platts.com/products/megawatt-daily).

[48] Section 451.

4. SCE's Proposal Requires No Netting

As a condition for participating under the successor tariff, the eligible customer-generator's meter must have the capability of recording imported energy from the utility and energy exports separately.[49] SCE will measure energy imports and energy exports separately. Energy imports will be charged at the OAT rate, and energy exports will be compensated at the ECR. Netting of energy imports from the utility with energy exports from the eligible customer-generator's renewable DG system is not required or appropriate under SCE's Proposal.

5. SCE Proposes a GAC to Recover Fixed Costs[50]

For eligible residential customer-generators, SCE proposes to implement a GAC of \$3.00/kW-month based on the installed nameplate AC kW capacity of the DG system. The GAC recovers fixed costs associated, in part, with providing access to the grid for exports and power quality services, and unavoidable costs associated with the energy displaced by the DG system.[51] Eligible customer-generators continue to use the grid even when their DG system is generating electricity. Such grid services include real-time balancing of supply and demand, voltage support and other power quality services, and to export the surplus power to the grid. In addition, because eligible customer-generators purchase less electricity from the utility, they bypass the portion of SCE's energy rate that recovers T&D costs even though the DG system's output is typically not reducing the customer's peak demand on SCE's system (especially in the winter months). Stated differently, DG customers impose costs at similar levels as they did prior to installing the DG system, but no longer make the same contribution to pay for those costs. DG customers also avoid non-bypassable charges intended to recover costs for (1) energy

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49 SCE's standard residential and non-residential revenue meters currently have this capability.
50 The GAC cost components and their derivation are included in Attachment 2.
51 Section 2827.1(b)(7) authorizes the Commission to impose "a fixed charge for residential customer generators that differ[s] from the fixed charges allowed pursuant to subdivision (f) of Section 739.9 . . . in a rulemaking proceeding involving every large electrical corporation."

efficiency and demand response programs, (2) the California Alternate Rates for Energy (CARE) program, and (3) the California Solar Initiative (CSI) — a program that directly benefits most of the eligible customer-generators SCE currently serves on NEM, in addition to other "non-bypassable" charges. SCE continues to incur these costs on customers' behalf despite their reduced consumption from the grid.[52]

The $3/kW-month GAC represents a conservative estimate of the aforementioned costs, and appropriately balances furthering the growth of renewable DG systems and minimizing the cost shift between customers. The GAC charge is applied as an overlay rate structure to both tiered and TOU residential rates. Moreover, as the figure below demonstrates, a GAC based on the installed AC capacity of the DG system reflects the correlation between existing participating customer-generator's non-coincident peak demand and the installed capacity size of the DG facility. SCE's calculations of its $3 per kW-month fixed charge are detailed in Attachment 2.

Based on the Federal Energy Regulatory Commission's (FERC's) and the Commission's authorized rate design principles, SCE allocates T&D costs based on the respective rate classes' contribution to SCE's grid-related costs, measured by peak demands. SCE's revenue requirement is allocated partially on the basis of non-coincident demand for distribution[53] and system peak coincident demand over a 12-month period for transmission. For residential customers, this allocated revenue is converted into a volumetric rate that is recovered based on consumed energy. As noted above, unlike energy efficiency, which permanently reduces a customer's load in a manner that allows the utility to account for that reduction in system planning, consumption from onsite DG operates intermittently under certain optimal conditions, such as when the sun is shining in the case of PV systems or when the wind is blowing for wind turbines. As a result, to ensure uninterrupted electrical service, eligible

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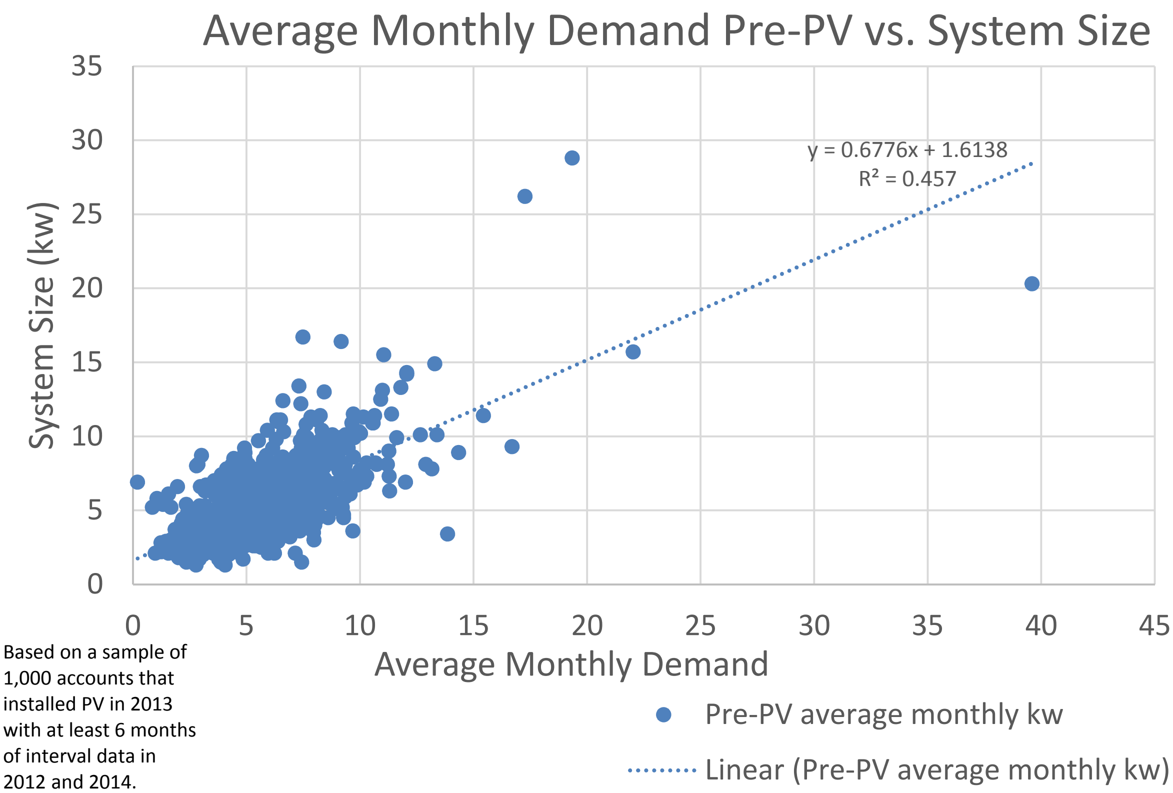
[52] Customers with DG systems also require the use of the utility's grid for services like VAR support to regulate voltage.

[53] Distribution cost allocation is also based on the Effective Demand Factor (EDF) that accounts for each customer's contribution to the peak load of the circuit from which it is being served.

customer-generators require the use of the utility's grid to back-up the generator, sometimes at a moment's notice. The utility must therefore carefully balance the distribution grid with standby capacity to support the customer-generator when their system is not operating. Due to the inherent structure of volumetric rates, when a current NEM customer offsets on-site energy consumption through the use of its DG system, that customer is effectively able to shift their equitable share of T&D costs to non-participating customers, even though the NEM customer continues to use these services. The GAC minimizes the displacement and harmonizes the successor tariff with basic principles of cost of service ratemaking and marginal cost pricing.

Figure II-1



Based on a sample of 1,000 accounts that installed PV in 2013 with at least 6 months of interval data in 2012 and 2014.

The Commission has long recognized that most distribution-related costs are incurred to equip the distribution grid to meet circuit peak loads.[54] The distribution system typically peaks at 3:00 PM in the summer, with approximately 30% of the peaks occurring during hours outside of peak solar production. In the winter, the distribution system peak typically occurs at 7:00 PM, with approximately 65% of the peaks occurring outside of peak solar production. This trend illustrates the potential for continued contribution to distribution-related costs by DG customers even after the installation of a DG system. Absent a GAC, SCE is unable to fully recover distribution costs from renewable DG customers, which unfairly shifts costs to non-participating customers.

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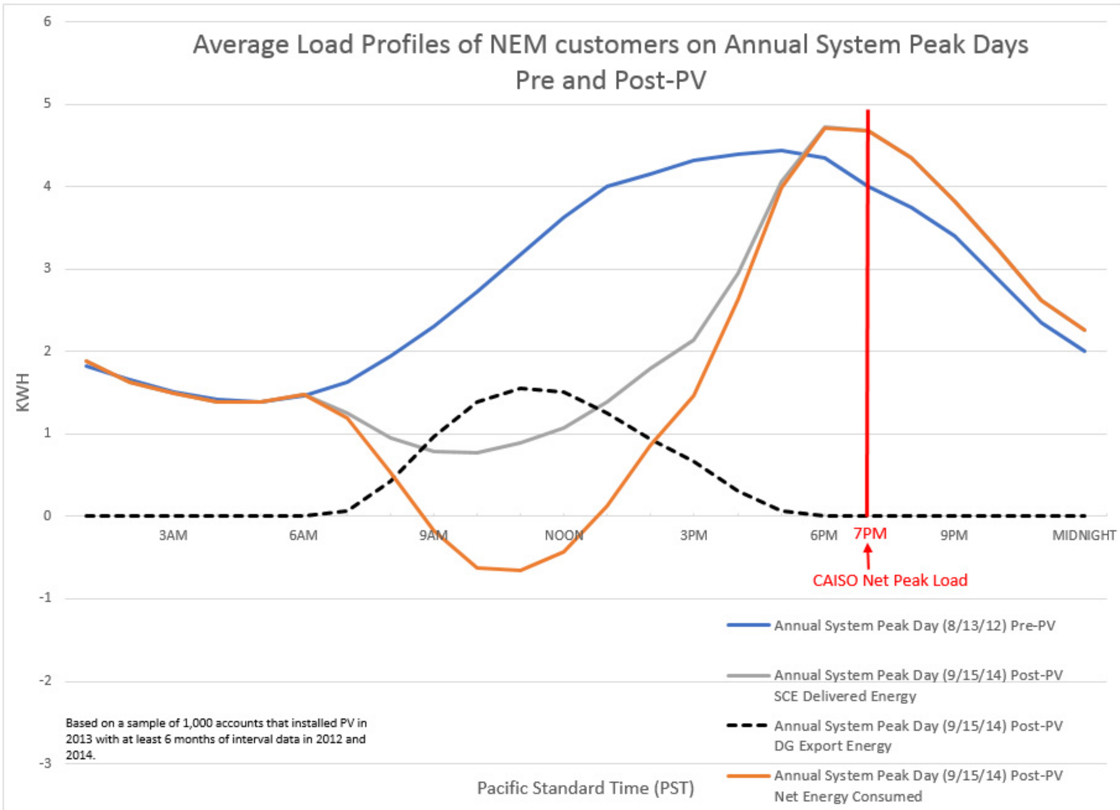
[54] D.05-03-022, the Decision approving SCE's 2003 GRC Phase 2, approved the use of a rate group's Effective Demand, which quantifies their contribution to circuit peak, to determine their share of distribution costs.

The following graph further illustrates this point by comparing the demand of a typical NEM customer before and after the DG system's installation. The typical demand was derived from a load study sample of 1,000 residential NEM customers. The before installation load shape ("Annual System Peak Day 8/13/12 Pre-PV" in Figure II-1) represents the typical NEM customer's demand on SCE's system peak day in 2012, while the post installation curves ("Annual System Peak Day 9/15/14 Post PV in Figure II-1) represent the typical NEM customer's demand on SCE's system peak day in 2014. The sample group's post installation peak occurs at 6:00 PM and persists near its highest point through 8:00 PM. Allowing for differences in usage from one year to the next, the post-installation peak is essentially the same as the pre-installation peak. Thus, the customer-sited generation profile neither eliminates nor reduces the customers' peak non-coincident demand and the subsequent contribution of such demand on distribution related cost of service. Accordingly, the installation of customer-sited DG should have no impact on the recovery of SCE's distribution and transmission cost components.

Figure II-2



The non-bypassable charges that participating customers avoid are the nuclear decommissioning charge (NDC), Competition Transition Charge (CTC), the Department of Water Resources Bond Charge (DWR BC), and the public purpose programs charge (PPPC), which funds energy efficiency[55] and the administrative costs for the CARE program, as well as the costs of New System Generation Contracts (NSGC) SCE enters into for system reliability. According to Commission mandates, SCE customers are required to bear an equitable share of non-bypassable charges.[56] These revenue components are applicable to all rate payers based on

[55] Costs for energy efficiency programs are not avoided by the utility when customer-generators install DG systems. Although PU Code 399.8 requires that costs for public purpose programs be "collected on the basis of usage," the Commission has approved Schedule DL-NBC that collects those costs through an *estimate* of the energy now served by the onsite DG. As SCE explains in Attachment 2, the customer's DG system size serves as a suitable proxy to estimate the energy now served by the onsite DG. As such, costs for energy efficiency can be appropriately recovered through the GAC.

[56] *See* Commission Decisions: D.95-12-063, D.03-07-030, and D.04-12-046.

pre-determined cost and revenue allocation parameters. SCE proposes to update Schedule DL-NBC prior to implementation of its Successor Tariff proposal to include rate components that were developed and adopted after the original Schedule DL-NBC was approved. These rate components include NSGC and DWR BC.

NEM customers are currently exempt from being placed on Schedule DL-NBC for their customer generation, meaning that no portion of the NEM generating facility's output (including output that serves the customer's load) is subject to these charges. Thus, even though the DG system does not diminish these non-bypassable costs, because these costs are recovered through volumetric energy rates, a typical NEM customer is able to offset their equitable share of non-bypassable charges, resulting in an increase in the revenue burden borne by non-participating rate payers.

These exemptions should nevertheless continue for residential customers under SCE's Proposal because they will be assessed a GAC that collects their share of non-bypassable costs. SCE's non-residential rates are structured to recover cost through a combination of energy, customer, and demand charges. Because the non-residential rates already reflect meaningful cost recovery through customer and demand charges, the level of cost shift associated with this class is significantly less than that experienced in the residential class.[57] That cost shift can be addressed through a correction of the netting structure and a reduction of the compensation rate applied to exports, rather than a redesign of the underlying rate structure.

Because T&D costs are recovered from non-residential customers through demand and customer charges, SCE does not propose to apply the transmission and distribution component of the GAC to the non-residential class. But because non-residential customers with DG systems should not be permitted to avoid costs the Commission and Legislature deem to be non-bypassable, and the responsibility of all ratepayers, SCE's Proposal *does* require non-

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[57] California Net Energy Metering Ratepayer Impacts Evaluation Report at pp. 67-68.

residential customers to pay non-bypassable charges through the application of the modified Schedule DL-NBC.

a) **Minimum Bill Alternative to the GAC**

In SCE's testimony submitted in R.12-06-013, SCE established that the fixed cost to serve a low-load residential customer exceeds $30/month.[58] The Commission deferred its consideration of fixed charges in that proceeding to 2019, but implemented a $10 minimum bill for non-CARE customers and $5 for CARE customers applicable to delivery charges. The Commission further ruled that the $10 statutory limit on fixed charges did not apply to minimum bills. The $30 minimum bill is a conservative minimum for customers whose average monthly usage before they install a DG system is well in excess of 1,000 kWh/month, or, approximately twice the average customer size. If the Commission opts to include minimum bills in lieu of the GAC or a demand charge rate component in this proceeding, the Commission should adopt a minimum bill of at least $30 for residential renewable DG customers. SCE performed a sample run using the Public Tool to model a $30 minimum bill for informational purposes. Attachment 3 provides the results of a two-tier minimum bill scenario paired with SCE's proposed ECR.[59]

6. **SCE's Proposed Updating Schedule and Vintages**

To further reduce the cost shift and to ensure that eligible customer-generators are assessed a fair GAC and receive a fair ECR based on DG costs and the market for renewable energy, SCE recommends that the Commission reassess the ECR and T&D portion of the GAC every three years, commencing with Phase 2 of the GRC cycle in 2021 and again in 2024, 2027 and so forth. Because Phase 2 of the GRC is the venue used to vet marginal costs and allocate

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[58] R.12-06-013, SCE-101 at p. 28.

[59] SCE notes that some issues may still exist with how the Public Tool includes minimum bills in its results.

revenue to the various customer classes, it is the appropriate proceeding to examine and quantify the fixed costs of grid infrastructure associated with serving renewable DG customers. The Commission should reassess the non-bypassable charge portion of the GAC outside the three year cycle, as needed, when non-bypassable charges change.

The updated ECR will be calculated on a levelized basis (20 years) and applied to customers interconnecting under that vintage. Because the costs that make up the GAC are not expected to fluctuate dramatically over time, if the Commission decides to update the GAC, that update should apply to all customers at the same cost per kW-month, regardless of the interconnection year of the customer's DG system. Customers already operating under the existing NEM tariff will not be affected. SCE will implement the updated ECR through a Tier 3 advice letter filed to coincide with a final decision in that year's Energy Resource Recovery Account (ERRA) proceeding. SCE will implement GAC modifications as part of SCE's GRC Phase 2 proceeding.

For each new vintage, the customers' ECR will be locked in for the 20-year life of the system.[60] For example, 2017 vintage customer-sited renewable DG systems will receive an $0.08/kWh ECR for 20 years through 2036. For a 2020 vintage, a 2020 ECR would apply through 2039. This proposal not only compensates renewable DG customers with a value commensurate with the benefits the exports provide to non-participants, but also provides participating customers with a reasonable degree of certainty about the compensation they may expect to receive for exported electricity.

The customers' vintage will be established based on the date the eligible customer-generator receives Permission to Operate (PTO) or, for existing systems, the date on which the customer begins service under the successor tariff. Material modifications that result in the customer requiring a new PTO for the system would also result in an updated vintage.

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[60] SCE proposes that the Commission authorize the utilities to update the vintage ECR through the Tier 3 advice letter process should conditions dramatically change.

Vintages are not portable, meaning that if customers move and take their systems with them, the vintage at the new location will be based on the PTO date issued at the new location. For customers who take over a property with an existing successor tariff in place, they would be eligible for the vintage associated with the system's initial PTO date. If a customer terminates an existing agreement and re-applies for PTO for the exact same system at the same location, the original PTO vintage will apply.

7. SCE's Proposal for Systems Larger than One Megawatt

Section 2827.1(b)(5) instructs the Commission to "[a]llow projects greater than one Megawatt (MW) that do not have a significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one MW are subject to reasonable interconnection charges established pursuant to the commission's Electric Rule 21 and applicable state and federal requirements." For the purposes of the Public Tool and Staff Paper, the Commission's Staff interpreted this language to mean that "systems larger than one MW are eligible to enroll in any of the illustrative successor tariff designs, and that eligibility for the program is limited to systems above one MW that pass the Fast Track Rule 21 Interconnection Process."[61] SCE agrees with this interpretation and approach because it best ensures compliance with the statutory requirements that projects greater than 1 MW that pass Fast Track will not "have a significant impact on the distribution grid" and that the customer will be subject to reasonable interconnection costs under Rule 21. Customers with renewable DG systems sized over one MW that do not pass Fast Track should not be eligible for the successor tariff, as such projects would constitute a "significant impact" to the grid.

Facilities that are eligible to select Fast Track evaluation include: (1) non-exporting regardless of nameplate capacity, (2) facilities interconnected under the current NEM tariff, which has a one MW limit; (3) exporting facilities with a gross nameplate rating no larger

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[61] Staff Paper at pp. 1-13.

than three MW on a 12 kV, 16kV, or 33 kV; and (4) exporting facilities that agree to install a distribution provider-approved protective device at the facility's cost so that the facility's net export will never exceed the Fast Track eligibility limits.[62]

Customer-sited renewable DG facilities sized larger than one MW will likely require telemetry and possibly additional electrical equipment to meet design standards for safety and reliability. These requirements will vary depending on the voltage level at which the facility is interconnecting and the specifics of the electrical facility. Due to the larger size of these renewable DG systems, it is likely that these systems may also require additional interconnection reviews and facility upgrades. As discussed further below, to most appropriately assign interconnection cost responsibility to the customer triggering the cost, SCE's Proposal discontinues all existing Rule 21 exemptions that apply to current NEM customers for successor tariff customers installing renewable DG systems sized larger than one MW. Current exemptions that would no longer apply to these customers include: (1) Rule 21 Interconnection Request Fees, (2) Rule 21 Supplemental Review Fees (if triggered), (3) Rule 21 Detailed Study Costs (if triggered), (4) and Rule 21 Distribution Upgrade and Transmission Costs (if triggered).

8. Additional Variations from the NEM Program

a) Virtual NEM Programs

SCE proposes that the successor tariff discontinue VNM and NEM-A, with the two exceptions described below. The primary purpose of both the existing NEM program and the successor program proposed by SCE is to allow eligible customer-generators to install renewable DG systems on their own property to offset their own load. Virtual NEM programs, by contrast, do not result in eligible customer-generators offsetting their own load with renewable generation. Instead, any customer load not served by the meter directly

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[62] SCE Tariff Rule 21E.2(b)(i) at Sheets 34-35.

connected to the generating facility relies solely on the utility to meet all of its electrical requirements. These customers then receive the economic benefits of renewable generation in the form of virtually allocated kWh, at the additional expense of all other customers both in terms of the upgrades that are needed to accommodate the interconnection requests of these larger renewable DG facilities and in the reduced charges paid by these customers, who continue to rely on the utility to serve their load.

(1) NEM Aggregation (NEM-A)

NEM-A allows a customer-generator with additional metered service accounts located on a property where the renewable generating facility is located on property adjacent or contiguous to that property to install a single generating facility to virtually serve the aggregated load of all the eligible meters. Because parcels of land can be acres in size, NEM-A allows a renewable generating facility to be sized to offset load that might be nowhere near the renewable generating facility and/or served on completely separate distribution circuits. Public Utilities Code Section 2827 was modified in 2013 to allow for the implementation of NEM-A under the existing NEM program, but a similar expansion of the NEM program was not included in Section 2827.1.

In SCE's experience, a number of NEM-A installations in its service territory result in 100% export to the utility grid – meaning no onsite customer load is directly offset by the onsite renewable DG. SCE's Proposal, by contrast (and those proposed by the Staff Paper), assumes that customer load is directly being offset by the renewable DG system, and requires that the renewable DG system be sized to offset all or part the load directly served by that meter (but no larger). Instead of attempting to utilize a program that is designed to allow customers to serve onsite load with appropriately sized renewable DG systems, SCE suggests that metered locations that are not suitable for the direct offset of load with onsite renewable DG instead utilize other renewable energy programs that are not intended to offset onsite customer load with renewable generation, such as SCE's new Green Tariff Shared Renewables (GTSR) program.

(2) NEM-V

Under NEM-V, SCE's general market VNM tariff, all individually metered eligible benefiting accounts must be located behind the same service delivery point as the renewable generating facility. SCE is no longer supportive of continuing NEM-V under its successor tariff proposal. Since SCE filed its comments in response to the ALJ's *February 23, 2015 Ruling Seeking Comment on Policy Issues Associated with Development of Net Energy Metering (NEM) Successor Standard Contract or Tariff*, in which it indicated that it was "open" to the successor program continuing the NEM-V option, SCE has crafted its Proposal and determined that it is not appropriate to continue this option given that it does not serve onsite load and NEM-V has had low customer participation since it was implemented in 2012. Specifically, in three years, only 12 customers have opted to participate on SCE's NEM-V tariff. Ten of the 12 customers took service in 2013 and only two customers total have newly taken service in 2014 and 2015 combined. Further relaxing eligibility criteria to increase participation would only exacerbate the fact that more and more customers who rely solely on the utility to serve their load are shifting their costs to other customers based on fictional allocation of kWh or credits, not a true reduction of load with directly connected renewable DG.

(3) Exceptions

As discussed more fully in the disadvantaged community section of SCE's proposal, SCE is supportive of the continuation of the MASH-VNM allocation structure under the successor program as a method for allowing growth of renewable DG among residential customers in disadvantaged communities only.[63] SCE's support is contingent,

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[63] SCE understands that it may also have to permit customers who receive a MASH incentive reservation under Track 1D pursuant to D.15-01-027 to have the benefits of the installed PV virtually

Continued on the next page

however, upon these customers receiving the ECR proposed in SCE's Proposal, as opposed to full retail rate credits.

In addition, because Section 2827.1(c) requires that "an eligible customer-generator that has received service under a net energy metering standard contract or tariff pursuant to Section 2827 that is no longer eligible to receive service shall be eligible to receive service pursuant to the standard contract or tariff developed by the Commission pursuant to this section," SCE recognizes that some option will need to be included in the successor program for existing NEMA and VNM customers who transition off of the existing NEM tariffs. SCE recommends that (1) all consumption from SCE be charged at the customer's OAT rate, (2) all exported kWh be valued at the ECR and applied solely as a monetary credit to the generating account's bill under NEM-A and to the previously designated benefiting accounts bills under NEM-V or MASH-VNM structures, and (3) the GAC be applied, as appropriate.

b) <u>NEM-MT and Paired Energy Storage</u>

(1) <u>NEM-MT</u>

The NEM-MT provisions apply where there are multiple generating facilities served pursuant to different tariffs that are behind a single revenue meter. To make sure that NEM credits are only applied to generation produced by the NEM-eligible generating facility, SCE employs either non-export protections or additional metering to appropriately credit customers. Because it is likely that customers will continue to want to install various types of generating facilities behind a single revenue meter, multiple tariff provisions will need to form a part of the new successor program. To efficiently determine the most

Continued from the previous page

allocated to designated benefiting accounts even if they receive PTO for the PV system after SCE's NEM program limit is reached or July 1, 2017, whichever is earlier. This is because the Track 1D incentives, as established in D.15-01-027, are predicated on the low income tenants receiving an economic benefit. However, for any system that doesn't receive PTO by the time SCE reaches its NEM program limit or July 1, 2017, whichever is earlier, while SCE would allow for the virtual allocation of credits, the compensation structure would be based on the successor tariff.

appropriate metering scheme and billing methodology, however, the Commission should finalize the successor tariff structure before resolving the multiple tariff provisions. That said, the existing NEM-MT provisions will continue to be effective under SCE's Proposal.

(2) Paired Energy Storage

The last variation from the existing NEM program the Commission should consider is the interconnection of on-site renewable DG systems that are paired with energy storage devices. Because the majority of energy storage devices will likely have the ability to be charged by the grid and the directly connected renewable DG system, parameters are necessary to ensure that the exported kWh being compensated under the successor tariff program is being generated by the renewable DG system. For NEM-paired storage systems where the storage device is sized larger than 10 kW (AC), the existing NEM program relies on the metering requirements of the NEM-MT option and sizing restrictions to ensure the integrity of the NEM program. For smaller systems, there are currently no protections in place to address this issue.[64] Similar to the NEM-MT discussion above, it is most effective to determine how to address paired energy storage systems once the successor tariff structure is defined.

9. Exemptions from Interconnection-Related Fees

The exemptions currently afforded to NEM customers from all interconnection costs is part of the unsustainable incentive program Section 2827.1 instructs the Commission to rectify through the successor tariff. As described in SCE's previously filed comments,[65] NEM customers are currently exempted from paying the following Rule 21 one-time interconnection costs, in addition to ongoing waivers.

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64 Decision 14-05-033 at p. 20 (stating that the Commission will issue a separate ruling in R.12-11-005 describing the process for finalizing the presumed generation profile based estimation methodology for eligible NEM generators and direct it to be incorporated into a revised NEM tariff to be applied to smaller NEM-paired storage systems. This subsequent ruling has not been issued.)

65 SCE Policy Comments at p.21.

- **Rule 21 $800 Interconnection Request Fee**: This fee functions like an application charge and covers the costs SCE incurs to review and process the initial interconnection request. It is applicable whenever a customer submits a request to interconnect a new generating facility, or to increase the capacity or make material modifications to an existing generating facility.
- **Rule 21 $2,500 Supplemental Review Fee**: This fee covers the costs that SCE incurs to perform the Supplemental Review technical analysis, when required, as part of the Fast Track interconnection process. If applicants pass Fast Track Initial Review, the Supplemental Review is not required and the corresponding fee is not charged. If the applicant does not pass Fast Track Initial Review, a NEM applicant is exempted from paying the Supplemental Review charge. The Fast Track Supplemental Review analysis consists of reviewing the applicant's Interconnection Request against Screens N through P of Rule 21, Section G.2.
- **Rule 21 Detailed Study Costs**: Detailed Study Costs and their associated deposit requirements vary based on the applicant's Interconnection Request, but in all cases, are waived for NEM customers who trigger the need for detailed studies. These fees cover the costs that SCE incurs to perform the technical analysis necessary to safely interconnect systems interconnecting under the Rule 21 Independent Study Process or the Distribution Group Study Process.
- **Rule 21 Distribution Upgrade and Transmission Network Upgrade Costs**: These costs vary based on the applicant's Interconnection Request, but, in all cases, are waived for NEM customers interconnecting under Rule 21 with Interconnection Requests that trigger these types of upgrades (costs triggered by an Interconnection Request under Rule 21 that transitions to the Transmission Cluster Study Process are allocated pursuant to the terms of

SCE's WDAT or other applicable tariff). These upgrade costs cover the costs that SCE incurs to upgrade its electrical system (e.g., increase transformer size) to safely interconnect the applicant's generating facility.

To mitigate the current cost shift to non-participating customers, SCE proposes that the Commission (1) require all successor tariff applicants to incur an interconnection application fee of $75, as opposed to the typical $800 fee;[66] and (2) require all successor tariff applicants to pay for all Rule 21 supplemental review fees, study costs (the current $2,500 Fast Track Supplemental Review Fee and Detailed Study Costs, including deposits) and upgrade costs triggered by the interconnection request, with the exception of residential applicants interconnecting systems sized 1 MW and below. For the time being, SCE supports continuing the exemption for residential systems sized 1 MW and below to avoid harming adoption rates. These costs likely do not present a sufficient barrier for sophisticated actors like non-residential customers and customers installing systems larger than 1 MW to justify continuing the exemption.

SCE proposes that all of the interconnection costs and exemptions adopted by the Commission as part of the successor tariff be subject to evaluation on a regular basis, but no less frequently than every five years, to adjust these costs and exemptions as the renewable DG market matures and costs change over time.

10. Standby Charges

In addition to one-time interconnection cost waivers discussed above, existing NEM customer-generators are also statutorily exempt from standby charges due to specific language included in Section 2827(g). Section 2827.1 contains no similar exemption. SCE recovers the costs it incurs to resources available to serve the participating customers' load when

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[66] SCE used the cost data filed in Tables 1, 2 and 3 of Advice 3239-E to determine the appropriate fee, which SCE recommends be re-visited over time if these costs significantly increase or decrease.

their DG system is not operating with standby charges. Rather than serving residential successor tariff participants on SCE's existing standby rate schedule (i.e., Schedule S), SCE's Proposal assesses a GAC to recover such costs. SCE's Proposal continues to assess standby charges for participating customers with systems sized above 1 MW and all non-residential customers, who are not assessed the T&D portion of the GAC.

C. <u>Safety</u>

Safety should always be the parties' and the Commission's paramount concern. SCE proposes that the successor tariff include safety standards that require at least the same, if not higher, level of safety and technical review than that which is currently required for the NEM program, particularly for systems larger than 1 MW.

As a precaution, SCE requires installers to use equipment that is certified by the California Energy Commission (CEC). The system design must also be in accordance with Rule 21, SCE's Electrical Service Requirements, SCE's Interconnection Handbook, the National Electric Code, and all applicable local codes and standards. The system must also receive a final inspection approval from the local Authority Having Jurisdiction (AHJ), such as the City or County. All of these requirements should be continued under the successor tariff.

One safety aspect that requires the Commission's additional consideration is the use of line side taps to interconnect renewable DG systems. Traditionally, a generator is connected "behind" the main breaker. A line-side tap is an interconnection method customers utilize to connect between the utility meter and the facility's main breaker. Customers often use this method of interconnection to avoid the expense associated with upgrades of their electrical panel. AHJ's are inconsistent about whether they allow line-side taps. Consistency is needed to avoid confusion for customers and contractors. Additionally, if line side taps are permitted, the utilities should be allowed to establish methods and standards associated with such interconnections to address any potential safety concerns.

D. **Consumer Protections**

Regardless of the type of entity, the Commission has the authority to impose consumer protections over entities engaging in activities under Commission-approved and regulated utility programs.[67]

SCE believes that the Commission should implement consumer protection in the successor tariff, including, but not limited to: (1) accepting and resolving customer complaints against market participants, (2) establishing financial responsibility standards, and (3) establishing standards for market participants' business practices in dealing with utility customers, with an enforcement mechanism for such standards. At a minimum, protections should include those that have existed for nearly a decade in the CSI Program. These basic protections will reduce the risks to all customers, including those with and without DG systems.

Consumer protections will also help the utilities protect the grid from unsafe or substandard equipment and installations. These consumer protections rely on the CEC or other equivalent agency continuing to maintain an independent "Approved Equipment list." This list certifies specific equipment by brand and model number, indicating that it is UL certified or otherwise approved by a Nationally Recognized Testing Laboratory. This list serves as an information source for customers looking for a safe equipment choice, and is recognized today by industry contractors, government agencies, and the utilities as a reliable reference source.

Because the IOUs are often the first entity to engage with a complaining or confused customer, the IOUs are currently responsible for administering consumer protections in other utility programs such as the CSI. SCE recommends that the IOUs similarly continue to administer such protections under the successor tariff.

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[67] D.10-12-060 (finding consumer protection jurisdiction over demand response aggregators); *see also* Section 701.

E. <u>Legal Issues</u>

As discussed in detail above, SCE's Proposal satisfies Section 2827.1's mandate. Although SCE Proposal complies and does not conflict with state and federal law, SCE's comments do not opine on what obligations, if any, customers and third-party entities entering into lease and power purchase agreements with participating customers who are being served under SCE's proposed tariff may have to separately satisfy to comply with state or federal law or the California Independent System Operator (CAISO) tariff. With respect to customers and market participants, SCE's Rule 21 requires that they comply with all applicable law. Customers and market participants are better situated to identify, opine on, and make a determination about their rights and obligations under applicable law than SCE. If other parties identify legal issues with SCE's proposal, it will address those issues on Reply.

DISADVANTAGED COMMUNITIES PROPOSAL EXECUTIVE SUMMARY

Section 2827.1 requires the Commission to include "specific alternatives designed for growth among residential customers in disadvantaged communities" in the successor tariff or standard contract.[68] Concurrent with SCE's proposal for a standard successor tariff, SCE proposes alternative incentives and benefits to help drive the adoption of customer-sited renewable DG among residential customers in disadvantaged communities.

SCE defines "disadvantaged communities" as the 25% most "disadvantaged" census tracts in California based on the socioeconomic and environmental criteria in the CalEnviroScreen2.0. Using this definition, SCE calculates that approximately half of California's disadvantaged community population is within SCE's service territory. Because SCE serves fewer than half of California utility customers, this represents a disproportionate amount of customers who live in SCE service territory and who also qualify as residents of disadvantaged communities. SCE approximates that 32% of its residential customers would be identified as living in a disadvantaged community, and might therefore be eligible for alternatives to the successor tariff for customer-sited renewable DG.[69]

To drive adoption of customer-sited renewable DG for this substantial customer segment, SCE's disadvantaged communities proposal relies upon the Joint Utility Guiding Principles for Disadvantaged Communities, as discussed at the Commission's Workshop for Defining and Developing Alternatives for Disadvantaged Communities.[70] Among other things, these principles advocate that the Commission adopt alternatives that are designed to: (1) target specific barriers using a least-cost approach to minimize impacts to non-participating customers;

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[68] Section 2827.1(b)(1).

[69] Based on comparison of CalEnviroScreen2.0 results for 25% most disadvantaged census tracts to SCE territory census tracts.

[70] Joint Utility Guiding Principles for Disadvantaged Communities. April 17, 2015. Presentation available at: http://www.cpuc.ca.gov/NR/rdonlyres/D3A0385D-B812-4078-BC3F-74AD99EDC4EE/0/11JointIOUProposal.pdf

(2) complement and leverage benefits from successful existing programs and incentives; (3) be transparent and easy for customers to understand; and (4) be administratively simple to implement.

SCE's alternative design provides (1) enhanced up-front incentives for low income customers living in single or multi-family residences in disadvantaged communities to install solar PV systems; (2) virtual allocations of credits for any individually metered multi-family residence located in a disadvantaged community, regardless of income level; (3) targeted marketing, education and outreach in disadvantaged communities regarding SCE's renewable programs; and (4) expanded community solar in disadvantaged communities either through power purchase agreements (PPAs) with third party developers or lower cost-of-capital utility-owned community solar systems built by third parties.

III.

SCE PROPOSAL FOR ALTERNATIVES DESIGNED FOR GROWTH AMONG RESIDENTIAL CUSTOMERS IN DISADVANTAGED COMMUNITIES

A. Alternative Design Features

1. Enhanced Incentives for Solar Installations:

SCE's proposal to provide enhanced incentives for solar installations closely resembles the Staff Paper's Proposal Option #2.[71] SCE proposes to offer upfront incentives to customers who install solar PV systems on low-income[72] single-family homes and multi-family residences in disadvantaged communities. These incentives address economic barriers by offsetting the upfront costs of installing solar PV systems for the customers who experience the most economic hardship. These incentives build on the success of the existing CSI Single Family Affordable Solar Homes (SASH) and Multifamily Affordable Solar Housing (MASH) programs, which demonstrate the success of providing upfront incentives to help offset the costs of installing solar PV results in residential DG adoption and growth.

Like SASH, SCE proposes to offer an upfront incentive for low income single-family homes in disadvantaged communities to offset the costs of installing solar PV systems. Low income customers are less likely to qualify for the $0-down PPA and lease arrangements currently offered by the solar industry.[73] Because the market is not reaching these customers,

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[71] Staff Paper at pp. 2-16.

[72] SCE's proposal defines "low income" using the eligibility criteria from the existing SASH and MASH programs. Each property must demonstrate that it is low-income residential housing as defined in Section 2852(3); and must demonstrate that the residents of the low-income residential housing have an annual income that is 80% or less of the Area Median Income (AMI).

[73] For instance, under the FAQ section of application materials provided by Vivint Solar, the "no out-of-pocket costs to homeowners" includes an asterisk that states "<u>for qualified customers</u> and subject to service availability." The residential PPA also indicates "we may have prescreened your credit." Energysage.com also specifies that a FICO score of 680-700 at minimum is required to qualify for solar PPA and lease agreements.

up-front incentives are necessary to proliferate customer-sited renewable DG in such communities. Similarly, SCE proposes a MASH-like up-front incentive for low income multi-unit residential property owners in which tenants would also experience an economic benefit from the installation of the renewable DG system. Specifically, SCE proposes to implement a two-tier incentive structure described in the Virtual Allocation of Credits section below.

2. Virtual Allocation of Credits

In addition to offering enhanced up-front incentives for low income residences in disadvantaged communities, SCE proposes to virtually allocate credits for *any* individually metered multi-family residence located in a disadvantaged community, regardless of income level, provided the compensation for the allocated kWh is based on the ECR proposed in SCE's standard successor tariff proposal. The virtual allocation of credits would allow residential tenants – not just landlords – to benefit economically from the installation of renewable DG. SCE's proposal retains the provision adopted in D.15-01-027 that higher incentives are provided to property owners who agree to allocate credits to the tenants such that the tenants' energy costs are at least partially offset.[74] Low income master-metered residential properties and low income residential multi-family properties that don't meet the 50 percent requirement would be eligible for the lower tiered incentive rate. The property owner would receive the up-front incentive to install, but would be billed the GAC based on the capacity of the solar system. The property owner and tenants would continue to be billed at the OAT for any energy that imported from the utility.

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[74] Property owners whose tenants receive at least 50% of the economic benefit of the allocated credits on a monthly basis for the life of the system, or 20 years, whichever is less, will receive the higher incentive.

3. Marketing, Education and Outreach (ME&O) Campaign

SCE's ME&O strategy is based on the targeted ME&O program conducted for the CSI program and addresses the marketing, education, and linguistic barriers identified in the Staff Paper.[75] SCE's ME&O campaign proposal informs customers in disadvantaged communities of the available renewable energy programs and services to meet their energy needs. In addition to providing information about the specific disadvantaged communities alternative offerings to the successor tariff, mentioned above, SCE's ME&O materials will also include information on other renewable energy programs, such as SASH, MASH, SCE's GTSR programs, and other programs that are suitable to help customers access the benefits of renewable DG.

SCE's ME&O efforts will target customers and industry professionals. SCE has existing relationships and contacts with companies that are active in the CSI and NEM programs, as well as Energy Storage firms active in the Self-Generation Incentive Program (SGIP). As it has done for CSI General Market and NEM, SCE will prepare contractor communication pieces designed to educate contractors about SCE's renewable DG and low income programs. Communications will include descriptions for available programs, resources directing individuals to more information on available programs, and other relevant program information. ME&O materials specifically discussing the successor tariff alternatives for disadvantaged communities will contain information about eligibility requirements, safety and consumer protection enforcement, and how virtual allocation and the two-tiered multi-family homes incentive structure work. To address language barriers in disadvantaged communities, SCE's ME&O materials will be translated into other languages and distributed in the communities in those languages based on demographic research.

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[75] Staff Paper at pp. 2-11.

Materials will be made available on SCE's website, at in person and web-based training seminars, and through regular media updates. SCE will leverage existing channels and develop new ones when appropriate. Trainings may include (1) a webinar on the new successor tariff and the alternative available for customers located in disadvantaged communities, (2) a Homeowner Solar Class Series, and (3) a Community College Solar/Renewable Job Skills Training Course. Courses will address qualifications for participating in programs, a detailed description of how participation impacts a customer bill as a tenant, and other program details and benefits. SCE would also participate in applicable tradeshows and events, including, but not limited to World Ag Expo, Solar Decathlon, SCE Hybrid-Powered Mobile Energy Unit (HPMEU) events, CARE events, and Local Public Affairs events. Customers can directly engage with SCE's program experts at these events to learn and share their program-related experiences and issues.

4. Program Administration:

SCE supports the Staff Paper's proposal that the current experienced SASH and MASH Program Administrators (PAs) administer the successor tariff's disadvantaged communities' incentive and ME&O activities.

5. Community Solar

SCE also proposes that the Commission explore options to extend Community Solar programs to customers in disadvantaged communities to address the property ownership and property structure barriers identified in the Staff Paper. Community Solar arrangements can expand renewable DG for disadvantaged communities because customers are allowed to share in the benefits of one or more local renewable energy power plants. Community Solar project need not be located on the site of the property/properties or within the geographic boundary of the disadvantaged community the system serves. Community Solar can be implemented either by the utility installing and owning the generation or the utility entering into PPAs with third party generators. SCE is open to both options and to coordinating with the Commission, renewable developers, and disadvantaged communities on other options for addressing barriers preventing renewable DG penetration for residential customers living in disadvantaged communities.

a) <u>Utility-Owned Structure</u>

As noted in the Staff Paper, installation of renewable DG by residential customer in CalEnviroScreen-designated disadvantaged communities is limited. Only 6% of residential renewable DG systems installed in the three IOUs service territories has been installed in disadvantaged communities (only 4% in SCE service territory).[76] In addition to the obvious environmental justice issue, it is also clear that there is some degree of market failure in such communities. Under such circumstances, it may be appropriate for the utility to contract with third party developers and own the renewable DG.[77] If the Commission finds that utility owned generation is the appropriate way to proliferate renewable DG in disadvantaged communities, SCE would leverage its competitive cost-of-capital, and work with third party developers to offer Community Solar to customers at a cost-competitive rate to mitigate the amount of cost shift to non-participating customers. A utility-owned Community Solar program would be rate-based as a utility asset.

SCE's expertise with the grid and its customers would also enable it to make informed siting decisions. SCE would identify areas to site projects that would serve disadvantaged community customers. SCE would prioritize lower income areas (higher penetration of CARE customers) because such customers likely have less access to renewable DG (either due to economic barriers to owning a solar systems, including difficulty qualifying for PPAs for third-party owned that requiring high credit scores). SCE could also seek out

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[76] Staff Paper at pp. 2-7.
[77] D.12-04-046 (requiring evidence of a market failure in the form of a failed RFO in the LTPP context.)

preferred areas to locate systems where projects would not require major infrastructure system upgrades, but which could still be accessed by customers in disadvantaged communities.

SCE would allow customers to subscribe to the solar system located in their area and would build projects sized to the number of accounts to be served by the Community Solar projects. As a subscriber, a customer could receive a credit on their monthly utility bill equal to the share of the power generated by the system proportionate to the size of the customers' home (or in the case of serving a multi-unit building, proportionate to the size of the tenant's unit). SCE is open to coordinating with the Commission and stakeholders to further develop an appropriate billing structure depending on whether, and in what form, the Commission may wish to implement utility-owned Community Solar.

b) Third-Party Owned – PPA Structure

SCE is also willing, similar to the existing GTSR program, to enter into PPAs with third party developers to offer community solar energy options to customers in disadvantaged communities. If a GTSR-like program is offered to disadvantaged communities, SCE proposes that any premium payment for renewable energy provided to customers be subsidized—to the extent possible—with available funding.

B. The Definition of Disadvantaged Communities

SCE supports the Staff's proposed methodology for defining Disadvantaged Communities using the CalEPA's CalEnviroScreen 2.0 to identify the 25% most disadvantaged census tracts, based on socioeconomic and environmental pollution factors.[78] SCE agrees with the Staff Paper that a definition based on a customer's income alone is not sufficient because AB 327 references low-income customers in other parts of the statute, and specifically identified "disadvantaged communities" with regard to alternatives to the standard successor tariff.[79]

[78] See SCE Policy Comments at p. 8.
[79] Staff Paper, p. 2-4 to 2-5.

However, recognizing that low-income customers within disadvantaged communities may experience greater barriers to installing solar than higher-income customers, and that they may benefit from specifically targeted alternatives that address economic barriers, SCE included provisions in its proposal specific to low-income customers within disadvantaged communities (i.e., Enhanced Incentives), in addition to benefits that would be available to non-low income customers located in disadvantaged communities (i.e., Virtual Allocation of Credits, Targeted ME&O).

C. **Barriers**

SCE's proposal sufficiently addresses the four barriers to adoption of renewable DG among residential customers in disadvantaged communities identified in the Staff Paper. With respect to economic barriers, SCE's enhanced incentives for renewable DG installations directly address economic barriers to installing solar.

SCE agrees with the Staff Paper's conclusion that upfront incentive programs would overcome the economic barriers of accessing capital for the upfront cost of installing solar panels, and issues associated with qualifying for PPA and lease-type arrangement. SCE agrees that SASH and MASH programs have clearly demonstrated the effectiveness of an incentive program in overcoming these barriers, and believe the successes of these programs should be leveraged in developing alternatives. Community Solar programs (whether utility, or third-party owned) can also address economic barriers associated with accessing capital for the upfront costs of owning a system, or meeting the credit requirements to qualify for a PPA or lease. Moreover, virtually allocating energy credits from these systems to offset charges on customer bills would provide relief to customers on their energy bills on an ongoing basis.

SCE's virtual allocation proposal addresses property ownership barriers by allowing for virtual allocation of credits at ECR for customers in *all* types of multi-family residential properties within disadvantaged communities, regardless of tenant income level. Although whether to install a DG system is ultimately the property owner's, SCE's proposal expands access to renewable energy through virtual allocation, and provides property owners with greater incentives to allow their tenants to benefit economically from the installation of the solar generating facility. If the Commission adopts a Community Renewables program, it could further address property ownership barriers by allowing for a greater proportion of customers to virtually allocate renewable energy credits from Community Solar systems, regardless of property ownership limitations.

Likewise, SCE's enhanced incentives for solar installation address property structure barriers because upfront incentives may free up money that would allow customers to make other investments to address roof quality issues and other improvements. A Community Solar program would circumvent property structure barriers associated with shading, roof condition, or roof orientation because a community solar project does not need to be located on the benefitting customer's property.

Finally, SCE's proposal includes a targeted ME&O campaign that specifically addresses barriers by actively engaging customers in disadvantaged communities through mixed media and venues, tailoring communications to customers' preferred language, and directing customers to the renewable energy programs that are most applicable to address their specific energy needs.

D. Application of Section 2827.1's Mandates for Growth and Costs and Benefits

SCE agrees with the Staff Paper that Section 2827.1's mandates regarding costs and benefits and growth in disadvantaged communities can and should be interpreted differently for the alternative design for disadvantaged communities.[80] Disadvantaged communities have not experienced growth to be continued, much less unsustainable growth, which is precisely why the statute instructs the Commission to design a specific *alternative* design for such communities. Some degree of cost shift is appropriate for this population of customers.

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[80] Staff Paper at pp. 2-9.

Similar to Staff, SCE proposes that, for the purposes of its proposal, the definition of "growth" be based on installed capacity, and be measured on an annual basis. Growth should be defined as an increase in the total annual capacity installed by residential customers in disadvantaged communities in each IOU service territory beyond the total annual capacity installed in the year prior to the implementation of the alternative for disadvantaged communities. SCE likewise suggests that subsequent years also be held to the same growth requirements, wherein they benchmark against the year before the alternative was implemented, rather than requiring year-over-year growth. The Commission should also periodically evaluate the costs and benefits to encourage cost effectiveness. SCE's proposal also takes costs and benefits into account by leveraging existing programs and expertise.

E. Funding

AB 217 increased the funding available for the existing MASH and SASH programs through 2021 (unless the available incentive funds are exhausted sooner). As the MASH program administrator in its service territory, SCE estimates that the additional MASH funding available for installations in its service territory will be exhausted in early 2016. Therefore, by the time SCE reaches its existing NEM program limit,[81] which triggers the need for the successor tariff program, MASH incentive funding will likely no longer be available, making the disadvantaged communities alternative in the successor tariff the only option for customers in disadvantaged communities.

To fund the incentives and ME&O activities for SCE's proposal for disadvantaged communities, SCE requests that the Commission authorize it to use 15% of the net greenhouse gas (GHG) Cap-and-Trade program revenue. Under D.12-12-033, *Decision Adopting Cap-and-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned*

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[81] The NEM program limit is reached when the total installed NEM capacity exceeds 5% of a utility's aggregate customer peak demand. For SCE, the NEM program limit is currently set at 2,240 MW.

Electric Utilities, the Commission held that the utilities may seek to allocate up to 15% of such revenue, including any accrued interest, for clean energy and energy efficiency projects established pursuant to statute that are administered by the electrical corporation and that are not otherwise funded by another funding source.[82] Because AB 327 was a statute and did not provide any additional funding, SCE believes its alternative proposal for growing DG among residential customers in disadvantaged communities qualifies as (1) a "clean energy" project, (2) established pursuant to statute, (3) administered by an electrical corporation, and (3) not otherwise funded by another funding source. SCE requests that up to 15% of its allowance revenues be directed towards funding its proposal for disadvantaged communities on an annual basis, which is approximately $59 million for the upcoming year. SCE suggests a budget breakdown of approximately 85-90% towards direct incentives, and 10-15% towards administration, marketing, measurement, and evaluation.

If utility-owned community solar is considered as a potential alternative, SCE would rate-base assets to all non-participating customers instead of utilizing GHG allocation funding.

F. Legal Issues

As with SCE's Proposal for the successor tariff overall, SCE's disadvantaged communities proposal complies with applicable law.

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[82] *See* D.12-12-033 at pp. 35.

IV.

CONCLUSION

SCE respectfully requests that the Commission adopt SCE's Proposal.

Respectfully submitted,

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Attachment 1

SCE's Case for Evaluating Proposal

As directed by the Commission, "all inputs that a party has modified in the Public Tool must be clearly documented, justified, and included as an attachment, clearly titled and identified, to the party's proposal."[1] SCE modeled the two bookend cases in the Public Tool. SCE also modified the Public Tool inputs, highlighted in green below, to reflect a third case (SCE's case).

SCE Case's Inputs:

Policy Inputs	
2030 Renewable Portfolio Standard (RPS) Policy Target	50%
Marginal Generation Capacity Avoided Cost Treatment	Non-Vintaged
Electric Vehicle Selection	Default – Base
Electric Vehicle Charging Scenario	More Daytime
Zero Net Energy (ZNE) Homes Policy Scenario	Policy Goal
DER Renewable Energy Credit (REC) Scenario	DER Does Not Count for Bucket 1
Avoided Cost Inputs	
Natural Gas Price	100%
RPS PPA Costs	100%
Carbon Market Costs	Default – Base
Resource Balance Year	Model Will Calculate
Ancillary Service Costs	1%
Marginal Avoided Transmission Costs	N/A
Marginal Avoided Energy Cost Locational Multiplier	100%
Marginal Avoided Subtransmission Cost Multiplier	N/A
Marginal Avoided Distribution Cost Multiplier	N/A
Utility Distribution Capital Expenses	
PG&E	100%
SCE	100%
SDG&E	100%
DER Costs	
Solar Cost Case	Low
NEM Successor (post 2017) DER Program Costs Paid By	Participating Customers
Assumed Utility Rate Escalation (nominal)	5%
Compensation Tax Treatment	Tax Exempt

[1] ALJ Ruling at p. 7.

Discount Rate Inputs	
Participant Nominal Discount Rate	9%
Utility Nominal Discount Rate	7.9%
Societal Nominal Discount Rate	5%
Inflation	2%

Policy Inputs:

- **2030 RPS Policy Target:** SCE assumes a state of the world in which IOUs will be required to increase their portfolio of renewable energy from 33% to 50%. Senate Bill (SB) 350,[2] which has passed the Senate and is currently being considered in the Assembly, requires 50% renewables by 2030.

- **Marginal Generation Capacity Avoided Cost Treatment:** SCE believes non-vintaged marginal generation capacity avoided cost treatment should be used in modeling proposals. Selecting this input ensures that the model accurately reflects dynamic changes in system conditions (rather than assuming that these hold constant over time).

- **Electric Vehicle Selection:** SCE maintained the default value in the Public Tool for this option.

- **Electric Vehicle Charging Scenario:** Based on internal SCE forecasts, SCE believes that the 10% EV Charging figure is too low. Current applications pending before the Commission, including SCE's ChargeReady Program application, aim to deploy

[2] Senate Bill No. 350 (De Leon). February 24, 2015. *See:* http://www.leginfo.ca.gov/pub/15-16/bill/sen/sb_0301-0350/sb_350_bill_20150224_introduced.htm

infrastructure to better enable EV growth, and drive greater daytime charging in support of California's 1.5 million zero-emission vehicles goal.[3]

- **DER Renewable Energy Credit (REC) Scenario:** Although SCE did not toggle this option "on" in the Public Tool, SCE requests that the Commission consider SCE's ECR to account for a premium payment for the renewable attributes of energy exports under the successor tariff. SCE attempted to model this in the Public Tool by toggling this option on in previous runs, but SCE did not agree with the Public Tool's calculated value of the premium for REC credits. Instead, as discussed in SCE's Proposal, SCE relied on Platt's MW Daily reports for bundled REC value when selecting an appropriate premium for energy exports to count towards RPS.

- **Zero Net Energy (ZNE) Homes Policy Scenario** – SCE assumes a state of the world in which the Energy Commission's Zero Net Energy (ZNE) goals for new residential buildings will be met by 2020, as per the California Energy Commission's 2013 Integrated Energy Policy Report (IEPR) recommendations. The 2011 and 2013 IEPR discussed the Energy Commission's policy recommendations regarding the pursuit of ZNE Buildings for newly constructed buildings within the Building Energy Efficiency Standards. These policies have been supported by the Commission in the Long-Term Energy Efficiency Strategic Plan, the California Air Resources Board in the Climate Change Scoping Plan, and Governor Brown's Clean Energy Jobs Plan.[4]

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[3] *See* description of ChargeReady program here: http://www.edison.com/home/our-perspective/charge-ready-a-plan-for-california.html

[4] See 2013 Integrated Energy Policy Report at pp. 24.

Avoided Cost Inputs:

SCE assumed default values for all avoided cost inputs, except for those outlined below:

- **Avoided Transmission, Sub transmission, and Distribution Costs–** SCE assumed *no avoided costs* associated with transmission, sub transmission and distribution. Rather than avoided costs, SCE has found a net cost to the utility for integrating DG at an amount of between $2.1 and$4.5 billion.[5] Navigant Consulting also conducted a study[6] on SCE's system and found that the cost of DG interconnection and distribution system upgrades for up to 4,800 MW on SCE's distribution system could range from $0.9 billion to $2 billion, depending on the project size, location, and the amount of DG clustering on distribution feeders. Although transmission costs were not derived for the Navigant study, estimates previously prepared by the California Independent System Operation and applied in the SCE study suggest the cost of transmission upgrades could add $1 billion to $3 billion. Accordingly, the Commission should not consider these costs to be "avoided."

DER Avoided Costs:

- **Solar Cost Case:** SCE assumes a Low Solar Cost Case in its DER avoided cost inputs, indicating a $4.46/kW for <10 kW Residential Systems, and $4.01/kW for >10kW non-Residential systems:

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5 The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, May 2012. http://www.energy.ca.gov/2013_energypolicy/documents/2013-08-22_workshop/SCE_Local_Energy_Resources_Study.pdf

6 Distributed Generation Integration Cost Study Prepared for California Energy Commission by Navigant Consulting, Inc. November 2013. http://www.energy.ca.gov/2013publications/CEC-200-2013-007/CEC-200-2013-007.pdf

Solar costs ($/W-AC in 2014)	High	Base	Low
< 10 kW (proxy for Residential)	$5.58	$5.17	**$4.46**
> 10 kW (proxy for non-Residential)	$5.01	$4.65	**$4.01**

SCE selected the low solar cost based on the most recent CSI Program data provided for Q1 2015, which shows a **$5.01/W AC** price for California Residential Solar Systems,[7] which are below the base case data. Because CSI prices are a lagging indicator[8] of solar prices, the Commission should not use the low case values to reflect today's market pricing. The CSI Annual Program Assessment findings support this conclusion, noting that "between the last quarter of 2008 and the last quarter of 2014, the average cost of installed residential systems has decreased 53 percent from $10.87 per watt to $5.14 per watt (CEC-AC), with figures adjusted for inflation. In the same time period, non-residential system costs have decreased 62 percent from an average of $10.30 per watt to $3.93 per watt."[9] This earlier study recognizes a dramatic trend in decreasing solar prices over the years, indicating that the base case is likely an inflated and outdated estimate for solar costs. SCE therefore assumed a continued downward trend in pricing, reflective of a value much lower than the $5.14/W Base Case, and closer to the Low Case value of $4.46/W.

In addition, SCE believes that the following trends, which further drive down prices, will continue: (1) increasing competition among renewable DG providers, (2) continued technological advancements, (3) increasing consumer awareness of renewable DG, and (4) California's progressive environmental policies. For these reasons, SCE selected the low as the most representative case for Public Tool modeling.

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7 California Solar Statistics database at: https://www.californiasolarstatistics.ca.gov/ (filtering for California, residential, customer-owned systems).

8 CSI prices are based on a systems completed per quarter, meaning that contracts may have been signed several months earlier, before project completion.

9 CSI 2015 Annual Program Assessment at p. 25.

Discount Rate Inputs:

SCE maintained default discount rate inputs, except in the case of the Utility Nominal Discount Rate, for which it selected 7.9% to reflect SCE's most recent weighted average cost of capital under Decision D.12-12-034.[10]

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[10] *See* D.12-12-034.

Attachment 2

GAC Cost and Revenue Components

SCE has developed the GAC consistent with the existing methodology used under the DL-NBC tariff. The Commission authorized SCE to establish Schedule DL-NBC to collect certain non-bypassable charges from customers who discontinue or reduce their purchases of electricity supply and delivery services and replace the reduced amount with another source.[1] In 2004, the Commission approved the use of historical consumption to determine the amount of departed load that would be subject to the volumetric non-bypassable charges.[2] Because of the administrative burden associated with the bill calculation methodology described in Special Condition 2 of Schedule DL-NBC, SCE proposes to instead recover the fixed costs described in Section III.B.5 through a GAC based on the customer's DG system size. As shown in the two scenarios described at the end of the attachment, SCE firmly believes that system size can be used as an accurate proxy for on-site displaced energy as well as a proxy of the amount of grid services the customer obtains to support and backup its own system. Because of the statutory requirement that systems be sized appropriately, *i.e.*, they may not be sized larger than the customer's electrical requirements, the system's nameplate capacity can be used to reasonably estimate the amount of on-site load expected to be served by the DG system. Assessing a GAC based on DG system size thus enables SCE to recover the appropriate amount of fixed costs from each participating customer, despite variation in levels of energy consumption, because it reasonably estimates the amount of departing load and the need for grid support.

To calculate the GAC, SCE determined the costs a typical NEM customer avoids as a result of the inherent structural design of volumetric residential rates using the following process: First, for the aggregate group of residential NEM customers, SCE developed a scaling factor by using SCE's interval data for delivered energy and exported energy. Second, SCE calculated *on-*

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[1] D.97-09-056.

[2] Advice 1829-E approved October 25, 2004.

site displaced energy by subtracting pre-solar and post-solar delivered energy. SCE determined post solar delivered energy by applying the scaling factor to net energy consumed from load studies. Third, SCE calculated the product of on-site displaced energy and the relevant rate factors to determine the displaced revenue. Fourth, SCE converted the displaced revenue to a GAC by dividing the displaced revenue by the typical AC rating of the installed system. Because SCE's proposal includes an ECR, SCE excluded all export energy from its GAC calculation, and instead relied solely on displaced energy. The table below lists the specific rate factors that are used in the calculating SCE's proposed GAC.[3]

Rate Factor Description	Rate Factor Value
Base Distribution - $/kWh	0.07333
Transmission - $/kWh	0.01227
PPPC - $/kWh[4]	0.00700
NDC - $/kWh	0.00028
DWRBC - $/kWh	0.00526
NSGC - $/kWh	0.00986
PUCRF - $/kWh	0.00024
Total - $/kWh	0.010824

A. <u>Load Study Parameters:</u>

SCE conducted a load study of a sample group of residential NEM customers over different time periods. The service accounts were identified by the residential NEM rate literal

[3] Reflects Residential rates effective June 1, 2015.

[4] Although PU Code 399.8 requires that costs for public purpose programs be "collected on the basis of usage," the Commission has approved Schedule DL-NBC that collects those costs through an *estimate* of the energy now served by the onsite DG. As described in this appendix, the DG system size provides a reasonable estimate of energy served by the onsite DG and can be used as the basis for a GAC that collects the participating customer's share of public purpose programs costs.

from SCE's billing system. A total of 10,939 service accounts were identified that, by SCE's estimate, had installed a solar generating system at some time between April 1, 2011 and March 31, 2012. Of this total population, only 8,944 service accounts could be included in the study due to the limitation of having a minimum of six months of billing data in 2010 before installation of the solar system. To maintain the efficacy of the study, SCE held the pool of accounts that were analyzed over the different time periods constant. Due to attrition, about 3% of the accounts became inactive during the study period, resulting in a further drop to 8,652 accounts in the post-PV April 2012 through March 2013 installation period.

Account level consumption was first analyzed for the year 2010, which in this case, represented consumption in kWh prior to the installation of the solar system. This was categorized as "pre" solar system consumption data. Billing data for the period after the solar system was installed was subsequently extracted and analyzed. This "post" solar system net consumption data was comprised of billing data from April 1, 2012 through March 31, 2013. SCE then aggregated the individual account level data to determine with the average consumption for a typical solar customer "pre" solar and "post" installation of the solar system.

B. <u>Interval data by Month for the Year 2014:</u>

SCE's AMI meters record NEM customer consumption on two channels. Channel One records energy delivered in kWh and Channel Two records energy that is exported to the grid in kWh. Based on existing residential metering configuration, SCE has no way to measure the actual amount of on-site consumption displaced by the installation of a solar system and in this attachment attempted to arrive at an estimate for the same. For the year 2014, SCE extracted the annual kWh from both channels for all NEM residential customers. The summary table below contains the monthly meter readings in kWh for the entire population of NEM customers in the year 2014. The "Net- kWh" is not a meter read, but a calculated value of the difference between the delivered-kWh and the exported-kWh for each month.

MONTH	YEAR	(A) Export - kWh	(B) Delivered - kWh	(C) Net - kWh
1	2014	16,956,224	58,162,896	41,206,672
2	2014	16,315,837	42,627,456	26,311,619
3	2014	24,979,458	43,403,392	18,423,934
4	2014	37,856,672	44,360,262	6,503,590
5	2014	39,268,059	46,724,118	7,456,059
6	2014	39,240,665	58,527,072	19,286,407
7	2014	34,430,100	82,421,968	47,991,868
8	2014	27,887,818	89,124,192	61,236,374
9	2014	30,850,829	98,704,526	67,853,697
10	2014	31,649,732	86,739,658	55,089,926
11	2014	23,216,308	53,821,203	30,604,895
12	2014	23,169,246	80,282,927	57,113,681
	Yearly Total	345,820,948	784,899,670	439,078,722

The summary table above was used to develop a scaling factor to convert the “net” energy delivered in kWh to “delivered” kWh. From the table above, a scaling factor value of 1.79 was derived by dividing the yearly total in column (B) by the yearly total in column (C). The table below further illustrates this calculation.

Description of Variable	Value of Variable	Legend
Channel 2 kWh - 2014 – Annual Export - kWh	345,820,948	a
Channel 1 kWh – 2014 – Annual Delivered - kWh	784,899,670	b
Implied Annual Net kWh - 2014	439,078,722	c = b-a
Scaling Factor	1.79	d = b/c

C. <u>Estimating On-Site Displaced Energy:</u>

Based on the load discussed above, before installing a solar system, a typical participating DG customer had an average consumption of 1,114 kWh per month. After the installation of the DG system, the same typical participating customer has a net energy consumption of 549 kWh per month. The amount of total displaced energy was calculated to be 565 kWh per month (1,114 kWh minus 549 kWh). To estimate delivered energy in kWh, SCE multiplied the net energy of 549 kWh by the 1.79 scaling factor described above, for an estimate of 981 kWh in delivered energy. The difference between 1,114 kWh per month in delivered energy, prior to the installation of a solar system, and the 981 kWh in delivered energy after the installation of a solar system is SCE's closest estimate of *on-site displaced energy* in kWh. This difference equates to 133 kWh. In summary, for a typical NEM customer, the 549 kWh in net energy can be separated into on-site displaced energy of 133 kWh and export compensated energy of 432 kWh (the difference between 565 kWh and 133 kWh). The calculation is also provided in the table below.

Description of Variable	Value of Variable	Legend
Average monthly pre solar delivered energy (kWh)	1114	**a**
Average monthly post solar net energy (kWh)	549	**b**
Average monthly post solar total displaced energy (kWh)	565	**c = a - b**
Scaling Factor (*ref section on interval data by month for 2014*)	1.79	**d**
Average monthly post Solar delivered energy (kWh)	981	**e = b x d**
Displaced Energy Summary		
Average monthly export compensated energy (kWh)	432	**f = e - b**
Average monthly estimate of on-Site displaced energy (kWh)	**133**	**g = a - e**
Average monthly post solar Total displaced energy (kWh)	565	**h = c = f + g**

An alternative approach to the one described above is to estimate on-site displaced energy from the load study sample group of NEM customers. SCE determined that after the installation of the solar system, the average delivered energy to a typical NEM customer is 833 kWh. SCE estimates the value of on-site displaced energy as the difference between consumed energy prior to the installation of a solar system (1114 kWh), and the post solar delivered energy from the load study sample (833 kWh). This estimate of on-site displaced energy amounts to 281 kWh and has been used in the Scenario 3 described in Section D below, Calculation of the Grid Access Charge:

Once an estimate of the on-site displaced energy in kWh is determined, the displaced energy cost responsibility is calculated as the product of the on-site displaced energy in kWh and the sum of rate factors for the relevant cost and revenue components. This displaced energy cost is then converted to a GAC by dividing the displaced energy cost by an estimate of the typical size of the solar system. To account for departures from average values, the table below uses two alternative scenarios for system size. Scenario 1 depicts a fixed charge calculation assuming a system size of 5kW. In the table below, SCE also enumerates Scenario 2 where the GAC is estimated based on a system size of approximately 6kW. To account for the larger size of the system in Scenario 2, SCE also proportionately increases the estimate of on-site displaced energy to 213 kWh. Scenario 3 illustrates the alternative approach of estimating on-site displaced energy using load study data described in Section C above. Using these three scenarios, SCE is better able to explain the sensitivity of the GAC to the valuation of on-site displaced energy. SCE proposes a more conservative value of $3/kW GAC to balance furthering the growth of renewable DG systems while minimizing the cost shift between customers.

	Scenario 1	**Scenario 2**	**Scenario 3**	Legend
Average monthly Pre solar delivered energy (kWh)	1114	1114	1114	a
Average monthly Post Solar delivered energy (kWh)	981	883	833	b
Average monthly estimate of On-Site displaced energy (kWh)	133	231	281	c = a - b
Cost Shift - ($/ month)	$14.4	$25.0	$30.4	d = c x rate factors
Typical system size (kW)	5	6	5	e
GAC estimate ($/ kW - month)	$2.9	$4.2	$6.1	f = d / e
GAC ($/kW - month)	$4.4			g = avg (f)

Attachment 3

Public Tool results for SCE residential DG customers with a $30/month Minimum Bill, using SCE's DG Case, two-tier rate and SCE's proposed ECR of $0.08/kWh

			All-Generation RIM results		***Export-Only RIM results***	
Adoption (MW)	**Payback (years)**	**PCT benefit-cost ratio**	**NPV cost impact ($ B)**	**RIM benefit-cost ratio**	**NPV cost impact ($ B)**	**RIM benefit-cost ratio**
3,483	5.6	2.18	-3.7	0.53	-0.2	0.90