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 CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION FOR THE NET ENERGY METERING SUCCESSOR TARIFF

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Pursuant to "Administrative Law Judge's Ruling (1) Accepting into the Record Energy Division Staff Papers on the AB 327 Successor Tariff or Contract; (2) Seeking Party Proposals for the Successor Tariff or Contract; (3) Setting a Partial Schedule for Further Activities in this Proceeding" (Ruling), issued June 4, 2015, and "Assigned Commissioner's Ruling Granting in Part Motion of The Alliance for Solar Choice and Revising Procedural Schedule," issued June 23, 2015, the California Solar Energy Industries Association (CALSEIA) submits the following proposal for the net energy metering (NEM) successor tariff. As California's large investor-owned utilities (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) approach their program limits for the current net metering tariff, CALSEIA urges the California Public Utilities Commission (Commission) to adopt the following proposal as the successor to that tariff.

Summary Page

CALSEIA proposes:

A. Maintain net metering, with credits equivalent to the full retail rate of the otherwise applicable tariff.
B. After the market recovers from the loss of the Investment Tax Credit (ITC), expand public purpose charges to electricity consumption that is offset by NEM credits.
C. Align the participation boundary of the market rate virtual net metering tariff with that of the low-income virtual net metering tariff.
D. Of utmost importance is that no changes be made to the NEM tariff in the 2017-2019 timeframe, when solar customers will need to see a value proposition in solar without the ITC.

The following determinations are made based on Public Tool results using inputs described in Appendix A.

- The proposal does not meet the requirement of Section 2827.1(b)(1). The Public Tool's projected rate of adoption of distributed energy resources (DER) is not sufficient to ensure that customer-sited renewable distributed generation (DG) continues to grow sustainably. CALSEIA projects that the investor-owned utilities (IOUs) will interconnect 1,117 MW of net metered DG in 2015, and the Public Tool only estimates 553 MW of adoption in 2017 from this proposal. CALSEIA does not endorse a violation of this provision in statute as a general rule, but nonetheless is not proposing an added incentive on top of NEM credits that would be necessary to fully comply.
- The proposal meets the requirement of Section 2827.1(b)(3) because the results of the Participant Cost Test (PCT) are significantly greater than one.
- The proposal meets the requirement of Section 2827.1(b)(4) because the Total Resource Cost (TRC) test results and the Societal Cost Test (STC) results are greater than one. Additionally, the Ratepayer Impact Model (RIM) test results are close to one without counting the greenhouse gas (GHG) benefits of renewable distributed generation and more than one when those benefits are included.

I. Successor Tariffs

Net energy metering is an established billing arrangement that the market has come to understand and trust. For customers considering investments in or commitments to on-site generation, the concept of the meter spinning backward when production exceeds usage sounds rational and reliable. Giving customers the ability to produce electricity for their own consumption is fair to consumers, and allowing them to provide electricity for their local circuits is gradually transforming the grid from a centralized, fossil-fueled system to a modern, nodal system. This transformation is necessary to create a low carbon future, where the economy is able to thrive without being limited by power constraints or devastated by climate disruption, and where health and welfare are strengthened by averting the worst impacts of climate change. To achieve these goals, CALSEIA proposes that the IOUs maintain NEM, with credits equivalent to the full retail rate of the otherwise applicable tariff.

One important factor that is missing from the Public Tool is the disruptive impact that wholesale changes to NEM would have on customer decision making. Customers are slow to trust new financial arrangements. It has taken years for customers to accept net metering. At this point, many people have friends and neighbors who have gone solar via net metering. The influence of the positive experiences of acquaintances cannot be overstated. If the basic structure of solar economics is changed, it would have a severe impact on the market even if the resulting economic value is equivalent.

As self-generation grows, there may be a need to spread the costs of programs funded by non-bypassable charges (NBCs) among a wider base, but reducing the value of NEM credits in 2017 could have an excessive negative impact on the market. Ratepayers have invested $2.4 billion in developing the solar market through the California Solar Initiative (CSI). That program has been a great success by causing the cost to customers of installing solar to drop dramatically. This has been achieved through economies of scale that are at risk if the market retracts. If the market loses efficiencies, prices will rise and the ratepayer investment will have been wasted. Further, there are now more than 54,000 Californians working in the solar industry, and market retraction would create a loss of jobs to a sector that has been a shining star in the state economy. For these reasons, and because the percentage of customers that are avoiding a portion of NBCs by generating their own power is growing only gradually, the Commission should delay assessing those charges on a broader pool of consumption. CALSEIA proposes that utilities revise the NEM tariff by advice filing after NEM interconnections in a 12-month period have exceeded the number of megawatts interconnected in calendar year 2016. This revision should assess NBCs on electricity consumption that is offset by NEM credits.

Virtual net energy metering (VNEM) and NEM aggregation (NEMA) are two variants of NEM that should continue along with the primary successor tariff. VNEM is necessary for apartment residents to participate in NEM, and NEMA is essential for many farmers to use the NEM tariff. The Commission should modify VNEM for market rate apartment complexes to allow all residents on a single property to participate. Currently, a majority of apartment complexes are effectively precluded from using the VNEM tariff because the properties have multiple service delivery points (SDPs) and the tariff limits participation to one SDP.

In creating the successor tariffs, the Commission should not adopt any solar-specific fees or end the exemptions in the current NEM tariff. Cost-benefit results do not support the need for fees, and new fees would harm the market at a point when it is highly vulnerable. If those factors change, the Commission has the opportunity to revisit fees and exemptions at a later date. The Legislature recognized that details of the successor tariffs may need to be changed over time by including language in AB 327 giving the Commission the authority to make periodic changes to the NEM tariff. Although Section 2827.1(c) directs the utilities to offer a NEM tariff without a cap,[1] Section 2827.1(b) states: "The commission may revise the standard contract or tariff as appropriate to achieve the objectives of this section."

Having a tariff without a cap is essential to give customers certainty about the rules they will operate under if they become customer-generators. The current market uncertainty stemming from the instant proceeding is a perfect example of the problems of a capped tariff. An uncapped tariff essentially means it will remain in place until it is changed, rather than expiring if no action is taken. However, having an uncapped tariff does not mean that it cannot be adjusted incrementally over time for new customers. Solar-specific fees can be considered later, but are unnecessary in the short term and should not be adopted as part of the creation of successor tariffs.

[1] Section 2827.1(c) states, "There shall be no limitation on the amount of generating capacity or number of new eligible customer-generators entitled to receive service pursuant to the standard contract or tariff after July 1, 2017."

Categorization of Proposal

The following characteristics of the proposal are responsive to Section I.B.3 of the Ruling.

As explained in the Joint Solar Parties' March 16, 2015 filing, titled, "Comments of the Alliance for Solar Choice, the Solar Energy Industries Association, the California Solar Energy Industries Association, and Vote Solar on Policy Issues Associated with Development of Net Energy Metering Successor Standard Contract or Tariff" (JSP Policy Comments), the successors to the current net metering tariffs should be tariffs because that would ensure proper Commission oversight.[2]

Because credits are at the full retail rate, there is not a need to make a price differentiation between generation that offsets on-site load and generation that is exported to the grid or to require structural changes such as adding a second meter. Generation used behind the meter simply reduces consumption, and credits should be applied to exported power, as they are in the current NEM tariff. Netting intervals and true-up periods should remain the same as they are now. Exemptions for standby charges and distribution upgrade costs should continue.

A. Statutory Criteria

1. Sustainable Growth

The first criterion for the successor tariff in Section 2827.1 is that it "ensures that customer-sited renewable distributed generation continues to grow sustainably…" The Public Tool rightly measures DER market growth as an S-curve, as shown in Figure 1. With less than 5% market penetration, the solar industry is still in the innovation phase and moving to the growth phase. According to the S-curve, growth should now be increasing at the fastest pace of the cycle. Dramatic changes to the underlying economics of the market could derail the industry at a crucial juncture.

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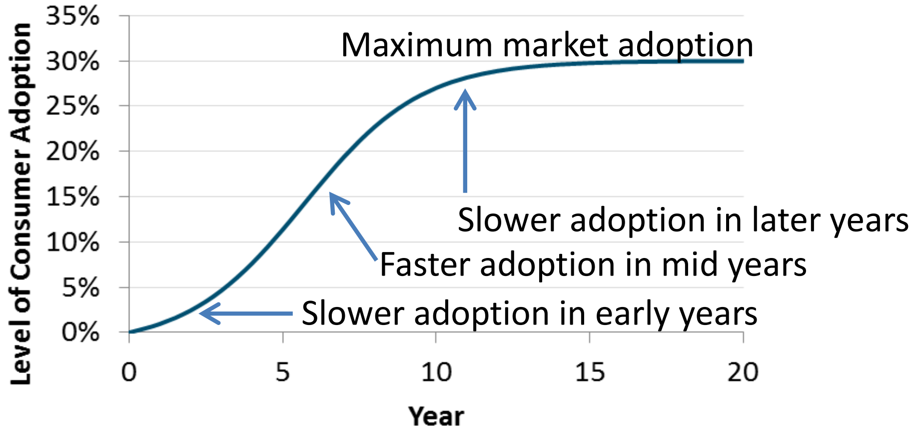
[2] R.14-07-002, JSP Policy Comments, March 16, 2015 at 4-7.

Figure 1. Rate of Adoption Curve from E3 Explanation of the Public Tool[3]



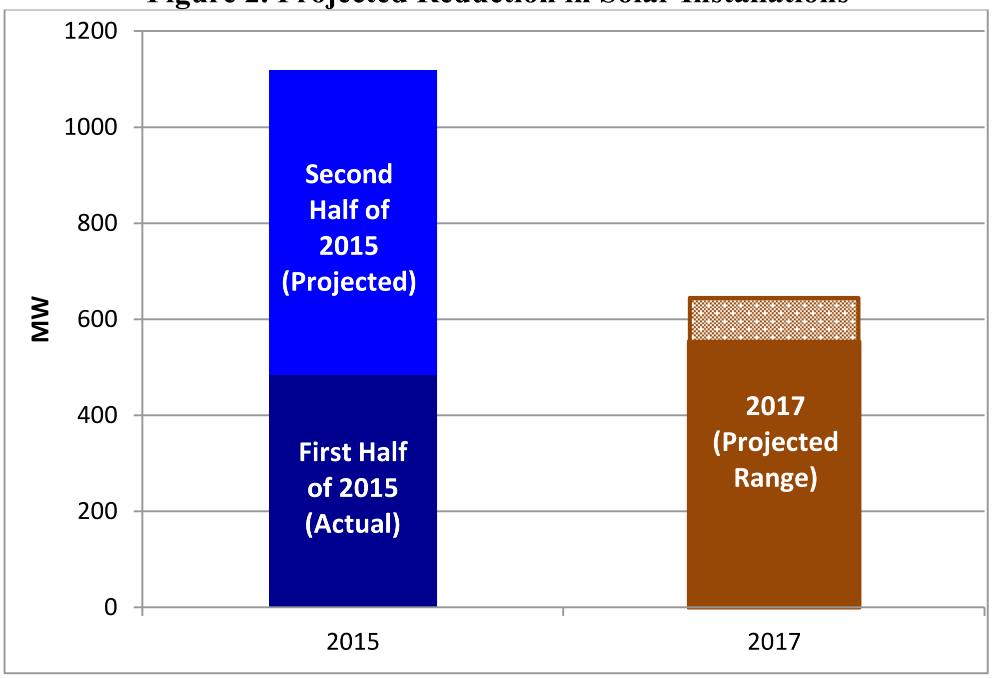
A sharp reduction in the market can be more than a short-term setback. If the entire industry is disrupted to the point where many actors are forced out of existence, sustaining growth and developing the next generation of technologies are not possible. It is extremely unfortunate that the termination of the current net metering tariff will happen at roughly the same time as the expiration of the ITC. Combined with the end of CSI and the abandonment of tiered residential rates, these forces are a potential train wreck that could cause the impact of the investment that California ratepayers have made in developing the solar market to be short-lived. Therefore, in determining whether the "continues to grow sustainably" standard will be met, CALSEIA looks first and foremost at 2017 adoption. If that number drops too sharply from current market activity, momentum and efficiencies will be lost.

California IOUs interconnected 484 MW of net metered generating capacity from January 1, 2015 through June 30, 2015.[4] This pace can be expected to increase in the second half of this year. From 2012-2014, the IOUs interconnected 32% more systems in the second half of the year than the first half.[5] Based on this experience, we can expect 635 MW to be interconnected in the second half of this year, for a 2015 total of 1,119 MW.

[3] Energy+Environmental Economics, "Public Tool Adoption Module and ELCC Module Overview," December 2, 2014 at slide 15.
[4] "Monthly AB 327 Net Energy Metering (NEM) Program Limit Reports," filed in advice letters by each IOU each month. Data derived by subtracting "Cumulative NEM Installations" each month from the same figure in the previous month's report.
[5] Data from IOU responses to CALSEIA data requests. See Appendix B for monthly numbers.

The Public Tool estimates that installations in 2017 will be 553-644 MW if net metering is continued without new fees,[6] around half of the actual installations the market will achieve this year. Any erosion of net metering benefits would reduce the 2017 market even further. Therefore, even a continuation of the current NEM tariff would violate Section 2827.1(b)(1) and alternate proposals would fare worse. The Commission must choose the option closest to satisfying that statutory requirement and continue NEM at full retail credit without new fees for the first few years of the successor tariff.

Figure 2. Projected Reduction in Solar Installations



In future years, the Public Tool shows adoption rebounding. In 2020, annual capacity installations surpass the level that the model predicts for 2016, though still below anticipated capacity additions for 2015 based on real market data. It is therefore essential that any changes to NEM be phased in. The Public Tool calculates that if exports were subject to non-bypassable charges in 2017, adoption would be 478 MW, compared to the 553 MW shown in Table 1. This is a reduction of 16%. Rather than having this hit while the market is struggling to rebound from the loss of the ITC, it should be delayed until approximately 2020.

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[6] These numbers, shown in Table 1, are overstated because they assume every solar customer will get a 10% ITC.

2. Costs and Benefits of the Facility

Section 2827.1(b)(3) requires that the successor tariff be "based on the costs and benefits of the renewable electrical generation facility." The standard is met with the CALSEIA proposal because the results of the Participant Cost Test show significantly more benefits than costs. As stated in the JSP Policy Comments, "the language directs the Commission to consider the costs and benefits of the facility itself, which are most directly experienced by the customer-generator who owns, leases, or buys power from the facility. For the electrical system perspective, the legislature included Section 2827.1(b)(4)."[7]

3. Total Benefits and Total Costs

a. Principal Findings

Section 2827.1(b)(4) requires that the "total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs." The CALSEIA proposal meets this requirement because the TRC test results are 1.21-1.23 and the SCT results are 2.07-2.10.

Table 1. Public Tool Results of CALSEIA Proposal – Before NBC Change

	2017 Adoption	TRC	SCT	Export RIM	All Gen RIM	NEM Credit Rate Impact
Tiered Rates - FC[8]	553	1.23	2.10	0.83	0.85	0.61%
TOU Rates - FC	618	1.22	2.08	0.76-0.81 [0.70]	0.80	1.11%-1.21%[1.31%]
Tiered Rates - ED	605	1.22	2.09	0.77	0.83	0.87%
TOU Rates 1 - ED	586	1.22	2.09	0.82-0.87 [0.76]	0.83	0.78%-0.85% [0.92%]
TOU Rates 2 - ED	644	1.21	2.07	0.85-0.91 [0.79]	0.70	1.12%-1.21% [1.32%]

Note: Results presented as ranges are increased (RIM) or decreased (Rate Impact) by 8%-15% from the Public Tool output to compensate for an acknowledged error in the model. The number in brackets is the Public Tool output value without correction.

[7] JSP Policy Comments at 14.
[8] The "FC" rates have a $10 fixed charge rather than a minimum bill, as explained in Appendix A, Section 1.B. They also have minor modifications to the CARE discount, as explained in Appendix A, Section 1.C. The Energy Division ("ED") rates are the structures contained in "Administrative Law Judge's Ruling Providing Further Instructions for Parties' Proposals and Accepting into the Record Certain Updates to the Public Tool," July 20, 2015 at 6.

Table 2. Public Tool Results of CALSEIA Proposal – After NBC Change

	2017 Adoption	TRC	SCT	Export RIM	All Gen RIM	NEM Credit Rate Impact
Tiered Rates - FC	478	1.24	2.12	0.83	0.89	0.57%
TOU Rates - FC	555	1.22	2.09	0.76-0.81 [0.70]	0.84	1.05%-1.14% [1.24%]
Tiered Rates - ED	557	1.23	2.09	0.77	0.86	0.85%
TOU Rates 1 - ED	548	1.23	2.09	0.78-0.83 [0.72]	0.86	0.95%-1.03% [1.12%]
TOU Rates 2 - ED	607	1.22	2.08	0.71-0.76 [0.66]	0.82	1.31%-1.42% [1.54%]

Note: Results presented as ranges are increased (RIM) or decreased (Rate Impact) by 8%-15% from the Public Tool output to compensate for an acknowledged error in the model. The number in brackets is the Public Tool output value without correction.

The results shown above include only the impact of systems installed 2017-2025 because that is the primary policy consideration in this proceeding. Including systems installed prior to 2017 reduces the TRC and SCT results but improves the results of the RIM test.

Table 3. Public Tool Results of CALSEIA Proposal Including Grandfathered Systems[9]

	2017 Adoption	TRC	SCT	Export RIM	All Gen RIM	NEM Credit Rate Impact
Tiered Rates - FC	553	1.08	1.71	0.89	0.92	0.54%
TOU Rates - FC	618	1.08	1.71	0.82-0.87 [0.76]	0.87	1.19%-1.29% [1.40%]
Tiered Rates - ED	605	1.08	1.71	0.83	0.89	0.89%
TOU Rates 1 - ED	586	1.08	1.71	0.87-0.93 [0.81]	0.90	0.86%-0.93% [1.01%]
TOU Rates 2 - ED	644	1.08	1.71	0.80-0.85 [0.74]	0.85	1.30%-1.41% [1.53%]

Note: Results presented as ranges are increased (RIM) or decreased (Rate Impact) by 8%-15% from the Public Tool output to compensate for an acknowledged error in the model. The number in brackets is the Public Tool output value without correction.

One limitation of the Public Tool is that it does not allow parties to use separate assumptions for different portions of customers. This functionality would be necessary to estimate the impacts of changes to the ITC. At the beginning of 2017, the ITC is scheduled to be reduced to 10% of installed cost for systems owned by commercial entities and to zero for systems owned by individuals. Because there will undoubtedly continue to be a mix of residential host-owned systems and third-party owned systems, assuming either 10% or zero for the tax credit is inaccurate.[10] The results shown above use the Public Tool's default input of 10%

[9] This does not include an expansion of NBCs.

[10] The reduced tax credit for commercial entities will likely make host-owned systems purchased with cash or financed with direct loans or property tax assessments more competitive with third-party owned systems financed by power purchase agreements.

ITC for all customers. CALSEIA performed separate model runs with the ITC in 2017 and beyond set at zero. This produces different values that can be viewed as part of a range of results.

Table 4. Public Tool Results of CALSEIA Proposal Without ITC[11]

	2017 Adoption	TRC	SCT	Export RIM	All Gen RIM	NEM Credit Rate Impact
Tiered Rates - FC	490	1.15	2.08	0.7	0.8	1.18%
TOU Rates - FC	418	1.17	2.11	0.90-0.95 [0.83]	0.84	0.46%-0.50% [0.54%]
Tiered Rates - ED	479	1.16	2.09	0.77	0.83	0.79%
TOU Rates 1 - ED	454	1.16	2.1	0.82-0.87 [0.76]	0.83	0.70%-0.75% [0.82%]
TOU Rates 2 - ED	525	1.15	2.07	0.76-0.81 [0.70]	0.78	1.02%-1.10% [1.20%]

Note: Results presented as ranges are increased (RIM) or decreased (Rate Impact) by 8%-15% from the Public Tool output to compensate for an acknowledged error in the model. The number in brackets is the Public Tool output value without correction.

When analyzed by individual year of installation, Standard Practice Manual (SPM) test results improve throughout the first decade for a successor tariff with full retail rate credit. In CALSEIA's base case, the TRC result is 1.23 when averaged over the 2017-2025 time period included in the Public Tool, but this is not consistent throughout that period. It begins at 0.99 in 2017 and steadily increases to 1.52 in 2025, as shown in Table 5.[12]

Table 5. SPM Test Results by Installation Year

Year of Installation	TRC	SCT	Export Only RIM	All Generation RIM
2017	0.99	1.59	0.80	0.81
2018	1.05	1.71	0.81	0.83
2019	1.11	1.82	0.81	0.83
2020	1.17	1.95	0.82	0.84
2021	1.23	2.08	0.83	0.85
2022	1.30	2.23	0.84	0.86
2023	1.37	2.37	0.84	0.86
2024	1.44	2.53	0.84	0.86
2025	1.52	2.70	0.85	0.87
2007-2025	1.23	2.10	0.83	0.85

[11] These results do not include grandfathered systems or expansion of NBCs.
[12] This scenario uses the "Tiered Rates - FC" rates.

b. Distributed Generation Policy Is Not Secondary to Other Policies

The Public Tool includes the ability to incorporate into its cost-benefit results the impacts of future policy changes beyond the successor tariffs. Most notably, a 50% renewable portfolio standard (RPS) and a zero net energy (ZNE) standard for new home construction are prominent options. However, the RPS and building codes are not within the scope of this proceeding. To make a judgment on the successor tariffs based on the combined impact of three major policy changes, two of which are out of scope, would violate proper procedure.

It is not the case that the RPS and ZNE policy are foundational and distributed generation policy is additional. As an increased RPS is debated, the cost-benefit analysis of that policy needs to be considered within that debate. When changes to building energy standards are considered, the Commission and the California Energy Commission can decide to evaluate the impacts using SPM cost-benefit tests. Those policies are not being debated in the instant proceeding. The Commission must make a decision on the successor tariffs for distributed generation in the current policy framework of a 33% RPS and existing building standards. Even if a party thinks it is likely that the state will adopt a 50% RPS, the cost-benefit impacts of that decision are impacts attributable to the RPS, not to the standard tariff for customer-generators.

c. DG Contribution to Meeting Long-Term GHG Targets

When counting the value of DER toward meeting the state's long-term GHG targets, the cost-benefit results of the CALSEIA proposal are even more strongly positive.

Table 6. Public Tool Results Including GHG Benefits

	2017 Adoption	TRC	SCT	Export RIM	All Gen RIM	NEM Credit Rate Impact
Tiered Rates - FC	553	1.38	2.14	1.06	0.97	-0.23%
TOU Rates - FC	618	1.51	2.17	0.98-1.05 [0.91]	1.03	0.35%-0.38% [0.41%]
Tiered Rates - ED	605	1.37	2.13	1.00	0.95	0.02%
TOU Rates 1 - ED	605	1.52	2.17	1.00-1.07 [0.93]	1.06	0.26%-0.29% [0.31%]
TOU Rates 2 - ED	646	1.51	2.16	0.92-0.98 [0.85]	1.02	0.59%-0.63% [0.69%]

Note: Results presented as ranges are increased (RIM) or decreased (Rate Impact) by 8%-15% from the Public Tool output to compensate for an acknowledged error in the model. The number in brackets is the Public Tool output value without correction.

On April 29, 2015, Governor Jerry Brown issued Executive Order B-30-15 that established a statewide greenhouse gas emission reduction target of 40 percent below the 1990 level by 2030 and reinforced the target of 80 percent below the 1990 level by 2050. To meet those targets from the electricity sector, the state will need to deploy a much greater amount of renewable energy than it has today. This will be a combination of utility-scale renewables and distributed renewables. If there is less distributed renewables, more utility-scale renewables will be needed to meet the same greenhouse gas reduction target. More utility-scale renewables would be accomplished by an increased RPS.

Distributed renewables must therefore receive credit as clean generation in statewide accounting at parity with the credit that utility-scale renewables receive in the RPS. However, creating a market for tradable RECs from distributed renewables would be inefficient. A better system would be to offer a NEM tariff that incorporates the RPS value of RECs into the cost-benefit calculation that justifies the tariff.

Fortunately, the Public Tool is able to calculate the value of distributed generation in terms of RPS credit. By using the methodology described in Section 1.F of Appendix B, the Public Tool makes a dynamic calculation of how the REC market would react to new distributed generation that counts toward RPS requirements. The value from that calculation can be incorporated into the NEM successor tariffs.

This level playing field was codified by AB 327, which stated, "The commission may require the procurement of eligible renewable energy resources in excess of the quantities specified…"[13] Previous to this, the RPS effectively acted as both a floor and a ceiling for the development of renewables that are given "Bucket 1" value. If distributed solar had been given the Bucket 1 level of RPS value, it would have resulted in less solar procured on the utility side of the meter because the RPS percentage was fixed. With the change, the Legislature directed the Commission not to treat the RPS as a ceiling. DG therefore should not result in offsetting large-scale renewables. The Commission can continue a requirement for set amounts of eligible renewables that is satisfied by the current definition of Bucket 1 resources and also incorporate RPS value into the standard tariff for distributed generation even though the utilities are unlikely to use DG as a Bucket 3 resource for compliance with the minimum requirements of the RPS.

d. Avoided Transmission Costs

CALSEIA supports the regression analysis contained in the successor tariff proposal of the Solar Energy Industries Association and Vote Solar. This analysis uses data for the CAISO

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[13] Section 399.15(b)(3).

transmission revenue requirement as a function of system peak demand, and finds that the slope of the curve is equal to $87 per kW-year. Based on actual data, every kW reduction in peak load saves $87 per year in transmission costs.

e. Non-Energy Benefits

CALSEIA has reviewed a paper prepared by Alison Seel of Sierra Club and Tom Beach of Crossborder Energy titled "Non-Energy Benefits of Distributed Generation for Use in NEM Successor Tariff Proceeding," which we understand will be submitted with the Sierra Club comments. CALSEIA supports the findings of that paper in their entirety and adopts the associated Public Tool inputs as the "Societal Inputs" for our model runs. Those inputs are the following.

- Carbon emission reduction benefit of $36 per ton of $CO2_{eq}$, based on the findings of the federal Interagency Working Group on Social Cost of Carbon. This is the lead government effort in this country to address the exact issue at question in this Public Tool input, and California is not in a position to overrule this important work.
- Particulate matter emission reduction benefit of $183.91/lb, based on the U.S. EPA's "Emission Factors and AP 42, Compilation of Air Pollutant Emission Factors."
- NOx emission reduction benefit of $23.69/lb stemming from the contribution of NOx to formation of both ozone and PM-2.5, based on an analysis from U.S. EPA published in June 2014.
- Avoided water use benefit of $0.0007/kWh of reduced thermal generation, using research from the CEC and E3 to measure the future increase in the cost of water availability.
- Reliability and resiliency benefit of $0.022/kWh of distributed generation output, recognizing that preventing outages is valuable to commerce, that energy storage will become an important tool in preventing outages, and that a strong solar market is essential to the development of energy storage.
- Land use benefit of $0.002/kWh of distributed generation output, based on research from the National Renewable Energy Laboratory and the U.S. Department of Agriculture on the value of land used by utility-scale solar plants.

- Local economic development benefits of $0.03/kWh of distributed generation output.

Including the full value of DER with these inputs demonstrates that benefits *to all customers* are more than twice as high as costs for a successor tariff that has full retail rate credit. SCT results in the CALSEIA base case are 2.07-2.10.

f. Impacts on Non-Participating Ratepayers

CALSEIA presents the results of the RIM test for purposes of comparison with the proposals of other parties, although Section 2827.1 does not require the Commission to consider those results and it would not be appropriate for the Commission to base its decision on the successor tariffs primarily on the RIM test. The Legislature made a conscious decision not to direct the Commission to include impacts on non-participating ratepayers as one of the statutory criteria in Section 2827.1(b). The Legislature has required "ratepayer indifference" in several policies related to distributed generation, but chose not to include such a requirement in AB 327.

- In 2009, the Legislature passed SB 32, which created the ReMAT feed-in tariff. The bill required: "The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff."[14]
- Also in 2009, the Legislature passed AB 920 to provide compensation to net metered customers with annual net surplus generation. The bill required: "The net surplus electricity compensation valuation shall be established so as to provide the net surplus customer-generator just and reasonable compensation for the value of net surplus electricity, while leaving other ratepayers unaffected."[15]
- In 2012, the Legislature passed AB 2514 to require a study on the costs and benefits of NEM. It required separate consideration of non-participating ratepayers by saying, "The study shall quantify the costs and benefits of net energy metering to participants and nonparticipants."[16]
- In 2013, the same year that the Legislature passed AB 327, it passed SB 43, which created the Green Tariff Shared Renewables program. The bill required: "The

[14] Section 399.20(d)(3).
[15] Section 2827(h)(4)(A).
[16] Section 2827.3(a).

commission shall ensure that charges and credits associated with a participating utility's green tariff shared renewables program are set in a manner that ensures nonparticipant ratepayer indifference for the remaining bundled service, direct access, and community choice aggregation customers and ensures that no costs are shifted from participating customers to nonparticipating ratepayers."[17]

During consideration of AB 327, the Legislature took the specific action of stripping language from the bill that directed the Commission to "Preserve nonparticipant ratepayer indifference." The September 3, 2013 amendments replaced that language with the current language in section 2827.1(b) on sustainable growth, disadvantaged communities, and the need for costs to be approximately equal to benefits. In that section, the Legislature directed the Commission to consider the impact on "all customers." According to the Standard Practice Manual, it is the TRC test that "represents the combination of the effects of a program on both the customers participating and those not participating in a program."[18]

Despite this, there is an interest by many parties to look at the RIM results, and the impact on non-participating ratepayers of the proposal is well within tolerable limits. According to the Public Tool, the RIM test results are 0.70-0.85, without considering GHG benefits. The Public Tool calculates that NEM credits in the proposal would increase rates by only 0.61%-1.21%. Including GHG benefits, the Public Tool calculates that NEM credits in the proposal would impact rates in a range of a 0.23% decrease to a 0.63% increase.

Further, as demonstrated in Table 5, the RIM test results improve throughout the first decade under a successor tariff with full retail rate credit. In the nine years of installations modeled in the Public Tool, both the all generation and export only RIM results increase in every year.

B. Bookend Cases for Comparative Purposes

The bookend cases may have value to help compare different proposals for the successor tariffs, but they are not useful information to understand the actual impacts of proposals. The low bookend case is completely unrealistic, the high bookend case has major flaws, and both cases have many incorrect values as described in Appendix A.

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[17] Section 2833(p).
[18] California Standard Practice Manual, October 2001 at 18.

1. Unrealistic Assumptions in Low Bookend

a. Curtailment

The low bookend case includes assumptions that the RPS will require 50% renewables and that much of that power will go unused. The resulting curtailment would be very expensive for customers, and increased distributed generation is accounted for making the situation worse.

First, as mentioned above, it is not the case that distributed generation policy is a secondary addition after establishment of utility procurement mandates. If there are cost-benefit impacts of a 50% RPS, those impacts must be attributed to the RPS and not to distributed generation. The Commission should not consider Public Tool results that contain curtailment costs as indicative of what will transpire from a decision in this proceeding. Significant curtailment under an increased RPS scenario would indicate a failure of the RPS program, not a failure of the DG tariff. It is not reasonable to penalize DG if centralized renewables are added to the electrical system without sufficient measures to ensure that contracted power will be used. To do so would be a determination that centralized renewables come first and DG is an afterthought if it fits. That is not the intention of the RPS.

Second, it would be irresponsible to create policy with the assumption that it will fail. The Commission and the Legislature are not considering a 50% RPS with the expectation that contracted power will not be consumed. Load shifting, demand response, regional trading, and other mechanisms will be employed if the state adopts a higher RPS.

The Commission must accord no weight to Public Tool results that include curtailment of renewables due to RPS requirements in future years.

b. No Avoided Subtransmission and Distribution Costs

The extent to which utilities can reduce their spending on the subtransmission and distribution systems is a legitimate debate, but to assume that such avoided costs are zero is unreasonable and is discriminatory against customer-generators. It is the responsibility of utilities to modernize their planning and forecasting. If the utilities spend as much money with DG as they would without it, that would be their failure in decision making and self-generators should not be penalized for such failures.

Preventing such a planning failure is a primary purpose of the distribution resources planning (DRP) process. Even without this process, utilities are able to defer expenditures due to reduced consumption resulting from DG. When the DRP process is fully developed, they will be able to reduce their spending even further.

c. ZNE Policy

The Public Tool contains an option to include an assumption of a future policy that zero net energy becomes mandatory for all new residential housing. This results in "410 MW of additional residential rooftop solar per year beginning in 2020." As such a policy is considered, the Commission can choose to consider various cost-benefit impacts of that policy. As explained in Section I.A.3.b above, because the ZNE policy has not been adopted, the Commission cannot include the impacts of that policy as an impact of the successor tariffs.

2. Unrealistic Assumption in High Bookend

a. Low Solar Cost

Solar companies understand that they need to work hard to reduce costs. Cost reductions in recent years are widely viewed as a success story, and there is hope that the success will continue. However, the largest cost reductions have come from high volume manufacturing of solar panels. As Lawrence Berkeley National Laboratory has found, "The decline in installed system prices since 2008 is largely attributable to module price reductions."[19] In the past year, the cost of panels appears to have hit bottom and in some cases has begun to increase. Future price reductions will come from "soft costs," which include customer outreach, labor efficiency, and the costs involved in permitting, design approvals, and inspections. If market volume continues to increase, it is conceivable that all of these costs will continue to decline. However, if the solar value proposition gets significantly worse, expanding the customer base will be harder. If total market volume decreases, it will be difficult to improve labor efficiency. And for improvements to the permitting and approval process local governments and utilities have to be willing partners.

From 2008-2013, the total installed price of solar in California declined by 11% per year.[20] For the reasons stated above, it will be hard to sustain that percentage reduction going forward, but it is reasonable to hope we can get close. That is the scenario in the Public Tool

[19] Galen Barbose, Samantha Weaver and Naim Darghouth, Lawrence Berkeley National Laboratory, "Tracking the Sun VII: The Installed Price of Photovoltaics in the United States from 1998 to 2013," September 2014 at 1.
[20] *Ibid.,* Table B-3 at 53.

base solar cost case, as shown in Table 7. The low solar cost case, in contrast, is not realistic. Expecting the rate of reduction to double at the same time that the value proposition to customers is tightening and manufacturing economies of scale have largely been achieved is not reasonable. The Commission must not base its decision on the successor tariffs on such a wishful price scenario that is not grounded in reality.

Table 7. Annual Price Reduction Assumptions in the Public Tool[21]

	Low	Base	High
2014	23%	10%	3%
2015	21%	9%	3%
2016	19%	9%	3%
2017	18%	8%	3%
2018	12%	5%	2%
2019	11%	5%	2%
2020	10%	5%	2%
2021	2%	5%	2%
2022	2%	5%	3%
2023	2%	5%	3%
2024	2%	5%	3%
2025	2%	5%	3%

3. Unrealistic Assumptions in Both Bookends

In addition to the many incorrect values listed in Appendix A, both bookends have the following glaring errors.

a. Rate Escalation

Both bookend cases include the assumption that people expect average electric rates to increase by 5% per year. This is double the escalation rate predicted by the Public Tool itself. Rate escalation from 2020-2050 within the Public Tool itself is 2.5% for PG&E, 2.6% for SCE, and 2.4% for SDG&E.[22]

Customers are skeptical of sales pitches that appear to overpromise, and rate escalation is a key factor in anybody's decision whether to install solar. Most customers like to see real data to back up claims on such an important factor. Also, it is not in the best long-term interests of solar companies to overstate expected savings. If actual rate escalation is 3% or less, that is what most

[21] Solar costs are listed in the Advanced DER Inputs tab in cells D31:J48.

[22] Average rate escalation for residential rates in the Rate Output Table tab of the Public Tool in the CALSEIA base case.

solar providers will be explaining to customers. For the Commission to say it expects rates to increase less than 3% per year but it expects solar companies to convince customers that rates will go up 5% per year is astounding and is not remotely reasonable.

b. Avoided Transmission Costs

Analysis contracted by the Commission has found that distributed solar frees up capacity on the transmission system.[23] When the Commission's own analysis finds that there are avoided transmission costs, it is not reasonable to base the NEM tariff decision, even in part, on a scenario that includes zero benefit for avoided transmission costs.

c. Non-Residential Rates

Many of the non-residential rate structures in the default inputs do not seem to be based on actual IOU tariffs. Accurate results cannot be expected from an analysis that uses fictitious rates.

4. Results from Bookend Cases

Despite the major problems with the bookend assumptions listed above and the many other inaccurate assumptions in the Public Tool listed in Appendix A, the TRC and SCT results are positive in the high bookend case. The adoption rate is unrealistically high, however, due to the 5% assumed rate escalation and the low solar cost case.

Table 8. High Bookend Case

	2017 Adoption	TRC	SCT	Export RIM	All Gen RIM	NEM Credit Rate Impact
Tiered Rates	1401	1.07	1.10	0.40	0.47	5.63%
TOU Rates 1	1373	1.09	1.11	0.41-0.44 [0.38]	0.47	5.02%-5.43% [5.90%]
TOU Rates 2	1288	1.11	1.14	0.40-0.43 [0.37]	0.46	4.89%-5.29% [5.75%]

Note: Results presented as ranges are increased (RIM) or decreased (Rate Impact) by 8%-15% from the Public Tool output to compensate for an acknowledged error in the model. The number in brackets is the Public Tool output value without correction.

[23] Itron/KEMA, "CPUC California Solar Initiative: 2009 Impact Evaluation," June 2010.

Table 9. Low Bookend Case

	2017 Adoption	TRC	SCT	Export RIM	All Gen RIM	NEM Credit Rate Impact
Tiered Rates	634	0.39	0.39	0.17	0.22	7.16%
TOU Rates 1	658	0.39	0.39	0.16-0.17 [0.15]	0.22	6.79%-7.35% [7.99%]
TOU Rates 2	669	0.39	0.39	0.15-0.16 [0.14]	0.21	7.10%-7.68% [8.35%]

Note: Results presented as ranges are increased (RIM) or decreased (Rate Impact) by 8%-15% from the Public Tool output to compensate for an acknowledged error in the model. The number in brackets is the Public Tool output value without correction.

Changing four of the most unrealistic assumptions in the low bookend greatly impacts the results. Removing curtailment, reducing anticipated rate escalation to 3%, counting some avoided transmission and distribution costs,[24] and using the base solar costs produces entirely different cost-benefit results. It more than doubles all of the SPM cost test results, and the TRC and SCT results are at or near one.

Table 10. Low Bookend Case With Removal of Four Unrealistic Assumptions

	2017 Adoption	TRC	SCT	Export RIM	All Gen RIM	NEM Credit Rate Impact
Tiered Rates	722	0.93	0.96	0.43	0.54	5.60%
TOU Rates 1	715	0.97	1	0.51-0.54 [0.47]	0.58	4.03%-4.36% [4.74%]
TOU Rates 2	747	0.93	0.95	0.40-0.43 [0.37]	0.52	5.81%-6.29% [6.84%]

Note: Results presented as ranges are increased (RIM) or decreased (Rate Impact) by 8%-15% from the Public Tool output to compensate for an acknowledged error in the model. The number in brackets is the Public Tool output value without correction.

C. Systems Larger Than One Megawatt

Section 2827.1(b)(5) requires that the successor tariffs, "Allow projects greater than one megawatt that do not have significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one megawatt are subject to reasonable interconnection charges established pursuant to the commission's Electric Rule 21 and applicable state and federal requirements." Allowing systems larger than one megawatt to participate in NEM is fair to large customers, especially because the cost-benefit test results are stronger for the large commercial and industrial sectors than the residential and small commercial sectors.

Rule 21 Section E.4.f states that NEM systems are exempt from distribution upgrade

[24] $40/kW-yr avoided transmission cost and 100% cost multipliers for marginal avoided subtransmission and distribution costs.

costs but can be required to pay interconnection facilities costs. In other words, if a NEM interconnection triggers the need for upgraded equipment that serves multiple customers, it is the utility's responsibility to pay for it. If it triggers the need for upgraded equipment that only serves the customer interconnecting the new generating facility, it is that customer's responsibility to pay for it. Because Section 2827.1(b)(5) requires that systems larger than one megawatt can only take service under the NEM tariff if they do not have significant impact on the distribution grid, it is reasonable to require such systems to pay for distribution upgrade costs that they make necessary in addition to interconnection facilities costs.

D. The IOUs Must Continue Virtual Net Metering and NEM Aggregation and Improve the Virtual Net Metering Tariff

Virtual net metering (VNEM) was developed to implement the Multifamily Affordable Solar Housing (MASH) program within CSI and later expanded to become available for non-MASH projects. NEM aggregation (NEMA) was developed to implement SB 594 of 2012, primarily to facilitate adoption of solar for agricultural entities that have multiple electric meters on a single farm. VNEM is essential for the continued expansion of solar for low-income communities, and NEMA has proven to be a valuable and functional option for farmers to stabilize their energy costs. Both options must continue, and VNEM for non-MASH projects should be fixed to make it available for a broader universe of apartment complexes.

1. VNEM

VNEM expands consumer options for renewable energy by removing significant hurdles commonly associated with traditional NEM. For example, VNEM can allow residents in a multitenant building to participate in a common system on the roof of their building, even if the residents are renters. And by allowing one system to address the load of multiple units, the system can be designed to maximize output and reduce installation cost rather than installing multiple systems at separate locations.

a. History of the VNEM Tariffs

In January 2006, the Commission committed to providing $2.8 billion for solar incentives over 11 years through the CSI, and set aside 10% of the money for low-income residential customers and affordable housing projects.[25] Later that year, the Legislature codified that commitment with SB 1.

To utilize the 10% set-aside of CSI funding, the Commission created the MASH Program in October 2008.[26] Recognizing that virtual net metering was essential for multifamily properties to be able to take advantage of the rebates, the need for a new utility tariff was apparent. Prior to the MASH Program kick-off, SDG&E proposed Schedule PVPC, the Photovoltaic Purchase and Credit tariff, in May 2007,[27] to serve as the tariff for MASH participants. This PVPC tariff was a form of VNEM, although credits were not carried forward from one month to the next, like the typical NEM arrangement. In addition, the credit rate was proposed to be equal to the class average rate for low-income customers at the time rather than their full retail rate. The Commission approved a tariff, but ordered that it include accumulation of NEM credits until an annual true-up, the same as in the standard net metering tariff, and credits at the full retail rate. VNEM was adopted on a pilot basis and only for the MASH program, but the decision stated that the Commission would issue a ruling at a later date to consider expanding the tariff to all multi-tenant properties.

The decision creating VNEM required utilities to, "Allow for the allocation of net energy metering benefits from a single solar energy system to all meters on an individually metered multifamily affordable housing property."[28] However, rather than define what constitutes a "property," the decision included a restriction that the accounts that receive virtual net metering credits be behind the same service delivery point (SDP) as the solar system. SDP is commonly defined as "the demarcation between the customer-owned electrical system and the utility distribution system."[29]

Affordable housing projects often consist of multiple buildings that each have individual SDPs. Property owners and project developers complained that solar installations were not cost-effective at many affordable housing properties because of the SDP limitation.

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[25] CPUC Decision 06-01-024.
[26] CPUC Decision 08-10-036.
[27] SDG&E Advice Letter 1895-E, filed May 7, 2007.
[28] *Ibid.,* p. 38.
[29] CPUC Decision 11-07-031, p. 6.

After three years of operation of CSI, Commission staff issued a report in July 2010 recommending various changed bases on lessons learned. The proposed changes related to virtual net metering included the following.

1. Make VNEM a standard tariff for customers in the MASH program rather than a pilot program.
2. Lift the SDP restriction for MASH projects, allowing all tenants on the property to have access to the solar benefits.
3. Expand VNEM to general market multifamily housing, outside of the low-income sector and MASH program, but only within a single SDP.

On the second recommendation, PG&E filed a proposal in August 2010 to temporarily address the SDP issue.[30] The changes were urgent because the SDP limitation prevented low-income multifamily property owners from taking advantage of American Recovery and Reinvestment Act funding. PG&E proposed to allow netting among a group of customers beyond a single SDP, but limited to customers within one low-income housing development. A single development was defined as "all of the real property and apparatus employed in a single low income housing enterprise on contiguous parcels of land."[31] It also specified that "parcels may be divided by a dedicated street, highway, or public thoroughfare or railway, so long as they are otherwise contiguous and part of the same single low income housing enterprise, and all under the same ownership."[32] The Commission approved this proposal as an interim measure with an effective date of September 2010 and a sunset date of December 2011.

The Commission then turned to the question of whether to make those changes for all three IOUs and to remove the sunset date for PG&E. In a July 2011 decision, the Commission pointed out that the SDP limitation hindered the Commission's ability to meet its goal "to allocate the benefits of solar energy systems to all tenants on the affordable housing property."[33] The Commission approved all three recommendations from the Staff Report.

1. It removed the sunset date on the MASH tariff.
2. It ordered the other two IOUs to match PG&E's MASH tariff by removing the SDP

[30] PG&E, Advice Letter 3718-E.
[31] CPUC Decision 11-07-031, p. 7.
[32] *Ibid.,* p. 8
[33] *Ibid.,* p. 13.

limitation.

3. It ordered the IOUs to create a VNEM tariff for non-low-income multitenant housing properties, but with participation limited to a single SDP.

This gradual expansion of VNEM is the result of an approach by the Commission to start with a narrowly defined tariff and expand it in measured steps as experience is gained. The Commission should continue that approach by making one important change as it adopts successor tariffs.

b. Need to Modify VNEM Tariff

Experience since D.11-07-031 reveals that the VNEM tariff for market rate apartment complexes should also be changed to remove the SDP limitation. Only 150 non-MASH VNEM projects have been installed to date.[34] This represents a small fraction of the potential opportunity. More than 6 million Californians live in apartment buildings, 17% of the state's population.[35]

Many apartment complexes consist of multiple buildings, each with their own master meter connected to the utility distribution system. Utilities have argued that allowing NEM credits to be transferred from a solar system on one building to offset consumption in another building on the same property involves usage of the distribution system and therefore full NEM credits are not justified. The Commission should reject this argument as an attempt to eliminate an important benefit for apartment dwellers based on an inconsequential or non-existent impact.

Adjacent buildings on a single property in nearly every case are on the same section of one circuit. The capacity of the circuit section is subject to minimum standards that exceed capacity requirements driven by distributed generation. National Electrical Code section 230.23(B) requires that all overhead aluminum service conductors shall be no smaller than American wire gauge #6, which is rated for 140 amps. A typical 1 MW system draws approximately 60 amps at 12 kV.[36] Therefore, the conductoring between one building and the next is always built to handle the power flow from a solar system sized to meet the load of an

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[34] Based on IOU interviews conducted by the Center for Sustainable Energy for the purposes of "Virtual Net Metering Policy Background and Tariff Summary Report," Center for Sustainable Energy, CALSEIA, and Interstate Renewable Energy Council, June 30, 2015.
[35] National Multifamily Housing Council, "Quick Facts: Resident Demographics," downloaded July 23, 2015 from https://nmhc.org/Content.aspx?id=4708.
[36] Assuming a 1.25 continuous loading factor.

apartment complex. If the service drop where the solar system is to be interconnected is not of sufficient capacity, or if there are multiple generators on the same circuit section with the potential to backfeed, there are existing procedures in Electric Rule 21 to address upgrades needed for interconnection, but the fact that some of the power will travel a short distance along the feeder does not impact utility costs.

The Commission should order the IOUs to revise their VNEM tariffs for market rate multifamily housing to allow participation by multiple SDPs on a single property, mirroring the same rule for low-income customers in the VNEM tariffs.

2. NEMA

The meter aggregation option in the NEM tariff began in February 2014 for PG&E and in July 2014 for SCE and SDG&E. It has been popular among customers, particularly for the agricultural customers that were the primary motivation for creating the option. PG&E reports that they are now receiving roughly ten NEMA applications per week.[37]

Implementation of NEMA has not been without problems. Customers have been subject to extreme delays and major unexpected costs. Many customers were initially denied participation in NEMA due to utility misinterpretation of statute. PG&E has a backlog to establish credit allocation for interconnected customers, so many customers' bills do not reflect their NEMA generation. CALSEIA does not believe that the IOUs have been implementing NEMA in good faith. This conclusion is echoed by the Energy Division in a July 7, 2015 letter to PG&E, stating, "some of the utility purported interpretations of the statute are disingenuous and appear to be intended to thwart the intent of the Legislation by minimizing the number of customers that could qualify for the Net Energy Metering Aggregation (NEMA) program."[38]

These problems are gradually being worked out as the utilities and solar providers gain experience. It is far too early to pull the plug on a program that is only beginning to realize the benefit that the Legislature directed the Commission to strive to achieve. CALSEIA recommends continuing NEMA without making any changes to the tariff as part of the development of the NEM successor tariff.

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[37] Letter from Patrick M. Hogan, Vice President of Asset Management for PG&E, to Edward Randolph, Executive Director of the CPUC Energy Division, July 15, 2015.
[38] Letter from Edward Randolph, Executive Director of the CPUC Energy Division, to Patrick M. Hogan, Vice President of Asset Management for PG&E, July 7, 2015.

II. Proposals for Disadvantaged Communities

CALSEIA strongly supports the CleanCARE proposal developed by the Interstate Renewable Energy Council (IREC) as part of the response to the requirement that the Commission include a net metering successor tariff alternative designed for growth among residential customers in disadvantaged communities. We defer to IREC to present the details of that proposal, but understand it to be a pilot program that uses the CARE budget more efficiently by funding solar installations and providing kWh credits to low-income customers rather than perpetually buying down their rates.

CALSEIA also strongly supports the neighborhood virtual net energy metering concept presented in "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." We will provide more comments on CleanCARE and neighborhood VNEM for the comments on party proposals and staff papers due September 1, 2015.

In addition, the Legislature is now debating AB 693, which would use cap and trade allowance revenue to subsidize solar installations on low-income apartment buildings. If this bill passes, it should be included as part of the disadvantaged communities requirement, although CALSEIA does not expect it should satisfy the entirety of the requirement because there are other sectors within disadvantaged communities beyond low-income apartment buildings that should also receive policy support.

III. Conclusion

CALSEIA appreciates the opportunity to submit this proposal and urges the Commission to adopt the recommendations herein.

Respectfully submitted at Santa Rosa, California this August 3, 2015,

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Appendix A. Public Tool Assumptions in CALSEIA Model Runs

1. Public Tool

A. Key Driver Inputs

2030 Renewable Portfolio Standard (RPS) Policy Target: 33%. As stated in Section I.A.3.b, although there is reasonable likelihood that the state will adopt a 50% RPS, any cost-benefit impacts of that policy change must be attributed to the RPS and not the successor tariff.

Marginal Generation Capacity Avoided Cost Treatment: Vintaged.

Electric Vehicle Selection: Default - Base. This assumption is aggressive enough to acknowledge California's leadership but conservative enough to be clearly attainable.

Electric Vehicle Charging Scenario: More Daytime. Electric vehicles are increasingly popular, and employers are seeking ways to attract high quality employees in a competitive job market. A combination of time of use price signals and direct incentives will compel employers to install charging stations at employment centers so that EVs can charge in the daytime.

Zero Net Energy (ZNE) Homes Policy Scenario: No ZNE Policy. Although there is a fair likelihood that building codes will be revised to encourage or require zero net energy design, any cost-benefit impacts of that policy change must be attributed to building code revisions and not the successor tariff.

DER Renewable Energy Credit (REC) Scenario: DER Does Not Count for Bucket 1. CALSEIA includes an analysis of GHG parity between DG and RPS resources rather than including DG as a Bucket 1 resource in a REC market.

Natural Gas Price: 100%. Default value.

RPS PPA Costs: 100%. Default value.

Carbon Market Costs: High. Gov. Brown recently issued Executive Order B-30-15, which creates a state GHG reduction target of 40% below the 1990 emission level. This will add major amounts of demand to the state carbon market and push prices higher.

Resource Balance Year: 2017. The recent approval of the Carlsbad Energy Center, multiple solicitations for local capacity, and the anticipated retirement of large generating units demonstrate that potential new units are an immediate issue.

Ancillary Service Costs: 1%. Default value.

Marginal Avoided Transmission Costs: $87/kW-yr. See Section I.A.3.d.

Marginal Avoided Energy Cost Location Multiplier: 104.8%. As stated in the JSP Policy Comments, "energy prices are higher, on average, in places where solar installation rates are higher. The Public Tool uses a statewide average energy cost that is not weighted based on the geographic concentration of DER. The Tool therefore undervalues solar because solar historically has offset utility costs in places where costs are high, and this trend should be expected to continue. Locations where the grid is congested are places with a high density of utility customers and therefore a high concentration of DER. Public Tool Revisions created an input option to correct for this shortcoming in the Public Tool methodology. An analysis by Kevala Analytics demonstrations that the statewide average energy cost understates utility avoided energy costs by 4.8%.

Utility Distribution Capital Expenses: PG&E: 100%; SCE: 100%; SDG&E: 75%. Because the SDG&E number is based on a proposed value rather than an adopted value, it is not a reliable figure. Utilities routinely propose much higher expenses than are approved. Recent SDG&E GRCs show the following difference between proposed rate changes and approved rate changes.

Solar Cost Case: Base. See Section I.B.2.a.

NEM Successor (Post 2017) DER Program Costs Paid by: All Customers. No change from current policy.

Assumed Utility Rate Escalation (nominal): 3%. Rate escalation within the model itself is less than 3 percent, as described in Section I.B.3.a. The Commission cannot count on customers to make inefficient decisions.

Compensation Tax Treatment: Tax Exempt. NEM credits are not taxable.

Societal Inputs: See Section I.A.3.e.

Discount Rate Inputs: Default values.

B. Basic Rate Inputs

Residential Fixed Monthly Charge: $10. The recent decision in the residential rate restructuring case, D.15-07-001, points toward adoption of a fixed charge as early as 2020. The Decision lays out four conditions and states, "Provided that all four conditions have been met, a fixed charge can be implemented with an effective date at least one year after the start of default TOU."[39] Although CALSEIA does not support fixed monthly charges, we consider it more likely than not that a residential fixed charge will be implemented on the early side of the 2017-2050 timeframe of the Public Tool. Therefore, a $10 residential fixed charge is included for both default rates and DER rates.

C. Advanced Rate Inputs

CARE Discount: Keep the SCE default value of 32%. Reduce the value for PG&E and SDG&E to 32.5%. Section 739.1(c)(1) requires that the effective CARE discount be in the range of 30%-35%. We used the middle of the range, except in the case of SCE, which is already lower.

[39] D.15-07-001 at 193.

Non-Residential Rates: The following rate schedules were used for non-residential rates.

	Class	Non-DER	DER
PG&E	Small Commercial Medium Commercial Large Commercial Industrial Agricultural	SCE TOU-GS-1[40] A-10 E-19 E-20 AG-4-A	SCE TOU-GS-1 voluntary E-19-R E-19-R E-20-R AG-4-A
SCE	Small Commercial Medium Commercial Large Commercial Industrial Agricultural	TOU-GS-1 TOU-GS-3-B TOU-8 TOU-8 TOU-PA-2	TOU-GS-1 TOU-GS-3-R TOU-8-R TOU-8-R TOU-PA-2
SDG&E	Small Commercial Medium Commercial Large Commercial Industrial Agricultural	TOU-A AL-TOU AL-TOU A6-TOU TOU-PA	TOU-A DG-R DG-R A6-TOU TOU-PA

D. Advanced DER Inputs

Curtail Renewables During Overgeneration: No. As stated in Section I.B.1.a, we assume that alternatives to overgeneration will be developed in concert with increased generation from renewables.

E. Adoption Model Tab

Correct for inaccurate system size calculation. As stated in the Joint Solar Parties' comments on the draft Public Tool, the model inaccurately estimates that a majority of customers will install systems that offset 100% of load. This is inaccurate for at least four reasons: A) Customers tend to be conservative. If the benefits are similar for different sized systems, then most will choose the smaller system; B) Many customers are limited by available roof space. Some people who are counted as potential customers in the technical potential of solar do not have enough roof space to size their systems to offset all of their load; C) Solar customers on TOU rates do not size their systems to offset 100% of onsite load; and D) Minimum bills eliminate the benefits of

[40] PG&E's small commercial rate, A-1, does not have demand charges. Although CALSEIA does not support the increasing dependence on demand charges, we understand that the utilities strongly support demand charges and the Commission is generally sympathetic. We therefore anticipate for purposes of analysis that in the long run PG&E will switch to a rate structure for small commercial customers similar to SCE's standard small commercial rate.

sizing a system beyond a certain percentage of annual consumption. To correct this error, CALSEIA assumes the system size for each customer bin is the same in 2017-2025 as the Public Tool calculates for that bin for 2008-2012. This is accomplished by pasting the Public Tool's calculated 2008-2012 system sizes for each bin into cells C102:H786, adding a formula to cell A11 to look up the historic system size when each bin is active,[41] and using that value for the ultimate determination of system size in cells N28:N30.[42] In the CALSEIA base case, this resulting mix of system sizes is 43% large, 35% medium, and 22% small. Without the change, it would be 75% large, 9% medium, and 16% small.

F. Avoided Cost Calculations Tab

As explained in Section I.A.3.c, CALSEIA included avoided GHG costs in some scenarios. To accomplish that, we valued DG at 100% of the RPS premium in each year by removing the Annual RPS Target from the formulas in lines 437 and 444,[43] and removed banking of avoided renewables costs from DER by setting line 438 equal to 437 and line 445 equal to 444.

2. Revenue Requirement Model

CALSEIA's revenue requirement model changes are identical to those of other solar parties. They are the following.

A. RR Inputs Tab

Integration Costs: $2.38/MWh in a 33% RPS, $2.79/MWh in a 40% RPS, and $3.38/MWh in a 50% RPS (cells G414-G416). The number for 33% is based on E3's January 2014 study of a 50% RPS, "Investigating a Higher Renewables Portfolio Standard in California" at p. C-60, and is escalated for 40% and 50% at the same proportion as the default values in the Public Tool.

PG&E and SDG&E interconnection costs: equivalent to those of SCE (cells G380-G384 and G396-G400). All of the IOUs are automating steps in the interconnection process and striving for industry best practices.

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[41] Formula is "VLOOKUP(activeBin,$C$102:$H$786,6)"
[42] Revised formula for these cells is "IF(MAX($I$28:$I$30)=MAX($I$28:$I$39),IF(C28=$A$11,1,0),0)"
[43] Revision to formula for cell E437 is "IF(E$1,($E$425+$E$426~~*E433~~)*$E$429/1000,0)"

Cost of CCGT Capacity (cell G300): $176/kW-yr, based on CAISO "2014 Annual Report on Market Issues and Performance" (CAISO Annual Report), Table 1.6 at 52.

Cost of CT Capacity (cell G301): $190 per kW-yr, based on CAISO Annual Report, Table 1.8 at 54.

Gas CCGT Heat Rate (cell G208): 7400 Btu/kWh, based on midpoint of values in CAISO Annual Report, Table 1.6 at 52.

Gas CT Heat Rate (cell G209): 9500 Btu/kWh, based on midpoint of values in CAISO Annual Report, Table 1.8 at 54.

Gas CT Economic Life (cell G180): 30 years, based on CEC "Estimated Cost of New Renewable and Fossil Generation in California," Table 14 at 41.

Fossil Steam Capacity Factor (cell G200): 5%, as a more reasonable assumption for steam-boiler generators, given the expected continued retirement of OTC units from service.

Portion of Distribution Capex Costs that Are Growth Related (cells G346-G348): 22%. The Distribution Resources Planning process should be expected not only to defer investment in distribution system expansion but also to avoid new investment in existing capacity.

Generation Rate Base Cost Adjustment Factor for SDG&E (cell G353): 75%, because the default input is based on an application and not an approved value.

Revenue Requirement Allocation to Customer Classes (cell D422): Option 3 – Settlement rate relationships maintained. Settlements are the norm for GRCs and have maintained the same basic cost allocation relationships among customer classes.

B. RR Calculations Tab

Remove Diablo Canyon O&M after plant shuts down in 2022. Add an item in row 266 for Diablo Canyon O&M starting at $300 million in 2013 and increasing 2% per year, based on GRC information, and subtract that amount from PG&E Generation O&M (line 265) starting in 2024.

Appendix B. Monthly NEM Installations

Source for Tables B-1 - B-3: IOU responses to CALSEIA data requests.

Table B-1. PG&E Monthly NEM Interconnections

	2011		2012		2013		2014		Total	
Month	**Count**	**MW**	**Count**	**MW**	**Count**	**MW**	**Count**	**MW**	**Count**	**MW**
Jan	1,447	12.46	1,229	19.14	1,576	17.16	3,052	27.65	7,304	76.40
Feb	1,100	12.77	1,132	11.10	1,595	16.96	2,276	20.98	6,103	61.81
Mar	996	12.27	988	13.95	2,042	17.56	2,847	29.49	6,873	73.26
Apr	867	9.62	915	10.40	2,196	15.62	3,158	21.92	7,136	57.57
May	880	8.87	1,201	15.06	1,900	20.29	3,154	20.94	7,135	65.16
Jun	1,038	15.76	1,274	20.34	1,854	17.54	3,830	28.62	7,996	82.26
Jul	942	12.69	1,685	14.07	1,977	17.72	3,857	28.74	8,461	73.21
Aug	1,122	19.15	1,686	15.88	2,672	24.63	4,167	27.75	9,647	87.41
Sep	1,125	17.63	1,503	14.10	2,738	25.33	4,514	31.86	9,880	88.92
Oct	1,406	19.76	2,275	21.18	2,747	23.07	4,496	37.08	10,924	101.10
Nov	1,430	15.02	1,775	17.95	4,079	30.40	4,506	32.23	11,790	95.60
Dec	1,280	35.69	1,794	26.80	3,284	33.04	5,387	37.86	11,745	133.38
Total	**13,633**	**191.70**	**17,457**	**199.95**	**28,660**	**259.31**	**45,244**	**345.12**	**104,994**	**996.08**

Table B-2. SCE Monthly NEM Interconnections

Year	Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2011	Apps	447	511	623	682	658	704	657	786	901	1204	1210	1360	9743
2011	MW	4.8	5.3	9.4	5.6	4.7	10.9	7.1	7.1	8.8	11.4	9.5	18.1	102.6
2012	Apps	1101	1372	1261	1106	1115	1270	1167	1521	1216	1670	1285	1397	15481
2012	MW	13.0	11.0	8.1	11.2	9.9	11.0	10.6	17.3	9.9	13.9	11.1	15.6	142.6
2013	Apps	1930	1428	1796	1933	1957	1741	1819	2011	2511	2544	3047	3423	26140
2013	MW	16.6	11.1	14.2	16.2	16.4	14.7	13.8	15.1	15.8	16.6	20.4	27.8	198.6
2014	Apps	2897	2515	2314	2863	2907	2983	3202	3004	2832	2421	2494	4043	34475
2014	MW	19.4	16.0	14.6	23.8	16.9	20.8	22.3	17.9	18.6	17.2	20.0	32.2	239.8

Table B-3. SDG&E Monthly NEM Interconnections

Year	Jan kW	Feb kW	Mar kW	Apr kW	May kW	Jun kW
1999	3	-	2	-	-	-
2000	-	2	9	3	1	-
2001	15	29	35	30	60	40
2002	106	98	52	158	117	54
2003	175	118	89	155	347	1,223
2004	426	198	298	254	539	130
2005	372	652	266	227	369	429
2006	341	329	481	420	458	229
2007	1,272	637	624	446	1,661	443
2008	435	683	522	1,681	887	1,565
2009	991	633	548	1,231	597	666
2010	1,969	1,296	1,955	2,224	1,525	2,241
2011	1,463	1,608	2,643	2,467	2,673	2,619
2012	1,714	1,998	2,292	2,515	2,485	2,647
2013	3,676	3,883	4,267	5,150	4,025	4,265
2014	7,072	6,630	7,039	7,208	6,867	7,870
	20,029	18,793	21,120	24,169	22,610	24,419

Year	Jul kW	Aug kW	Sep kW	Oct kW	Nov kW	Dec kW	Total kW
1999	-	10	-	-	-	3	17
2000	4	12	6	18	20	14	88
2001	76	126	73	176	87	85	831
2002	75	117	186	59	131	117	1,269
2003	232	262	246	198	268	480	3,793
2004	389	343	198	374	424	318	3,889
2005	613	777	511	343	207	283	5,048
2006	335	626	691	446	420	431	5,206
2007	255	865	313	655	348	967	8,487
2008	969	499	1,661	1,431	1,104	3,760	15,196
2009	1,006	973	1,479	1,658	1,364	5,273	16,418
2010	1,722	1,725	1,626	1,834	2,157	6,521	26,793
2011	2,630	2,788	2,037	4,541	4,494	6,418	36,381
2012	3,687	3,821	3,357	3,414	4,171	8,067	40,168
2013	4,283	5,847	8,412	6,859	7,619	9,432	67,717
2014	8,181	7,996	9,640	14,933	7,622	13,997	105,055
	24,458	26,786	30,434	36,937	30,435	56,166	336,355