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)

PROPOSAL OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR FOR A NET ENERGY METERING SUCCESSOR STANDARD TARIFF

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SUMMARY: NEM SUCCESSOR TARIFF

The Solar Energy Industries Association and Vote Solar (collectively, the Solar Parties) propose a successor tariff that continues net energy metering (NEM) at the retail rate under the same structure and rules which have been so successful in California to date. Today, the NEM tariff allows utility customers who install renewable distributed generation (hereafter abbreviated to 'renewable DG' or 'DG') to receive a retail rate credit when the output of their DG system exceeds their on-site use of electricity. In other words, NEM simply allows the meter to "run backwards." NEM is easy for customers to understand, and the linkage to the familiar retail rate facilitates customers' investments in on-site renewable DG. NEM at the retail rate has been a foundational policy essential to the success of California's efforts to build a sustainable DG program for all types of utility customers – both residential and commercial/industrial (C&I). Continuing the growth in renewable DG is a critical element of California's clean energy goals, including its efforts to reduce the state's emissions of greenhouse gases (GHGs).

The Solar Parties fully support the Commission's and the Legislature's desire to continue to extend the benefits of net-metered DG to all Californians, with particular emphasis on customers who live in disadvantaged communities. For these ratepayers, we propose additional alternatives to NEM, specifically CleanCARE and Disadvantaged Communities Virtual Net Metering, as discussed in the separate summary and section of this filing.

As the Commission requested, the Solar Parties have used the Public Tool to analyze the benefits and costs of our successor tariff proposal from a variety of perspectives. These include all of the points of view required in Assembly Bill (AB) 327, which established the statutory requirements for the NEM successor tariff. The following table summarizes the key results of the Solar Parties' Base Case analysis of continuing NEM in its present form over the period from 2017-2025 that is modeled in the Public Tool. These summary metrics combine the results for the increasing block and time-of-use (TOU) rate designs which the Commission recently adopted in its major decision on residential rate design, D. 15-07-001.

Table ES-1: *Key Metrics from the Solar Parties' Base Case (new systems, 2017-2025)*

Perspective	Benefit-Cost Ratio	**Annual Net Benefits** ($ millions per year)
All ratepayers	1.45	$900
Societal: California as a whole	1.76	$1,680
Ratepayers who install DG	1.44	$755
Non-participating ratepayers	1.04	$110

The results of the Solar Parties' Base Case modeling with the Public Tool demonstrate that our NEM successor tariff satisfies the metrics adopted in AB 327 [P.U. Code §2827.1(b)(1), (3), (4), and (5)]. The results of the Total Resource Cost (TRC) and Societal tests show benefit/cost ratios greater than 1.0, indicating that our proposed tariff will result in a reasonable balance of total benefits and total costs "to all customers and the electrical system," as required by §2827.1(b)(4). Continuing NEM will result in about $900 million per year in net benefits for all ratepayers over the 2017-2025 period, in the form of lower overall bills for electric service.

The benefits for the state of California will be even larger ($1.7 billion per year) when one considers the quantifiable societal benefits of net metered DG, including the enhanced reliability and resiliency of the electric system, land use benefits, and local economic benefits.

AB 327 requires the Commission to consider the economics of the successor tariff for future customers who install distributed generation, and provides that the successor NEM tariff adopted by the Commission must ensure that the DG industry continues to "grow sustainably." The Solar Parties' Base Case analysis shows that the economics for new DG customers remains favorable, although less DG will be installed for several years beginning in 2017 due to the expected step-down in the federal investment tax credit (ITC) for solar. In addition, the bill savings for DG customers will be reduced significantly by the changes that the Commission has adopted in residential rate design. More broadly, the overall level of DG adoption that the Public Tool models, assuming continuation of NEM, is about 8,000 MW (8 GW) installed from 2017-2025. This 8 GW is, however, at the low end of what we consider to be sustainable for the industry and for attaining the state's clean energy and GHG goals. This result underscores the need for the Commission to maintain the basic, time-tested structure of NEM, without the inevitable disruption that would occur with a move to a completely new compensation paradigm. Moreover, while the Public Tool does not model the impacts on DG adoption of such a disruption in the NEM tariff, it does show clearly that the step-down of the federal investment tax credit at the end of 2016 will have a significant negative impact on solar DG adoption at the same time that the NEM successor tariff is being implemented. Accordingly, 2017 would be a poor time for the Commission to experiment with an untested approach to compensating DG customers.

Using the Ratepayer Impact Measure (RIM) Test, the Solar Parties also have examined the effects of maintaining the NEM retail rate credit on utility revenue requirements and on non-participating ratepayers, even though neither AB 327 nor prior Commission direction on evaluating DG cost-effectiveness require such an analysis. The Commission does not rely on the RIM Test to evaluate the cost-effectiveness of other demand-side programs, such as energy efficiency. Nonetheless, past NEM studies have examined NEM from this perspective, and RIM analyses do illuminate the impacts of changing rate design. Application of the RIM Test to the Solar Parties' Base Case and No Parity Case produces results that show clearly that the major changes in residential rate design which the Commission has adopted in R. 12-06-013 will contribute significantly to eliminating the adverse impacts of net-metered DG on non-participants, compared to the impacts under today's four-tier increasing block rates. As a result, all utility customers – participants and non-participants – will benefit from a continuation of NEM in California. Finally, even if the Commission finds that there is some adverse impact on non-participating ratepayers, the Commission should keep such a result in perspective, given that the state's longstanding energy efficiency programs, for which California is justly lauded, result in far greater cost impacts on non-participating customers. California has wisely accepted this result, recognizing the long-term benefits of steady, consistent policy support for demand-side programs. The Commission should maintain that support for renewable DG, by maintaining NEM based on a retail rate credit.

The Solar Parties provide a detailed explanation of the key assumptions and modeling changes used in our Public Tool runs. This includes, in our Base Case, valuing DG "at parity" with new renewable generation from utility-scale projects developed under the state's Renewable Portfolio Standard (RPS) program. The DG and RPS programs have long proceeded in parallel, both resulting in the construction of new renewable generation, and it is clear that the state needs both programs to reach its long-term goals to reduce GHG emissions. The fact is that if there were no DG program, the state would need to replace the lost DG output on a one-for-one basis with more utility-scale renewable power through the RPS program, in order to maintain the same overall penetration of renewable generation on the California grid and to maintain progress toward the state's GHG goals. If there were no renewable DG, it is simply no longer conceivable that the Commission would replace this renewable resource with greater use of fossil fuels. Assuming "parity" treatment of DG and RPS is fully consistent with the changes to the RPS statute adopted in AB 327, in which the Legislature determined that the RPS goal should be a floor, not a cap, on the amount of new renewable generation.

The Commission has asked parties to show the impacts of the modifications that they make to the Public Tool. Accordingly, we also provide a sensitivity case that does not assume DG/RPS parity, using the outdated assumption that DG principally replaces greater marginal natural gas-fired generation. In this sensitivity case, we include the recognized and quantifiable societal benefits of reduced emissions from this gas-fired generation, as well as the lower market prices that result from reduced demand for market-priced generation, and show that the results are similar to the Base Case with DG/RPS parity. These results demonstrate that it is reasonable to assume DG/RPS parity, as the benefits to California from increasing the penetration of renewable generation are worthwhile for the state as a whole, with minimal impacts on other, non-participating ratepayers.

The Solar Parties have also made changes to the Public Tool's model for customer adoption of DG, to make that model more realistic in terms of how customers evaluate DG economics and how system sizing will be impacted by non-economic constraints such as available roof space, shading, and other factors. We have included the marginal costs of high-voltage transmission as an avoided cost of DG, because DG located on the distribution system at the point of use can reduce demand and avoid future investments in bulk transmission. Finally, the Solar Parties use data from the Sierra Club's successor tariff proposal that quantifies a range of important societal benefits of DG, and we ask the Commission to make findings in this case that substantiate that DG provides these important benefits to all the citizens of California.

Due to the declining costs of renewable DG, and the comprehensive suite of programs that the state has adopted, in the near future virtually all utility customers will have the opportunity to increase their access to renewable energy and to become participants in the clean energy revolution. This includes both customers that have a suitable site for renewable DG and those that do not. For customers who seek to install renewable DG, this opportunity can best be maintained and expanded by retaining the essential policy foundation – NEM with a retail rate credit – that has made California the nation's leader in customer-sited solar.

SUMMARY: PROPOSAL FOR DISADVANTAGED COMMUNITIES

AB 327 directs the Commission to ensure that the NEM successor contract or tariff includes "specific alternatives designed for growth [of customer-sited renewable distributed generation] among residential customers in disadvantaged communities." Disadvantaged communities deserve special focus in this proceeding because, while installed rooftop solar capacity in the state has increased most quickly in moderate-income zip codes in recent years, disadvantaged customers still face additional and more significant barriers to solar adoption. As noted in a letter submitted to the Commission earlier this year by the Brightline Defense Project on behalf of a number of advocacy organizations representing communities of color, disadvantaged communities have a strong interest in expanding local solar installations so that the communities that are disproportionately impacted by the negative impacts of traditional energy generation can take greater part in the clean energy transformation and receive the many related benefits.[1]

"Disadvantaged Communities" in this proceeding should be defined as disadvantaged compared with the general California population with regards to both socioeconomic and environmental pollution factors. Including both factors in the definition would be consistent with other recent California statutes that define disadvantaged communities, for example SB 43, the 2013 statute that required the development of Green Tariff Shared Renewables programs for the three large investor-owned utilities (IOUs).

We support the use of the most recent version of the California Communities Environmental Health Screening Tool (CalEnviroScreen), currently CalEnviroScreen 2.0, as one appropriate method for identifying disadvantaged communities in the context of this proceeding. However, we do not take a position regarding what percentage ranking within the tool should be the cutoff for identifying disadvantaged communities, and we raise the question of whether rural communities are accurately represented if the CalEnviroScreen ranking is done statewide. We also recommend that the Commission allow California Alternative Rates for Energy (CARE) customers and SASH and MASH program participants to participate in the approved disadvantaged communities alternatives, regardless of their geographic location.

We note five barriers to clean DG adoption that particularly affect disadvantaged communities: 1) barriers to accessing capital or financing, 2) small or nonexistent tax liability, 3) barriers to education and marketing, 4) low levels of home ownership and 5) lower electric rates which reduce bill savings. As a proposal for measuring and defining growth among residential customers in disadvantaged communities, we propose ensuring that, on average over at least the

[1] The letter, signed by 16 leaders representing California's communities of color, supports the continuation of net metering after the 5% cap and supports exploring innovative additional approaches to provide greater clean energy access to disadvantaged communities. The letter and its accompanying ex parte notice are available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K794/151794314.PDF.

four-year period 2017 – 2020, the megawatts installed to serve residential customers in disadvantaged communities increase from current levels by at least 30% annually.

We propose three guiding principles for designing effective policy alternatives for disadvantaged communities:

1. The policy effectively addresses or avoids two or more of the barriers specific to Disadvantaged Communities.

2. Projects facilitated by the policy will be financeable.

3. The policy is truly scalable, allowing it to facilitate meaningful DG growth in Disadvantaged Communities on an ongoing basis.

Keeping in mind these principles we propose that two complementary alternatives be available to residential customers in disadvantaged communities, in addition to the broader NEM successor tariff:

1. **CleanCARE**: We support CleanCARE, a concept developed and discussed in greater detail by the Interstate Renewable Energy Council (IREC), as a new rate option for customers eligible for CARE. CleanCARE would enable a portion of CARE funds to be invested in the development of shared renewable distributed generation located in disadvantaged communities. The generation would be owned and operated by a third party, with the output purchased by the utilities via a request for offer (RFO) process on behalf of participating CleanCARE customers. CARE customers choosing the CleanCARE option would move to the standard rate for their rate class, and would offset a portion of their monthly bills via virtual net metering for a portion of the renewables facility's output, achieving comparable bill savings to what the standard CARE subsidy would have provided.

2. **Disadvantaged Communities Virtual Net Metering (VNEM)**: VNEM is currently available in California only to multi-tenant, multi-meter properties where the renewable generation is located on the same property as the participating customers. We propose an expanded VNEM program that allows residential customers located in disadvantaged communities to be assigned credits from a project also located in a disadvantaged community within the same IOU territory. The Disadvantaged Communities VNEM program would be available to both CARE and non-CARE residential customers in disadvantaged communities, and with the use of a PPA model, developers could offer eligible customers the ability to participate with no upfront investment.

The Commission has the latitude in this proceeding to determine what policy alternatives will most effectively increase access to clean DG among residential customers in disadvantaged communities, without the same requirement to balance the costs and benefits for all customers that applies to the NEM successor tariff. Accordingly, the Commission should evaluate which proposals will be the most effective and efficient at expanding access to clean DG in these communities. In this regard, our proposed policy alternatives have the signal advantages of not requiring additional funding and not raising legal issues. The Solar Parties recommend their adoption as the best means to extend the benefits of the clean energy economy to California's disadvantaged communities.

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FOR A NET ENERGY METERING SUCCESSOR STANDARD TARIFF

The Solar Energy Industries Association[2] and Vote Solar (collectively, the Solar Parties) present the Commission with a proposal for a successor tariff for net energy metering (NEM) in California, in accordance with the Administrative Law Judge's (ALJ) June 4, 2015 *Ruling… Seeking Party Proposals for the [NEM] Successor Contract or Tariff* and the subsequent Assigned Commissioner's Ruling revising the procedural schedule dated June 23, 2015 and the ALJ's Ruling on revisions to the Public Tool dated July 20, 2015.[3] The Solar Parties' proposal for a NEM successor tariff is to continue the basic structure of NEM in California – that is, to allow a DG customer to use the production from its own DG system to offset its on-site electric use, and, when DG output exceeds on-site use and the customer's meter rolls backward, to receive a rate credit based on the volumetric components of the customer's retail rate. Continuing to offer NEM is justified from a cost-benefit perspective when one evaluates the impacts on all of the customers of the investor-owned utilities (IOUs). In particular, the Commission's recent approval of residential rate redesign reforms in D. 15-07-001 will significantly reduce the non-participant rate impacts from NEM compared with today's four-tiered residential rate structure.

2 This proposal represents the position of the Solar Energy Industries Association as an organization, but not necessarily the views of any particular member.

3 Hereafter, the "June 4 Ruling," the "June 23 Ruling," and the "July 20 Ruling."

As requested in the June 4 Ruling, we include an executive summary of our proposal as the initial pages of this submittal, and conform the organization of this proposal to the comprehensive outline set forth by the ALJ. As requested, we provide extensive, detailed information about all aspects of our proposal, including the justification for how our proposal and the associated modeling differ from the analysis presented in the CPUC Energy Division's paper on NEM that accompanies the June 4 Ruling (the "Staff Tariff Paper"). We have made available to the Energy Division the input assumptions for our Public Tool runs, as well as the modified version of the Public Tool that we have used.[4] As requested in the June 23 Ruling, we have described and justified the changes we have made to the Public Tool, and we discuss how they change our results compared to the unmodified Public Tool. We include as an attachment to this filing a detailed, cell-by-cell description of those changes. Most important, we show below how our proposal meets each of the criteria set out in P.U. Code Sections 2827.1(b)(1), (3), (4), and (5).[5]

I. INTRODUCTION AND POLICY CONTEXT FOR SOLAR PARTIES' PROPOSAL

NEM is a foundational policy that has been a cornerstone of the success of California's efforts to build a sustainable program to encourage utility customers to install renewable distributed generation (DG). Continued sustainable growth in renewable DG will be an essential element of achieving California's clean energy goals, including its ambitious efforts to reduce the state's emissions of greenhouse gases (GHGs). However, the sustainability of this progress is uncertain, as a result of the significant near-term pressures on the economics of customer-sited DG, including:

- the end to the direct state incentives provided under the California Solar Initiative (CSI),
- the major step-down (from 30% to 0%-10%) of the federal investment tax credits for solar at the end of 2016, and

4 The Solar Parties also are willing to make their full Public Tool available to other interested parties, via data request.

5 June 4 Ruling, at pp. 3-4.

- the reforms to residential rate design that the Commission adopted last month in D. 15-07-001 in its rulemaking on residential rate design (R. 12-06-013).

Using the Public Tool that the Commission and its consultant, Energy and Environmental Economics (E3), have developed for the use of the parties to this proceeding, the Solar Parties will show that, under today's circumstances, continuing the state's foundational NEM policy is necessary to comply with the Legislature's directive in AB 327 that renewable DG "continues to grow sustainably." [6] Continuing NEM with a retail rate credit will ensure that DG resources contribute a significant portion of the new renewable generation needed to meet California's clean energy goals. Moreover, our NEM proposal effectively balances the interests of DG customers, non-participating customers, and all ratepayers as whole. Importantly, the impacts of the NEM successor tariff on non-participants will be substantially eliminated, as a result, in significant part, of the Commission's residential rate reforms. Any remaining modest impacts on non-participating ratepayers are far smaller than the rate impacts of the state's other essential clean energy initiatives, including the Renewable Portfolio Standard (RPS) program and California's many energy efficiency (EE) initiatives. Finally, the Solar Parties have included in our modeling the significant societal benefits of DG for California using data from the federal government and other sources, as presented in the Sierra Club's proposal. We call upon the Commission to recognize and substantiate that DG provides such important benefits to all Californians.

One critical factor which the Public Tool cannot capture is the simplicity and intuitive appeal of NEM to prospective DG customers. Customers understand the concept of "running the meter backward" and believe that it represents fair compensation for their DG output. They also are familiar with the retail rate that they pay, which enables them to evaluate the economics of a DG investment more readily than if excess NEM output were compensated at an unfamiliar and periodically changing wholesale rate. Customer understanding and acceptance are critical elements of a successful rate tariff. NEM has demonstrated its ability to support the significant growth of renewable DG that has occurred in recent years throughout the U.S. 45 out of 50 U.S.

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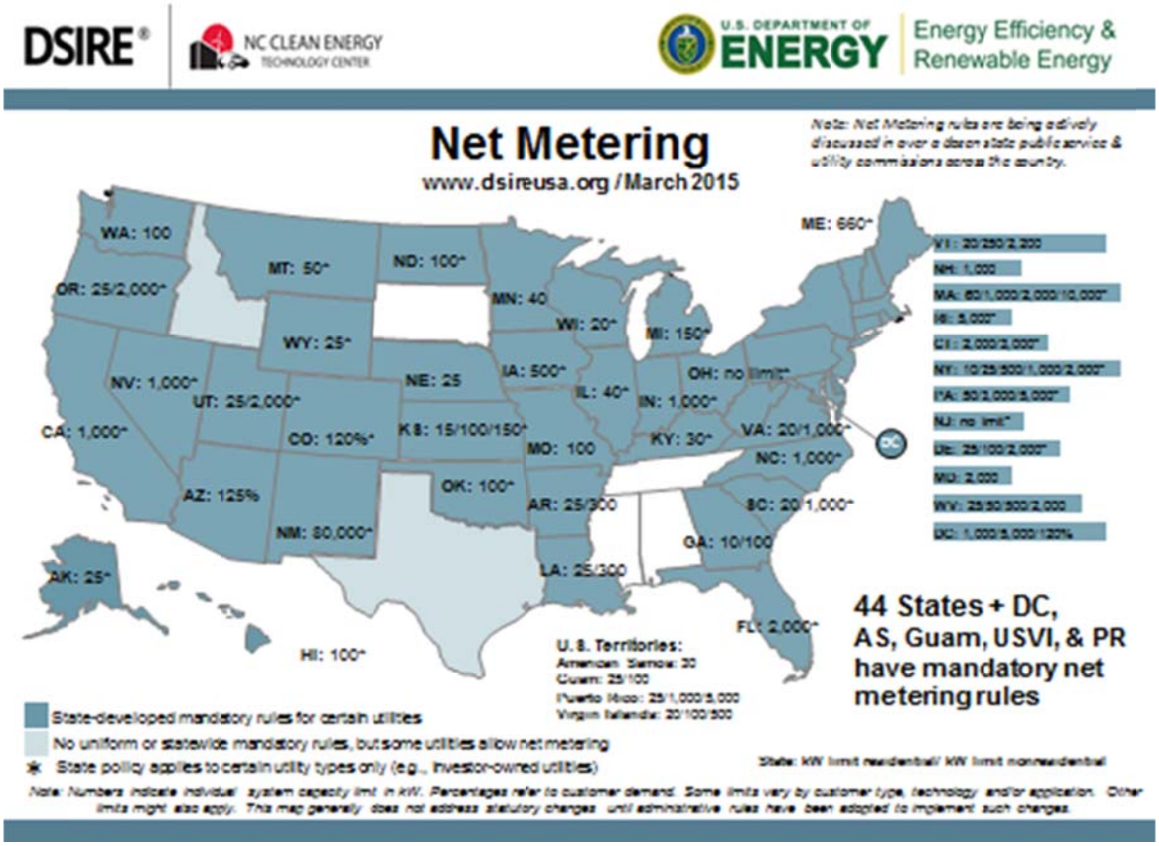
[6] *See* Public Utilities Code Section 2827.1(b)(1). All references hereinafter are to the California Public Utilities Code unless otherwise stated.

states have adopted NEM as a foundational policy to support DG, including South Carolina, which recently implemented NEM, and Mississippi, which will be implementing NEM this year.

Figure 1: *States with Net Energy Metering*



Source: http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2015/04/Net-Metering-Policies.pdf. As noted above, Mississippi is in the process of implementing NEM.

The success of NEM in California and the U.S., as well as the headwinds for renewable DG noted above, should give the Commission pause before adopting any untested alternative to NEM that may be proposed in this case. The Commission must find that any alternative not only complies with state and federal law, but also would be more effective than NEM at encouraging the sustainable growth of customer-sited DG during this time of market changes and uncertainties, including the consideration that any other compensation mechanism will result, at a minimum, in additional short-term disruption to the state's DG program that is not captured in the Public Tool modeling.

The Commission is considering proposals for a NEM successor tariff or contract at a time when it has become clear that renewable DG is today, and has the potential to continue to be, a major future clean energy resource for California. This has been demonstrated by the success of the CSI program and the recent significant reductions in the installed cost of solar DG.[7] When the 5% NEM cap is reached for each of California's three major investor-owned utilities, almost certainly in the 2016-2018 time frame, the systems of the three IOUs will have about 5.26 gigawatts (GW) of renewable DG capacity, producing over 9,000 gigawatt-hours (GWh) per year, close to 4% of the IOUs' gross loads. In comparison, by 2020 the 33% RPS program will result in about 80,000 GWh of renewable generation, 33% of the IOUs' sales (i.e. of the IOUs' load net of DG output). Combining DG and RPS generation, by 2020 the overall penetration of renewable generation on the California grid should equal or exceed 36% of the IOUs' gross loads, well above the 33% RPS goal alone. As discussed in this proposal, if NEM is continued, an additional 8 to 11 GW of DG is projected to be added between 2017 and 2025, expanding the penetration of DG to about 10% of IOU gross loads. Although fewer DG megawatts have been installed compared with utility-scale renewable generation, it is clear that DG has become a major, complementary, and potentially substitutable source of new renewable generation. Further, state policy supports both of these programs as essential and complementary:

- Both the RPS and DG programs are longstanding, with many years of successful implementation. In fact, California's initial DG program, the Emerging Renewables Program (ERP), dates from the late 1990s, and predates the state's RPS.

- The Legislature has repeatedly raised both the RPS goal and the cap on NEM generation.

- The Commission's longstanding "loading order" for new electric resources explicitly includes DG along with utility-scale renewables in the second tier of the loading order.[8]

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[7] The Commission's June 2015 CSI Annual Program Assessment noted that between 2008 and the end of 2014, the average installed price of CSI systems declined by 53% for residential systems, and by 62% for commercial systems; see http://www.cpuc.ca.gov/PUC/energy/Solar/2015_Annual_Program_Assessment_landingPage.htm.

[8] The state's adopted "loading order" for new resources is presented in the Energy Action Plan II adopted by this Commission and the California Energy Commission in October 2005, at page 2. The Energy Action Plan II and the 2008 Update to this plan can be found at http://www.cpuc.ca.gov/PUC/energy/resources/Energy+Action+Plan/.

- The Governor's Clean Energy Jobs Plan for 2020, released in 2010, included 12 GW of distributed generation, including both wholesale DG and retail, customer-sited, behind-the-meter DG.[9]

- The California Air Resource Board's (CARB) *First Update to the Climate Change Scoping Plan*, issued in May 2014 (hereafter, *AB 32 Update*), discusses the RPS and DG program as complementary sources of renewable generation.[10]

- AB 327's admonition that renewable DG must "continue to grow sustainably" demonstrates continued state insistence on a strong DG program.

Today, California is planning its post-2020 clean energy goals. It has become clear that a progressively cleaner electric system will be essential in realizing California's long-term goal for GHG reductions, which is an 80% reduction compared to 1990 emissions by 2050. CARB's *First Update to the Climate Change Scoping Plan*, finalized in May 2014, notes that academic studies of achieving the 2050 goal have concluded that reaching this goal "will require energy demand reduction through efficiency and activity changes; large-scale electrification of on-road vehicles, buildings, and industrial machinery; decarbonizing electricity and fuel supplies; and rapid market penetration of efficiency and clean energy technologies that requires significant efforts to deploy and scale markets for the cleanest technologies immediately."[11] **Table 1** below is taken from one prominent study cited by CARB, and compares California's sources of primary energy in 2010 and 2050 if the state's GHG goal is to be achieved.[12] Note that, first, electricity replaces a significant portion of today's fossil fuel use, in transportation, industry, and buildings. Electricity is the one primary energy source that continues to grow at historical levels between 2010 and 2050, at a rate of growth of about 1.3% per year. Second, the percentage of renewable generation in 2050 will have to be as high as 74%, requiring substantially more renewable generation than the state's present goals for 2020. Another similar study projects that California's electricity supply will have to double from 2020 to 2050 (an annual growth rate over

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9 See http://gov.ca.gov/docs/Clean_Energy_Plan.pdf.

10 CARB, *First Update to the Climate Change Scoping Plan* (May 2014, hereafter *AB 32 Plan Update*), at pp. 40-41, available at http://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm.

11 *AB 32 Plan Update*, at p. 32.

12 Source: J.H. Williams et al., "The Technology Path to Deep Greenhouse Gas Emission Cuts by 2050: the Pivotal Role of Electricity," *Science* 335, 53 (2012), at Table 1. Other such studies are listed and discussed in the CARB's *AB 32 Plan Update*, at pp. 32-33, footnote 61.

2% per year), with RPS-eligible renewable resources constituting about 80% of the electricity supply in 2050.[13]

Table 1: *California Primary Energy Sources, 2010 vs. 2050*

Primary Energy (Exajoules)	**California 2010**		**California 2050**	
Direct Fossil Fuel Use	5.59	*64%*	0.94	*14%*
Direct Biofuel Use	0	*0%*	0.73	*11%*
Electricity	3.11	*36%*	5.14	*75%*
% Renewable	***Less than 20%***		***Up to 74%***	
Total all fuel types	8.70	*100%*	6.81	*100%*

In Governor Brown's second inaugural address, the Governor announced a bold, new energy goal of 50% renewable electricity by 2030. The first two initiatives the governor mentioned to support this goal were "more distributed power, expanded rooftop solar…"[14] The bottom line is that California is relying on both the DG and RPS programs as significant and complementary sources of the carbon-free, renewable generation that will be an essential foundation for achieving the state's long-term clean energy and GHG goals. DG is no longer a minor, marginal source of generation that simply can be modeled as displacing mostly the short-term output of the gas-fired resources that are marginal source of short-term market generation in California. Instead, DG is a major, long-term source of renewable generation on which the state is relying to meet its ambitious clean energy goals. The Solar Parties agree with the Staff Tariff Paper on "the critical role that renewable DG will play in meeting California's deep greenhouse gas (GHG) emissions reduction goals," citing Governor Brown's recent executive order setting a 2030 goal of a 40% reduction in GHG emissions compared to 1990.[15]

In valuing the benefits of DG resources, the key consideration is to determine what the state would do in the absence of, i.e. "but for," DG resources – in other words, to answer the

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[13] S. Yeh and C. Yang, *Modeling Optimal Transition Pathways to a Low Carbon Economy in California: Results from CA-TIMES v1.5 Energy System Model and Implications for Policymakers* (University of California, Davis), presented at the CARB Research Seminar, May 1, 2014, at Slides 19 and 27.

[14] Available at http://gov.ca.gov/news.php?id=18828.

[15] Staff Tariff Paper, at p. 1-14.

question “what resources does DG avoid?” The answer to this question is that, as demonstrated by the Williams study cited above, if California did not have DG resources available, the state would need to procure additional utility-scale renewable resources in order to achieve and maintain a high penetration of renewables on the California grid in support of the state’s ambitious 2030 and 2050 goals for emissions reductions. This is particularly true given that a clean grid will be the necessary foundation for emission reductions in multiple sectors of the state’s economy. There clearly are multiple ways to reduce GHG emissions to achieve California’s goals, but a common denominator for many of them is a clean electric grid run mostly on renewable energy. The Solar Parties ask the Commission to affirm this long-term perspective on the critical role of DG in its decision on the NEM successor tariff. Our comments below will describe how this long-term perspective should inform the modeling of the benefits of net-metered DG resources going forward.

II. STANDARD NEM SUCCESSOR TARIFF/CONTRACT

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

“Sustainable growth” [Section 2827.1(b)(1)]. As detailed in the Solar Parties’ policy comments dated March 16, 2015 (at pages 6-10), “sustainable growth” of renewable DG means that, in the near term, the year-over-year growth in solar MWs installed should equal or exceed the growth in the prior year, in order to match the appropriate slope of the logistic adoption curve. Based on the Solar Parties’ and Energy Division’s modeling using the Public Tool, a significant exception to this metric of sustainable growth is that the step-down in the federal solar ITC may result in a short-term slowdown in DG installations in 2017 over 2016. Solar Parties note that this metric for sustainable growth does not assume that year-over-year growth increases in perpetuity.[16] As a result, it is not inconsistent with this metric that, in the final years of the 2017-2025 period modeled in the Public Tool, the growth in installations of DG may slow as solar penetration for some types of customers approach the full technical potential for those customers (i.e. as installations move onto the “flatter” upper portion of the adoption curve).

[16] Joint Solar Parties’ March 16 comments, at p. 8.

The standard contract/tariff is "based on the costs and benefits of the renewable electrical generation facility." [Section 2827.1(b)(3)]. As explained in the Joint Solar Parties' March 16 comments, the plain statutory language of 2827.1(b)(3) requires the Commission to consider the costs and benefits of "the renewable generation facility," so the logical interpretation of 2827.1(b)(3) is that the clause requires the Commission to ensure that the tariff is based on costs and benefits that the participant customer realizes from their choice to install a DG facility.[17] This reading of Section 2827.1(b)(3) is consistent with the sustainability requirement in 2827.1(b)(1), by ensuring that the perspective of the customer choosing to invest in the DG resource is considered in developing the successor standard tariff/contract. If the standard contract or tariff creates for a participant an adequate margin of benefits over costs, then renewable DG will continue to grow in a way that can be sustained over time. As a result, this section of AB 327 calls for the successor tariff to be reviewed using the Participant Test from the *Standard Practice Manual (SPM).* Our Public Tool results include Participant Test results as well as an adoption forecast based on those results. The Staff Tariff Paper appears to support this view of Section 2827.1(b)(3).[18]

"The total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs" [Section 2827.1(b)(4)]. This section requires the Commission to review the standard tariff/contract from the broader perspective of <u>all</u> customers, under the *SPM*'s Total Resource Cost (TRC) and Societal Tests.[19] These are the only two tests that consider costs and benefits to all customers; these tests are also modeled in the Public Tool. Combined with the Participant Test perspective that is called for in Section 2827.1(b)(3), the use of these tests provides for the balanced, multi-perspective approach embodied in Section 2827.1(b) – an approach which is necessary for the continued, sustainable growth of renewable DG.

17 *Ibid.*, at p. 13.
18 Staff Tariff Paper, at pp. 1-9 to 1-10.
19 Joint Solar Parties' March 16 comments, at pp. 13-17.

The clear emphasis in AB 327 is on evaluating the NEM successor tariff from the perspectives of participating ratepayers (through the Participant Test) and of all ratepayers (with the TRC and Societal Tests). In contrast, the Staff Tariff Paper chooses to evaluate compliance with Section 2827.1(b)(4) only from the perspective of non-participating ratepayers, through the RIM Test, even though non-participants are only a subset of all ratepayers.[20] The RIM Test alone clearly does not satisfy the standard in Section 2827.1(b)(4) because it does not consider whether "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs" (emphasis added). Further, even before the passage of AB 327, when the Commission last formally considered how to evaluate the cost-effectiveness of DG resources in D. 09-08-026, the Commission emphasized the importance of the TRC and Societal Tests and the desirability of mirroring the tests used to evaluate energy efficiency programs.[21] That decision de-emphasized the importance of the RIM Test, finding that "we will not require that the RIM Test be performed as part of our DG cost-effectiveness evaluation efforts."[22] Similarly, in evaluating energy efficiency programs, the Commission does not require the RIM Test to be performed and does not use it to evaluate cost-effectiveness.[23] Given the important role of DG as a future source of zero-carbon electricity for California and the clear statutory directives of AB 327, the Solar Parties believe that the Commission should use the same cost-effectiveness standards to evaluate DG that it has long employed for the state's other critical demand-side programs.

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[20] Staff Tariff Paper, at p. 1-10. The staff report justifies examining this perspective, to the exclusion of considering the perspective of all ratepayers through the TRC and Societal Tests, on the grounds that the Commission's prior NEM cost-effectiveness studies have used only the RIM test, and therefore that this approach is "well established." However, both of the Commission's prior NEM studies were initiated and conducted under different statutory guidance and before the effective date of the new legislative direction in AB 327.

[21] D. 09-08-026, at pp. 28-29.

[22] *Ibid.*, at pp. 24-26. The Staff Tariff Paper, at page 1-10 and footnote 23, mistakenly cites page 53 from this order as finding that NEM should be evaluated using the RIM test. Pages 53-54 of the order generally describe NEM, and address certain details of how to account for NEM exports in the *Standard Practice Manual* tests, including the RIM test. However, it is the prior section of this decision, on pages 24-26, that discusses the general policy on the use of the RIM test for assessing DG cost-effectiveness. That section concludes that the only purpose of conducting the RIM test would be to examine certain rate design issues associated with DG resources on-line before June 1, 2003 under Section 353.9, issues that the Commission found had been resolved in prior orders. See p. 25, footnote 10.

[23] *See* D.05-04-051, Ordering Paragraph 5; also, D. 09-08-026, at p. 26.

Finally, over-reliance on the RIM test for the design of the successor tariff would fail to recognize that Californians in all rate classes and economic circumstances have increasing opportunities to participate in the state's DG programs. This is the result of declining DG costs, expanded financing opportunities, and California's comprehensive suite of programs intended to allow all types of customers to participate directly in producing and consuming their own clean energy. These include:

- NEM is available for individual utility customers who install on-site renewable DG;
- AB 327 has specific provisions designed to ensure that the NEM successor tariff will benefit disadvantaged communities;
- The SASH and MASH programs continue to provide incentives for low-income customers to install solar on single- and multi-family housing;
- The utilities' "green tariff" programs now being implemented pursuant to SB 43 and D. 15-01-051 will allow bundled utility customers to obtain a higher percentage of renewable energy in their generation mix;[24] and
- The "enhanced community renewables" portion of the SB 43 program will encourage like-minded communities of consumers to contract to purchase generation from specific local renewable projects.

In short, an increasing number of California ratepayers, of all types and economic circumstances, will have the opportunity to become participants in the state's growing markets for renewable DG.

The RIM test is one of the *SPM* tests, and this test is included in the Public Tool. We acknowledge that the RIM test is the only test to evaluate the impact on non-participants of changing rate designs, which is of interest given the significant reforms to residential rate design adopted in R. 12-06-013. Although we disagree with the Staff Tariff Paper on the emphasis to be accorded the RIM test, we do agree with Energy Division's focus on the percentage impacts on utility revenue requirements as the most meaningful metric for assessing the future rate impacts of the NEM successor tariff on non-participating ratepayers. For example, we agree

[24] The Solar Parties note that they are concerned that the high rate premiums that will be required to participate in the SB 43 programs, as they are currently structured, will inhibit participation by renters and lower-income ratepayers.

with the Staff Tariff Paper that annual revenue requirement increases of 2% to 3% per year considering all DG output would be a reasonable outcome for all ratepayers, including non-participants.[25] As presented below, the revenue requirement impacts of the Solar Parties' Base Case are well below this standard. The Commission's goal should be to ensure that the impacts on non-participants are reasonable and are trending down over time due to initiatives such as residential rate reform.

B. Using the Same Bookend Input Values and Retail Rate Assumptions.

1. Solar Parties' NEM Successor Tariff Proposal

The Solar Parties' proposal for the NEM successor tariff is to continue to use the DG customer's retail rate as the basis for the credit for net energy. NEM should continue under the tariffs, rules, and procedures that exist today and that have proven to be successful in California. These include:

- NEM should be a **tariffed service**, for the reasons discussed in the Joint Solar Parties' March 16 policy comments. In short, a tariff-based approach will allow the Commission to retain greater oversight over the successor program than will a contract-based program.

- In the NEM tariff, exported energy should continue to receive a **bill credit**. This will avoid the possibly serious tax implications if DG customers are paid for generated and/or exported energy.

- We understand that the data used in the Public Tool is based on a 30-minute netting interval. The Solar Parties strongly recommend the **use of a one-hour netting interval**, given that customers are presented with smart meter data in one-hour intervals. The use of a one-hour interval will prevent customer confusion if the netting interval is not consistent with the data presented to DG customers. It is not our impression that there is a significant difference in the net usage of NEM customers between 30-minute and 60-minute netting intervals.

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[25] Staff Tariff Paper, at 1-37 and Updated Table 22, finding that the 2%-3% revenue requirement impact in the Value-Based Export Compensation case "satisfies Staff's proposed metrics to determine whether the total benefits of the successor tariff are approximately equal to the total costs."

2. The Solar Parties' Base Case and Sensitivity Cases

The Solar Parties **a**ppreciate the opportunity to present our own analysis of the costs and benefits of a NEM successor tariff, using the Public Tool.[26] We have developed the Solar Parties' Base Case which embodies our view of the "State of the World," and we also provide certain sensitivity cases that show the results if key concepts or assumptions in the Base Case are modified. As requested in the June 4 and 23 Rulings, the Solar Parties provide as **Attachments A1** and **A2** to these comments a list of the most significant inputs and changes that we have made to the Public Tool in our Base Case, with an explanation and justification for each change. We discuss the most important of these assumptions and modifications in the next section of this proposal, and note how each of the changes we have made to the Public Tool impacts our results, compared to the unmodified Tool. As required, the Solar Parties have analyzed our successor tariff proposal in the Public Tool using three of the new increasing block (IB) and time-of-use (TOU) residential rate designs which the Commission recently adopted in D. 15-07-001. A TOU rate design may become the default residential rate design as early as 2018.

a. Public Tool Changes

Adoption Model. The Solar Parties have made two significant changes to the adoption model in the Public Tool. First, we have revised from 5% to 3% per year the assumption for participants' future expectation for annual utility rate increases. As detailed in Attachment A1, a 3% per year assumption for this metric is more consistent with the available data – historical, current, and forecasted:

- IOU rate increases since 1993 have averaged less than 2% per year for PG&E and SCE and less than 3% per year for SDG&E.

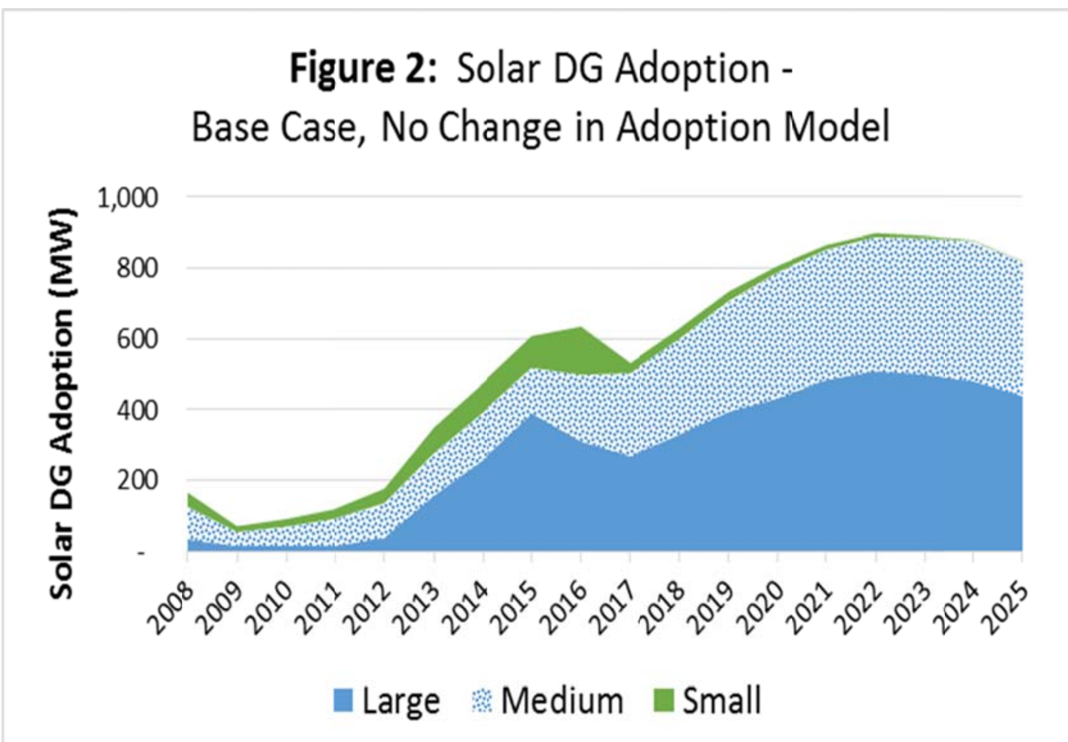
- Today, the assumed future rate increases used by major solar installers in marketing solar in California range from 2.9% to 3.5% per year.

[26] This is the Solar Parties' "third case to evaluate their proposal using their own input drivers," as discussed on pages 6-7 of the June 4 Ruling. We also discuss and present the results below for modeling our proposal with the Staff Tariff Paper's two "bookend" cases.

- The future rate increases modeled by the Public Tool itself over the next 33 years are in the range of 2.5% to 2.7% per year.

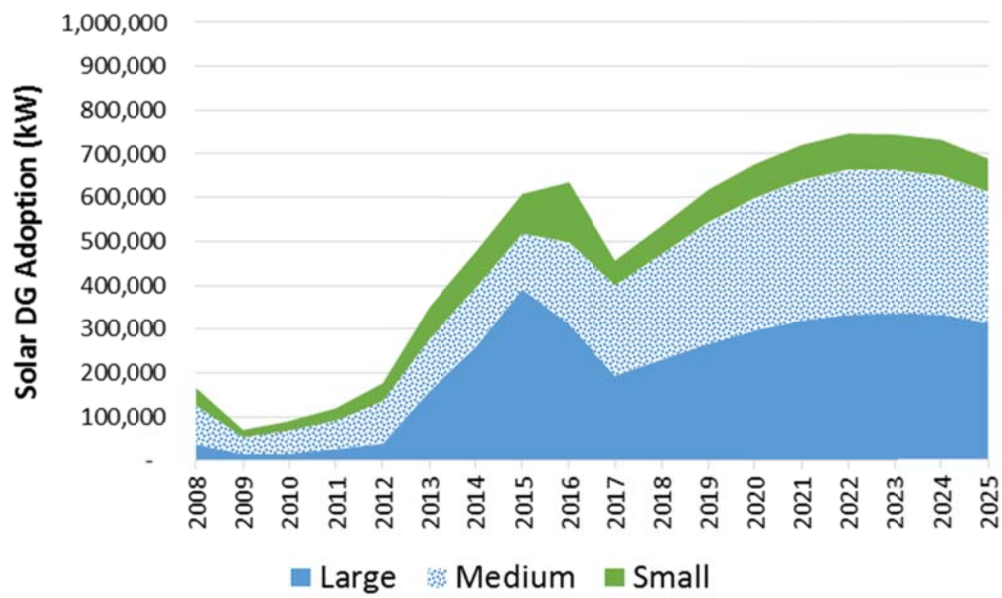
Based on this data, the assumption for future utility rate increases should be no higher than 3% per year. The Commission should not assume that DG customers have unrealistic expectations for future rate increases.

Second, the Public Tool chooses the size of future DG systems (Small, Medium, or Large) based entirely on economics, without considering the constraints of other factors such as available roof space, building orientation, shading, aesthetics, or customers' available budgets. Generally, all of these non-economic factors will tend to reduce system sizes. The E3 adoption model selects a particular system size for all installations in a "bin" of similar customers purely on the basis of the best economics, even if another system size has economics that are almost as favorable. The result is that the unmodified Public Tool adopts Large systems, offsetting 100% of the customer's load, to an extent that differs significantly from the historical distribution of system sizes. The following figure shows solar DG adoption in the Solar Parties' Base Case, with no changes to the Public Tool's Adoption model.



The Solar Parties recognize that changes in rate structure will impact the distribution of DG system sizes, but we submit that the adoption model should recognize that other factors also will tend to reduce system sizes. As a result, the adoption model should start from an allocation of system sizes based on past experience, which reflects not only economics but also the other constraints on system sizing. As a result, we have modified the adoption model to limit the system size adopted for a particular bin of similarly-situated customers to the historical system size for that bin, using E3's data through 2012 on the actual system size for each bin. This change maintains the historical system size that customers have adopted in each bin (i.e., if a bin was "small" in 2012, it will be "small" in 2017-2025), but continues to allow the economics to determine how much of each bin's technical potential is adopted. Thus, if the economics favor large systems, the bins with large systems will fill up faster, resulting in a growing percentage adoption of large systems from 2017-2025, just not to the same extent as E3's unmodified model. We believe that this modification strikes a better balance between economics alone and the many other factors that will tend to limit system sizing. The resulting distribution of system sizes is more diverse and more reflective of historical experience, as shown in **Figure 3** from the Solar Parties' Base Case. This change also results in a somewhat lower level of adoptions (8.0 GW from 2017-2025 in our Base Case with the change, compared to 10.4 GW without it).

Figure 3: Solar DG Adoption - Base Case, With Change in Adoption Model



DG / RPS Parity. The key choices in determining the benefits of DG are deciding what costs DG avoids, in other words, answering the question "what resources would replace DG, if DG were not available." Past NEM studies have assumed that new DG avoids a mix of short-term, market-priced, gas-fired generation and RPS renewable generation, in the following proportions, using the year 2020 as an example and assuming a 33% RPS target:[27]

- 33% RPS utility-scale renewables
- 67% marginal generation, mostly gas-fired

This treatment has been continued in the Public Tool.[28] This approach assumes that the RPS target (e.g. 33% by 2020) places a cap on the amount of renewable generation as a share of the IOU's procurement portfolios. This assumption is outdated, as a result of the passage of AB 327 and Governor Brown's Executive Order B-30-15. AB 327 revised P.U. Code Section 399.15(b) to remove the language that limited RPS procurement to no more than the RPS percentage;[29] thus, this change in law clarified that the RPS goal is a floor, not a cap. Governor Brown's Executive Order B-30-15, issued on April 29 of this year, requires a California greenhouse gas reduction target of 40 percent below 1990 levels by 2030, which the Governor's press release noted is "the most aggressive benchmark enacted by any government in North

[27] For example, the *2010 NEM Cost-effectiveness Evaluation*, at p. 18, noted that "… any reductions to total retail sales will reduce the required supply of renewable energy to remain compliant with the [33%] RPS target."

[28] The only exception is if one assumes that DG generation receives "Bucket 1" treatment for its renewable energy credits (RECs), such that DG RECs would count toward the RPS requirement with the same status as utility-scale, RPS-eligible renewable generation delivered into the California Independent System Operator (CAISO) grid. Under existing CPUC policy, DG RECs are not "Bucket 1." Instead, if DG RECs could be sold to a load-serving entity (which is impractical today, as discussed further below), they would be classified as unbundled "Bucket 3" RECs that have a much lower value. As discussed further below, the Joint Solar Parties do not assume in our Base Case that DG RECs receive Bucket 1 treatment.

[29] The language that AB 327 removed from Section 399.15(b) stated that "the commission shall not require the procurement of eligible renewable energy resources in excess of the quantities identified in paragraph (2)." Paragraph (2) is the one which specifies the RPS goal. The revised language for this section in AB 327 authorized procurement of renewables above the cap: "the commission may require the procurement of eligible renewable energy resources in excess of the quantities specified in paragraph (2)." The exports from net-metered DG are an example of above-RPS generation procured by the IOUs.

America to reduce dangerous carbon emissions over the next decade and a half."[30] The Executive Order required that "all state agencies with jurisdiction over sources of greenhouse gas emissions shall implement measures… to achieve reductions of greenhouse gas emissions to meet the 2030 and 2050 greenhouse gas emissions reductions targets." As noted above, academic studies cited in CARB's *AB 32 Plan Update* show that large-scale electrification of the state's transportation and building sectors, supported by renewable generation penetrations much greater than 50%, will be required to meet California's long-term GHG goals.

As a result, it is clear that, but for DG providing an alternative source of renewable generation, the Commission or the Legislature would need to authorize the utilities to procure a higher amount of utility-scale renewable generation to maintain the overall penetration of renewable generation on the IOU systems. In other words, "but for" the DG program, the state would need more RPS power in order to prevent a loss in the state's overall penetration of renewable resources. We are not arguing here that renewable electricity will be the only emissions reduction option available, but rather noting that analysis shows that without an electric grid run mostly on renewable energy, California is unlikely to achieve its aggressive GHG goals. This long-term perspective recognizes the complementary nature of the DG and RPS programs. From this perspective, DG should not be valued assuming that it avoids 67% short-term fossil generation and 33% RPS utility-scale renewables; instead, DG should be valued on the basis of replacing 100% of the additional utility-scale renewables that would have to be procured to meet the state's long-term clean energy and GHG goals in the absence of DG.

The Solar Parties present a simple example in **Figures 4** to **8** and **Table 2** below to illustrate this point. Again, the key question is "what would the utilities procure in the absence of (i.e. "but for") renewable DG?" The answer to this question has changed with the passage of AB 327 in combination with the state's aggressive GHG goals. The example assumes that the total demand for power is 10 units, of which 9 units (90%) are served by utility sales and 1 unit (10%) by customer-sited renewable DG. See **Figure 4**.

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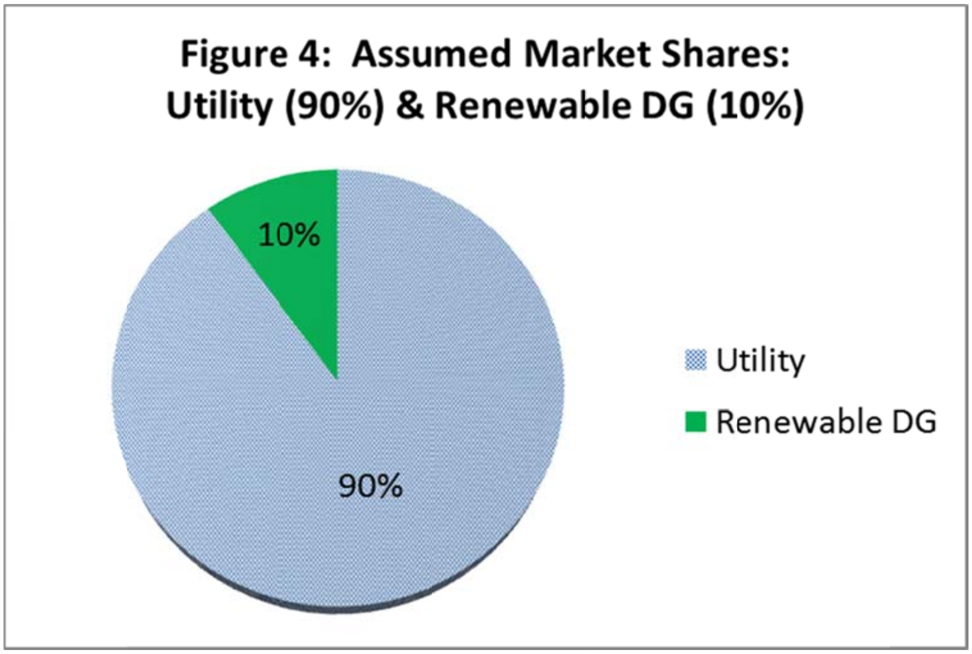
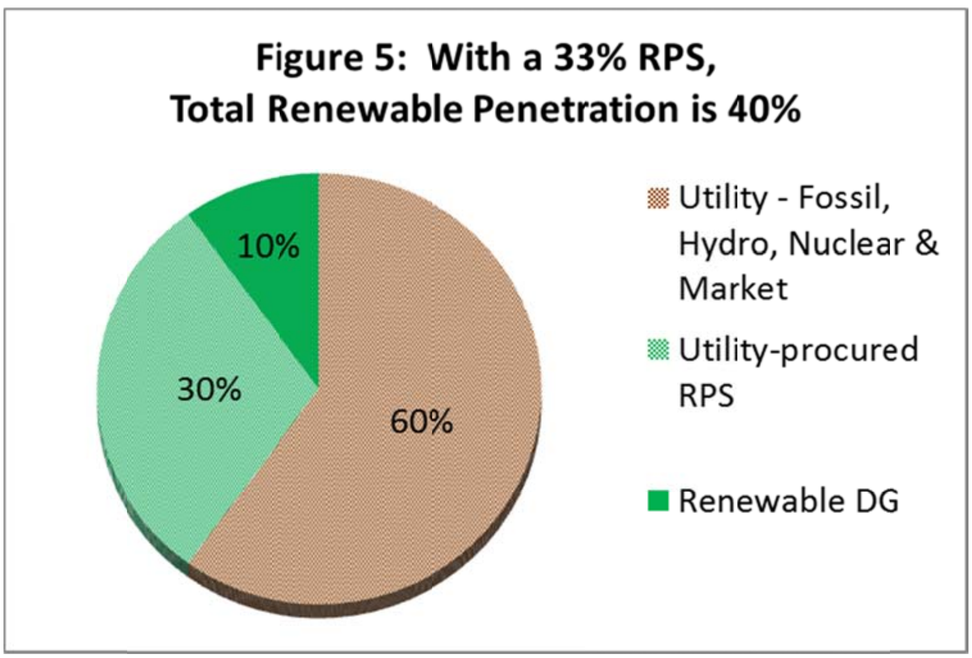
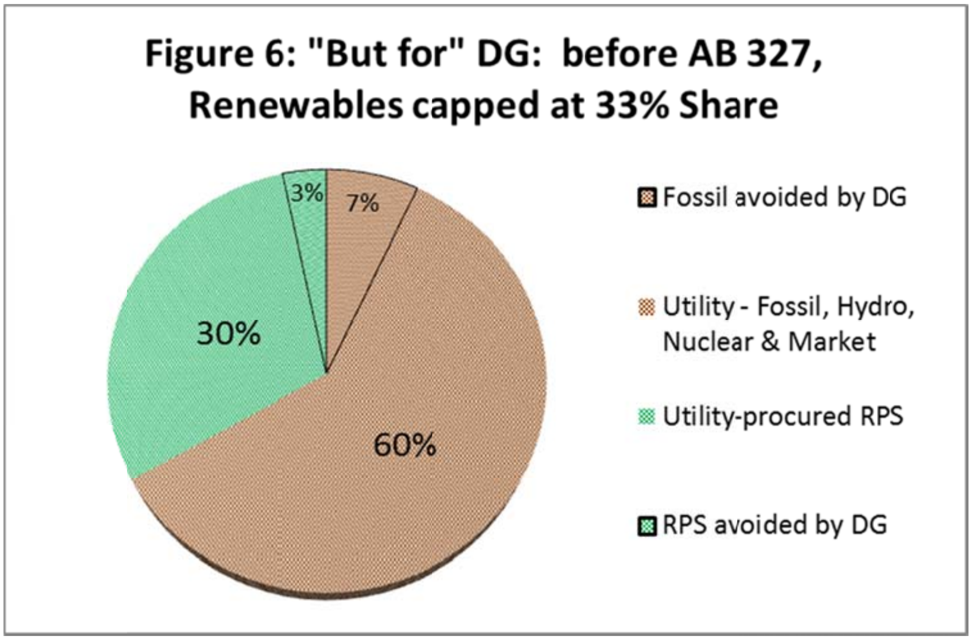
[30] See http://gov.ca.gov/news.php?id=18938.



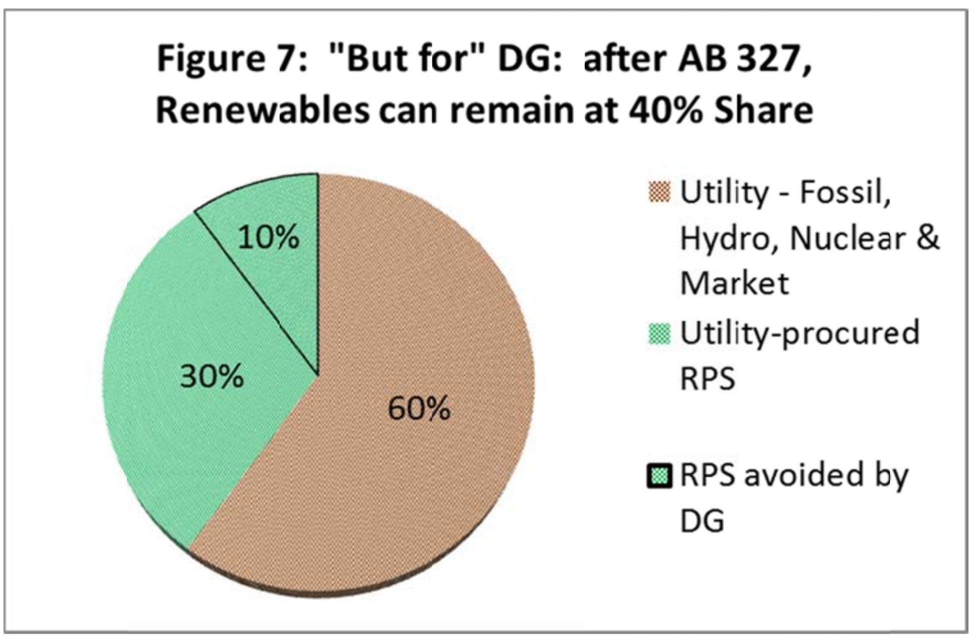
With a 33% RPS, the utility procures 3 units of wholesale renewable power to serve its 9 units of total demand. Adding the 3 units of RPS power to the 1 unit of renewable DG, the total penetration of renewable generation overall is 40%, as shown in **Figure 5**.



Before the passage of AB 327, if there were no DG, the utility's sales would rise from 9 to 10 units, and its RPS requirement would have been capped at no more than 3.33 units (33%), an increase of just 0.33 units compared to the "with DG" scenario. In other words, 1 unit of DG could not avoid more than 0.33 units (3%) of RPS power, with the remainder of the DG output (7%) avoiding utility-procured "brown" power, as shown in **Figure 6**.



However, AB 327 has now removed that cap, so that, if there were no DG, the Commission can authorize the procurement of additional RPS generation above the minimum 33% requirement to replace the lost DG such that the state's penetration of renewable generation remains at 40% and does not drop in the "without DG" scenario. This is shown in the next **Figure 7**.



In the post-AB 327 world in which California needs to steadily increase its penetration of renewables without backsliding in order to meet its GHG emission reduction goals, 1 unit of DG will avoid 1 unit of RPS generation. In other words, in the absence of DG, the most reasonable assumption is that the state would not allow the overall penetration of renewables to fall, but would replace the lost DG with utility-scale renewables on a one-for-one basis, as shown in **Figure 8**. Thus, AB 327's change in law enables DG to avoid 100% RPS generation, and this is what the Solar Parties have assumed in our Base Case.

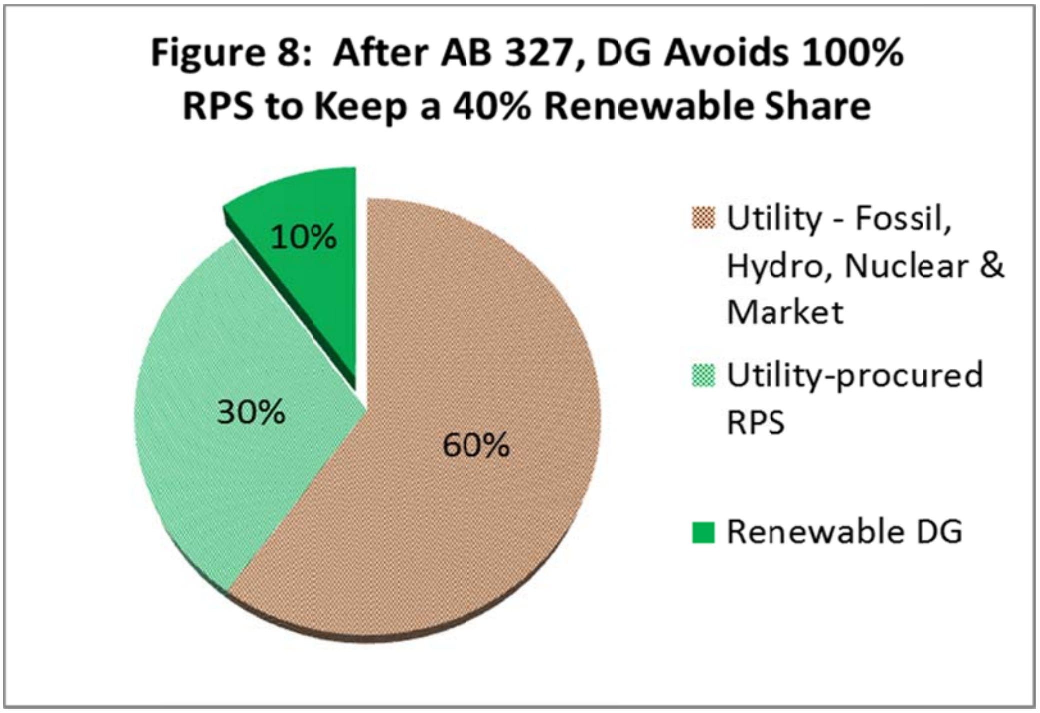


Table 2 presents the same example in tabular form.

Table 2: *RPS Avoided by DG, both Pre-AB 327 and Post-AB 327*

Quantity	Units / %	Reason
Assumptions		
Total gross load	10	
IOU-served retail load	9	
Load served by renewable DG	1	
IOU RPS procurement for 33% RPS	3	33% of 9
Total renewables	4	3 RPS + 1 DG
... as a share of total gross load	*40%*	*4 out of 10*
Pre-AB 327		
IOU-served load if no DG	10	
RPS procurement if no DG	3.33	Capped by 33% RPS
RPS procurement avoided by DG	0.33	3.33 less 3
... as a share of DG output	*33%*	*0.33 out of 1*
Post-AB 327		
IOU-served load if no DG	10	
RPS procurement if no DG	4	RPS is no longer capped, 40% penetration is maintained.
RPS procurement avoided by DG	1	4 less 3
... as a share of DG output	*100%*	*1 out of 1*

It could be argued that DG does not avoid a higher renewable penetration than the 33% RPS, because DG customers own the renewable energy credits (RECs) associated with their facilities, could sell those RECs to the utility for RPS compliance within the 33% RPS, and thus gain the same value that we are assigning to DG as part of the NEM transaction. This argument fails for a number of reasons, primarily having to do with, first, the limited ability to monetize these RECs in the compliance market and, second, the low value that behind the meter RECs command in that market. The key factors that drive this are described below:

- **High transaction costs** must be incurred to bring these RECs to market. Metering requirements and costs, WREGIS registration and transaction fees, and limitations on the ability to aggregate systems all function to impact adversely the ability to bring these RECs to market.
- **Current designation of RECs** from behind the meter facilities as a "portfolio content category 3" compliance instrument within the RPS compliance framework limits their value as a compliance instrument. Because of statutory limits on the use of these

instruments in meeting the utilities' RPS compliance goals, they have very limited value to load-serving entities that have RPS compliance obligations.

Because DG RECs have little to no financial value to DG customers under the current policy construct,[31] the associated benefits of DG as renewable generation are realized by all ratepayers, without any monetization of the value of those benefits for or by the DG customer. The Commission should recognize that, consistent with AB 327 and the state's GHG goals, the renewable value of DG should be assumed to be comparable to – at parity with – the value of RPS generation, for the purpose of calculating the benefits of DG for the NEM successor tariff in the Public Tool.

Because DG and RPS generation are complementary and substitutable long-term resources that are essential to meeting California's clean energy and GHG goals, they should be valued at parity in the Public Tool. But for DG, utility-scale generation would need to be increased to meet the state's long-term GHG goals, and vice versa. The Solar Parties' Base Case makes two modifications to the Public Tool to recognize DG/RPS parity. The Public Tool calculates an "RPS premium" in each year – the difference between the cost of RPS generation and the short-term market price of energy, capacity, and GHG allowances. As discussed above, DG should be assumed to avoid 100% of the RPS premium in each year, instead of the RPS target for that year (e.g. 33% in 2020) times the RPS premium. Second, the Public Tool assumes that even the discounted 33% RPS benefits of DG do not accrue until after forecasted banked RPS RECs have been used, including RECs from RPS projects that are contracted but not yet on-line. In some scenarios, this means that the value of DG as new renewable generation is not recognized in the Public Tool until several years after the DG comes on-line.[32]

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[31] While RECs are not easily monetized in California, RECs are an important instrument for managing and accounting for the renewable attributes of energy production. For example, many corporations manage their RECs as part of tracking their performance on corporate sustainability initiatives and verifying the additionality of those efforts over business-as-usual.
[32] For example, in the Energy Division's Public Tool runs, DG that comes on-line in 2017 does not avoid RPS costs until 2019.

It is consistent with the parity treatment of DG and RPS generation to assume that the renewable value of DG is realized in the year that DG output is produced, without sequencing the renewable value of DG output behind that of RPS resources. The Solar Parties' Base Case modifies the Public Tool to credit DG with its renewable value in the year it is produced. This is reasonable in the post-AB 327 world in which there is no longer a cap on the amount of RPS generation that DG can avoid on the electric systems of the IOUs. **Attachment A1** details the changes to the Public Tool that we have made to provide for DG/RPS parity, and we include a sensitivity case showing the results of a Public Tool run without this change.

Include Marginal Costs for CAISO Transmission. The Public Tool provides an input for the marginal costs of CAISO transmission. Behind-the-meter DG clearly provides appreciable output in peak periods, when the transmission system peaks, because DG serves both on-site loads (where the power never touches the grid) or is exported to the distribution system (where the power serves nearby distribution loads without using the transmission system). Impact evaluation reports for the CSI have shown that CSI systems reduce peak transmission system loadings on at least a one-for-one basis (in other words, each kW of DG output in the peak hour reduces transmission loadings by at least one kW). Thus, DG makes additional capacity available on the high-voltage transmission system and avoids transmission expansion costs.[33] A major policy reason for the state's <u>distributed</u> generation programs is to avoid the need for more bulk transmission lines.[34] Past IOU GRCs have calculated marginal costs for CAISO-controlled transmission,[35] as have other solar DG studies.[36]

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33 Itron, *2009 CSI Impact Evaluation Report*, at page ES-17. Also, Itron, "CPUC Self-Generation Incentive Program – Sixth Year Impact Evaluation Report" (August 30, 2007), at 5-29 to 5-33. These Itron reports are available on the CPUC website at http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm and http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm.

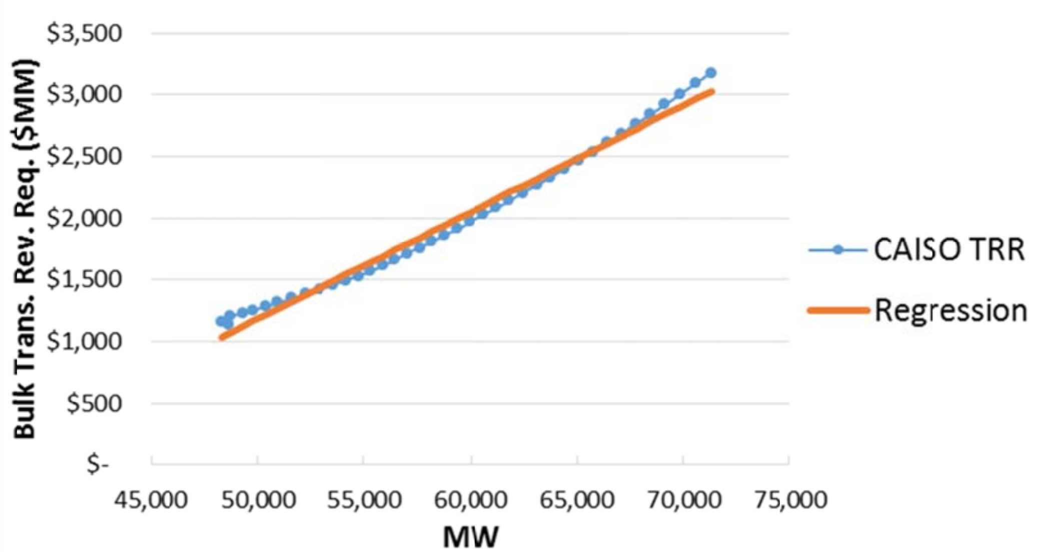
34 For example, the California Energy Commission's *2009 Integrated Energy Policy Report (IEPR)*, at pages 8 and 95) recognized the importance of DG as an alternative to investments in T&D infrastructure, stating "*[b]ecause the generation is located near the location where it is needed, distributed generation reduces the need to build new transmission and distribution infrastructure and also reduces losses at peak delivery times.*"

35 SCE's 2011 recent GRC (A. 11-06-007) shows a marginal cost for CAISO-controlled transmission of $59.18 per kW-year (2012 $). *See* A.11-06-007, SCE Workpapers, "MCCR" sheet, "Input Sheet" tab, cells D17-D19.

36 *See* the *San Diego Distributed Solar PV Impact Study* (Black & Veatch and Clean Power Research for the Energy Policy Initiative Center, University of San Diego School of Law, February 2014) at p. 38, Table 18, which calculated a marginal cost of CAISO transmission for SDG&E of $102.83 per kW-year,

Transmission costs at the CAISO level are FERC-regulated, but this jurisdictional difference does not mean that they should be ignored in this analysis, or that these costs do not vary as a function of the demand for electricity in the IOU territories. The Solar Parties have included marginal CAISO transmission costs in our Base Case, and we strongly recommend that the Commission find that DG sited behind the meter will avoid these costs. We have calculated marginal CAISO transmission costs based on a regression of the CAISO base transmission revenue requirement (TRR) used in the Public Tool over the 2012-2050 period, as a function of CAISO coincident peak (CP) demand over the same period, as shown in **Figure 9**. The TRR data used in this regression excludes the costs in the Public Tool for "policy-driven" CAISO transmission expansions designed to access RPS renewable resources. The marginal CAISO transmission costs that we have used are $87 per kW-year (2015 $).

Figure 9: CAISO TRR vs. CAISO Peak Demand



Consistency in the Use of Marginal Costs. Electric rates in California are based on marginal costs. Marginal costs for generation, transmission, and distribution are developed in each IOU's General Rate Case (GRC) Phase 2, with the exception of marginal costs for the FERC-regulated high voltage transmission system that the CAISO operates. Marginal costs

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escalating at 3% per year, based on the costs for the Southwest Powerlink. This study is available at http://freepdfs.net/san-diego-distributed-solar-photovoltaics-impact/f746dc30f50349f3ec87d4fd13e20cfc/.

measure how the utility's costs vary with changes in demand for energy or capacity on the utility system. Changes in the demand for power can be the result in variations in the customer's end use of electricity, from the customer's installation of energy efficiency measures, or from the customer's installation of behind-the-meter DG. A one kilowatt (kW) or kilowatt-hour (kWh) change in demand from any of these sources should produce the same change in the utility's costs, as measured by its marginal costs. However, the marginal costs used in the Public Tool to calculate the benefits of DG when DG reduces the demand for energy or capacity are not always the same as the marginal costs used to develop rates.. This inconsistency is particularly apparent for SCE and SDG&E, and has not been justified in the documentation for the Public Tool. We believe that the marginal costs used to develop rates in the Revenue Requirement section of the Public Tool should be the same as the marginal costs used to calculate the avoided costs for these utilities, and we have modified the subtransmission and distribution avoided costs for SCE and SDG&E to provide this basic consistency. No such modification was needed for PG&E.[37]

We note that this consistency between the marginal costs used to set rates and those used to measure DG benefits is, if anything, a conservative assumption. Today marginal costs are largely developed on a system-wide basis, or are aggregated to a system basis before rates are developed.[38] This assumes that marginal and avoided costs are the same everywhere on a utility's system, and that DG cannot be targeted to those portions of the utility distribution system where DG has a greater-than-average value. However, California now is devoting significant effort to understanding the impacts of increasing penetrations of DG on utility transmission and distribution systems, work that is continuing in the Distribution Resource Plans (DRP) proceeding (R. 14-08-013). In that docket, on July 1, 2015 the utilities filed distribution resource plans as required by Public Utilities Code Section 769 of AB 327. A central element of the DRPs will be a unified locational net benefits methodology, which will provide a means to assess the locational net benefits of DG. The Solar Parties expect this work to provide the basis

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[37] We modified these avoided costs on the "Avoided Cost Calcs" tab of the Public Too l (in Cells E328-E329 and Cells E339-E350) in order to use the exact marginal costs for SCE and SDG&E. Cells C18 and C19 on the Key Driver Inputs tab allows these marginal / avoided costs to be scaled, but these inputs scale the marginal costs for all three IOUs equally. In this case, only the marginal costs for SCE and SDG&E needed to be changed.

[38] For example, PG&E develops marginal distribution costs by distribution planning area, but aggregates these costs to a system-wide value for the purpose of calculating system-wide rates.

for understanding how DG can be developed to provide benefits to the utility distribution system that are greater than the system-average marginal costs.

Locational Energy Value. One of the benefits of DG is that it allows the utility to avoid energy costs. The Public Tool calculates these avoided energy costs based on a simplified model of the market-clearing price for energy at the trade hubs of the CAISO system. This does not capture the more specific locational value of energy in the CAISO's locational marginal pricing (LMP) market. Energy prices vary across the CAISO grid by location as a function of congestion costs and line losses, and these variations are captured in the LMP prices at 3,000 nodes across the CAISO grid. LMP prices tend to be higher in the state's load centers, principally due to congestion and losses incurred in moving power into these areas. Clearly, DG systems also are located principally in the load centers. As a result, the average LMP price that DG avoids will be higher than the CAISO average market-clearing price, which is what the Public Tool simulates. Accordingly, the Public Tool allows the user to adjust the avoided energy cost benefit of DG by a locational multiplier. The Public Tool captures the variation of marginal line losses by TOU period and by the customer's voltage level, but does not model the impact of congestion costs on LMP prices. To estimate the locational value of DG at avoiding congestion costs, we have examined the difference over the last two years between the congestion costs in (1) CAISO trade hub prices (NP-15 and SP-15) and (2) the default load aggregation point (DLAP) prices for the three IOUs. This difference provides a high-level estimate of the congestion costs avoided by DG sited downstream of the CAISO grid, on the IOUs' distribution systems. For PG&E and SCE, these avoided congestion costs averaged about 1.1% of NP-15 and SP-15 prices across all hours. Congestion costs in SDG&E DLAP prices were much higher as a percentage of the SP-15 price, averaging 10% over this period. Weighting these results by the amount of DG expected on each IOU's system, we have estimated a locational premium of 2% due to avoided congestion costs.[39] This adjustment is conservative in that it is based on congestion costs across all hours.[40]

[39] The Public Tool includes only a single locational factor that applies across all three IOUs.
[40] Based on the sample of CAISO congestion costs that we examined, a solar-weighted average of congestion costs between the trade hub and DLAP points would be significantly higher, especially in San Diego.

Market Price Mitigation. The Solar Parties also have considered that behind-the-meter DG will have the added benefit of reducing CAISO market prices broadly, in the sensitivity case in which DG is assumed to avoid market priced gas-fired generation in the CAISO market (the No DG/RPS Parity sensitivity case). This "market price mitigation" benefit does not occur if DG is assumed to offset 100% RPS renewable generation (as in the Solar Parties' Base Case), because RPS renewables would have the same effect on market prices as does DG.

Here is how the market price mitigation benefit is produced: if DG avoids marginal gas-fired generation, it reduces the market demand for both the marginal megawatt-hour (MWh) of power and the marginal MMBtus of natural gas used to produce that MWh. This reduction in demand has the broad benefit of lowering prices across the electric and gas markets in which the California IOUs operate.[41] The resulting lower prices reduce costs for ratepayers across all of the "net short" volumes that the utilities buy from these markets. In the New England ISO market, a market with transparent, hourly locational marginal prices (LMPs) for energy like the CAISO, this market price mitigation benefit, also called the demand reduction induced price effect (DRIPE), is included as a standard component of the avoided costs of demand-side programs and has been estimated at as much as 35-36% of summer peak energy prices.[42]

This benefit can be modeled using the Public Tool, which includes a supply stack of resources that is used to calculate CAISO market-clearing prices. By comparing the electric market prices from our Public Tool run in the No Parity sensitivity case to those from another run with a lower level of DG adoption, the effect of DG on lowering CAISO market prices can

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41 In A. 12-03-026, PG&E and the Coalition of California Utility Employees (CCUE) argued that a new gas-fired combined-cycle plant with a low heat rate, the Oakley Project, would produce such market price reduction benefits, because Oakley's low-cost bids into the market would reduce CAISO market clearing prices generally. The Commission accepted this argument in its order approving PG&E's purchase of this project. See D. 12-12-035, at p. 28. As another example, a Lawrence Berkeley National Lab study has estimated that the consumer gas bill savings associated with increased amounts of renewable energy and energy efficiency, expressed in terms of $ per MWh of renewable energy, range from $7.50 to $20 per MWh. Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (January 2005), at ix, http://eetd.lbl.gov/sites/all/files/publications/report-lbnl-56756.pdf.

42 Synapse Energy Economics, "Avoided Energy Supply Costs in New England: 2013 Report" (July 12, 2013), at page 1-6, Exhibit 1-2. Available at http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-07.AESC_.AESC-2013.13-029-Report.pdf.

be readily estimated. As discussed below, this added benefit amounts to about 0.5 cents per kWh, or 6% of the avoided energy costs from DG. The Solar Parties have included this benefit in the TRC, Societal, and RIM Test results for the No Parity sensitivity case.

Societal Benefits. The Commission should include findings in its order in this case on the quantifiable societal benefits of net metered DG. The Solar Parties have reviewed and support the summary and quantification of societal benefits in the attachment to the proposal of the Sierra Club. Societal benefits impact our Public Tool modeling in two ways. First, the Solar Parties' Base Case assumes that DG avoids 100% renewable generation under the RPS, based on the parity treatment of DG and RPS resources discussed above. As a result, there is only a limited set of societal benefits that result from DG that cannot also be attributed to the higher amount of utility-scale renewable generation that the IOUs would procure in the absence of DG. These DG-specific societal benefits include:

- **Enhanced reliability and resiliency.** A grid with a large number of relatively small, distributed resources is inherently more reliable than a centralized grid that relies on a few large resources. In addition, DG enables the development of on-site backup (if DG is paired with storage) or can serve as the foundation for a local micro-grid that enhances reliability and resiliency.
- **Land use benefits.** DG is assumed to be able to use the built environment, avoiding the land use impacts of central station renewable projects.
- **Local economic benefits.** The capital and operating costs of DG are higher than those associated with central station renewables. However, a portion of those added costs – primarily for installation labor, marketing, and permitting – is spent in the local area and thus provides additional benefits for the local economy.

The second type of societal benefits is those that result from renewable generation of all sizes (i.e. from both DG and RPS resources). These are the societal benefits that result if DG is assumed to displace gas-fired resources. We do <u>not</u> include these benefits in the Solar Parties' Base Case where DG is assumed to displace 100% RPS renewables. However, these additional societal benefits are included in the Solar Parties' sensitivity case where DG/RPS parity is not assumed and where DG avoids two-thirds marginal generation, mostly gas-fired. They include:

- **Added benefits from reduced carbon emissions.** Renewable resources avoid the short-term costs associated with complying with California's cap & trade program to limit GHG emissions. However, there are additional, longer-term benefits associated with avoiding the adverse impacts of climate change. These long-term carbon reduction benefits have been quantified most prominently in the federal government's social cost of carbon.
- **Health benefits from reduced PM 2.5 and NOx emissions.** Combustion of natural gas for electric generation is a source of particulate (PM 2.5) and oxides of nitrogen (NOx) emissions. The U.S. Environmental Protection Agency has quantified the health benefits of reducing the emissions of such criteria pollutants in California, as part of its Clean Power Plan.
- **Water use.** Thermal generation using fossil fuels consumes water for cooling. Although California is moving away from once-through-cooling using sea water, with its attendant impacts on marine environments, fresh water resources are used for cooling at gas-fired power plants. This water use can be avoided if DG displaces this thermal generation. Although the PT includes an avoided cost for water based on current water supply costs, we calculate an additional societal benefit based on the higher costs of avoiding the future need to develop new water supplies given that the state's existing water resources are fully developed.

The Sierra Club/Crossborder Energy white paper has quantified all of these benefits, for inclusion in the Public Tool. They are summarized in the following table, which presents them in the form in which they are input to the Public Tool.

Table 3: *Societal Benefits used by Solar Parties*

Benefit	Value		Input cell	Included in Case?	
				Base Case (DG/RPS Parity)	Sensitivity Case (No Parity)
Reliability/resiliency	$0.022 / kWh DG output		C39	Yes	Yes
Land use	$0.002 / kWh DG output		C39	Yes	Yes
Local economic	Average	$0.030 / kWh DG			
	Residential	$0.035 / kWh DG	C40	Yes	Yes
	Sm. Com'l.	$0.012 / kWh DG	C40	Yes	Yes
	Lg. Com'l.	$0.006 / kWh DG	C40	Yes	Yes
Social cost of carbon	$30 / tonne		C33	No	Yes
Health: PM 2.5	$184 / lb		C34	No	Yes
Health: NOx	$24 / lb		C35	No	Yes
Water	$0.0007 / kWh thermal gen		C37	No	Yes

In D. 09-08-026, the Commission approved the use of both the TRC and Societal Tests for evaluating the cost-effectiveness of DG programs, finding that "each provide a useful perspective in assessing the costs and benefits of DG projects and programs."[43] The Commission should place significant weight on the quantifiable societal benefits of DG resources, as analyzed in the Societal Test. In particular, the Solar Parties emphasize that, if the Commission does not value DG at parity with RPS resources, and instead assumes that DG displaces gas-fired resources, then the Commission should recognize the additional societal benefits of this displacement and should include in the Public Tool all of the societal benefits listed in Table 3. Together, these societal benefits add 10.9 cents per kWh to the levelized benefits of DG development from 2017-2025. In the High Case for carbon benefits listed by the Sierra Club, the societal benefits increase to 13.3 cents per kWh on a levelized basis.[44]

b. Base Case Results

The Solar Parties' proposal for the NEM successor tariff is that credits for exported power will continue to be based on the DG customer's retail rate. The results of the Public Tool modeling of this proposal, using the Solar Parties' Base Case, are presented in **Table 4**. The table shows the modeling results for all customers, both residential and commercial / industrial

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[43] D. 09-08-026, at p. 29.

[44] Includes all of the societal benefits discussed in this section, as modeled in SEIA's No Parity sensitivity run with residential TOU rates with a 4 p.m. to 8 p.m. summer on-peak period.

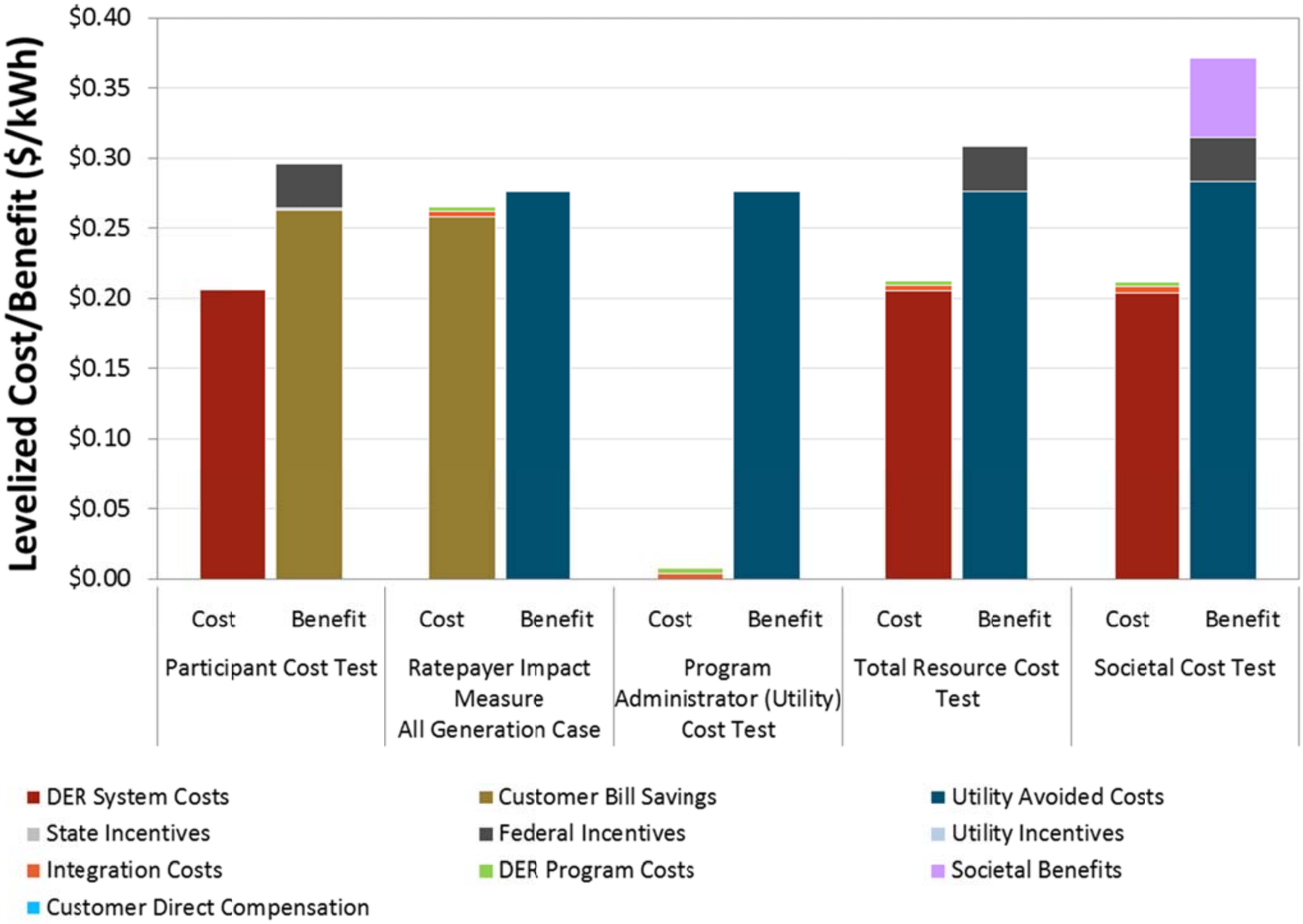
(C&I). As requested in the July 20 Ruling, the modeling of NEM in the residential market uses the increasing block rates and two TOU rate designs that are based on the new residential rate design policies which the Commission recently adopted in D. 15-07-001. The results are presented using each of the metrics for the statutory criteria for the NEM successor tariff that are set forth in Section 2827.1, as discussed in Section I.A of this proposal. The results in Table 4 are based on analyses of all of the generation from NEM facilities. The Public Tool also presents the results for the revenue requirement and non-participant impacts only for the NEM generation exported to the grid, in recognition that the majority of NEM output is immediately consumed on-site without requiring the use of the utility system. From this perspective, NEM only impacts other ratepayers through the crediting mechanism for exported power.

Table 4: *NEM Successor Tariff Results for the Solar Parties' Base Case*

Metric	**Rate Design**		
	2-tier IB	TOU-1 2-8 p.m.	TOU-2 4-8 p.m.
1. §2827.1(b)(4) – *Total Costs and Benefits for All Ratepayers*			
TRC Test	1.46	1.45	1.45
Societal Test	1.76	1.75	1.76
TRC Net Benefits ($ millions/year)	$901	$920	$896
Societal Net Benefits ($ millions/year)	$1,680	$1,725	$1,675
2. §2827.1(b)(3) – *Costs and Benefits of DG Facilities for DG Customers*			
Participant Cost Test	1.44	1.50	1.44
Implied Payback (years)	6.8	6.5	6.8
3. §2827.1(b)(1) – *"Sustainable growth"*			
2017-2025 Adoption (GW)	8.0	8.3	8.0
2018-2020 Average Year-over-Year Growth (MW/yr)	106		107
4. Rate Impacts, including on non-participants			
Annual Rev. Req. Change (%)	-0.34%	+0.01%	-0.30%
RIM Test *(new systems only, 2017-2025)*	1.05	1.00	1.04
RIM Net Benefit (*new only*, $ millions/year)	+115	+5	+104
RIM Net Benefit (*new only*, $millions/GW/year)	+14	+1	+13
RIM Test *(all systems, including grandfathered)*	1.14	1.09	1.14
RIM Net Benefit (*all systems*, $ millions/year)	+508	+337	+501

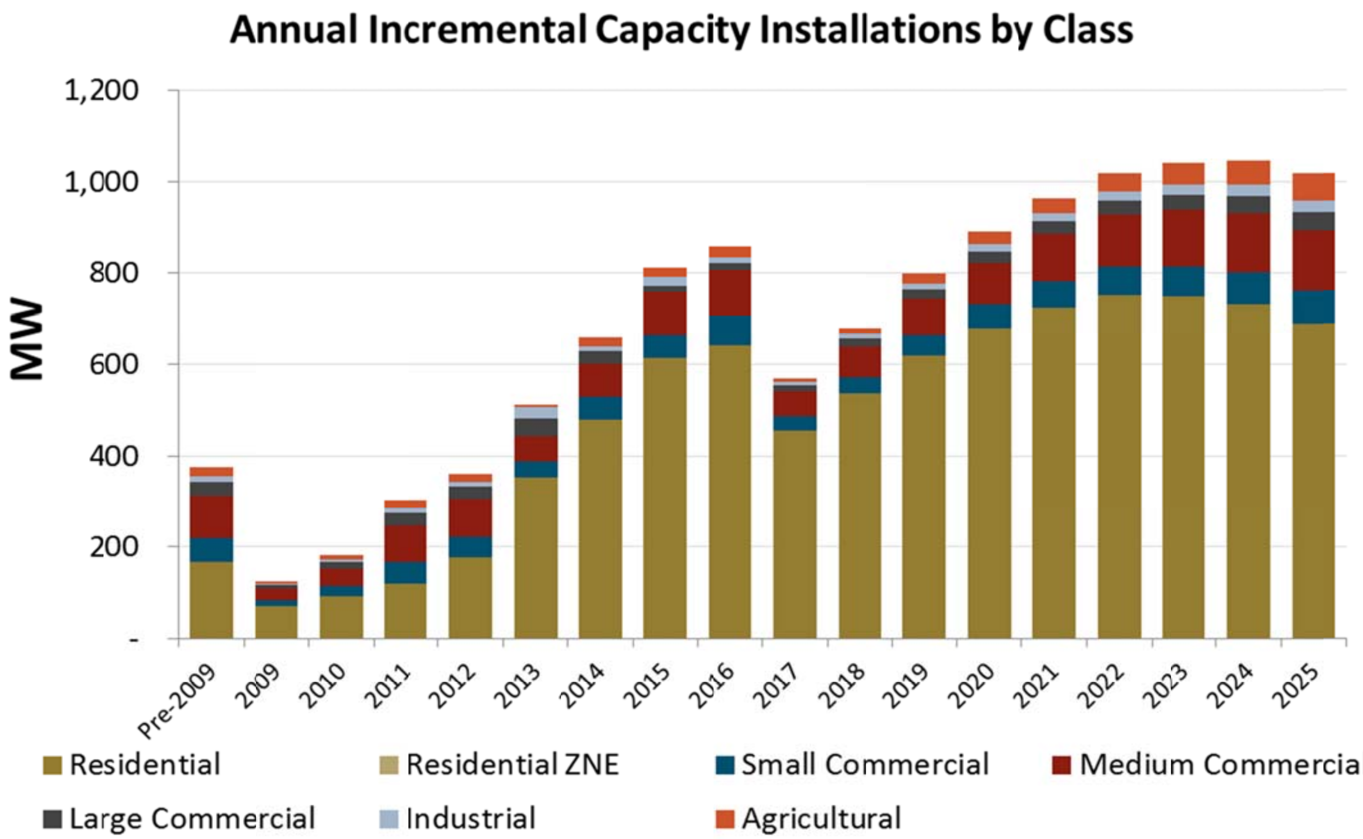
Figure 10 below shows graphically the results of the *SPM* tests for the TOU-2 rate design.

Figure 10: *SPM Results for TOU Rates in Solar Parties' Base Case (TOU-2 Rates)*



Discussion of Results. The Public Tool results of the Solar Parties' Base Case show that our NEM successor tariff proposal – retention of retail NEM – fully satisfies the statutory criteria adopted in AB 327. First, the successor tariff passes the TRC and Societal tests by a significant margin, showing that "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs," as required in Section 2827.1(b)(4). Second, continuing NEM with the same basic structure would be a reasonable investment for DG customers "based on the costs and benefits of the renewable electrical generation facility" [Section 2827.1(b)(3)], as shown by the favorable Participant Cost Test results and an implied payback of between 6 and 7 years. The Joint Solar Parties are concerned with the relatively low amount of DG adoption over the 2017-2025 period (8.0 to 8.3 GW) and with the fact that the year-over-year growth in DG adoptions from 2017-2020 (just over 100 MW/year) is somewhat below recent year-over-year growth rates (143 MW in 2013 over 2012, and 164 MW in 2014 over 2013). We submit that these levels of adoption are at the low end of what the Commission should view as acceptable for "sustainable growth." The following figure shows year-by-year adoptions, by type of customer, in the SEIA Base Case with TOU-2 rates.

Figure 11: *DG Adoption Results in Solar Parties' Base Case*



Finally, the metrics for the impacts on non-participating ratepayers show that residential rate design reform, combined with the changes to the Public Tool that the Solar Parties have made, will have a substantial positive impact to substantially reduce or even eliminate the impacts of NEM on non-participating ratepayers. The RIM test results for the Solar Parties' Base Case are close to or above 1.0 for successor tariff systems installed in 2017-2025, and exceed 1.0 for all systems (i.e. including the grandfathered systems installed before 2017). To put the non-participant results in Table 4 in perspective, **Table 5** provides comparable metrics for non-participant impacts from both the Commission's 2013 NEM Study and the Staff Tariff Paper's Existing Policy Case, both of which are based on the present four-tiered increasing block rate design. The impacts from the 2013 NEM Study are calculated at the 5% NEM cap in 2020;

the Existing Policy Case impacts are for DG adoption over the Public Tool's 2017-2025 forecast period.

Table 5: *Comparison to 2013 NEM Study and Staff Tariff Paper Existing Policy Cases*

Metrics	2013 NEM Study[45] Results	Staff Paper High DG Case	SEIA Base Case NEM 2.0
Annual RevReq (%)	+3.13%	+6.29%	-0.30%
RIM Annual Net Benefit or [Cost] *($ millions)*	-1,093	-2,225	+104
Annual Net Benefit (Cost) *($millions/GW)*	-208	-192	+13
Levelized RIM ($/kWh)	-0.15	-0.17	+0.01

The comparison presented in Table 5 shows that the upcoming changes in residential rates will significantly reduce, and, in combination with policies such as DG/RPS parity, substantially eliminate the adverse impacts of NEM on non-participants. A similar improvement can be seen compared to the NEM impacts calculated in the 2013 NEM Study.

The *SPM* Tests in Perspective. The Commission should evaluate the *SPM* tests as applied to the NEM successor tariff in the same way that it evaluates these tests as applied to other demand-side resources such as energy efficiency and demand response. All of these resources are preferred resources in the state's loading order, and should be evaluated in a comparable fashion. As the Solar Parties have noted above, prior NEM studies in California have focused on the costs and benefits of NEM for non-participating ratepayers, that is, on the RIM test results. However, in California, the RIM Test is not used as the primary test to assess other types of demand-side programs. In essence, California long ago made the policy decision that it would assess demand-side programs based on whether they reduce overall customer bills,

[45] See *California Net Energy Metering Ratepayer Impacts Evaluation* (E3, October 2013). Available at http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm. The annual revenue requirement impacts, in both % and dollars, are in Table 35. The revenue requirement impacts per GW at the 5% NEM cap assume 5.26 GW of DG at the 5% NEM cap. The levelized RIM impacts are from Table 37. Negative values for the annual net cost and levelized RIM mean a net cost for non-participating ratepayers.

not electric rates. The result has been California's signal accomplishment of keeping per capita electric use constant for the last thirty years.

The state's energy efficiency (EE) and demand response (DR) programs generally pass the TRC test, but fail the RIM test, resulting in impacts on non-participating ratepayers that far exceed the small (or favorable) impacts of the NEM successor tariff, without raising significant concern from policymakers.[46] The Commission's most recent decision approving the IOUs' EE portfolios relied on the TRC Test to determine cost-effectiveness and required a TRC score of 1.0 for approval.[47] For demand response, the Commission has defined cost-effectiveness as a DR portfolio scoring at 0.90 or above on the TRC Test.[48] The additional 10% leeway for TRC results for DR is to recognize "a certain error band in our analysis due to the first-time nature of applying the protocols onto our programs."[49] To the extent RIM results are considered in evaluating DR programs, it is "when the context makes sense," for example, for programs where the TRC results indicate marginal cost-effectiveness.[50] As another example, RPS resources are not necessarily required to be less expensive than other generation options; for example, RPS costs in the first stage of that program significantly exceeded the Market Price Referent benchmark of the long-term costs of fossil generation.[51] The Commission should consider such comparisons and precedents in evaluating the results of the *SPM* tests as applied to the successor tariff/contract, and should afford net-metered renewable DG the same consideration in evaluating

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[46] The Solar Parties note that the lost utility sales from energy efficiency programs in 2016 are expected to be about seven times the amount of kWh produced by DG at the 5% NEM cap, based on the committed EE savings from the California Energy Commission's 2014-2024 Baseline Revised Demand Forecast - Mid Demand Case. In addition, the approved electric energy efficiency program costs for the three IOUs in 2015 are about $820 million per year. See D. 14-10-046, at Figure 6, pp. 104-105. We calculate that these EE programs will raise rates by about $3 billion per year, assuming that these programs reduce revenues at the average retail rate, adding the EE program costs, and subtracting avoided costs at $0.14 per kWh for a baseload profile. Similarly, D. 12-04-045, at pp. 32-33, shows that the RIM scores for the IOUs' DR portfolios range from 0.57 (SDG&E) to 0.98 (SCE).

[47] See D. 14-10-046, at p. 109. Significantly, the TRC Test is applied to the IOUs' EE activities on a portfolio basis, so some EE programs have TRC scores below 1.0 while others exceed this benchmark.

[48] D. 12-04-045, at p. 44.

[49] *Ibid.*

[50] *Ibid.*, at p. 43.

[51] See the general description of the initial cost containment provisions of the RPS program in Resolution E-4442 (December 1, 2011), at pp. 2-4. SB 2(1x), adopted in 2011, included new cost containment provisions for the RPS program, which the Commission has yet to implement.

cost-effectiveness that is given to California's other high-priority demand-side and renewable generation programs.

C&I Results. The Public Tool enables parties to analyze results by market segment and customer class. As noted above, the recent changes in residential rate design have significantly reduced the impacts of residential NEM on non-participating ratepayers. The C&I rates used by solar customers also have changed in recent years, as the Commission has approved rate designs for solar customers that feature reduced demand charges and greater reliance on TOU volumetric rates. These include SDG&E's Schedule DG-R and Option R rates for SCE's medium and large C&I customers (Schedules GS-2, TOU-GS-3, and TOU-8) and for PG&E's large C&I customers (Schedules E-19 and E-20). These "solar friendly" rate designs are popular with C&I customers who install solar. The utilities have expressed concerns, in recent GRC Phase 2 proceedings, that these C&I rate designs will add to the rate impacts of NEM on non-participating customers.[52]

To test this concern, the Solar Parties ran our Base Case with two sets of future rate designs for C&I customers. The first case assumes that <u>all</u> future C&I solar customers who are in customer classes that have these "solar friendly" rates actually elect them. In this case, our Public Tool run selects the DG-R or Option R rate as the "DER Rate" in all classes for which such a rate is available today. This is very conservative, as all C&I customers who install solar do not necessarily elect, or even qualify for, these optional rates.[53] **Table 6** below shows the C&I rates modeled in the Option R case. The second case we modeled assumes that C&I customers elect the standard, default rate in each class, rather than any special solar rate. These two cases thus span the full range of possible outcomes for C&I customers who install DG.

52 For example, see D. 14-12-080, at pp. 18-20; D. 15-06-037, at pp. 12-13 and 15-18.

53 For example, PG&E's Option R rates require a customer to install a solar system large enough to serve at least 15% of their on-site usage.

Table 6: *Non-residential Rate Schedules Modeled in the Option R Case*

Customer Class	PG&E		SCE		SDG&E	
	Non-DER	DER	Non-DER	DER	Non-DER	DER
Small Commercial	A-1	A-1	TOU-GS-1	TOU-GS-1	TOU-A	TOU-A
Medium Commercial	A-10	A-10	TOU-GS-3 – Option B	TOU-GS-3 – Option R	AL-TOU	DG-R
Large Commercial	E-19	E-19 Option R	TOU-8 Sec – Option B	TOU-8 Sec – Option R	AL-TOU	DG-R
Industrial	E-20	E-20 Option R	TOU-8 Pri – Option B	TOU-8 Pri – Option R	A-6	DG-R
Agricultural	AG-4B-E	AG-4B-E	TOU-PA-2 – Option B	TOU-PA-2 – Option B	TOU-PA	TOU-PA

The results for the C&I classes modeled in these two cases are presented in **Table 7** below. Even assuming that all future C&I solar customers elect Option R rates, the RIM Test result for the C&I class in this case is a benefit/cost ratio of 1.0. The results for these two cases, with RIM results at or above 1.0 in both instances, clearly underscore and bolster the findings of the Commission's Option R decisions, namely that net metering for C&I solar customers under the current Option R rate designs are fair from the perspective of impacts on other ratepayers.

Table 7: *Results for the Solar Parties' Base Case – C&I Classes*

Metric	C&I Results	
	Option R Case	Default Case
1. §2827.1(b)(4) – *Total Costs and Benefits for All Ratepayers*		
TRC Test	1.58	1.42
Societal Test	1.92	1.72
2. §2827.1(b)(3) – *Costs and Benefits of DG for DG Customers*		
Participant Cost Test	1.66	1.53
Implied Payback (years)	5.9	6.4
3. § 2827.1(b)(1) – *"Sustainable growth"*		
2017-2025 Adoption (GW)	2.1	1.7
4. Rate Impacts, including on non-participants		
Annual Rev. Req. Change (%)	+0.01%	-0.04%
RIM Test *(new systems only, 2017-2025)*	1.00	1.02
RIM Net Benefit (*new systems*, $ millions/year)	-2	+8
RIM Test *(all systems, including grandfathered)*	1.21	1.26
RIM Net Benefit (*all systems*, $ millions/year)	+214	+226

c. Sensitivity Results

The Solar Parties have modeled a number of sensitivity cases that illustrate how our Base Case results change with modifications to key conceptual or input assumptions. These include (1) not assuming DG/RPS parity but including market mitigation benefits and a higher level of societal benefits if DG displaces gas-fired generation, (2) a 50% RPS goal plus other new clean energy initiatives, and (3) certain changes in NEM. Each of these sensitivities was modeled using the adopted TOU residential rate design with the later 4 p.m. to 8 p.m. on-peak period. **Table 8** presents the key results of these sensitivity cases; we discuss them in detail below.

Table 8: *NEM Successor Tariff Results for the Solar Parties' Sensitivity Cases*

Metric	No DG/RPS Parity	50% RPS Plus	Changes to NEM
1. §2827.1(b)(4) – Total Costs and Benefits for All Ratepayers			
TRC Test	1.11	1.46	1.43
Societal Test	1.66	1.76	1.73
2. §2827.1(b)(3) – Costs and Benefits of DG Facilities for DG Customers			
Participant Cost Test	1.44	1.58	1.38
Implied Payback (years)	6.8	6.2	7.1
3. § 2827.1(b)(1) – "Sustainable growth"			
2017-2025 Adoption (GW)	8.0	8.6	7.4
2018-2020 Average Year-over-Year Growth (MW/yr)	107	120	106
4. Rate Impacts, including on non-participants			
Annual Revenue Requirement (%)	+1.7%	+0.24%	-0.47%
RIM Test *(new systems only, 2017-2025)*	0.77	0.97	1.07
RIM Test w/Added Benefits *(new systems only, 2017-2025)*	0.98	n/a	n/a
Annual Net Benefit or (Cost) (*new systems only*, $ millions/year)	-17	-$81	+160
RIM Test *(all systems, including grandfathered)*	0.84	1.06	1.16
RIM Test w/Added Benefits *(all systems, including grandfathered)*	1.05	n/a	n/a
Annual Net Benefit (*all systems*, $ millions/year)	+$240	+$264	+$556

No DG/RPS Parity. This sensitivity returns to the Public Tool's original assumption that DG avoids a mix (in 2020) of about 67% fossil generation and 33% renewables. In this scenario, we include the additional societal benefits (social cost of carbon, health benefits, and water) that will be realized if DG displaces short-term fossil generation.

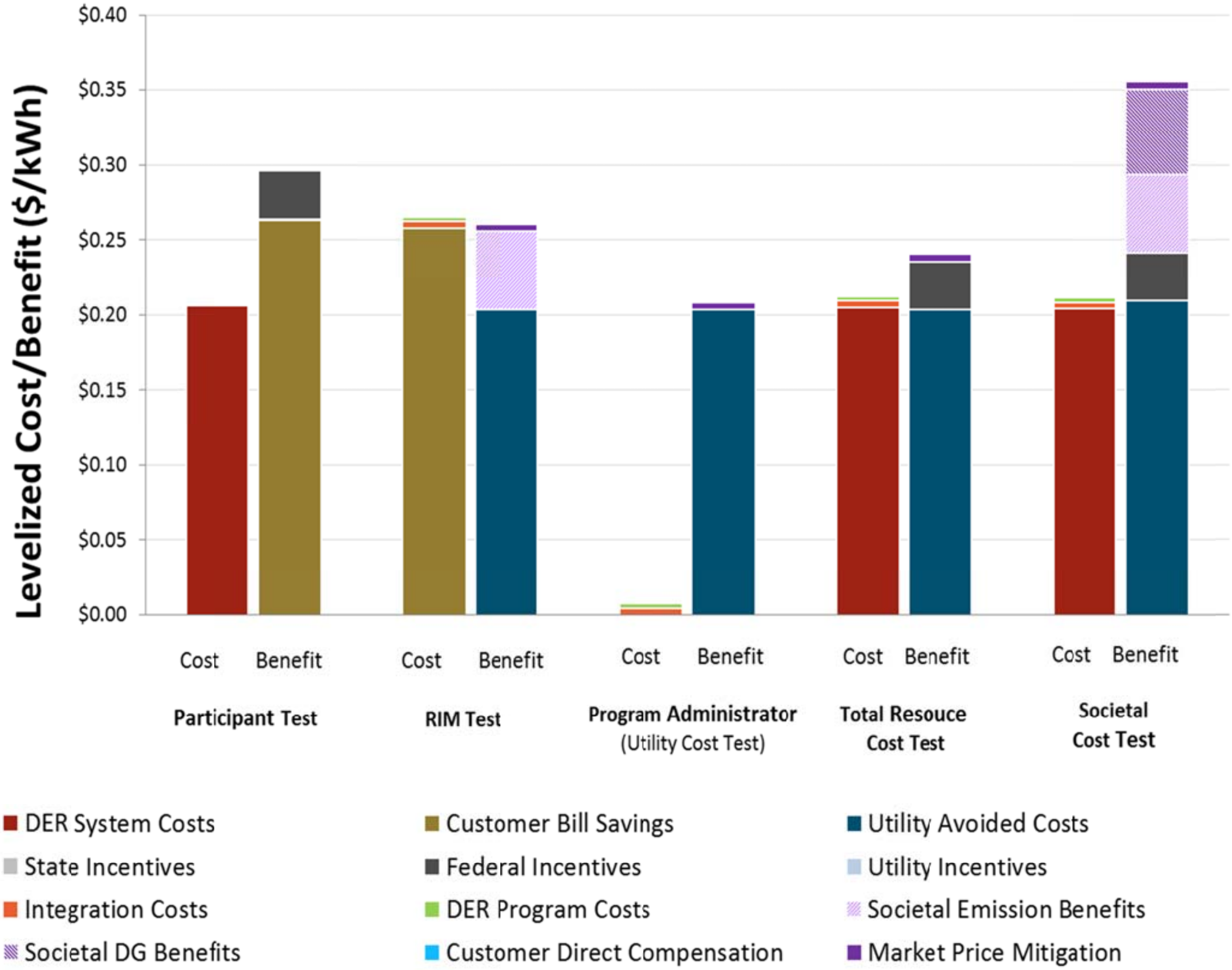
As discussed above, in this scenario the Solar Parties also have included the market price mitigation benefit. Behind-the-meter DG reduces the demand for electricity in the CAISO market, as well as for the natural gas used to produce the marginal kWh of power.[54] The result is lower market prices which benefit ratepayers across all of the "net short" volumes that the utilities buy from the market. We calculated this benefit by comparing the market prices in this sensitivity case to market prices in another run of the Public Tool with 2.4 GW less DG adoption over 2017-2025.[55] This added benefit amounts to about 0.5 cents per kWh, or 6% of the avoided energy costs from DG. The Solar Parties have included this benefit in the TRC, Societal, and RIM Test results for this sensitivity case.

The following figure shows the results for this sensitivity case.

[54] This market price mitigation benefit does not occur if DG is assumed to offset 100% RPS renewable generation, so this benefit is not included in the Solar Parties' Base Case.

[55] We produced this second case by reducing the assumed level of future rate escalation from 3% to 0%.

Figure 12: *Results of the Solar Parties' No DG/RPS Parity Sensitivity Case*



The most important result from the No DG/RPS Parity case is that the additional societal and market mitigation benefits in this case compensate for the reduced value of DG if it is assumed to avoid short-term fossil generation, instead of being valued at parity with utility-scale RPS generation. These additional benefits offset most of the difference between the costs and benefits in the RIM test, as shown in Figure 12, and the TRC and Societal test results remain positive. This result shows that California as a whole will benefit from the continued development of renewable generation, such that it is reasonable to assume that DG avoids 100% RPS generation. The Commission should not assume that the RPS target places a cap on the amount of renewable generation in California.

50% RPS. We also modeled a scenario with a 50% RPS goal for 2030. Increasing the state's utility-scale renewable generation goal raises significant issues with renewable curtailments in certain months of the year and hours of the day, as the penetration of wind and solar resources grows. These issues will arise as a result of both RPS and DG renewables; thus, the Commission should not regard the cost impacts of a 50% RPS in this scenario as due entirely to DG. We anticipate that the state will take steps to moderate the impacts of such curtailments, by expanding regional markets for clean generation from California and by developing new in-state markets that also contribute to the state's clean energy goals, such as increasing the charging of electric vehicles (EVs) during mid-day periods when renewable generation is abundant. Thus, our 50% RPS case includes expanded mid-day charging of EVs and assumes that excess renewable generation can be sold for a zero price in regional markets. The results from the 50% RPS sensitivity show a modest amount of additional adoption of DG (8.6 GW with a 50% RPS) compared to the Base Case (8.0 GW with a 33% RPS). The other key metrics for DG remain favorable, with a TRC Test of 1.46 and RIM results in a range of 0.97 to 1.06.

Possible Changes to NEM. The Solar Parties also examined a sensitivity case that includes two possible modifications to NEM that shift some costs to participants while retaining the retail rate credit that is the essence of NEM. The first change is to remove non-bypassable public purpose program (PPP), nuclear decommissioning, competition transition charges (CTC), and Department of Water Resources (DWR) bond costs from the retail rate credit for exported power. Such an adjustment to NEM may be viewed as more equitable, since it would result in DG customers contributing to these programs based on their total rather than their net use of power from the utility system. The second modification that the Solar Parties include in this sensitivity case is for new DG customers to begin to pay upfront for the interconnection and processing costs associated with connecting their systems to the grid, so that non-participants do not pay for NEM program costs.

As shown in Table 7, these two modifications together would result in an increase in the RIM test from 1.04 to 1.07 compared with the Solar Parties' Base Case with the same residential rates, and a slight increase in the payback period for participants. However, this sensitivity also shows a 7.5% drop in adoptions over the 2017-2025 period, from 8.0 GW to 7.4 GW, indicating that even modest departures from full retail NEM can begin to erode the sustainability of customer adoption of DG technologies. The Solar Parties already are concerned with the relatively low level of adoptions modeled in the Public Tool in our Base Case, which continues NEM in its present form, and submit that the further erosion of adoptions in this sensitivity would take the industry below AB 327's goal of sustainable growth. This concern is reinforced by the imminent step-down of the federal ITC at the end of 2016.

3. Staff Tariff Paper "Bookend Cases" and Rates.

The June 4 Ruling asks parties to run their successor tariff proposals in the Public Tool using the two "bookend cases" in the Staff Tariff Paper. The Solar Parties propose to continue NEM with a retail rate credit. This is a case which the Staff Tariff Paper has already modeled using the two "bookend" cases.

C. Systems Larger Than One Megawatt

Section 2827.1(b)(5) removes the current net metering program's 1 MW participation cap for projects that "do not have significant impact on the distribution system" so long as those systems are "built to the size of onsite load" and are "subject to reasonable interconnection charges established pursuant to…Rule 21 and applicable state and federal requirements." As stated in our March 16 policy comments, the Solar Parties support expanding access to NEM to systems over one megawatt, while requiring all interconnection upgrade costs, plus all application, processing, and study fees, for systems over 1 MW to be paid by the DG customer. This extension of NEM would be a benefit to large users and can be done in a way that addresses each of the requirements of Section 2827.1(b)(5). First, the Rule 21 interconnection process is designed precisely to review any proposed interconnection for impacts on the grid through a standardized review process. If that review identifies impacts to the distribution system, remedial measures are designed to mitigate those impacts, with the interconnecting party bearing those costs in order to interconnect. Second, the requirement that facilities be sized to meet on-site load can be addressed by using Section 2.2.4 of the Commission's *CSI Handbook*, which describes how systems are currently sized to meet on-site load under a variety of circumstances.

D. Additional Elements

The Solar Parties have no additional elements to propose at this time, but reserve the right to do so in response to proposals from other parties.

E. Safety and Consumer Protection Issues

As detailed in the Joint Solar Parties' March 16 policy comments, the Solar Parties take safety and consumer protection issues seriously. Rule 21 addresses the process and requirements for safely interconnecting and operating DG systems in parallel with the grid. Equipment certification standards and local permitting requirements provide additional layers of oversight and regulation focused on safety. Similarly, there are in place multiple levels of consumer protection, from approved equipment lists to industry self-regulation to oversight of the solar market by state and federal regulatory authorities. The DG industry accepts that DG will not continue to grow sustainably unless the industry offers safe, quality products based on reasonable terms that consumers understand, accept, and find to be a reasonable economic transaction. In this regard, we submit that the Commission should give high value to the long and successful track record of net metering at enabling hundreds of thousands of Californians to obtain safe and reliable access to the benefits of renewable DG serving their homes, businesses, and neighbors.

F. Legal Issues

The Solar Parties have discussed at length, both above and in our policy comments, the legal issues concerning the provisions of AB 327 related to the NEM successor tariff.

III. ADDRESSING GROWTH IN DISADVANTAGED COMMUNITIES

A. Proposed Method for Defining and Identifying Disadvantaged Communities

"Disadvantaged Communities" in this proceeding should be defined as disadvantaged compared with the general California population with regard to both socioeconomic and environmental pollution factors. As noted in comments by the California Environmental Justice Alliance (CEJA) and The Greenlining Institute[56] and in the *Energy Division Staff Paper Presenting Proposals for Alternatives to the NEM Successor Tariff or Contract for Residential Customers in Disadvantaged Communities in Compliance with AB 327* (hereafter, Staff Disadvantaged Communities Paper),[57] AB 327 refers to "low-income" customers frequently, but refers only once, in 2827.1(b)(1), to "disadvantaged communities," implying a difference to legislators in the meaning between the terms "low-income" and "disadvantaged."

Including both socioeconomic and pollution factors in the definition in this context would be consistent with other recent California statutes that define disadvantaged communities. For example, SB 43 (Wolk), which was enacted in 2013 and required the development of Green Tariff Shared Renewables programs for the three large IOUs, defines disadvantaged communities as "areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation," and "areas with socioeconomic vulnerability."[58]

After considering comments from stakeholders in this proceeding and attending the April 27, 2015 staff workshop on disadvantaged communities alternatives, we support the use of the most recent version of the California Communities Environmental Health Screening Tool (CalEnviroScreen), currently CalEnviroScreen 2.0, as one appropriate method for identifying disadvantaged communities in the context of this proceeding. CalEnviroScreen has been developed by the Office of Environmental Health Hazard Assessment (OEHHA) for the California Environmental Protection Agency (CalEPA) over several years and with much stakeholder input, to "identify communities in California most burdened by pollution from

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[56] CEJA and Greenlining Institute March 16 comments, p.7
[57] Staff Disadvantaged Communities Paper, pp. 2-4 and 2-5
[58] See SB 43, CA Pub Util Code section 2833(d)(1)(a)

multiple sources and most vulnerable to its effects, taking into account socioeconomic characteristics and underlying health status."[59] CalEnviroScreen 2.0 creates scores for each census tract in California, by combining the scores for 19 individual indicators that relate to pollution exposures, environmental conditions, and population characteristics.[60]

In March comments in this proceeding, CEJA and The Greenlining Institute support the use of CalEnviroScreen 2.0 to identify disadvantaged communities in this proceeding, as do SCE and IREC. In addition, Energy Division staff supports the use of CalEnviroScreen 2.0 to identify disadvantaged communities.[61] GRID Alternatives supports the use of CalEnviroScreen in this context, but also proposes that all CARE customers and MASH and SASH program participants (even those outside CalEnviroScreen designated communities) also be eligible. GRID Alternatives urges the Commission to adopt a broad definition so as not to exclude disadvantaged populations unnecessarily, which agrees with the Joint Solar Parties' recommendation in our March 16 comments. GRID Alternatives states that other identification methods that should be considered are the Internal Revenue Service's Qualified Census Tracts (QCTs), Federally-designated Empowerment Zones, Enterprise Communities and Targeted Employment Areas. Clean Coalition proposes that CalEnviroScreen should be used, with some modifications to allow for greater dispersion across regions and to factor in race and ethnicity.[62] Use of CalEnviroScreen in this proceeding would be consistent with a February 2015 Commission decision in the Green Tariff Shared Renewables proceeding to use the same tool to identify disadvantaged communities in the context of that program.[63]

While we support the use of CalEnviroScreen as an appropriate tool for identifying disadvantaged communities in the context of this proceeding, we do not take a position regarding what percentage ranking within the tool should be the cutoff for identifying disadvantaged communities, nor whether that ranking should be conducted on a statewide or a regional basis. Both Marin Clean Energy and Clean Coalition highlighted issues in their March 16 comments that raise the question of whether rural communities are accurately represented if the

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[59] CalEPA, OEHHA, *Approaches For Identifying Disadvantaged Communities*, p. 1 (Aug. 2014), available at http://oehha.ca.gov/ej/pdf/ApproachesnIdentifyDisadvantagedCommunitiesAug2014.pdf
[60] CalEnviroScreen scores are viewable at http://oehha.ca.gov/ej/ces2.html.
[61] Staff Disadvantaged Communities Paper, pp. 2-4 to 2-6.
[62] Clean Coalition March 16 comments pp.4-5.
[63] D.15-01-051, pp. 53-54.

CalEnviroScreen ranking is done statewide. A visual review of the color-coded map on the CalEnviroScreen website indicates that the top-ranked 25% of census tracts are largely in urban areas, with many in LADWP's service territory and therefore inaccessible via IOU programs. Few communities are designated in the top 25%, we note, in the wide coastal swath between San Jose and northern Los Angeles.[64] We urge the Commission to investigate this question further, to ensure that customers who live in disadvantaged rural communities have fair access to policies that will increase their access to clean DG.

In addition, we agree with GRID Alternatives that a truly equitable outcome requires that low-income IOU customers who do not live in the most disadvantaged communities as designated by CalEnviroScreen should be eligible for the NEM alternatives adopted in this proceeding. In this way, poor customers who do not happen to live in the most polluted areas can still receive new opportunities for accessing the benefits of clean DG. CARE eligibility and SASH and MASH program participation are designations already made by the IOUs that identify socioeconomically disadvantaged IOU customers. We recommend that the Commission also allow CARE customers and SASH and MASH program participants to participate in the approved disadvantaged communities alternatives, regardless of their geographic location. While the statute implies a difference between "low-income" and "disadvantaged communities" as noted at the beginning of this section, the Commission has the discretion to allow tariff alternatives for disadvantaged communities also to be made available to low-income customers located outside disadvantaged communities.

B. Barriers to Adoption Specific to Disadvantaged Communities

Residential customers in disadvantaged communities frequently face the following barriers to renewable DG adoption in addition to the barriers other customers may face:

1) Barriers to Accessing Capital or Financing: Lower income Californians often do not have access to the lump sum needed to buy a solar array outright. In addition, although minimum FICO score requirements/criteria continue to decline as experience with solar increases, low credit scores and lower-than-average bill savings if the customer is on CARE rates may limit the

[64] See http://oehha.maps.arcgis.com/apps/Viewer/index.html?appid=112d915348834263ab8ecd5c6da67f68.

ability to access certain types of solar financing. To make solar accessible to low-income customers, therefore, solar projects generally need to be cash-flow positive immediately.

2) Small or Nonexistent Tax Liability: Lower income Californians have lower tax liability, preventing full monetization of renewable energy tax credits.

3) Barriers to Education and Marketing: As GRID Alternatives noted in comments, residents of disadvantaged communities tend to be multilingual and multicultural, presenting challenges to communicating with these customers about new programs. In addition, customers in disadvantaged communities historically have been the victims of predatory lending arrangements or other subprime financial offerings, leading to some distrust of "zero down" sales pitches.[65]

4) Low Levels of Homeownership: For customers who rent their homes, the landlord who makes the decision regarding whether to purchase or lease the system does not benefit from net metered bill reductions. As discussed in the Staff Disadvantaged Communities Paper, data from 2013 showed 66% of low-income California households rent, and 54% of the total population in CalEnviroScreen-designated disadvantaged communities are low-income.[66] Thus, while many millions of low-income California homeowners have the potential to explore rooftop solar, real options must be developed to provide solar access to low-income renters.

5) Lower Rates Reduce Bill Savings: Due to the CARE discount, low income customers on CARE rates have reduced monthly bill savings from net metering compared with non-CARE customers. Lower-than-average savings are often still meaningful savings to low-income customers, but they do reduce the financial incentive to go solar when combined with the other barriers discussed above.

In Section D below, we discuss how our policy proposals for disadvantaged communities will address these barriers to adoption.

[65] GRID Alternatives March 16 comments, pp. 6-7.
[66] Staff Disadvantaged Communities Paper, p. 2-10.

C. Proposal for Measuring and Defining Growth Among Residential Customers in Disadvantaged Communities

Equity requires that California make meaningful strides toward greater access to renewable DG and related benefits, including bill savings and job growth, in disadvantaged communities. The Legislature clearly intended that real progress be made in this important goal, otherwise it would not have enacted Section 2827.1 (b)(1)'s requirement to "include specific alternatives designed for growth among residential customers in disadvantaged communities." The Obama administration underscored the importance of this goal in early July when it launched a new initiative "to increase access to solar energy for all Americans, in particular low- and moderate- income communities, while expanding opportunities to join the solar workforce."[67] The Staff Disadvantaged Communities Paper confirms that we are currently far from an equitable geographic distribution of customer-sited renewable DG within disadvantaged communities; the top 25% of disadvantaged communities as defined by CalEnviroScreen cover a population of approximately 9 million Californians, some 24% of the state's population, but only 6% of cumulative residential net metered installations were located in these communities as of Q1 2015.[68]

In the Joint Solar Parties' March 16 comments, we proposed that growth among residential customers in disadvantaged communities should be defined as an increase of at least 30% annually over the next several years, measured on a megawatt basis.[69] We now add more specificity by proposing using a benchmark of the number of megawatts of net metered generation installed for residential customers in disadvantaged communities in 2014, or the average of such during the years 2014 and 2015, and then ensuring that on average from 2017 – 2020 if not beyond, the megawatts installed to serve residential customers in disadvantaged communities increase by at least 30% annually. Thirty percent annual growth was much discussed during the creation of CSI and was achieved in the general market in 2013 and 2014.

[67] See https://www.whitehouse.gov/the-press-office/2015/07/07/fact-sheet-administration-announces-new-initiative-increase-solar-access . The Obama administration's initiative includes a new goal to install 300 megawatts of renewable energy in federally subsidized housing as well as providing technical assistance to make it easier to install solar on affordable housing.
[68] Staff Disadvantaged Communities Paper, p. 2-7.
[69] JSP March 16 comments, p. 11.

The following provides a numerical example of this proposal for defining growth for disadvantaged communities. The Staff Disadvantaged Communities Paper notes that in 2014, 40.37 MW of residential net metering generation was installed in the top 25% of disadvantaged communities – equivalent to 8% of the total residential installations in the census tracts in the IOUs' service territories.[70] For instance, if the benchmark were set to 2014, then the annual goals for disadvantaged communities would be:

- (40.374* 1.3) = 52.48 MW installed in 2017,
- (40.374* 1.3^2) = 68.23 MW installed in 2018,
- (40.374* 1.3^3) = 88.7 MW installed in 2019, and
- (40.374* 1.3^4) = 115.31 installed MW in 2020.

If the 2020 goal were achieved and maintained in future years, by the mid-2020s residential customers in the top 25% disadvantaged communities would be installing approximately 25% of residential DG systems, which would be an equitable outcome corresponding to the overall share of the residential market in these communities.

Setting the first disadvantaged communities MW goal in 2017 provides time for policy implementation in 2016, and also avoids the complications of a possible decline in installations between 2016 and 2017 resulting from a large decline in the federal ITC. Averaging across multiple years, 2017 - 2020, makes allowance for some inevitable "lumpiness" in actual megawatts installed in any given year.

D. Proposed Policy Alternatives

In choosing our proposed policy alternatives, we kept in mind the following guiding principles as means for ensuring success in the growth of customer-sited renewable DG in disadvantaged communities.

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[70] Staff Disadvantaged Communities Paper, p. 2-8.

Guiding Principles for Designing Effective Alternatives for Disadvantaged Communities

1. *The policy effectively addresses or avoids two or more of the barriers specific to disadvantaged communities listed above.* These include 1) barriers to accessing capital or financing, 2) small or nonexistent tax liability, 3) barriers to education and marketing, 4) low levels of homeownership and 5) lower rates which reduce bill savings.
2. *Projects facilitated by the policy will be financeable.* For example, the geographic footprint of the program must be large enough to identify sufficient customer offtakers, and developers must have sufficient certainty about the contract price they will receive.
3. *The policy is truly scalable, allowing it to facilitate meaningful DG growth in disadvantaged communities on an ongoing basis.* Policies or programs that rely on a temporary pool of incentive funds that are likely to be exhausted over a short period, for example, should be lower priority than policies that make more efficient use of existing, ongoing subsidies or that do not require dedicated funding at all.

Keeping the above in mind, we propose the following policy alternatives for promoting the growth of renewable DG in disadvantaged communities. Both of these proposals square well with all three guiding principles, and would complement each other to provide effective options for both CARE and non-CARE customers in disadvantaged communities.

1. **CleanCARE**

We propose that CleanCARE, as described in detail in IREC's proposal filed today, be approved by the Commission in this proceeding as a policy alternative for disadvantaged communities. Vote Solar has collaborated with IREC, CALSEIA and other stakeholders in this proceeding to refine the CleanCARE concept over the past year. CleanCARE would be a new rate option for customers eligible for California Alternative Rates for Energy (CARE), allowing those customers increased access to affordable renewable energy.

We include here a short summary of the CleanCARE concept, and refer for greater detail to IREC's more in-depth proposal filed today. CleanCARE, as conceived for the early years of the program, would enable a portion of CARE funds to be invested in the development of shared renewable distributed generation which would be owned and operated by a third party, with the generation purchased at competitively set prices by the utilities via a request for offer (RFO) process on behalf of participating customers in disadvantaged communities. CARE customers choosing the CleanCARE option would move to the standard rate for their rate class, and would offset a portion of their monthly bills via virtual net metering for a portion of the renewable facility's output. The program would be third-party administered, and could initially be launched as a five megawatt pilot program and expanded once successful. At a later date, CleanCARE could also be expanded to incorporate energy efficiency, energy storage and demand response as means of reducing participants' bills.

CleanCARE meets our first guiding principle for designing effective alternatives for disadvantaged communities, addressing all five of the barriers listed in Section B above. First and second, CleanCARE participants would make no upfront or ongoing financial investment, meaning that barriers to accessing capital or financing and low tax liability will not prevent participation. Third, barriers to education and marketing will be reduced because CleanCARE could be marketed as a CARE option by existing third-party CARE administrators. Fourth, since participants would be investing in an offsite DG project, low levels of homeownership in disadvantaged communities will not reduce participation. And finally, because the bill savings from CleanCARE are tied to the amount of renewable generation that the utility can purchase with the CARE discount on behalf of participants, and participants would no longer receive the CARE-discounted rate, low discounted bill savings is not a barrier; in fact, CleanCARE will allow participants to receive more efficient price signals on the standard rate for the remaining generation they purchase outside of CleanCARE.

CleanCARE also squares well with Guiding Principle 2, as projects facilitated by CleanCARE will be financeable. The utilities would use a request for offer (RFO) process to procure energy from shared renewable generation facilities for the CleanCARE program using a portion of CARE funds as a long-term payment stream, thereby providing financiers necessary certainty on pricing. While some individual CARE-eligible customers may be cycled between CARE and CleanCARE by the third-party administrator based on which saves them more money in a given month, there is likely to be a long list of interested and eligible customers since the program guarantees the same or greater savings compared with CARE.

And finally, CleanCARE meets Guiding Principle 3, as a truly scalable program structure. The pilot program phase of 5 MW would be small in relation to potential demand within disadvantaged communities, limiting risk to ratepayers if the program model does not prove successful. However, assuming it is successful, the structure could be greatly expanded, using ongoing existing CARE subsidies to provide greater bill savings for customers, while also providing all the environmental and economic benefits that accrue from the shared renewable generation facilities built.

While we believe that CleanCARE holds much promise for making clean distributed generation more available to disadvantaged communities, more than one policy will be necessary to address different portions of the market for disadvantaged communities. Only CARE customers would be eligible for CleanCARE, and the program will save the most money for higher-use CARE customers who can use CleanCARE generation to offset higher-tier rates. The Commission should therefore adopt additional alternatives to increase renewable DG adoption among customers in disadvantaged communities who do not qualify for CARE, and if possible among lower-use CARE customers in disadvantaged communities. In addition, CleanCARE will presumably undergo testing and streamlining as a program model in the near-term, meaning that additional complementary policies will be needed to achieve 30% average annual growth in installations during the 2017 - 2020 timeframe, as proposed above.

2. **Disadvantaged Communities VNEM**

As the Joint Solar Parties discussed in our March 16 comments, we support the continuation, expansion and improvement of virtual net metering (VNEM)[71] as a key goal of this proceeding. One decisive characteristic of a VNEM program that makes it effective – particularly for disadvantaged communities – is that the host and the participating customer need not be co-located. As we discussed earlier, low income communities tend to include higher concentrations of renters and customers with lower creditworthiness, limiting the prospective customer's ability to qualify on their own for a long-term PPA or secure financing to cover the system costs. By allowing customers to benefit from net metered generation at a separate location, challenges to providing solar energy to customers who either rent or do not have a well-suited roof for solar are addressed. VNEM also addresses challenges around the low credit scores and short time-horizons of renters by expanding the pool of eligible participating

[71] Joint Solar Parties' Comments, at pp. 12-13.

customers, from one to many, thereby mitigating the risk of customer default or relocation. Rather than requiring one homeowner to commit to one PPA for the lifetime of the investment, VNEM programs enable a developer to provide solar power through PPA agreements with a number of participants in a geographical area, and replace them with other participants throughout the lifetime of the project. The risk of contracting with customers with lower credit is resolved by the availability of other eligible participants that can replace them. Enabling a PPA model makes the challenges to accessing capital irrelevant, since the participating customer does not need to make an upfront investment.

In the Staff Disadvantaged Communities Paper, Energy Division staff endorsed the expansion of VNEM as a way to better serve disadvantaged communities.[72] Staff's "Neighborhood VNEM" proposal pointed to the Massachusetts VNEM (MA VNEM) program as a model for use in disadvantaged communities.[73] The MA VNEM program has been very successful at supporting projects and garnering participants. We agree with Staff that the MA VNEM program is a valuable model in this context, and we propose the following program design specifically focused on the needs of disadvantaged communities.

VNEM is currently available in California only to multi-tenant, multi-meter properties where the renewable generation is located on the same property as the participating customers.[74] We propose a Disadvantaged Communities VNEM program that allows residential customers in disadvantaged communities to be assigned credits from a host customer regardless of whether they are co-located with the net metering projects. Since the focus must be on disadvantaged communities, our proposal allows the host site (either residential or non-residential) and participating residential customers to be in any designated disadvantaged community, so long as they are both within the same IOU service territory. This differs somewhat from Staff's

[72] Staff Disadvantaged Communities Paper, pp. 2-12 to 2-16.

[73] Massachusetts also has in place a separate program known as 'Neighborhood VNEM.' This program has not been successful, due in part to a less favorable rate structure and a lack of administrative clarity about what constitutes a "neighborhood." In these comments, we refer to the successful MA VNEM program, not the unsuccessful Neighborhood VNEM program.

[74] As discussed at page 33 of the JSP March 16 comments, a complex and restrictive requirement for all multi-tenant properties other than affordable housing, that all customers be at the same Service Delivery Point, has stymied growth of customer-sited DG on multi-tenant properties in California. The Commission should consider removing the single-SDP barrier for all multi-tenant properties in this proceeding, and would definitely need to remove it for Disadvantaged Communities VNEM.

Neighborhood VNEM proposal, which suggests that both the project and participant need to be in the *same* disadvantaged community census tract. A census tract is a relatively small area, containing an average of about 4,000 residents.[75] As we noted, the key to enabling solar for renters and residents with lower credit ratings is to provide the project owner with a wide enough pool of eligible customers to effectively mitigate the risk of customer default or relocation. The size of the geographical area in which the host can provide credits to customers is therefore critical to ensuring that enough prospective customers are available to serve that risk mitigation function, and a census tract is not large enough for that purpose. A larger eligible area is needed to ensure that both developers and customers have the flexibility they need to make the program viable.

While there is a clear case for restricting both the project site and the participating customers to census tracts that have been designated disadvantaged communities because of the potential benefits to both hosts and customers, the justification for the two parties being in the *same* census tract is less clear. We do not see any clear technical benefit to limiting the project and participating customers to the same census tract in terms of lowering the impact on the distribution system, since participating customers that are in the same census tract as the project are not necessarily more electrically related to the generating facility than participating customers in other census tracts.

We propose that the generating system meet the size interconnection limit that is determined under the NEM Successor Tariff, but that the size not be limited to the aggregate load of subscribing customers. There is good reason for this. One, such a limit would require project developers to sign up customers before completing project development, when the optimum is exactly the opposite – customers want to sign on to projects that are ready to deliver electricity in the near future. Two, an administrative determination is probably not as effective as a market mechanism for ensuring that participants' load is matched to system capacity. Instead, we propose to include a host system sizing requirement that ensures appropriate sizing without restricting project development. Under this mechanism, the VNEM credits remain on the host bill unless and until they are transferred to another participating customer account within some period of time (we propose within one year of being generated). As a result, project owners will

[75] See https://www.census.gov/geo/reference/gtc/gtc_ct.html.

lose the value of any generation that is not assigned to participating customers and that cannot be credited to their own load. This structure will send an effective market signal to match facility production to the load of participating customers, but will give market participants the necessary flexibility to sign up customers late into the project development process, and dynamically replace them as necessary over time.

Under our proposal, the host customer need only have parasitic load in order to qualify; for example, a ground-mounted PV project can qualify as a host customer, allowing for greater flexibility in project location. Since a VNEM program is based on the notion that credits from a project site can be allocated to customers who are not the host and do not reside on the same property, then there is no difference between *most* or *virtually all* of the project's generation benefitting offtakers on other sites.

Finally, we propose that Disadvantaged Communities VNEM credits be allocated on a volumetric basis based on the participant's retail rate, consistent with the existing California VNEM construct (but differing from Massachusetts, where a monetary credit is calculated based on the host customer's rate structure for administrative efficiency). As discussed above, however, CARE customers' (and particularly low-use CARE customers') retail rates are much lower than average rates, making them less attractive prospective customers for developers to target, and making the economics of participating less attractive for those customers. To remedy this, CARE customers could receive a credit multiplier on their VNEM bill that corrects for the size of the average CARE subsidy. In addition, we also propose that CleanCARE be an available option for CARE customers in disadvantaged communities.

Our Disadvantaged Communities VNEM proposal meets Guiding Principle 1, because it addresses or avoids at least four of the barriers specific to these communities. First, since participants are able to receive credit from an offsite DG project, <u>low levels of homeownership</u> in disadvantaged communities will not reduce participation. Second, if CARE customers are offered a credit multiplier, <u>low discounted bill savings</u> are not a barrier. Since participants would not own the system, but rather participate in a PPA agreement with a developer, <u>low tax liability</u> will not prevent participation. The Disadvantaged Communities VNEM program also addresses <u>barriers to accessing capital or financing</u>. By expanding the pool of eligible participants to those off-site, the risk of contracting a PPA with customers with lower credit is mitigated by the availability of other eligible participants to replace those customers in the event of a default or relocation, and therefore credit requirements can be lower than for on-site NEM projects. By enabling a PPA model, customers do not face the challenge of accessing capital to finance their own system, since they do not have to provide upfront capital in order to participate. Barriers to education and marketing could also potentially be overcome if developers are incented to target these communities in order to secure customers.

Disadvantaged Communities VNEM also squares well with Guiding Principle 2, resulting in financeable projects. The geographic area for eligible participants is key to ensuring this principle is met. A large enough eligible area is needed to ensure that both developers and customers have the flexibility they need to make the program viable and financeable. So long as developers are able to access a wide pool of potential customers and to replace them if a customer moves outside a disadvantaged community or defaults on a PPA, the risks of developing projects for lower-income communities will not deter investments.

And Disadvantaged Communities VNEM also meets Guiding Principle 3, as a truly scalable program structure that leverages private capital, does not require dedicated funding, and could serve large numbers of customers in disadvantaged communities.

We acknowledge that this proposed Disadvantaged Communities VNEM structure has some similarities to the Green Tariff Shared Renewables (GTSR) program currently being finalized at the Commission. However, customers participating in GTSR are projected by the IOUs to pay a significant rate premium; for example, SCE's GTSR Advice Letter 3219-E, filed in A.12-01-008 in May 2015, projects a net premium of 2.64 cents per kWh to participate in 2015.[76] Customers in disadvantaged communities by and large simply do not have the ability to pay more for clean energy, thus preventing GTSR from being a real option for many of these customers, at least until solar costs decline enough to turn the current net premium into a net savings. By contrast, a VNEM PPA pricing structure that avoids an upfront payment and saves customers money every month is a model that can work well for low-income customers in disadvantaged communities.

[76] See p.16; the net charges (12.43 c/kWh) minus the net credits (9.79 c/kWh) equal the net premium (2.64 c/kWh).

E. Applicability Of Criteria Addressing Costs And Benefits In Section 2927.1(b)

As discussed above, a significant increase in the rate of growth of customer-side renewables generation in disadvantaged communities must be achieved to ensure equitable distribution of the benefits from that generation. Due to the specific barriers to DG growth for these communities, and as Section 2827.1(b) recognizes, supporting greater growth in customer-sited DG in disadvantaged communities must be given specific, separate program treatment. Because these communities have suffered disproportionately from the impacts of traditional energy generation for decades, ongoing incentives may well be justified.

Therefore, it is appropriate not to apply the same cost-benefit tests used for the NEM successor tariff to the programs designed for disadvantaged communities. The Legislature agreed that more incentives are needed for low-income customers when it approved additional incentive funding for the low-income solar programs in 2013 with the passage of Assembly Bill 217, authored by Assembly member Bradford. The Commission has the latitude in this proceeding to determine what policy alternatives will most effectively increase access to customer-sited renewable distributed generation among residential customers in disadvantaged communities, without a requirement to balance the costs and benefits for all customers.

In addition, the structure and wording of the statutory language in Section 2827.1(b) indicate that legislators intended that policy alternatives for disadvantaged communities need not be considered using the same cost and benefit criteria as for the broader NEM successor tariff. Section 2827.1(b)(1) requires "specific alternatives designed for growth [of customer-sited renewable distributed generation] among residential customers in disadvantaged communities." The requirements of 2827.1 (b)(3) and (b)(4) may reasonably be interpreted to apply specifically to the broader NEM successor tariff, since they refer to "the standard contract or tariff" described in Section 2827.1(b) as "a standard contract of tariff… for eligible customer-generator." 2827.1 (b)(3) and (b)(4) do not also refer to "alternatives designed for growth among residential customers in disadvantaged communities."

F. Funding

1. CleanCARE

CleanCARE does not require any additional source of funding, instead making use of a portion of the existing CARE rate discount and associated administrative funding. Only CARE-eligible customers would be eligible to sign up to participate in CleanCARE, and the funds that would have been allocated to those customers as a CARE bill discount would simply be redirected to fund the IOU's RFO for third party-owned solar in disadvantaged communities. As IREC describes in its proposal, CleanCARE will definitively ensure that participating customers see the same or greater bill savings compared to if they had continued to consume their CARE subsidy as a rate discount. This innovative use of a portion of existing funding makes CleanCARE an efficient approach to increasing renewable DG growth in disadvantaged communities.

2. Disadvantaged Communities VNEM

Disadvantaged Communities VNEM would not require an additional source of funding. Rather, the policy would expand eligibility for VNEM to a broader set of customers.

G. Legal Issues

1. CleanCARE

In discussions with stakeholders regarding CleanCARE, some have raised the question of whether CleanCARE's bill crediting arrangement is permissible under the statutory language authorizing the CARE program. A look at this statutory language shows that it is. California Public Utilities Code Section 739.1 requires that the Commission and IOUs provide a "level of discount for low-income electric and gas customers" on their electricity bills "that correctly reflects the level of need,"[77] and requires that the "entire discount shall be provided in the form of a reduction in the overall bill for the eligible CARE customer."[78] California Public Utilities Code Section 382 states that "Energy expenditure [sic] may be reduced through the

[77] § 739.1(a).
[78] § 739.1(c)(3).

establishment of different rates for low-income ratepayers, different levels of rate assistance, and energy efficiency programs," and states "Nothing in this section shall be construed to prohibit electric and gas providers from offering any special rate or program for low-income ratepayers that is not specifically required in this section."[79]

CleanCARE provides the required bill discount via kWh bill credits generated as a result of CARE-funded investments in renewable energy. There is no statutory requirement that the bill reduction for a CARE customer be in the form of a *rate* reduction rather than a *bill credit*. Thus, the Commission has flexibility regarding how the required bill discount is structured, and CleanCARE is consistent with the CARE statutory language.

2. Disadvantaged Communities VNEM

We are not aware of legal issues that would need to be resolved in order to implement Disadvantaged Communities VNEM.

[79] § 382(b) and (c).

IV. CONCLUSION

The Solar Parties appreciate the opportunity to provide the Commission with this proposal for a NEM successor tariff which will build upon the success of California's program for renewable distributed generation.

Respectfully submitted at Berkeley, California,

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Regional Director, West Coast for Vote Solar

Date: August 3, 2015

Attachment A1: Solar Parties' Public Tool (PT) Model Changes

<table>
<tr><th>Change</th><th>Location</th><th>Description / Justification</th></tr>
<tr>
<td>Modify Assumed Utility Rate Escalation to 3%</td>
<td>Key Driver Inputs, Cell C29.</td>
<td>
3% is a more realistic assumption for future utility rate escalation than 5%. This change is supported by the following data:

1. Historical utility rate escalation (1993-2012, % per year))
<table>
<tr><th>Utility</th><th>Residential</th><th>C&I</th></tr>
<tr><td>PG&E</td><td>1.4%</td><td>1.2% to 1.8%</td></tr>
<tr><td>SCE</td><td>1.0%</td><td>1.0% to 1.8%</td></tr>
<tr><td>SDG&E</td><td>2.6%</td><td>1.8% to 2.8%</td></tr>
</table>
The range in C&I rate escalation reflects both commercial and industrial rates.
Source: California Energy Commission, http://energyalmanac.ca.gov/electricity/Utility-Wide_Average.xls .

2. Current escalation rates (% per year) marketed or cited by solar companies
<table>
<tr><th>Company</th><th>Escalation Rate</th><th>Source</th></tr>
<tr><td>Solar City</td><td>2.9%</td><td>Solar City PPA: http://www.solarcity.com/sites/default/files/solarcity-contract-resi-ppa-example.pdf</td></tr>
<tr><td>Sunrun</td><td>3.5%</td><td>Sunrun FAQs on advertised 20% savings: http://www.sunrun.com/lock-in-savings/save20/</td></tr>
<tr><td>Vivint</td><td>2.9%</td><td>Vivint PPA: http://investors.vivintsolar.com/files/doc_financials/VSLR-2014-Annual-Report.pdf , at p. 4.</td></tr>
</table>

3. Public Tool future rate escalation (2017 – 2050, % per year)
<table>
<tr><th>Public Tool Case</th><th>PG&E</th><th>SCE</th><th>SDG&E</th></tr>
<tr><td>SEIA Base</td><td>2.5%</td><td>2.7%</td><td>2.5%</td></tr>
</table>
Residential rate escalation from Solar Parties' Base Case.
</td>
</tr>
</table>

Change	Location	Description / Justification
Start the Adoption Model Using Historical Distribution of Bin Sizes	**Adoption Module.** Cells N28:N30 have revised formulas that pick the winning size based on historical (2008-2012) system sizes for each bin. 2012 data on system sizes by bin are written down in cells C117:G801, including "large" assignment for bins 676-685. A bin size reference is added in Cell A11. Thus, Cells N28:N30 are changed so that winner is the bin's size selection from cell A11 if solar is the winning technology, e.g. Cell N28 is *=IF(MAX($J$28:$J$30)=MAX($J$28:$J$39),IF(C28=$A$11,1,0),0)*	This change is designed to produce a more realistic distribution of solar system sizes, recognizing that economics alone does not determine system sizing. Available roof space, home orientation, shading, and limited budgets also impact system sizing, and all tend to result in smaller systems, but are not reflected in the PT's adoption model. This change maintains the historical system size that customers have adopted in each bin of similarly-situated customers (i.e. if a bin was "small" in 2012, it will be "small" in 2017-2025), but continues to allow the economics to determine how much of each bin's technical potential is adopted. Thus, if the economics favor large systems, the bins with large systems will fill up faster, resulting in a growing percentage adoption of large systems. SEIA believes that this modification strikes a better balance between economics alone and the many other factors that influence system sizing.

Change	Location	Description / Justification
DG / RPS Parity	**Avoided Cost Calcs.** (1) Remove Annual RPS Target (line 433) from the formulas in lines 437 and 444, to value DG at 100% of RPS premium in each year. For example, here is the new formula for Cell N437: *=IF(N$1,($E$425+$E$426)*$E$429/1000, 0)* And in Row 444, Cell N444 is *=IF(N$1,($D$425+$D$426)*$D$429/1000, 0)* These changes should be copied across to all cells in Rows 437 and 444, through the year 2050. (2) Set lines 438 and 445 equal to lines 437 and 444, respectively, to remove any banking of the avoided renewables costs from DER. Here are the new formulas for Cells 438 and 445 to remove banking: Cell N438 is *=N437* and Cell N445 is *=N444*. These changes should be copied across to all cells in Rows 438 and 445, through the year 2050.	Recognizes that, but for California's DER program, the state would adopt higher goals for utility-scale renewable generation, if the state's goals for greenhouse gas reduction are to be met. As a result, 100% renewable DER avoids additional 100% renewable utility-scale generation, not 67% marginal fossil and just 33% renewable. Also, because DER RECs are not used for RPS compliance, we do not assume that the avoided renewables benefits of DER only accrue after banked utility-scale RECs are completely used. This also recognizes that the DER program has proceeded for many years in step with the RPS program, that both programs produce new renewable generation, and thus that both programs should be valued at parity. Thus, we do not bank the avoided renewables value of DER until after all contracted RPS RECs are used.

Change	Location	Description / Justification
Parity in Marginal Costs for Rates and Avoided Costs for SCE and SDG&E	**Avoided Cost Calcs.** Cells E328-E329 and Cells E339-E350. Set Cell E328 = $34.00 for SCE subtransmission; and Cell E329 = $27.85 for SDG&E substation. Set Cells E339-E346 = $84.00 for SCE distribution; and Cells E347-E350 = $74.06 for SDG&E distribution.	Set SCE and SDG&E subtransmission and distribution avoided costs equal to the marginal cost values used to set rates, as shown in the RevAlloc tab of the Revenue Requirement model. These marginal costs apply to changes in customers' loads served from the grid, including EE, DG, and regular variations in usage. PG&E's avoided costs in the PT are set equal to its marginal costs, so no changes are needed. We also include SDG&E's marginal substation costs as its marginal subtransmission costs. SCE marginal costs use settled values from A. 11-06-007, approved in D. 13-03-031. SDG&E marginal costs use filed values in A. 11-10-002 (Ehlers Testimony, Chapter 4, pp. RME-2 to RME-6), as the approved settlement in this case did not present specific marginal cost values.

Attachment A2: Solar Parties' Revenue Requirement Model Changes

Change	Location	Description / Justification
In the "RR Input" tab:		
Use recent modeling of the integration cost adder for solar	Cells G414 to G416	Use E3's June 12, 2015 "Marginal Integration Cost Calculations" for solar of $2.38 per MWh for the 33% RPS. See Slide 20. Based on updated calculations using method adopted in D. 14-11-042. Integration cost adders for 40% and 50% RPS use the same escalation assumed in the default Public Tool assumptions in Cells F414 to F416, resulting in an adder of $2.79 per MWh for a 40% RPS and an adder of $3.38 per MWh for a 50% RPS.
Use SCE interconnection costs for PG&E and SDG&E	Cells G380 to G384 (PG&E) and Cells G396 to G400 (SDG&E)	Large differences between utility-estimated interconnection costs are unexplained in the PT. We use the lowest reported costs (from SCE), assuming that the other utilities can achieve a similar level of cost efficiency in the interconnection process.
Cost of CCGT Capacity	Cell G300	Use $176 per kW-year, based on CAISO "2014 Annual Report on Market Issues and Performance" (hereafter, "CAISO Annual Report"), at Table 1.6.
Cost of CT Capacity	Cell G301	Use $190 per kW-year, based on CAISO Annual Report, at Table 1.8.
CCGT Heat Rate	Cell G208	Use 7,400 Btu/kWh, based on CAISO Annual Report, at Table 1.6. Use midpoint of typical operating range of heat rates.
CT Heat Rate	Cell G209	Use 9,500 Btu/kWh, based on CAISO Annual Report, at Table 1.8. Use midpoint of typical operating range of heat rates.
CT Useful Life	Cell G180	Assume 30 years, not 20 years. See CEC, "Estimated Cost of New Renewable And Fossil Generation In California" (March 2015), at Table 14, hereafter "CEC Cost of Generation Study."
Fossil Steam Capacity Factor	Cell G200	Over-ride the 10% capacity factor with a more reasonable 5% capacity factor assumption for steam-boiler generators, given the expected continued retirement of OTC units from service.
Growth-related Distribution CapEx Costs	Cells G346 to G348	Over-rides the 11% default value with 22%, as one should not assume that DER only defers investment for distribution circuit capacity expansions. Other investment (i.e. for maintaining existing circuit capacity) may also be avoided.
Generation rate base cost	Cell G353	Over-rides the 100% default value with a 75% assumption for SDG&E, as the SDG&E inputs were

Change	Location	Description / Justification
adjustment factors		based on an application and not approved GRC values.
Revenue requirement allocation to customer classes	Cell D422	Set to "3" (Settlement Rate Relationships maintained) instead of "2" (Current deviations maintained), as settlement cost allocations in the last 10 years support continuation of the same basic cost allocation relationships among customer classes.
In the "RR Calculations" tab:		
Correct Diablo Canyon O&M to remove costs after Diablo Canyon shuts down in 2022.	Rows 265 and 266	Added a line item in row 266 for Diablo Canyon O&M starting at $300MM in 2013 plus 2% per year, based on GRC information, and subtracted that amount from line 265 starting in 2024 (i.e. from V265 through AV265). For example, B266 = *300*, V266=*$B$266*PRODUCT($J$264:V264)*, and V265=*PRODUCT($J$264:V264)*SUM($B$262:$B$263)*V90-V266*. The -V266 term removes the post-2023 Diablo Canyon O&M costs from the total generation O&M costs shown in row 265. The adjustment to the formula in rows 265 is not made prior to 2024 (i.e. no change from J265 to U265).