**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)

**PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
PROPOSAL FOR NET ENERGY METERING SUCCESSOR TARIFF**

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August 3, 2015

## Summary of PG&E's Proposal for The NEM Successor Tariff

**Introduction.** Pacific Gas and Electric Company, which has interconnected more rooftop solar than any utility in America, is pleased to propose smart energy reform that will support the long-term growth of rooftop solar as a vital resource for California. PG&E's proposal would allow new solar customers to achieve significant reductions in typical electric bills while beginning the process of creating a more sustainable approach that is necessary to support long-term investments in a smarter, stronger grid that can accommodate the growth of solar, battery storage, home automation and other advanced technologies.

**PG&E's Proposal**

- Residential and small commercial NEM customers will take service on rate schedules that feature a small maximum demand charge with commensurately lower time-of-use (TOU) energy charges. Larger commercial and industrial customers and agricultural customers are already served on schedules with demand charges; no new rate schedules will need to be created for these customers.
- Exports to the grid will be compensated at the energy (per kWh) portion of the generation rate for the schedules described above.
- Customers will receive full retail credit for all generation serving simultaneous at site load, allowing them to avoid paying the non-bypassable charges (NBCs) that other DG customers pay.
- As long as NEM customers pay the demand rate proposed above, they will not pay standby charges.
- Charges and credits will be trued-up monthly and net surplus generation will be compensated at the same rate that is now available.
- Customers will pay newly established interconnection application fees, costs of any required engineering studies, and interconnection facility costs. For small systems (generation capacity of 30 kW or less), the application and study fee will be only $100; for large systems (generation capacity greater than 30 kW), the application and study fee will be $1,600. Customers installing generation with capacities of 500 kW or smaller will not pay distribution upgrade costs; owners of larger systems will pay such costs.
- The CPUC should review and revise the NEM successor rates and policies on a regular basis starting in 2019 or sooner.

**How PG&E's Proposal Meets The Statutory Criteria.** This proposal will allow the solar market to continue to grow sustainably. PG&E's proposal would enable customers to achieve significant bill savings by installing solar at the prices available to customers today, which include large profit margins for solar vendors. The Public Tool created by the CPU C projects that adoption under its proposal using one of the Public Tool's default scenario results in 5,500 to 6,000 MW of new solar adoption between 2017 – 2025. This represents nearly four times the amount installed in PG&E's service area over the last 20 years. Even the default

Public Tool cases that show the lowest level of adoption still show more incremental solar installations by 2025 under PG&E's proposal than over the entire last 20 years. As solar prices and vendor margins drop in California to come closer to those charged in nearby states, there will be expanded opportunities for growth.

**Bookend Results and Third Case.** As requested, PG&E tested its proposal against six scenarios within the Public Tool using the Energy Division's (ED) two bookend assumptions and three specified rate structures. PG&E also tested its proposal using its own Independent Scenario. Table 1 presents the results of those runs of PG&E's proposal in this proceeding.

**Table 1: Results of Public Tool Runs for PG&E Customers on PG&E's Proposal**

| Scenario | PCT | RIM | 2025 Cost Shift ($ Millions) | RIM as % of Rev Req | % COS of Residential Customers | 2017-2025 Installations (MW) |
|---|---|---|---|---|---|---|
| **Bookend_High_TwoTiers** | 1.70 | 0.72 | ($620) | 3.28% | 95% | 6,213 |
| **Bookend_Low_TwoTiers** | 1.02 | 0.38 | ($491) | 2.28% | 83% | 2,106 |
| **Independent_PGE_TwoTiers** | 1.91 | 0.40 | ($1,322) | 6.28% | 91% | 7,220 |
| **Bookend_High_TOU4to8** | 1.74 | 0.70 | ($590) | 2.59% | 97% | 5,906 |
| **Bookend_Low_TOU4to8** | 1.07 | 0.36 | ($573) | 2.59% | 83% | 2,150 |
| **Independent_PGE_TOU4to8** | 1.96 | 0.39 | ($1,338) | 6.09% | 93% | 6,698 |
| **Bookend_High_TOU2to8** | 1.78 | 0.68 | ($549) | 2.51% | 99% | 5,494 |
| **Bookend_Low_TOU2to8** | 1.10 | 0.35 | ($590) | 2.78% | 83% | 2,215 |
| **Independent_PGE_TOU2to8** | 2.02 | 0.39 | ($1,298) | 5.99% | 94% | 6,497 |

Under PG&E's proposal, customers who install solar will pay a small demand charge based on their actual use of the grid, which will pay for a portion of the cost of the distribution system they rely on. The proposal provides customers with an incentive to reduce and manage their demand. Further, setting export compensation equal to the energy portion of the generation rate will bring compensation for this power closer to its value. These proposals, if adopted, will still provide substantial incentives and subsidies to solar customers, but will begin the transition to a more sustainable long-term rate structure. The CPUC should establish a process to regularly review and modify the tariff beginning in three years or less. This process will enable the CPUC to update the tariff as the market continues to evolve.

PG&E agrees with Energy Division that the Participant Cost Test (PCT) and the Ratepayer Impact Measure (RIM) test from the Standard Practice Manual are appropriate metrics to ascertain whether a given proposal meets the statutory criteria. Both the PCT and the RIM test are needed to measure "sustainable growth," the PCT will measure whether the proposed tariff is based on the costs and benefits of the facility from the perspective of the customer considering solar; and the RIM will measure whether the proposal ensures that total benefits equal total costs for all customers and the electrical system. As can be seen in Table 1 above, for many of model runs, the PCT is well above 1.7, meaning that economics favor customers continuing to adopt solar as the customer benefits of a facility substantially outweigh its costs. PG&E believes that the runs that show lower PCT results are not realistic, for reasons discussed in detail below.

The RIM remains substantially below 1.0 in all these runs, meaning growth is not sustainable in the long run, and that non-participating customers face significant bill increases to pay for this program. However, this proposal would significantly reduce the non-participant bill increases shown in the Public Tool compared with the results shown if the current NEM program were to continue unchanged.

**Important Statutory, Policy, or Practical Issues**

PG&E believes that this proposal begins the move to an appropriate policy and rate design structure to facilitate an unconstrained, sustainable future for customer renewable generation. While not fully resolving the cost-shift, it takes a meaningful step in the right direction and provides a path for future revisions. Rate structures with demand charges are supported as a rate-making mechanism to enable customer DG by a number of energy industry thought leaders. This proposal provides the following benefits:

a) Supports the CPUC's long-term policy objectives around Distributed Energy Resources (DERs) by sending price signals that align energy value with price;
b) Sends price signals (i.e., demand charges and TOU energy charges) to customers that better align customer energy use patterns with costs incurred by the IOU;
c) Allows customers to manage the size of the fixed component of the bill;
d) Provides a timeline to phase-in reform to meet the full legislative intent of AB 327;
e) Improves customer experience by aligning compensation cycles with billing cycles; and
f) Encourages adoption of new technologies such as storage and energy management systems.

## Summary of PG&E's Proposal For NEM for Disadvantaged Communities

**PG&E Proposal: Solar CARE.** PG&E proposes that a subset of customers eligible for CARE located in areas designated by the CalEnviroScreen as disadvantaged communities would be eligible to participate in a new program called Solar CARE administered by PG&E. This program would be partially modelled on the Green Tariff Shared Renewables Programs approved by the CPUC in January 2015 by Decision 15-01-051. In this proposal, CARE customers in disadvantaged communities would have the opportunity to enroll to have 100% of their annual usage provided by a local solar project sited in their community. PG&E would work with local governments, community leaders, and program participants to ensure that the most appropriate solar project sites are chosen to benefit these communities, and where possible, the grid and customers as a whole.

Customers would continue to take service on their regular CARE rate and would not pay any additional premium for this service. Additional premiums that would otherwise be due for the cost of solar generation would be subsidized through new funding. The program would be capped at 28 MW for the first three years. The 28 MW will be in addition to the 45 MW of additional solar PV facilities reserved for service to customers in disadvantaged communities under D.15-01-051.

**Bookend Results and How The Proposal Meets The Statutory Criteria.** The Public Tool cannot model this proposal for disadvantaged communities. As explained more fully below, PG&E believes that it would meet the requirement of section 2827.1(b)(1) by providing a specific "alternative designed for growth among residential customers in disadvantaged communities." The proposal would be a relatively economically efficient program for expanding solar adoption in disadvantaged communities.

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**PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)**
**PROPOSAL FOR NET ENERGY METERING SUCCESSOR TARIFF**

# I. INTRODUCTION

In accordance with the Administrative Law Judge (ALJ) Ruling dated June 4, the Assigned Commissioner Ruling dated June 23, and the ALJ Ruling dated July 20, 2015, Pacific Gas and Electric Company (PG&E) submits this proposal for the Net Energy Metering (NEM) Successor Tariff. PG&E looks forward to working productively with stakeholders to achieve the goals in Assembly Bill 327 to support continued growth of solar generation as a vital energy resource for California, while also beginning to address cost imbalances. These comments include the topics listed in the June 4 ALJ Ruling, and generally follow the organization requested in that Ruling, except that the details of PG&E's proposal are all presented together in the same section.

In addition to the work underway in this docket, as part of its decades-long commitment to solar, in legislation now pending in Sacramento, PG&E is also advocating that the state count rooftop solar toward ambitious new renewable energy targets as another way to help ensure the continued growth of solar. However, unless that legislation passes in time to be considered here, it is not part of PG&E's proposal in this docket.

### A. PG&E Supports A Sustainable Solar Future

PG&E has actively supported our customers' choice of renewable generation to meet their energy needs. In fact, PG&E has been the leading solar utility in the United States for at least five years in a row.[1] A quarter of all rooftop solar in the United States is in PG&E's service area. More than 180,000 PG&E customers now have solar, and the number of installations continues to grow rapidly. PG&E interconnected 45,000 new solar customers in 2014, and this year is on pace to exceed last year's numbers by over 50%.[2] PG&E appreciates the challenge undertaken by the CPUC, and all parties to this proceeding, to meet the Legislative direction to recognize the market changes that have occurred and reform the existing net metering program.

PG&E absolutely believes this is the right time and place to begin to define and implement the smart energy reforms needed to benefit all our customers. The cost of solar continues to fall dramatically[3] and customer interest in solar is at an all-time high in California. In this past June alone, nearly 6,000 customers installed over 44 MW of renewable generation using our current NEM tariffs. This amount alone is far greater than the amount of solar installed in many other states over many years. Given the dramatic drop in the cost of solar, California is well positioned to ensure the future continues the success of the past, while reducing the impact on other customers.

The Legislature agreed that it is time to revise the NEM tariff and rate structure to address market changes. In the past, as the NEM cap has neared, the Legislature simply raised the cap, sometimes also expanding the program to more customers or establishing more relaxed

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1 We recognize that this proceeding involves renewable customer-sited generation of all kinds, but the vast majority of customers have been primarily interested in installing solar panels.

2 In 2014, about 45,000 customers installed renewable generation under NEM tariffs. PG&E currently expects at least 70,000 customers to interconnect renewable generation under our current NEM program by the end of 2015.

3 "America Will Achieve Its Sunshot." Forbes. June 21, 2015. http://www.forbes.com/sites/jeffmcmahon/2015/06/21/america-will-achieve-its-sunshot/

rules. However, that approach has changed. When the Legislature raised the NEM cap in 2012, it also ordered the CPUC to examine the rate impacts of the NEM program itself. The CPUC did that, reporting that once the cap was reached, the rate impacts on non-participating customers would be over $1 billion annually for the three IOUs. Most parties agree that at least part of this impact was created because of the steeply tiered residential rates – an unintended consequence of the legislative and regulatory response to the energy crisis. The Legislature responded to this report in two important ways in AB 327. It directed the CPUC to address residential rate reform and also to design a NEM successor tariff that would reduce the significant bill impacts on customers who choose not to install their own renewable generation.

The CPUC recently addressed residential rate reform with the issuance of D.15-07-001.[4] Action is needed in this proceeding to address the remaining bill impacts and put the state on a path to a sustainable and unconstrained future for customer renewable generation. The Public Tool developed in this proceeding plays an important role in that regard. All of the scenarios presented in the White Paper written by the Energy Division[5] show that the cost impact of continuing the current NEM program, even after residential rate reform, will be substantial.[6] This was true for both the high DG value and low DG value cases.

To estimate the rate impacts not addressed by residential rate reform, PG&E analyzed three scenarios using the Public Tool – the Energy Division's High Two Tier and the Low Two Tier and an Independent Scenario, which PG&E believes reflects more realistic assumptions.

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4 PG&E notes that D.15-07-001 anticipates further residential rate reform following completion of pilots and studies of time of use rate designs.

5 The Energy Division White Paper is Attachment 1 to the June 4 Ruling ("White Paper.") The Energy Division recently provided the same analysis using the final Public Tool bookends, with the same results.

6 The RIM test measures the impact on other customers. All RIM results in the White Paper are well below 1.0 (where other ratepayers are indifferent). The White Paper had bookends based on the PD and APD, not the actual reforms adopted in D.15-07-001. The final decision falls between those bookends, however, so even after full implementation of the rate reform, there will still be a huge cost shift.

All three runs were done using the current NEM tariff in order to capture the range of outcomes likely to result with no reform to the existing NEM program at all. Results for the three model runs without incorporating any changes to the current NEM program are presented in Table 2. We include these results to demonstrate what the impact would be if the current NEM program were to be simply extended indefinitely.[7]

**Table 2: Current NEM Tariff after Residential Rate Reform -- Public Tool Runs With Default Rate Design for PG&E Customers**

| Scenario | PCT | RIM | 2025 Cost Shift ($$ Millions) | RIM as % of Rev Req | % COS of Residential Customers | 2017-2025 Installations (MW) |
|---|---|---|---|---|---|---|
| **Bookend_High_TwoTiers_RROIR** | 2.18 | 0.52 | ($1,522) | 6.6% | 32% | 7,618 |
| **Bookend_Low_TwoTiers_RROIR** | 1.30 | 0.23 | ($1,766) | 7.9% | 31% | 4,675 |
| **Independent_PG&E_TwoTiers_RROIR** | 2.66 | 0.23 | ($2,937) | 13.7% | 23% | 8,824 |

The results of this exercise, showing an annual rate impact of $1.5 billion to $2.9 billion in 2025 and a cumulative NPV impact of $12 billion to $24 billion over the lifetime of the installed systems, clearly indicate that the CPUC must take further action to reduce the rate impact and associated incentives for customer distributed generation. These costs will be borne by all customers, including CARE customers and residential customers with only baseline usage, since the recently approved residential rate design decision provides that cost increases shall be shared among all residential customers. The Energy Division recently provided results from the six bookend scenarios for all three IOUs with similar results. RIM tests ranged from 0.21 to 0.47, and the impact on residential revenue requirement ranged from 9.41% to 17.34%. Again, these results indicate that further reform is critical.

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7 These figures are only for new NEM projects, and do not include the cost shift associated with grandfathered projects interconnected prior to the NEM transition. The annualized cost shift associated with these projects is another $337 MM, $155 MM, and $338 MM in the Low Bookend, High Bookend, and Independent PG&E case respectively..

In contrast to the current NEM design, the annual rate impact (also included in Table 1) under PG&E's proposal ranges from $500 million to $1.3 billion per year. While PG&E's proposal goes a long way towards resolving the cost impacts caused by the NEM program, non-participants would continue to face significant burdens. Under the two tiered rate scenario, PG&E's residential tier 1 rates would increase by 15.6% and 15% in the low and high bookends respectively due to NEM related cost shifting by 2025, resulting in the typical non-participant paying $20-$23 more per month. Under PG&E's more realistic independent scenario, this customer would face a 30.5% increase in rates and pay $45 more per month. Clearly there is more work to be done to satisfy the legislative requirement in PUC Section 2827.1(b)(4) that the resulting successor tariff "[e]nsure that the total benefits … to all customers and the electrical system are approximately equal to the total costs." The CPUC clearly cannot simply extend the NEM program as it currently exists.

Table 2 also includes the results of the Participant Cost Test ("PCT"), which measures the value of a program for participating customers. A PCT greater than 1.0 means participants are better off, and a PTC below 1.0 means they are worse off (and would generally result in unsatisfactory adoption). The Energy Division White Paper suggests that the PCT be used as the metric for "sustainable growth," or at least the "growth" part of this requirement. As is discussed more fully below, PG&E believes that a PCT value above 1.25 means that the value proposition for participating customers will provide at least a 20% savings over their investment; or, in the case of PPA, lease, or self-financing, a 20% *bill savings* over the life of the renewable generator. As shown in Table 2 above, implementation of residential rate reform leaves customers in a position to continue adopting Distributed Generation (DG) technologies under extremely favorable terms. For customers able to install solar, the existing NEM policy would allow them to reduce their total energy spending by 54% to 62% in the more realistic scenarios. This means the CPUC can ensure continued industry growth by implementing a successor tariff that significantly reduces the remaining cost imbalance *and* continues to provide an effective value proposition for participating customers.

As a result of the Legislative direction, the CPUC has called for proposals to address the remaining bill impacts. Now is the time to begin this process by establishing the appropriate long-term structure and the regulatory mechanism by which the successor tariff will be reviewed and updated. While there exists some uncertainty around several long-term energy policy issues such as whether to expand the RPS requirement, or whether to expand GHG emissions goals and how to integrate distributed energy resources into utility planning processes, delays while we wait for perfect information will not help us achieve the goals set out by the legislature..

PG&E believes it is of primary importance to establish the appropriate tariff structure that would allow for a sustainable unconstrained customer renewable generation market. Therefore, the focus of this proceeding should be to establish the right long-term structure and a regulatory path to review and modify the tariff, with the secondary objective of setting the right rate. As discussed in more detail later, PG&E believes a demand-differentiated tariff with reduced export compensation rates is the right structure. To ease in the transition to this structure, PG&E proposes to size the demand charge initially at a level below the full cost based level and an export compensation rate above the avoided cost level. With the right structure in place, the CPUC can continue to address necessary modifications in the future to continue the evolution to a true cost-of-service rate.

PG&E believes that any rate design adopted in this proceeding that does not fully resolve the cost imbalance created by NEM must be revisited in the future. *In fact, while making significant progress toward addressing such impacts, the rate design proposed by PG&E in this proceeding deliberately leaves in place significant subsidies for solar and other renewable technologies.* Accordingly, PG&E recommends the Commission establish a regulatory process to revisit the successor tariff on a regular basis. This process is particularly important, given the considerable uncertainty about many inputs into the Public Tool, the timing constraints in this phase of the proceeding, the fact that the NEM successor tariff will allow for unconstrained adoption, and the sizable economic impact of this policy decision on customers. The next review should occur in no more than the next three years or at a prescribed adoption level.[8] Building in a cycle of regular review will also provide parties and the CPUC with greater comfort that if NEM reform results in unintended market changes (such as a material reduction in solar adoption) a process is in place to revisit the policy.

To provide an opportunity to revisit successor tariff rate design in the future, PG&E recommends that continuing reform be reviewed in either an extension of this proceeding or an entirely new proceeding. Public Utilities Code Section 2827.1, paragraph (b) 7, in part provides: "The commission shall determine which rates and tariffs are applicable to customer generators only during a rulemaking proceeding. Any fixed charges for residential customer generators that differ from the fixed charges allowed pursuant to subdivision (f) of Section 739.9 shall be authorized only in a rulemaking proceeding involving every large electric corporation." This requirement means that either the Commission must adopt rate design in the current proceeding that is adequate for renewable distributed generation customers forevermore, or alternatively, requires that the Commission be prepared to establish future rulemaking proceedings where its policies can be revisited. Since PG&E does not believe it is possible to develop "rates and tariffs" in this proceeding that will be adequate indefinitely, it would be prudent for the Commission to establish a review opportunity for the successor tariff in the future.

PG&E proposes that the Commission's next review of the successor tariffs be initiated in 2019 or once customer renewable generation installations reach 7800 MW (statewide), which is when cumulative NEM and NEM successor installations would exceed the current cap by 50%.[9]

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8 Even if the rate of adoption remains flat at current levels, total DG in PG&E's service area will almost double from an estimated 1800 MW at the end of 2015 to over 3500 MW by the end of 2018.

9 The current NEM is capped at 2409 MW for PG&E, 2240 MW for Southern California Edison, and 607 MW for San Diego Gas and Electric, per PU Code section 2827(c)(4), or approximately 5200 MW.

### B. Summary Of PG&E's Transition Proposal

The key elements of PG&E's proposal for the NEM successor tariff are the adoption of four primary changes to the current NEM structure. First, PG&E proposes that the Commission adopt new schedules for NEM service for residential and small commercial customers that include a small maximum demand charge of $3 per kilowatt (kW)-month to recover a portion of the costs related to the distribution system used to serve these customers. Because these new rates will be revenue neutral in design, energy charges will be reduced by an amount commensurate with expected revenue collection from the demand charge. Since all of PG&E's other customer groups are served on schedules that include demand charges, new NEM customers on these schedules may continue to take service on their current schedules. Customers will receive full retail credit against their volumetric energy charges for all generation serving simultaneous at-site load, allowing them to avoid paying the non-bypassable charges (NBCs) that other DG customers would pay. This provision provides continuity with the current NEM structure.

Second, PG&E proposes that generation exported to the grid by NEM-eligible systems receive a credit based on the generation portion of the energy charges in the relevant utility rate. Currently the average bundled generation price is approximately 9.7 cents per kilowatt hour, but a NEM customer would receive a credit based on the time of use period when the power was delivered. As shown in the rate table below, a residential NEM customer delivering in the summer on peak period would receive more than 20 cents per kWh for exports. Both this price and the average price are well above the value of this exported generation.[10] Non-renewable power can be purchased now for two to four cents per kWh in CAISO markets, and there have been public announcements of recent solar power purchase agreements for utility scale solar at

10 Because exported generation will be valued at the energy portion of the generation rate, customers on schedules with generation demand charges will generally receive a smaller credit. For example, about 20 percent of current generation rates for standard E-20 schedules are collected in demand.

prices in the neighborhood of four cents per kWh.[11] However, the generation export rates proposed here is much closer to its value than the full retail credit received under the current NEM program. Setting export compensation to that value rather than a calculation of avoided cost also has the secondary benefit of being simpler to calculate and administer than a "value-of-solar" rate.

Third, PG&E proposes that customers installing renewable generation go on Time-of-Use (TOU) volumetric energy rates. For non-residential customers, this is already a requirement. For residential customers, that is consistent with the Commission's recent residential rate reform decision, which stated that the Commission expects to move to default TOU volumetric energy rates for all residential customers by 2019.

Fourth, PG&E moves from an annual true-up period to monthly true-up period. This will simplify the program for our customers, which they have indicated they want.

In addition, PG&E proposes a process for revisiting these policies and rates in the future. PG&E does not believe that the rates and policies that will be adopted in this proceeding will be adequate indefinitely, and should be revisited based on then-current circumstances.

PG&E's proposal is quite supportive of customers that want to invest in solar. Such customers will still pay less than the costs of serving them, and will receive compensation for their solar energy far in excess of the avoided cost value to the utility. Further, they remain exempt from higher standby charges paid by other DG projects, as well as non-bypassable charges on self-supplied power. Finally, these customers remain exempt from many interconnection costs.

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11 See footnote 16 below.

Additional details of PG&E's proposal[12] are set out in the detailed discussion in section II.A below.

### C. Why This Proposal Should be Adopted

The Public Tool results indicate that adoption of this proposal would facilitate considerable growth of California's retail distributed solar market, and would reduce the cost imbalances discussed above. The Public Tool shows that customers will continue to achieve bill savings under PG&E's proposal, as measured by both the PCT figures and the adoption figures. This is true under the bookend scenarios in the Public Tool, as well as PG&E's Independent Scenario with assumptions that more accurately model costs and benefits. Under the six default scenarios adoption by PG&E customers between 2017 and 2025 grows by 2,000 MW to 6,000 MW. Under PG&E's proposal, incremental adoption in PG&E's service territory in the more reasonable Public Tool runs ranges from 6,500 – 7,200 MW between 2017 to 2025, representing approximately 400% over today's cumulative adoption of 1,500 MW installed over the last 20 years in PG&E's service area.

Outside of the public tool, PG&E has modelled the bill impacts of its successor tariff proposal for prospective DG customers. Under the final RROIR decision, a representative customer with an average monthly maximum demand of 5 kW considering solar will now pay $160 per month. With PG&E's successor tariff, installing a 3.7 kW system (offsetting 2/3 of load) would reduce its bill to $77 per month, a bill savings of $83. While these savings are a reduction from the $104 per month bill savings under the existing NEM structure for the same customer and system, PG&E believes this is still sufficient to drive substantial adoption, as confirmed by the results of the Public Tool.

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12 As noted above, as part of its decades-long commitment to solar, in legislation now pending in Sacramento, PG&E is also advocating that the state count rooftop solar toward ambitious new renewable energy targets as another way to help ensure the continued growth of rooftop solar. However, unless that legislation is enacted before this proceeding has concluded, it is not reflected in PG&E's proposal here.

PG&E's modeling within the Public Tool shows that under the six bookend scenarios, PG&E's proposal still results in significant subsidies to customers who install renewable energy generations which results in significant bill impacts for other customers. The rate impacts identified by the six book end scenarios range from $440 million to $620 million annually even with PG&E's proposal. Substitution of PG&E's preferred input assumptions reveals that the real rate impact is about $1.3 billion annually by 2025. Over time, the need for any such incentives is expected to disappear altogether, as utility electricity prices will increase, and installed solar system costs continue to decrease. In the past six years alone, solar panel prices have declined by more than 80%,[13] and cost reductions in panels and other system components are expected to continue.[14]

Currently, competitive sales prices for residential rooftop solar are already averaging below 10 cents per kWh in some states like Arizona;[15] low-end prices for non-residential / small utility-scale solar projects in California are in the 5–7 cent per kWh range;[16] and some recently announced, large utility-scale projects in states like Texas and Nevada are now bid at about 4 cents per kWh.[17] Academic and market research clearly indicates that solar costs have been decreasing dramatically over the last 4-5 years; yet, in residential rooftop markets in California, these cost declines have not translated to reductions in prices for customers. It has been well-documented that solar prices are much higher ($0.15/kWh to $0.18/kWh) owing to higher vendor

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13 International Renewable Energy Agency (IRENA). "Renewable Power Costs in 2014." 2015, p. 29. http://www.irena.org/DocumentDownloads/Publications/IRENA_RE_Power_Costs_2014_report.pdf

14 "America Will Achieve Its Sunshot." Forbes. June 21, 2015. http://www.forbes.com/sites/jeffmcmahon/2015/06/21/america-will-achieve-its-sunshot/

15 Bloomberg New Energy Finance (BNEF). "1H 2015 North American PV Outlook." January 16, 2015. Renewable Market Adjusting Tariff (ReMAT) from Senate Bill 32.

16 http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page.

17 "Solar Prices Keep Dropping, Says Austin Energy." Austin Monitor. June 29, 2015. http://www.austinmonitor.com/stories/2015/06/solar-prices-keep-dropping-says-austin-energy/ Nevada may see more solar plants as price tag drops." Las Vegas Review-Journal. July 19, 2015. http://www.reviewjournal.com/business/energy/nevada-may-see-more-solar-plants-price-tag-drops.

margin, and "value-based" pricing opportunities that are enabled by current policy and market designs.[18] One peer-reviewed journal article published in 2015 documented that lease prices in California were essentially flat from 2010–2012 despite dramatic industry cost declines. In the authors' words: "Our study indicates that, while installed PV costs have declined rapidly, the real contract price to the customer has remained largely unchanged."[19] In this context, PG&E proposes that over time, as subsidies become unnecessary, the NEM successor tariff design must be revised to reflect the costs to serve those customers and continue to address any remaining cost shift.

PG&E is committed to achieving California's clean energy goals. We believe that this proposal will allow customer solar to have a continuing and growing role in meeting the state's clean energy future.

# II. DETAILED DISCUSSION OF PG&E'S PROPOSAL FOR THE NEM SUCCESSOR TARIFF

## A. Detailed Description of PG&E's Proposed Successor Tariff

### 1. Tariffs, Not Contracts

PG&E's proposal would be implemented by tariffs, avoiding the necessity for hundreds of thousands of customers to execute contracts in order to take advantage of the opportunity to install renewable generation.

PG&E proposes two new mandatory tariffs for residential and small commercial customers interconnecting renewable DG systems to its distribution system and taking NEM

18 "As SolarCity noted in a recent earnings call with investors: "…we haven't changed pricing [in California] for some time now." SolarCity Corporation Earnings Report: Q1 2015 Conference Call Transcript." May 6, 2015. http://www.thestreet.com/story/13140649/9/solarcity-corporation-scty-earnings-report-q1-2015-conference-call-transcript.html; Also, see LBNL. "Tracking the Sun VII." 2014. http://emp.lbl.gov/publications/tracking-sun-vii-historical-summary-installed-price-photovoltaics-united-states-1998-20.

19 Environmental Research Letters. "Exploring the market for third-party-owned residential photovoltaic systems: insights from lease and power-purchase agreement contract structures and costs in California." February 4, 2015. http://iopscience.iop.org/1748-9326/10/2/024006/pdf/1748-9326_10_2_024006.pdf.

service from PG&E. For residential customers there would continue to be special discounted rates for low income customers (currently on CARE rates).[20] All other customers installing renewable generation would remain on their otherwise applicable tariff, subject to changes in conditions of service (e.g., treatment of exported energy).

PG&E believes continued use of tariffs, rather than contracts, is most supportive of our customers. The tariffs are posted publicly, including explanatory information on PG&E's website, and educated representatives are available to field questions at PG&E's call centers. PG&E notes that most parties in this proceeding agreed that a tariff was superior to a contract.[21]

### 2. Rate Proposal

PG&E proposes to establish new rate schedules for NEM service for residential and small commercial customers that feature a small per-kW demand charge along with commensurately lower TOU energy charges. PG&E does not seek other changes to the rates or rate structures for other customer groups in this proceeding. However, PG&E looks forward to approval of a pending settlement concerning TOU periods for residential customers in its 2015 Rate Design Window proceeding,[22] and plans to seek revision of TOU periods for other customer groups in PG&E's 2017 General Rate Case (GRC) Phase II proceeding.

Demand based rate structures are commonly used for all customer groups except for the small commercial and residential customer classes.[23] Historically, these rate designs have been implemented in customer groups where the metering infrastructure was available because a

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20 This is the CARE rate for *any* CARE customer, and is in addition to our Disadvantaged Communities proposal.

21 PG&E's comments on this topic can be found on pages 2-4 of PG&E's NEM Policy Comments filed in this docket on March 16, 2015.

22 As discussed in more detail later in this filing, PG&E's proposed peak hours, 4-9 pm, vary from the TOU scenarios which are modeled in the Public Tool.

23 Although relatively uncommon to date, there are at least 10 utilities across the US that include a demand charge as one portion of a rate open to residential customers.

demand structure is consistent with cost causation principles.[24] Specifically, costs that are incurred on PG&E's system to provide transmission, distribution and generation capacity are driven by and measured in units of kilowatts. From a rate-making perspective, it is inappropriate to allocate and collect these costs using volumetric energy rates. A rate structure that collects demand-driven costs in demand charges encourages efficient use of the distribution system by incenting customers to spread their loads more evenly over time.

PG&E's proposal to establish demand charges for future NEM service is necessary to ensure these customers pay an appropriate share of the infrastructure costs required to serve them regardless of their net usage. Failure to do so would not only fail to reduce the amounts paid for by other groups, but would also fail to properly recover costs within the participating customer group. For example, today, a customer that offsets most of their load pays very little for distribution service if distribution rates are collected only in volumetric energy (per kWh) rates. This subsidy in rates has the effect of increasing rates for all other customers, including customers that install solar. PG&E's proposal to establish a maximum demand charge designed to collect a portion of distribution costs where that charge type does not exist today helps mitigate this issue by reducing the distribution revenue collected in energy rates and is more closely aligned with cost causation principles.[25]

A variety of authorities have recognized the benefits of demand charges in the distributed energy resource context, noting that demand charges unleash, rather than mute, deployment of

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24 Two part tariffs, consisting of demand and energy rates, distinguish between those costs that vary with changes in the system's output of energy, and those costs that vary with the plant capacity. See, for example, Principles of Public Utility Rates, Bonbright, Danielsen and Kamerschen, 1988, p. 400.

25 See "Rediscovering Residential Charges", Ryan Hledik, The Electricity Journal, August-September 2014. Institute for Electric Innovation, "Net Energy Metering: Subsidy Issues and Regulatory Solutions." See also Issue Brief, September 2014. http://www.edisonfoundation.net/iei/Documents/IEI_NEM_Subsidy_Issues_FINAL.pdf; See also EEI/ NRDC Joint Statement to State Utility Regulators, Feb. 2014.

innovative DERs, and unlike a fixed charge, the customer can still manage a demand charge by taking actions or making investments that alter their load.[26]

Demand charges have not previously been used as part of California residential and small commercial rate design, but they have been used for larger business customers for decades, and make good sense for customers with NEM service because they align the price customers pay with the costs that they impose. Traditionally, outside the NEM context, California has long used standby charges to assure recovery of at least some portion of the cost of the services used by a customer with distributed generation. See the CPUC's Standby Policy Decision, D.01-07-027. This is another approach to assuring that some portion of the cost of the distribution system used by this customer is recovered. The demand charge proposed here would result in a lower monthly charge for most customers than the current standby charge.[27] Moreover, customers would only be charged for their actual demand and could control their demand in many ways, by reducing total usage, and by shifting the time in which they use power, through batteries, home energy control systems, or otherwise.

*Residential Class*

For residential NEM customers, PG&E proposes a revenue neutral, non-tiered TOU rate design with a small demand charge. This rate would then be mandatory for all customers with renewable generation and may be optional for all other residential customers.[28] PG&E's new Schedule E-TOU, which will be offered to residential customers on a voluntary basis, serves as

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26 See Rocky Mountain Institute, "Fixed Charges Aren't The Answer: Utilities Need New DER Pricing Model," June 2, 2015. See also "Rate Design for the Distribution Edge." August 2014. See also, "Rediscovering Residential Charges", Ryan Hledik, The Electricity Journal, August-September 2014.

27 A representative residential customer with 4.5 kW of demand installing a 3 kW solar system will pay a lower demand charge per month with a $3 demand charge ($13.50 per month) than it would pay under the rate design settlement pending approval in A.13-04-012 for 2017. ($6.27 per kW times 3 kW times 85 percent would result in a monthly standby bill of $16 per month).

28 In D.15-07-001, the Commission adopted a two-tier TOU rate, Schedule E-TOU, with a minimum charge rather than a customer charge, and also approved an optional TOU rate without tiers.

the starting point for PG&E's proposed design for NEM customers. Schedule E-TOU consists of TOU energy rates and a minimum charge. PG&E recommends the following design for residential NEM service.

- Demand Charge: A portion of the distribution capacity revenue collected in energy charges under Schedule E-TOU will be moved to a demand charge. The demand charge rate will be the same in the summer and the winter and will be applied based on the customer's highest metered demand during the month.[29] The currently proposed maximum charge rate of $3 per kW per month reflects a fraction of those distribution capacity costs that are not peak-related and are therefore properly recovered in a non-time varying demand charge.

- Customer Minimum Bill: As determined by D.15-07-001, before 2020, the rates for standard residential service will include a minimum bill, rather than a fixed customer charge. The residential successor tariff proposed here will include the same minimum charge adopted for standard residential service: a minimum charge of $10 per month for non-CARE customers and $5 per month for CARE customers. PG&E anticipates that the residential NEM schedule will be revised to include changes to the minimum charge or addition of a fixed customer charge as they are adopted for standard service residential rate schedules.

Minimum charges applicable to residential customers, both NEM and standard service, will be for delivery (that is, non-generation) charges. Each month, the minimum delivery charge will be compared to the sum of the applicable non-generation demand and energy rates. If non-generation demand and energy charges sum to less than the minimum delivery charge, the minimum delivery charge will apply. Under PG&E's proposal for output compensation based on the generation component of the rate, credits (for deliveries to PG&E) and charges (for deliveries to the customer) will be summed over the month. Any net generation charges will be applied to the customer bill while any net credits will be set to zero. PG&E will pay for any net surplus generation (kWh) at the end of the month as described in section II.A.4, below.

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29 Billing demand will be based on the standard 60 minute interval for residential customers.

- Energy Charges: Energy charges will not vary by tier, and will be based on the TOU periods to be established in the 2015 RDW for the non-tiered version of Schedule E-TOU. Revenue not collected in demand or minimum bill charges will be collected in energy charges. Generation energy rates will be time differentiated and will be set equal to those approved for Schedule E-TOU. Energy rates will include a peak-related distribution capacity portion that will be used to seasonally differentiate energy rates in the same manner as Schedule E-TOU. Energy rates will also include a flat distribution rate to recover any remaining distribution capacity or customer-related revenue. All other energy charge components will be equal to those on Schedule E-TOU (which are the same as those on Schedule E-1), and will be collected in a flat energy rate.

- CARE rates: CARE rates will be established based on the average percentage discount provided under standard residential rates. The minimum bill will be set at $5 per month and the remaining portion of the discount will be applied evenly to the distribution demand and energy components of the non-CARE rate. The minimum bill for CARE customers will be applied in the same manner described above for non-CARE customers.

Illustrative rates for successor tariff are provided below.[30] These rates are based on current (effective March 1, 2015) residential revenue. For this illustration, a CARE discount of 35.7 percent is used, although the current discount is somewhat higher.

**Illustrative Residential Rates for PG&E Proposal**

| E-TOU Proposed Successor Tariff | Non-CARE | CARE |
|---|---|---|
| Minimum Charge* ($/mo) | $10.00 | $5.00 |
| Maximum Distribution Demand Charge ($/kW-mo) | $3.00 | $0.55 |
| **Unbundled Energy Rates ($/kWh)** | | |

30 Illustrative rates utilize PG&E's proposed TOU periods from its 2015 RDW: Summer is June through October; Winter is November through May. The peak period is 4 to 9 pm weekdays except holidays. All other hours are off peak.

| | | |
|---|---|---|
| Summer Distribution Energy | $0.075 | $0.014 |
| Winter Distribution Energy | $0.046 | $0.008 |
| Summer Generation On Peak Energy | $0.207 | $0.207 |
| Summer Generation Off Peak Energy | $0.104 | $0.104 |
| Winter On Peak Energy | $0.101 | $0.101 |
| Winter Off Peak Energy | $0.082 | $0.082 |
| Other Energy Charges | $0.033 | $0.022 |
| **Total Energy Rates ($/kWh)** | | |
| Summer On Peak Energy | $0.315 | $0.243 |
| Summer Off Peak Energy | $0.212 | $0.140 |
| Winter On Peak Energy | $0.180 | $0.131 |
| Winter Off Peak Energy | $0.161 | $0.112 |
| * Minimum charges are shown above as a minimum monthly charge. However, these charges will be expressed in tariffs and assessed on a dollar per day charge consistent with current practice. | | |

*Small Commercial Class*

Small commercial NEM customers eligible for service on Schedules A-1 or A-6 will be required to take service on a new schedule for these customers. Currently, Schedules A-1 and A-6 include a fixed customer charge that varies for single and polyphase service, and energy rates which recover all other costs. In this proceeding, PG&E proposes to modify the revenue neutral TOU option of Schedule A-1 for customers with renewable generation. The modified rate would be mandatory for these customers and optional for other customers. PG&E's approach to modifying small commercial rates for NEM customers is similar to the approach for residential customers described above. PG&E's proposed successor schedule for small commercial customers is based on Schedule A-1 TOU subject to the following changes.

- Demand Charge: A portion of the distribution capacity revenue collected in energy will be moved to a maximum demand charge [i.e., from energy rates]. The maximum demand charge will be the same in the summer and the winter and will be applied based on the customer's highest demand during the month.[31] The currently proposed maximum demand charge of $3 per kW per month reflects a fraction of those distribution charges that are not peak related and are therefore properly recovered in a non-time varying demand charge.

- Customer Charge: PG&E will retain the currently adopted fixed customer charges for Schedule A-1. However, these charges will be subject to adjustment in future proceedings.

- Energy Charges: Revenue not collected in demand or customer charges will be collected in energy charges. Generation energy rates will be set equal to those approved for Schedule A-1 TOU. Energy rates will include peak-related distribution capacity portion that will be used to seasonally differentiate energy rates in the same manner as Schedule A-1 TOU. Energy rates will also include a flat distribution rate to recover any remaining distribution capacity or customer cost. All other energy charge components will be equal to those on Schedule A-1 TOU and collected in a flat energy rate.

Illustrative rates for service under the successor tariff are provided below. These rates are based on current (effective March 1, 2015) Schedule A-1 revenue. At this time, PG&E proposes to utilize its current TOU periods for the NEM small commercial rate. However, the TOU periods will be subject to revision in Phase II of PG&E's 2017 GRC.

**Illustrative Small Commercial Rate for PG&E Proposal**

| Rates A-1 NEM | Proposed |
|---|---|
| Fixed Customer Charge Single-Phase* ($/mo) | $10.00 |
| Fixed Customer Charge Poly-Phase* ($/mo) | $20.00 |
| Maximum Distribution Demand ($/kW-mo) | $3.00 |
| **Unbundled Energy Rates ($/kWh)** | |
| Summer Distribution Energy | $0.059 |
| Winter Distribution Energy | $0.042 |

31 Billing demand will be based on the standard 15 minute interval for non-residential customers.

| | |
|---|---|
| Summer Generation Peak Energy | $0.136 |
| Summer Generation Part Peak Energy | $0.109 |
| Summer Generation Off Peak Energy | $0.084 |
| Winter Generation Part Peak Energy | $0.109 |
| Winter Generation Off Peak Energy | $0.092 |
| Other Energy Charges | $0.036 |
| **Total Energy Rates (Current TOU Periods) ($/kWh)** | |
| Summer Peak Energy | $0.231 |
| Summer Part Peak Energy | $0.204 |
| Summer Off Peak Energy | $0.179 |
| Winter Part Peak Energy | $0.187 |
| Winter Off Peak Energy | $0.170 |
| * Customer charges are shown above as a fixed charge per month. However, these charges will be expressed in tariffs and assessed on a dollar per day charge consistent with current practice. | |

*Medium and Large Commercial and Industrial Class*

Rate schedules in this class include Schedules A-10, E-19, E-20 and E-37.[32] Schedules E-19, E-20 and E-37 feature maximum demand charges, TOU demand charges and energy charges, while Schedule A-10 includes only a seasonal maximum demand charge and TOU energy charges. At this time, PG&E is not proposing any changes to these standard rates for customers that elect to take service under the successor program.[33] As noted above, however,

32 PG&E has entered into a settlement in its 2014 GRC Phase II (A.13-04-012) to eliminate Schedule E-37 beginning November 1, 2017.

33 PG&E currently offers "Option R" alternative rates for NEM customers served on Schedules E-19V, E-19 and E-20. While PG&E intends to continue to offer this program as part of this proceeding, the cost shift associated with this rate option is substantially more compared to the cost shift under the standard rates. Based on the Public Tool, PG&E found that Option R creates an additional cost shift of about $60 million annually relative to standard rates in its Independent Scenario. PG&E remains concerned that this rate option creates cost shift that must be supported by non-participating customers and intends to review the cost basis for this rate in future proceedings.

PG&E expects that the TOU periods for non-residential rates will be revised in Phase II of PG&E's 2017 GRC.

*Agricultural Class*

Like the Medium and Large Commercial and Industrial Classes, PG&E does not propose changes to the current rates for Agricultural customers participating in the successor program. PG&E's current agricultural rate program features a number of different rate schedules. All rate schedules, however, include a combination of TOU energy and demand charges. At this time, PG&E is not proposing any changes to these standard rates for customers that elect to take service under the successor program. As noted above, however, PG&E expects that the TOU periods for all rates will be revised in Phase II of PG&E's 2017 GRC.

*Implementation and Adjustment of Rates Adopted by this Proceeding*

Rates presented herein are based on rate and revenue levels effective March 1, 2015, and sales forecasts for 2015. Rates applicable to renewable generation customers upon implementation of the successor tariff will therefore not be equal to the illustrative values included here. Instead, like PG&E's other rate schedules, changes in rates due to revenue requirement changes will be allocated to each class and schedule based on the rules adopted in GRC Phase II proceedings. In general, rate changes will then be implemented as equal percentage changes to demand and energy charges by component as necessary to collect the revenue assigned to each schedule. PG&E may seek structural changes to successor tariff rates in GRC Phase II proceedings or other rate design cases, provided it seeks the same change for other non-NEM customers.

**3. Credits for Exported Energy and Billing True Up**

Under the current NEM program, customers receive credit for energy delivered to the grid priced at the full retail energy rate. The full retail bundled rate includes all of the following:

(1) Generation, (2) Transmission,[34] (3) Distribution, (4) DWR Bond, (5) Competition Transition Charges, (6) Public Purpose Programs, (7) Nuclear Decommissioning, (8) Energy Cost Recovery Amount, and (9) the New System Generation Charge. Direct Access (DA) and Community Choice Aggregation (CCA) customers are subject to all the utility rates described above except generation, and are charged for the Power Charge Indifference Adjustment (PCIA) and the Franchise Fee Surcharge.

PG&E's proposal for the successor tariff is to provide a credit for energy delivered to the grid limited to the energy portion of retail generation rates. That is, the credit for all kWh exported to the grid under the successor tariff will earn a credit equal to the energy (per kWh) portion of the generation rate of the successor tariff (or, for agriculture, medium and large commercial and industrial customers, the underlying tariff). Customers will receive no credit for the non-generation components listed above (as they do today) because these non-generation components are not included in the energy portion of the generation rate. However, customers *will* continue to receive an exemption from these charges for their departed load; in other words, all load served at the site by the renewable generation will be able to avoid the full retail rate.

PG&E's proposal to compensate customers for exports at the retail generation rate assigns a value to exported energy that is significantly higher than the avoided cost that the utility realizes. For example, the generation rate includes items such as fixed cost of operating flexible generation resources that are not mitigated (or become even more necessary) due to intermittent renewable resources such as solar. In addition, as ever greater levels of solar generation (both customer sited and utility-scale) flow onto the grid the value of energy produced

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[34] Transmission rates include a number of components including basic transmission (Transmission Owner, or TO), the Transmission Access Charge, the Transmission Revenue Balancing Account Adjustment, the End Use Customer Refund Account, and Reliability Services.

by solar decreases.[35] PG&E believes the avoided cost (value of solar) is lower than the 6 cent/kWh value reported by the Energy Division in the low DG value bookend. Under PG&E's proposal the export compensation rate, as well as the size of the demand charge, would be subject to further review and modification in a proceeding established by the CPUC to regularly update the NEM successor tariff.

PG&E's proposal for the successor is to align the true-up period with the standard monthly billing process and eliminate the confusion caused by the current 12 month NEM true up. Under the current NEM program, charges and credits for energy are accumulated over a 12 month period. At the end of the 12 month period, these credits and charges are accumulated and the customer is billed for any net due amount. If a customer's total usage is negative over the 12 month period (i.e., net deliveries to PG&E / the grid) the customer is paid for that net surplus energy at wholesale price formula set in D.11-06-016. This process has proved difficult for customers to understand and is the source of significant confusion. Over 60% of the calls PG&E receives in its solar call center are billing-related and a significant portion of these relate to the annual true-up process.[36] PG&E instead proposes to allow credits and charges to be accumulated over the monthly billing period.

#### 4. Compensation for Net Surplus KWH

In 2009, Assembly Bill ("AB") 920 required the Commission to establish a program to compensate customers installing renewable generation for electricity produced in excess of on-site load at the end of a 12-month true up period. In this proceeding, PG&E proposes no changes to the current net surplus compensation scheme adopted by the CPUC in D.11-06-016 and

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35 See for example, the February 10, 2015 CPUC Energy Division Presentation on RPS resource valuation, which discusses various saturation impacts on energy and capacity value, as well as integration and curtailment cost, located here: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/RPS+Calculator+Home.htm

36 PG&E has done some focus group research with our NEM customers. They are often caught by surprise when they get their first true-up bill, with some having difficulty paying large true-up charges. In addition, many customers, including veteran NEM customers, do not understand how net metering works.

Resolution E-4422 (September 22, 2011), other than changing from an annual to a monthly calculation. Under the CPUC's prior decisions, surplus kilowatt hours each annual true up are compensated at a CAISO Market Rate, unless the customer conveys renewable value to the participating utility, in which case it is paid a Market Rate plus a Renewable Energy Credit value.[37]

PG&E submits that no major changes in this basic structure are needed. Only two net surplus compensation issues need to be addressed in the successor tariff. One is that projects currently receive credits at annual true up. As discussed above, PG&E proposes a monthly true up, and the net surplus compensation credits should be provided monthly.

A second issue is treatment of projects larger than 1 MW. As the CPUC observed in D.11-06-016, projects smaller than 1 MW are Qualifying Facilities whether or not they file with FERC for such authority. That does not occur for larger projects, so QF certification must be obtained for larger projects. This topic is discussed in the legal discussion in section II.E below.

#### 5. NEM Eligibility and Treatment of Direct Access and Community Choice Aggregation Customers

Currently, PG&E Direct Access (DA) and Community Choice Aggregation (CCA) customers are eligible to participate in NEM. They receive generation services from another provider, and pay PG&E all bill elements other than generation. They receive a credit for exports from PG&E based on all energy elements of the applicable tariff except generation. The CCAs currently providing service in PG&E service area (Marin Clean Energy and Sonoma Clean Power) provide these customers with a generation credit.

PG&E proposes to keep this basic structure in place for DA and CCA customers on the successor tariff, except that they will go on the rate schedules described above, and will no

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37 The NSC rate energy price is to be calculated monthly based on the hourly day-ahead electricity market price at each utility's DLAP price as published on the California Independent System Operator ("CAISO") Open Access Same-Time Information System ("OASIS"), ending the twentieth day of each month. Resolution E-4422 p. 7.

longer receive a credit from PG&E for such exports, and instead will receive such a credit from their energy supplier. Such customers would pay all non-generation charges for on-site use, as they do today. Since they do not receive generation services from PG&E, they would not pay PG&E for such supplies, or receive a credit for exported power, but would be eligible for any generation credits from their DA or CCA supplier.[38]

### 6. Interconnection Cost Responsibility

All interconnection customers will continue to comply with interconnection policies and procedures as outlined in Rule 21, with its accompanying forms, as modified by this proceeding or the Interconnection Rulemaking. Currently NEM customers do not pay interconnection costs, unless there is a need to upgrade interconnection facilities serving the NEM customer. The costs *not* paid by today's NEM customers include: application fees, engineering study fees, and distribution upgrade costs necessary to safely and reliably interconnect the customer's renewable facility. These costs are currently being borne by other PG&E customers. PG&E proposes to incorporate the following modifications into the successor tariff:

- All customers installing renewable generation will pay a combined application and study fee. The fee will apply to all studies required for the interconnection project (e.g. Initial Review and Supplemental Review). For customers installing generation with capacities up to 30 kW the fee would be approximately $100. For customers who are installing generation with capacities over 30 kW, the fee would be approximately $1,600.

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38 NEM Aggregation arrangements for agricultural customers would have to be entirely CCA accounts or entirely PG&E bundled customer accounts.

- All interconnection customers, who have interconnection facilities identified as mitigation in the study, will be responsible for the cost of the facilities. This is consistent with today's interconnection cost responsibility for NEM customers.[39]
- All NEM customers installing renewable generation facilities over 500 kW would pay the costs of any distribution upgrades identified in their project's interconnection study. However, NEM customers installing generation facilities sized at 500 kW or smaller would continue to have distribution upgrades costs paid by all rate paying customers, as they are today.

### 7. Metering

PG&E proposes to require that customers enrolling in the successor tariff provide access to their gross generation data as a condition of interconnection and suggests that the selection of a technology of choice to implement this condition be deferred to a public workshop. The value of information about gross generation to the utility customer service, operations, and planning is increasing as the penetration of customer generation increases dramatically. Given that the successor tariff is unconstrained with respect to adoption and penetration levels of solar are increasing exponentially, this is the appropriate time to consider how better information could be collected and included in the utility processes.

Given the operational and planning challenges associated with high levels of distributed customer generation in which hundreds of thousands of customers are choosing to both consume utility supplied energy and produce and export their own energy onto the grid, it is becoming increasingly important for the utility to have access customer generation production data.

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39 Interconnection facilities costs are the cost of equipment and facilities required to allow electric Distribution Service to an interconnection customer. New facilities and upgrades on the Distribution System that are located at or beyond the point of interconnection are called distribution upgrades. Distribution upgrades do not include Interconnection Facilities. Electric Rule No. 21, Generating Facility Interconnections, Advice Letter 4110-E, D. 12-09-018, September 20, 2012. .

Potential use cases for and benefits from improved insight into DG production could include the following:

- Fully informed real-time decision making capability with respect to grid operations;
- Enhanced safety and reliability from knowledge of where and how much electricity is being produced by behind-the-meter resources;
- Enhanced power quality and control through new smart grid technologies, such as smart inverters or Volt-VAR optimization equipment (VVO);
- Improved ability to plan for future distribution system upgrades due to increased DG;
- Improved load forecasting, which in turn will help drive more accurate procurement;
- Improved billing through presentation of full picture of generation, usage, and exports to customers to limit bill confusion and reduce call center volume;

In this proposal, PG&E does not prescribe the method by which the data would be provided to the IOUs, but believes that the Commission should establish the general requirement as a condition of interconnection starting at a given date and establish a forum in which stakeholders would select the means by which customers would provide this data. There are several important considerations that must be addressed in evaluating and selecting the appropriate method of data backhaul, including cost, customer privacy, data quality, ease of implementation, and preservation of interconnection efficiencies. PG&E has assessed a variety of options and believes that the Smart Inverter Working Group provides a promising path for conveyance of production data through the smart inverter and AMI network. However, PG&E believes an open process with all stakeholders exploring how best to collect production information would be beneficial.

### 8. Future Revisions to Net Energy Metering Pricing and Policies

PG&E believes that the current rulemaking to develop a successor tariff has been both essential to satisfy the legislative requirement concerning the successor program, and to establish rate design that is a solid first step to addressing the bill impacts inherent in the current NEM program. However, PG&E expects that any rate design that is adopted in this proceeding will not fully resolve those impacts and will need to be revisited in the future. *In fact, while making* *significant progress toward addressing such impacts, the rate design proposed by PG&E in this proceeding deliberately leaves in place significant subsidies for solar.* Accordingly, PG&E proposes the Commission establish a process by which the successor tariff will evolve and will be addressed regularly as the market continues to evolve.

To provide an opportunity to revisit the successor tariff rate design in the future, PG&E recommends that continued reform be addressed in either an extension of this proceeding or an entirely new proceeding. Public Utilities Code Section 2827.1, paragraph (b) 7, in part provides: "The commission shall determine which rates and tariffs are applicable to customer generators only during a rulemaking proceeding. Any fixed charges for residential customer generators that differ from the fixed charges allowed pursuant to subdivision (f) of Section 739.9 shall be authorized only in a rulemaking proceeding involving every large electric corporation." This requires that either the Commission adopt rate design in the current proceeding that is adequate for distributed generation customers for evermore, or alternatively, require that the Commission establish a rulemaking where its policies can be revisited in the future. There are many important assumptions imbedded in the public tool used to run scenarios out to 2025 that could have a significant impact on adoption and rate-payer impact. Since PG&E does not believe it is possible to develop "rates and tariffs" in this proceeding that will be adequate indefinitely into the future, it would be prudent for the Commission to establish a review process and timeline at this time.

PG&E proposes that the Commission's next review of the successor tariffs be initiated in 2019 or once total, statewide NEM installations reach 7,800 MW, which is 50% beyond the current NEM cap, whichever comes earlier.

At that time, the Commission can consider the relative progress of installation of distributed renewable generation as well as the success that has been achieved in reducing bill impacts. Based on this review, the Commission can consider further program enhancements or pricing changes.

Because PG&E is requesting that pricing policies be revisited for DG customers, PG&E has not made a proposal for those rate changes here. In fact, any proposal made for 2020 and beyond will, of necessity, be dependent on the outcome of the current proceeding. It is PG&E's expectation that over time there will be significant room to adjust rates closer to the cost of service and compensation for exports closer to the utility avoided cost.

### 9. PG&E Proposal For Systems Larger Than 1 MW

PG&E would permit customers larger than 1 MW to participate in NEM, subject to a 3 MW cap per installation. As PG&E's proposal, and likely whatever proposal is ultimately adopted by the commission, includes significant ongoing cost shifts, it remains appropriate to limit the size of NEM eligible projects, and such projects are more likely to have significant distribution system impacts. Such projects would follow the rules above, which include interconnection cost responsibility for all projects larger than 500 kW. The CAISO may require special metering for such projects. In addition, as discussed in the legal section II.E below, if such projects wish to make sales of surplus kWh, they will need to file at FERC to obtain Qualifying Facility status.

### 10. Virtual Net Metering, V-NEM MASH, and NEM Aggregation

PG&E maintains that the clear language of AB 327 indicates a Legislative intent that the CPUC be allowed to establish the successor tariff with a clean slate and without any of the lingering bill impacts created by or added to the existing NEM program. This means there is no legislative requirement that the CPUC incorporate any of the various forms of virtual net metering that have been created by either the legislature or the CPUC. That being said, PG&E suggests two limited situations where virtual or aggregated net metering be permitted - one to support the continuation of such programs for the MASH program for our low income customers and the other to support our agricultural customers. Other virtual net metering and NEM Aggregation (NEMA) programs should not be part of the NEM successor tariff. PG&E opposes retention of virtual net metering as it has been demonstrated to significantly increase cost shifting to non-adopting customers. Moreover, to the extent it allows generation in one location to serve remote load, it is essentially *de facto* Direct Access, in which the energy supplier gets free-wheeling service.[40]

PG&E believes the value of extending the benefits of rooftop solar to low income customers, who would not otherwise be able to take advantage of renewable generation programs, mitigates the concerns about shifting costs to other customers. In addition to our proposal for disadvantaged communities, PG&E continues to support the current MASH rules permitting allowing aggregation of CARE customer accounts in the successor tariff. All participating customers, however, would need to be on the successor tariff for CARE.

A similar situation exists for our agricultural customers who were initially somewhat underserved by the NEM program. PG&E has observed that solar adoption rates by agricultural customers lagged that of other customer groups. Although interest has always been high, the more recent implementation of our NEMA tariff has led to a significant increase in activity in the

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40 Even moving power from a generator to load located nearby involves wheeling, and both FERC and the CPUC have rejected proposals for providing such service without paying for all the necessary elements of such service, including transmission costs. *See Pacific Gas and Electric Co*., 100 FERC ¶ 61,156 (2002) (distribution-only service would unjustly permit a customer, such as Enron, to avoid its share of the costs associated with the construction, maintenance, and operation of the ISO Grid). Similarly, the CPUC rejected a request for a "Distribution-Only Tariff" in D.03-02-068. There, at pages 29-37, the CPUC considered whether a generator connected at distribution who makes a retail sale to a customer on the same distribution circuit (1) utilizes the transmission system, and (2) should be eligible for a distribution-only tariff. It concluded that distribution system operations rely on the transmission system, and

> Establishment of a distribution-only tariff would "unjustly permit a customer to avoid responsibility for its share of the costs associated with the construction, maintenance, and operation of the [Cal] ISO Control Grid without which the transactions in question would not be possible." PG&E, 88 FERC ¶ 63,007 at page 65,073 (1999). As PG&E points out, "(t)hese transmission and grid management costs will not go away; instead, they will be unfairly shifted to other utility ratepayers."

agricultural sector. The cost shift from these installations[41] has been problematic, as has billing, interconnection, and interpretation of vague NEMA program rules. Some of these concerns have been addressed in PG&E's proposal. PG&E would support continuation of the ability to aggregate accounts for agricultural customers, so long as the exports are only credited at the generation component of the retail rate; so long as customers are on a demand charge; so long as the true-up is monthly; so long as customers pay all interconnection costs -- including interconnection and distribution upgrades triggered by the installation,[42] and so long as customers pay increased set-up and billing costs. In this case, the desire to extend the customer choice to install renewable generation could mitigate some of the cost shift concerns.

Currently NEMA is only available to "contiguous and adjacent" customers. There have been some concerns about implementation of PG&E's current NEMA tariff, and PG&E recently filed proposed tariff changes to improve the NEMA tariff customer experience, as suggested by Energy Division, while maintaining the "contiguous and adjacent" requirement. In addition, PG&E proposes that the NEMA tariff for agricultural customers that is part of the NEM successor tariff include the following additional changes: First, consistent with PG&E's proposal for other customers, the true-up would be monthly, not annual. Second, the allocation from the generating account to the benefitting accounts would be determined by the customer, not based on the monthly usage of the individual benefitting accounts. This removes the most complex and problematic feature of the existing NEMA program, which has proved difficult to program and difficult for our customers to understand.

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41 Of note, generally publicly owned utilities in California have not adopted the aggregation provisions in PUC Section 2827. The statute requires utilities to first find that there will be no increase in costs, as the CPUC did in Resolution E-4610. On August 4, 2015, Merced Irrigation District will address this issue. The staff recommendation is that MID *not* institute account aggregation, finding that aggregation *will* increase the cost shift, and noting that other POUs have not allowed aggregation, citing specifically Alameda Municipal Power, the city of Anaheim, Modest Irrigation District and Sacramento Municipal Utility District. http://mid.novusagenda.com/AgendaPublic/.

42 Generation sized to aggregated accounts can be located at remote locations where the distribution system was sized to a modest pumping load. It simply is not equipped to accept the significant exports that NEMA can cause.

### 11. Standby Exemption

PG&E's proposal includes a mandatory demand charge. For this reason, so long as a demand charge is adopted as proposed here, PG&E proposes that under the successor tariff, NEM customers will continue to receive a standby charge exemption. Please note that a representative residential customer with 4.5 kW of demand installing a 5 kW solar system will pay a lower demand charge per month ($13.50 per month) than it would pay under PG&E's recently updated standby rate in 2017. ($6.27 per kW times 5 kW times 85 percent would result in a monthly standby bill of $26.65 per month).

Currently, combined heat and power projects pay standby charges, even if they are on a rate with demand charges. However, to avoid double charging, PG&E's Schedule E-19, for example, provides that if the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge.[43] As review of demand charges continues in upcoming cases, it would be appropriate to review the interaction of demand and standby charges, both for customers with projects that operate intermittently, like wind and solar, versus other kinds of self-generation, which often operate much of the time. However, PG&E's proposal here is that during the initial (three year) phase of the NEM successor tariff, customers who install NEM generation and are on a rate that includes a demand charge would be exempt from standby charges.

### 12. NBC Exemption

For the time being, NEM customers would continue to receive the full retail credit for simultaneous offsets supplied by their at-site generator, including nonbypassable charges. As Energy Division explained in its White Paper, NBCs "cover the costs associated with programs such as low-income ratepayer assistance, energy efficiency, and nuclear decommissioning. Other nonbypassable charges are remnants of California's transition to a deregulated electric

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43 PG&E's Rate Schedule E-19, sheet 3.

industry."[44] Non-NEM customers must pay such NBCs on self-supplied power, but PG&E's proposal here is to allow the current NEM exemptions from NBCs to continue for now.

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

In this section, PG&E addresses the appropriate metric to ensure compliance with the various subparts of PUC Section 2827.1, as requested in the June 4 Ruling. In general, PG&E supports the direction taken by the Energy Division in its White Paper attached to that Ruling, as discussed more fully below.

The Legislature directed the CPUC, in AB 327, to address the cost shift from the current NEM program, identified by the CPUC on several occasions. In addition, the legislature directed the CPUC to reform NEM in such a way as to ensure continued sustainable growth of customer renewable generation. Parties have long recognized that at least part of the cost shift from the existing NEM program is caused by the broken rates resulting from the energy crises. In fact, AB 327 directs the CPUC to address this as well. PG&E recognizes that at least some of the existing cost-shift will be reduced by implementation of the decision in the recently completed Residential Rate Reform OIR.[45] The Legislature directed the CPUC to address any remaining rate impacts, which it will do in this proceeding.

Table 3, below, summarizes PG&E's proposed metrics to measure whether a proposal meets the Legislative requirements. The following sections explain the rationale for PG&E's suggested metrics.

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44 White Paper p. 1-24, fn. 34.

45 R.12-06-013, D.15-07-001.

**Table 3: PG&E Proposed Metrics To Satisfy Legislative Criteria**

| Legislative Mandate | PCT Threshold | RIM Threshold |
|---|---|---|
| **Sustainable Growth** | >= 1.25 | >= 1.0 |
| **Costs = Benefits (Facility Perspective)** | >= 1.0 | N/A |
| **Costs = Benefits (Rate + Grid Impact)** | N/A | >= 1.0 |

### 1. Metric for "Sustainable Growth"

PG&E continues to believe the appropriate metric to measure sustainable growth is the economic opportunity afforded by the successor tariff. As discussed on pages 4-10 of "Opening Comments of Pacific Gas and Electric Company on Administrative Law Judge's Ruling Seeking Comments on Policy Issues" dated March 16, 2015 ("PG&E's NEM Policy Comments"), the Commission should measure sustainable growth by assessing whether customers have a sufficient economic incentive to adopt renewable DG technologies. Specifically the "effective compensation" discussed on page 5 of PG&E's NEM Policy Comments should yield savings to motivate adoption. Secondarily, PG&E continues to advocate that the CPUC assess whether vendors are sufficiently (or overly) incented by the successor tariff to provide customers with distributed renewable energy systems. It is critical to assess both the demand (customer) and supply (vendor) side of any policy impact on a market. Unfortunately, the Public Tool does not provide the appropriate data (i.e., DG system costs) that would be necessary to conduct this analysis.

The Energy Division White Paper suggests two measures of sustainable growth: the Participant Cost Test (PCT) and participating customers' payback period. PG&E again suggests that payback period is an inappropriate measure of sustainable growth as it has little relationship with how customers actually make decisions.

Payback would only be relevant if a customer is paying cash for their renewable generation, in which case they would want to know how long it would take to recover their capital investment. However, few customers pay out-of-pocket for renewable generation. Most customers elect to take advantage of a power purchase agreement, a lease arrangement with a third party owner of their renewable generation , or zero-down loan financing now offered by DG vendors. In these cases, payback period is irrelevant because the customer is saving from the first day.

Most of the customers who want to own their generator will finance the installation either with a bank or with the solar company installing the system. In this case, their purchase decision will be driven by whether the savings on their electricity bill is greater than the loan repayment – again payback plays no role in their decision. A recent NREL study of California energy consumers' supports the notion that the majority of customers considering solar use "monthly bill savings" as the economic metric to evaluate whether to adopt solar.[46] Furthermore, leading solar vendors now market their systems based on monthly bill savings.

The other metric recommended in the White Paper is the PCT, which compared the benefits to the customer over the life of the system with the cost to the customer over the life of the system. This is essentially the same thing as evaluating whether the "effective compensation" under the proposed successor tariff is sufficient to motivate customers to install renewable generation. The PCT for a customer who averages 20% savings on their electric bill each month would be 1.25. PG&E suggests a PCT rating of 1.25 would indicate that the successor tariff exceeds the statutory requirement for sustainable growth.

As discussed in response to Question 2 in PG&E's March Policy Comments, the necessary adjustments to the PCT that will ensure it appropriately measures the true economic incentive available for customers include: 1) use of the most recently available information from objective sources regarding price and costing of renewable technologies; and 2) assumption that the cost of renewable generation, especially solar systems, will continue to fall.

In addition, PG&E would suggest that examination of the RIM test results are also a relevant metric for "sustainable growth." The reason is simple. There are two concepts

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46 NREL. "Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics." 2014, page 1.

contained in the phrase "sustainable growth." The second is growth, which can be assured by any proposed tariff that produces a PTC above 1.25. This indicates savings, for customers who install renewable generation, of at least 20% over the life of their system and will ensure customer adoption continues. But the word "sustainable" needs to be included in the measurement of compliance with this requirement as well. The Legislature did not say "continued growth" or "maximum growth" or even just "growth." The Legislature intentionally used the word "sustainable" to describe the growth the proposal must ensure. No proposal can be labeled "sustainable" if it creates a continually increasing cost shift from one group of customers to another.[47]

PG&E suggests that neither adoption rates nor payback period should be included as appropriate metrics for sustainable growth or value to participating customers. As discussed above, payback is irrelevant for most customers installing renewable generation and we do not repeat those arguments here.

While actual adoption is a clear indicator of growth of a market, it is inappropriate to use forecasted adoption as a measure of whether the successor tariff meets the "sustainable growth" provision of AB 327. As the commission staff itself indicated in its White Paper, there are too many factors outside of the control of the CPUC, the legislature and the utilities, to require some number of installed MW to affect the policy decision of whether a given proposal is superior to another.[48] In fact, one might see more growth with a proposal that is inferior because the high growth is spurred by an unacceptably high impact on other customers. Where high adoption is coupled with a low RIM result, the proposal under examination is clearly not sustainable.

In the context of the Public Tool results, PG&E does not believe that the predicted adoption levels should be given much weight in determining the sustainability of a specific

47 Energy Division expressed the same perspective in its White Paper (at page 1-27): "ED Staff interprets a part of 'sustainable growth' to include minimizing potential cost impacts to non-participants gradually over time."

48 White Paper p. I-9.

successor tariff proposal beyond the PCT or other similar metrics of participant economics. While there have been significant improvements by E3 in the adoption forecasting algorithm in the final public tool, forecasts of any emerging technology are inherently prone to error. While adoption forecasting is helpful to understand the magnitude of potential impacts contingent on overall levels of adoption (rate impacts, avoided costs, etc.), adoption forecasts simply add a layer of uncertainty to the already uncertain results of participant cost tests.

### 2. Metric for a Tariff Based On The Costs And Benefits Of The Renewable Electrical Generation Facility

PG&E agrees with the White Paper's choice of the PCT as the appropriate measure for comparing the costs and benefits of the renewable generation from the customer's perspective. A PCT of 1.0 indicates that the costs exactly equal the benefits, from the customer's perspective. PG&E suggests any proposed tariff with a PCT greater than or equal to 1.0 would satisfy the Legislative requirement in PUC Section 2817.1(b)(3). This is consistent with PG&E's proposed metric in PG&E's March Policy Comments.

### 3. Metric for Ensuring Total Benefits to All Customers and the Electrical System Are Approximately Equal to Total Costs.

PG&E continues to maintain the appropriate metric to measure compliance with PUC Section 2827.1(b)(4) is the Ratepayer Impact Measure or RIM test. This was discussed in PG&E's NEM Policy Comments pages 19 through 26. Consequently, PG&E agrees with the White Paper's use of the RIM test. A RIM test of 1.0 indicates that all customers are indifferent to the proposed successor tariff, and the costs created by the tariff equal the benefits to all ratepayers of that tariff. A RIM result above 1.0 indicates that all ratepayers are actually better off as a result of the renewable generation installed under the proposed successor tariff. And any RIM test less than 1.0 indicates the presence of a rate impact created by the proposed successor tariff and nonparticipating ratepayers are worse off.

The Energy Division includes in the White Paper several results from the Public Tool, where possible outcomes from the Residential Rate OIR are combined with low and high DG value input assumptions to produce the metrics identified by the White Paper as appropriate to measure whether a proposal complies with the legislative direction in AB 327. In every single case, including every case with high value DG assumptions (where DG presumably is of highest value to customers and the electricity system), the RIM test is less than 1.0. This clearly indicates that the bill impacts in the current NEM program, identified by the CPUC more than once,[49] persist regardless of the residential rate reform outcome. To achieve a sustainable outcome, the successor tariff must go beyond simple rate reform (although many parties recognize that the broken residential rates contributed significantly to the rapid growth of roof top solar and the resultant rapidly growing cost shift to nonparticipating customers).

### C. PG&E's Proposal Meets the Statutory Requirements Using The Default Assumptions In The NEM Public Tool and PG&E's Modified Assumptions.

#### 1. Changes Needed To Examine PG&E's Proposal In The NEM Public Tool.

Below, PG&E presents its results using the default assumption in the NEM Public Tool. In addition, in Appendix A: Public Tool Results for PG&E's Proposed Tariff Using Modified Input Assumptions, PG&E documents the scenario analysis using modifications from the six bookend cases. When possible, PG&E implemented its NEM Successor tariff within the Public Tool exactly as described above. However, due to limitations within the tool, PG&E was forced to implement a slightly altered version to evaluate its proposal. In this section, PG&E describes these compromises and their impact on the results of the tool.

##### a. Residential Time of Use Periods

The Public Tool cannot precisely model PG&E's proposed time-of-use periods (with a 4-9 PM peak period and with a 4 month summer). Instead, in its Independent Scenario, PG&E selected an on peak period of 4-8 PM and maintained a 6 month summer. The one hour

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49 Energy and Environmental Economics, Inc., "California Net Energy Metering Ratepayer Impacts Evaluation" October 2013; and Energy and Environmental Economics, Inc., "California Solar Initiative Cost-Effectiveness Evaluation", April 2011. Both studies were prepared for and under the direction of the CPUC Energy Division.

reduction of the on peak period has negligible impacts on participant economics, as little solar production occurs from 8-9 PM. However, the 6 month summer season results in solar offsetting more electricity at higher summer rates than it would under PG&E's actual proposal. To mitigate this, PG&E has produced rates with a 6 month summer season with seasonal and peak: off peak ratios so as to ensure that the average rate offset by the solar generator is approximately equal to that offset under the PG&E's actual proposal.

In the 2-8 PM on peak period default TOU rate scenarios, PG&E also applied the 2-8 period to its residential successor tariff, as the public tool cannot model different TOU periods within a class. Given that PG&E has filed a settlement agreement in its 2015 Rate Design Window to implement its proposed TOU periods, it is extremely improbable that the default TOU rate will have an on peak period starting before 4 PM. Therefore, the scenarios with a 2-8 PM on peak period for residential customers should receive little attention and are reported for compliance purposes only.

#### b. Monthly Netting

The Public Tool does not allow netting cycles (for the purposes of determining net surplus compensation) other than the current annual true up. The impact of this change on participant economics can vary according the correlation of one's usage to solar production, along with system sizing relative to usage. Based on the current residential NEM population, about 2% of DG generation (and 4% of exports) receive net surplus compensation. Moving to a monthly netting cycle would result in 7% of DG generation and 14% of exports receiving net surplus compensation. However, this impact is concentrated among a minority of customers apparently oversizing their systems, as for the median DG customer no generation receives net surplus compensation and only 1.8% of generation and 3.5% of exports would receive it with monthly netting. Since these exports would receive approximately $0.04/kWh instead of about $0.097/kWh, the impact on overall DG economics is likely to be negligible for most prospective customers. Nevertheless, to ensure we do not overstate the DG value proposition within the

Public Tool, the initial export compensation rate is set to $0.092/kWh rather than PG&E's actual retail generation rate, which is approximately $0.097/kWh.

### c. Export Compensation

To model PG&E's proposal to compensate exports at the generation component of the energy charge in the underlying rate, PG&E had to use a similar workaround as used in the Energy Division's "Modified NEM Credit" scenario. On the "Basic Rate Inputs" tab, PG&E set all value based compensation inclusion values to "No" and inserted a societal value adder set to an approximation of PG&E's current retail generation rate ($0.092/kWh) with a 2% escalator. This reasonably approximates the credit that would be applied for exports under PG&E's proposal. This is slightly lower than the actual generation rate to account for the move to monthly netting, as discussion in the previous section.

## 2. PG&E Has Also Presented A Reasonable Independent Scenario

In addition to the required six bookend runs, PG&E ran an Independent Scenario. As required by the ALJ Rulings, in Appendix A, PG&E presents the details documenting, justifying and comparing its proposed inputs to the Public Tool "bookend cases." Regarding avoided costs, PG&E's inputs to the Public Tool differ from Energy Division's bookend cases as described in Table 4 below. The most important inputs with regard to affecting the output of the model are described below.

**Table 4. PG&E's Avoided Cost Inputs to the Public Tool**

| Public Tool Input Item | PG&E Independent Scenario Input | High Renewable DG Value Bookend Case Input | Low Renewable DG Value Bookend Case Input |
|---|---|---|---|
| **2030 RPS Policy Target** | 50% | 33% | 50% |
| **Marginal Avoided Cost Treatment** | Non-Vintaged | Vintaged | Non-Vintaged |
| **EV Charging Scenario** | More Daytime Charging | More Daytime Charging | Less Daytime Charging |

| ZNE Policy Scenario Selection | Policy Goal | No ZNE | Policy Goal |
|---|---|---|---|
| **Carbon market costs** | Base | High | Base |
| **Resource Balance Year** | Model Will Calculate | 2017 | Model Will Calculate |
| **Marginal Avoided Energy Cost Locational Multiplier** | 100% | 100% | 100% |
| **Marginal Avoided Subtransmission Cost Multiplier** | 0% | 100% | 0% |
| **Marginal Avoided Distribution Cost Multiplier** | 0% | 100% | 0% |
| **Solar Cost Case** | Low Cost | Low Cost | High Cost |
| **Storage Price Selection** | High | Low | High |

PG&E's Independent scenario differs from the two bookends in that it has both low avoided costs and low solar PV costs. As discussed in more detail below and in Appendix A, PG&E believes these assumptions are more realistic than the bookend cases and yet still underestimate cost-shift because the Public Tool inputs overestimate the avoided energy and avoided RPS values. PG&E has observed that there is little variance in the total impact on non-participants between the two bookends, as the higher per kWh ratepayer impact in the "Low Bookend" is largely cancelled out by the much lower adoption when compared to the "High Bookend." While the two bookends serve to provide a useful range of potential adoption levels, they are not useful for determining the range of potential ratepayer impacts. In combining both high adoption with high per kWh ratepayer impacts, as PG&E has done in its Independent Scenario, one sees a much greater impact on rate increases on non-participants.

### 3. PG&E's Proposal Optimally Meets Legislative Requirements as Demonstrated By The Public Tool Results

In this section, PG&E provides the results of three scenario runs of the Public Tool and explains how the proposed tariff optimally satisfies the requirements set by the Legislature.

Table 5 below shows the summary results of nine model runs to test whether PG&E's NEM successor proposal meets the legislative requirements of AB327, as measured by the criteria outlined above. The model runs reflect the two book-end cases required by the ALJ ruling using unmodified input assumptions provided by the Energy Division/E3 in the "high" and "low" cases, and a proposed "independent" scenario that modifies the input assumptions, as described in Appendix A. In this section, PG&E compares its modeling results to the Legislative requirements for sustained growth (subsection (i)); balancing costs and benefits of the generator (subsection (ii)); and balancing costs and benefits of the generator to ratepayers and the electrical system (subsection (iii)).

**Table 5. PG&E's Proposal best Satisfies Legislative Criteria**

| Scenario | PCT | RIM | 2025 Cost Shift ($ Millions) | RIM as % of Rev Req | % COS of Residential Customers | 2017-2025 Installations (MW) |
|---|---|---|---|---|---|---|
| **Bookend_High_TwoTiers** | 1.70 | 0.72 | ($620) | 3.28% | 95% | 6,213 |
| **Bookend_Low_TwoTiers** | 1.02 | 0.38 | ($491) | 2.28% | 83% | 2,106 |
| **Independent_PGE_TwoTiers** | 1.91 | 0.40 | ($1,322) | 6.28% | 91% | 7,220 |
| **Bookend_High_TOU4to8** | 1.74 | 0.70 | ($590) | 2.59% | 97% | 5,906 |
| **Bookend_Low_TOU4to8** | 1.07 | 0.36 | ($573) | 2.59% | 83% | 2,150 |
| **Independent_PGE_TOU4to8** | 1.96 | 0.39 | ($1,338) | 6.09% | 93% | 6,698 |
| **Bookend_High_TOU2to8** | 1.78 | 0.68 | ($549) | 2.51% | 99% | 5,494 |
| **Bookend_Low_TOU2to8** | 1.10 | 0.35 | ($590) | 2.78% | 83% | 2,215 |
| **Independent_PGE_TOU2to8** | 2.02 | 0.39 | ($1,298) | 5.99% | 94% | 6,497 |

### a. PG&E's Proposed Successor Tariff Ensures Sustainable Growth for Renewable Generation

PG&E suggests a PCT above 1.25 will identify a program that can ensure sustainable growth. A PCT of 1.25 – indicating bill savings of at least 20% over the life of a DG generator – represents a very strong value proposition for customers. Leading DG solar companies are currently marketing bill savings of 20% for residential customers and reporting to investors that participating small businesses are saving "5% to 25% from day one."[50] These levels of customer savings have demonstrated an ability to spur dramatic growth in these markets.

Results from the Public Tool's six bookend scenarios show PCT values ranging from 1.02 to 1.78, with the most credible values well above the range that indicates sustainable growth (1.25).[51] When PG&E modified the inputs for its independent scenario using reasonable assumptions for avoided costs[52] and the costs for solar and storage, PCT values ranged from 1.92 to 2.02.

In every reasonable case modeled, PCT values exceed 1.25, indicating strong value propositions for the population of likely adopters.[53] As discussed previously, PG&E believes this is a favorable value proposition to ensure sustainable growth of DG markets. The results of PG&E's analysis suggests that modifications of the NEM successor tariff – that go beyond the

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50 Among other leading solar installers, SunRun advertises bill savings of "20% on your electric bill" to get current residential customers to adopt DG solar. As the solar industry continues to mature over the next ten years and consumer awareness increases, homeowners will likely adopt solar for lower levels of saving. http://www.solarindustrymag.com/e107_plugins/content/content.php?content.15419; "SolarCity Earnings Report: Q2 2015 Conference Call Transcript." July 30, 2015. Page 10. http://www.thestreet.com/story/13237877/10/solarcity-scty-earnings-report-q2-2015-conference-call-transcript.html

51 As is discussed more fully below, all three low DG value bookend cases use unreasonably high costs to consumers, resulting in unrealistically low PTC values.

52 The avoided cost is only indirectly relevant for the PCT. As penetration increases, a lower avoided cost means a higher cost shift, with a greater rate impact, with the resulting greater bill savings for participants. A higher avoided cost would have the opposite effect.

53 PG&E notes that only about 25% of our residential customers are in the population of potential adopters, the others not being able to take advantage of any successor tariff because they do not live in their own home, or have a credit rating that is too low, or significant shading, etc.

initial proposal – could better align the tariff with cost of service and avoided costs for exports without undermining sustainable growth.

The only case in which PG&E's proposal results in a PCT lower than 1.7 is when using the scenario described by the Energy Division as the "Low Renewable Value DG or "Low DG value" cases. PG&E strongly believes that these low value bookend cases are unrealistic. The Tool's outputs in the low value cases, such as relatively low levels of solar adoption, are driven mostly by the very high solar price inputs. As illustrated below, the Public Tool's "High Price" solar scenario (associated with the "Low DG value" cases) starts at a level that is about 50% higher than the 2014 pricing levels in California reported by Bloomberg New Energy Finance and others.[54] Worse yet, these unrealistically high solar prices are only reduced at a nominal rate over time, which contrasts sharply with the forecasts of leading industry research organizations and announcements by solar companies that predict continued dramatic reductions in solar costs and associated pricing, as shown in the two graphs for residential and commercial solar systems below.[55]

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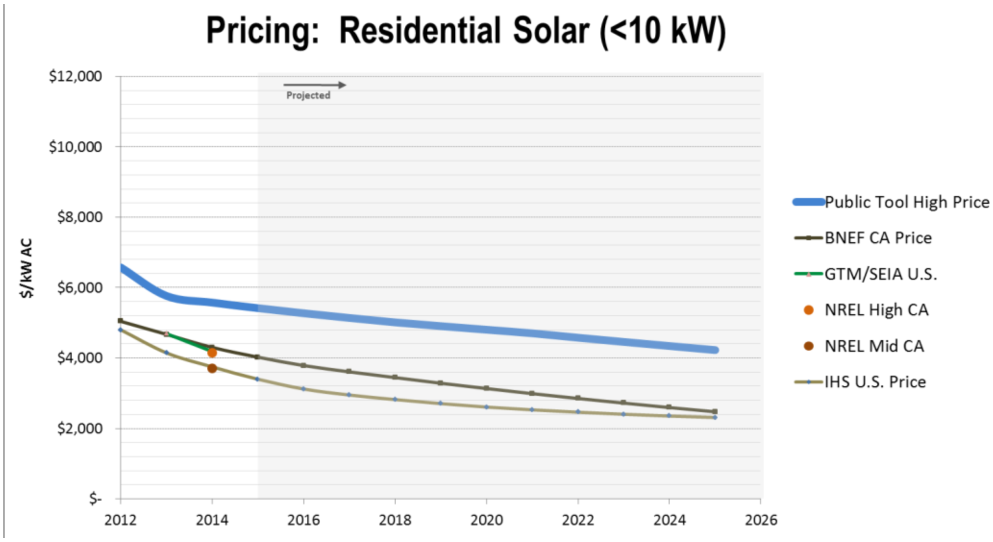
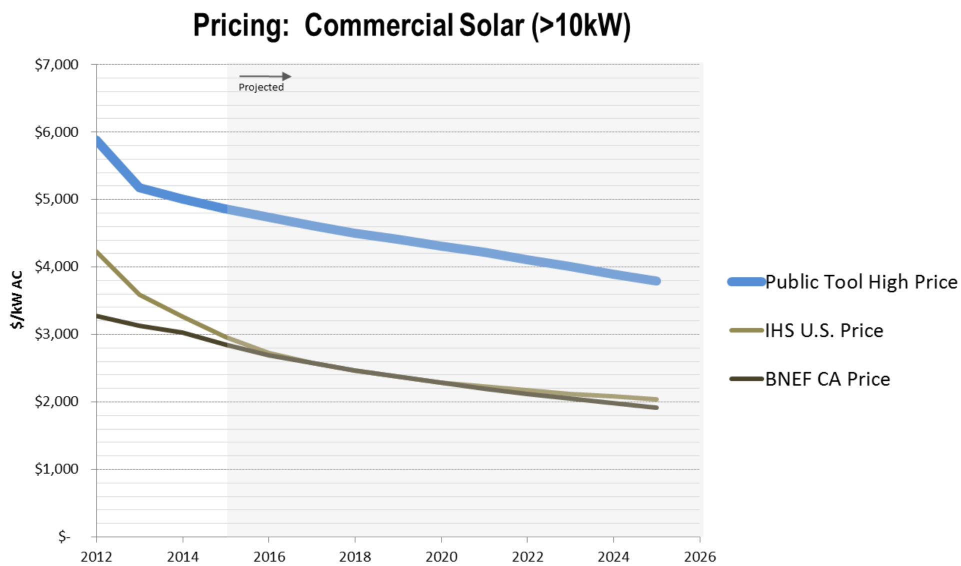
54 The low case bookend scenario uses a "High Price" solar systems price forecast, as stated in the White Paper at p. 1-17, and the prices shown in Chart E on page 1-19 of the White Paper.

55 Sources: Bloomberg New Energy Finance (BNEF), January 2015. Solar Insight Service. "Data for 1H 2015 North American PV Outlook." IHS Energy, October 2014. "Outlook for US Solar PV Capital Costs and Prices." NREL, 2014: "U.S. Photovoltaic System Prices, Q4 2013 Benchmarks." http://www.nrel.gov/docs/fy15osti/62671.pdf. And, NREL, 2012. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States." http://www.nrel.gov/docs/fy12osti/53347.pdf . DC to AC conversion factor of 1.15 from Energy Policy, 2013. "The Prospects of Competitive Solar." http://www.sciencedirect.com/science/article/pii/S0301421512009688.




Importantly, the large gaps in pricing illustrated above are effectively even greater than shown due to the Tool's conversion methodology to PPA pricing. The Public Tool uses its solar price scenarios ("High Price" illustrated above) as inputs in a *pro forma* analysis to calculate PPA prices that are inflated by additional costs in the Tool; these fixed-rate PPA values (listed in the "DER Pro Forma" tab, cells D46 to W46) are what matter because they are used to calculate solar adoption and the associated costs and benefits in the Tool (see Appendix A for more information). Described another way, the Public Tool is "designed to mimic a third party lease" transaction, and it assumes that 100% of DG solar sales over the next ten years will be leases.[56] First, many inputs in the *pro forma* do not represent the documented costs of today's third party providers and are inappropriately conservative for 2015 let alone 2025. For example, in 2012 Borrego Solar published an article about assessing PV system pricing and suggested using an insurance expense value that is half the cost used in the Public Tool's *pro forma* (0.5% vs. 1%), which has a measurable impact to inflate the Tool's PPA values.[57] Furthermore, research suggests that insurance expenses for the solar industry will decrease over time as the insurance industry gains greater comfort with the technology,[58] yet the *pro forma* uses double 2012 industry estimates for every year, including 2025. Similarly, other factors that inflate the calculated PPA values in the Public Tool include arguably high debt-service-coverage ratios, debt and equity costs, and O&M expenses. Second, it is unlikely that all DG solar systems will be sold as leases between now and 2025, especially as technology costs continue to decline. In this regard, PG&E's views are aligned with leading solar industry participants.[59] Therefore, on the whole, we believe the design of the Public Tool's *pro forma* adds superfluous costs that are unlikely to characterize DG solar markets of the future, which further skews the already improbably high solar price inputs used in the Tool's Low DG value simulations to even higher levels. As illustrated below, the Public Tool's fixed-rate PPAs from the low value (high price)

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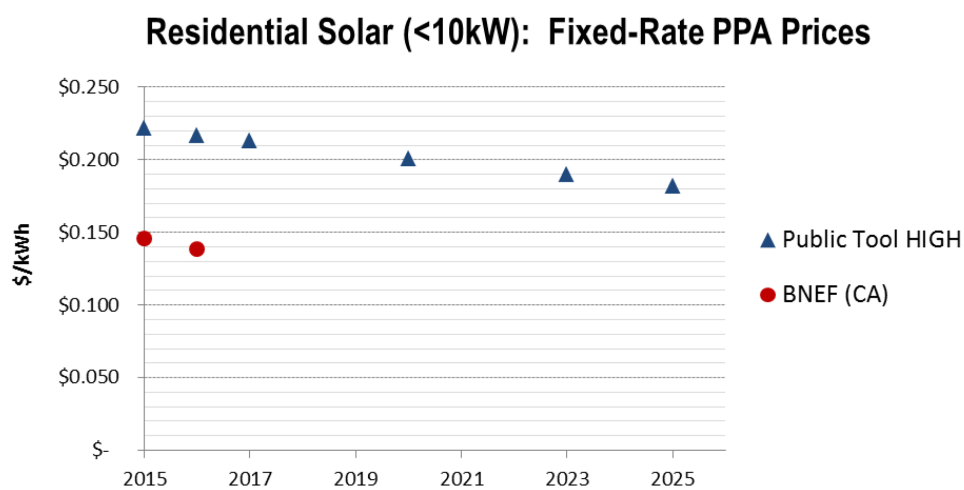
56 Page 21 of the Energy Department's "Public Tool Updates and Questions on the Tool." http://www.cpuc.ca.gov/NR/rdonlyres/D8E05965-F612-4355-91A1-C07B45F62904/0/PublicToolQA7172015.pdf.

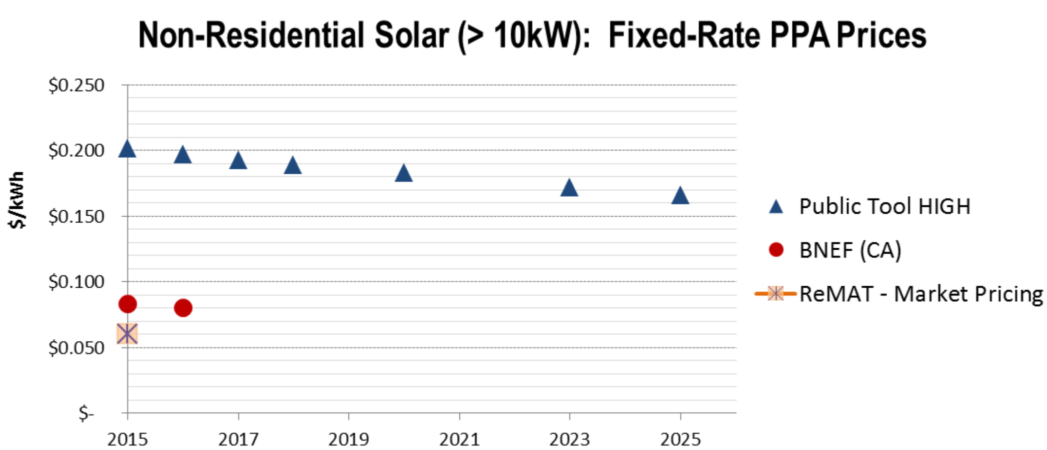
57 Solar Pro Magazine. "Levelized Cost of Energy – the new PV metric?" April/May 2012. http://borregosolar.com/index.php/download_file/756/527/.

58 NREL. "Continuing Developments in PV Risk Management: Strategies, Solutions, and Implications." February 2013. http://www.nrel.gov/docs/fy13osti/57143.pdf.

59 Greentech Media. "SolarCity CEO: Solar Loans Could be Half of New Business by End of Year." October 2014. http://www.greentechmedia.com/articles/read/SolarCity-CEO-Half-of-New-Business-by-End-of-Next-Year-Could-Be-Solar-Loan. Solar Industry Magazine. "How To Make The Pitch That Owning Residential Solar Beats Leasing." November 2014. http://www.solarindustrymag.com/e107_plugins/content/content.php?content.14808. "Why Lease Solar When You Can Buy." WholeSale Solar. http://www.wholesalesolar.com/solar-information/solar-leasing-option.

scenario in 2025 never even reach *today's* solar market prices for the residential (<10kW) and non-residential (>10kW) segments. The Public Tool's low DG value scenario (and/or other high price scenarios) are not an appropriate basis for setting the compensation terms for future DG markets.




Note: This figure illustrates a 30% ITC across all scenarios to enable comparisons among the outputs as well as to current PPA prices.[60]

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60 Bloomberg New Energy Finance (BNEF). "1H 2015 North American PV Outlook." January 16, 2015. Renewable Market Adjusting Tariff (ReMAT) from California Senate Bill 32. http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page.

In addition, the 2-8 pm TOU model runs show lower levels of customer adoption measured in MW, relative to the 4-8 runs, even though the PCT figures are higher. PG&E believes it is quite unlikely that the CPUC will adopt a 2-8 time peak period. PG&E recently presented in its 2015 Rate Design Window case detailed testimony and cost support showing why the peak time period in TOU rates should move to 4-9 p.m. That case proceeded to hearing, and ORA supported PG&E's proposal with similar testimony. On July 23, 2015, PG&E, ORA, and the solar parties filed a settlement agreement in that case requesting that the approved residential TOU rates move to a 4-9 pm peak period by 2020.[61]

PG&E suggests that the CPUC also consider the word "sustainable" in the legislative requirement in PUC Section 2827.1(b)(2). The legislature clearly indicates that while growth is important, growth that relies on significant cost shifts (such as those in the current NEM program) cannot continue indefinitely. While the NEM program has always been capped, to prevent excessive cost shifts to nonparticipants, the Legislature made it clear that the successor tariff will not be capped. Further, the legislature asked the CPUC to explore expanding the 1 MW size limit as well. PG&E believes this is only possible because the Legislature insists that the successor tariff ensure *sustainable* growth, and by sustainable they mean able to be in place indefinitely. This can only happen if the cost imbalances are appropriately addressed. Hence, PG&E suggests the CPUC also consider the RIM test, which is the measure of this cost shift.[62]

Table 5 also includes the RIM test results for the three scenarios PG&E modeled in the Public Tool. All RIM results are significantly below 1.0, indicating that there is a continuing cost shift. In fact, using the model results from the three PG&E's input modification scenarios,

61 The Settlement Agreement filed in A.14-11-014 provides that a Tiered residential TOU rate would be available for residential customers with 3-8 pm TOU period from 2016-2019, but that the peak TOU period would move to 4-9 pm on January 1, 2020. It also provides for a non-tiered TOU rate with a 4-9 pm peak period beginning in early 2016.

62 Since most of the installations are PV, a rough estimate of the annual cost shift can be arrived at by multiplying the project size in MW times 1000 (convert MW to kW) times 8760 (hours per year) times 0.19 (capacity factor for PV) times the per kWh cost shift found in cell J:46 of the Results tab of the Public Tool.

combined with the 2025 installations in those scenarios, which range from 6,497 MW to 7,220 MW, PG&E calculates the annual cost shift in 2025 will range from $1.29 billion to 1.34 billion. PG&E suggests that this is not sustainable.

Focusing on PG&E's own analysis of its proposed rate, and using its independent scenario assumptions described in Appendix A, we find that the Public Tool estimates a PCT of approximately 2.0 for all three scenarios; and a RIM test of approximately 0.40. If no further action were taken, this would not be acceptable. However, as PG&E describes in sections I.A.1 and II.B.8, above, the proposal we analyzed in the Public Tool for this submittal should be reviewed again in the next three years, which would provide an opportunity for reducing the cost imbalances over time. The cost shift identified by the Public Tool should be corrected well before 2025.

**b. PG&E's Proposed Successor Tariff Is "Based on the Costs and Benefits of the Renewable Electrical Generation Facility" From The Perspective of the Participating Customer**

As discussed in I.A.2, above, PG&E agrees that the PCT is a valid metric[63] to measure the participating customer's value proposition – which in turn is the appropriate measure of whether a proposal satisfies the legislative requirement in PUC Section 2827.1(b)(3). In the six bookend cases, PG&E results ranged from 1.02 to 1.96. In general a PCT of 1.0 would mean the "costs and benefits of the renewable electrical generation facility" are equal, from the perspective of the customer who installs the renewable generation. We believe anything above 1.25 would clearly satisfy the legislative mandate.

When considering PG&E's proposal using the input assumptions we believe are appropriate, the PCT is still above 1.0 for all three scenario. In all nine scenarios, PG&E's proposal demonstrates that the tariff is based (at least) on the costs and benefits of the renewable generating facility to the participating customer.

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[63] See White Paper, page I-9.

#### c. PG&E's Proposed Successor Tariff Does A Better Job Than The Current Tariff In Setting The Total Benefits Approximately Equal to the Total Costs To All Customers and the Electrical System

PG&E re-affirms that the best measure of whether a proposal satisfies the legislative directive in PUC Section 2827.1(b)(4) would be to measure whether ratepayers are receiving value from the renewable generation that is approximately equal to the total costs (to them) of the generation installed and taking advantage of the successor tariff. The RIM test is designed to measure exactly that.[64] It captures the ratepayer impact by comparing bill savings (a cost, because of decoupling) of participants with avoided costs resulting from the renewable generation installation (which are the benefit other ratepayers receive). A RIM value of 1.0 means, of course, that the cost exactly equals the benefit. Any RIM result above 1.0 means that all customers are better off; while a RIM value of less than 1.0 means they are worse off as a result of the successor tariff proposal.

As discussed above, in these results, benefits do not "approximately" equal costs. As seen in Table 5, all six bookend cases have RIM results that fall well below 0.8 – ranging from 0.36 to 0.72. In addition, the three scenarios run with modified input assumptions also show RIM test results from 0.39 to 0.40. As discussed above, even though the Public Tool indicates that the bill impacts are still too high, PG&E's proposal is still appropriate when coupled with a commitment to continue to modify the successor program to achieve a future with sustainable growth, appropriate participant value, and significant mitigation of cost shifts to other customers.

## D. Safety and Consumer Protection Issues

### 1. The Interconnection Process and Local Inspections Will Address Safety and Reliability Concerns

To ensure the safe interconnection of all customer sited generators, generation projects must apply for interconnection with PG&E. The potential safety and reliability of the customer sited generation, as it relates to the interconnection to PG&E's distribution system, is addressed

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64 White Paper, page I-10.

by PG&E during the study phase of the interconnection process. Any safety or reliability concerns and corresponding mitigations are identified through the Rule 21 study screens. A NEM applicant's permission to operate their generator is contingent on the installation of mitigations identified in the study phase and will not be provided until all mitigations are complete. In addition, authorization of the local permitting authority is required to interconnect. We do not believe any additional safety issues need to be adopted as part of the NEM Successor process.

### 2. Consumer Protection

Legal protections for solar consumers were enacted in California under the Independent Solar Energy Producers Act of 2009, Public Utilities Code sections 2868 – 2869. These sections provide, in addition to other consumer protection measures, "The commission may require, as a condition of receiving ratepayer funded incentives, that an independent solar energy producer provide additional disclosure to the buyer or lessee, the commission, or both." In addition, in D.10-12-060, the Commission claimed jurisdiction to exercise consumer protection authority over various energy providers, even if non Public Utilities under state legislation. We recommended that Commission utilize these provisions under any net-energy metering successor tariff.

As an important first step, PG&E proposes that all new solar customers be required to sign a statement acknowledging that rates, and rate structures, may change in the future. Customers need to understand that rates change over time and make financial decisions accordingly. This requirement would aid in the education process. It would also address a recurring contentious issue in rate-making proceedings – whether to "grandfather" customers who made the decision to invest in solar under a given rate structure that would otherwise no longer be available.

Under this authority, PG&E recommends that the Commission consider three other core areas of consumer protection:

(1) Product performance;

(2) Buyers' contractual terms (legal and financial); and,

(3) Sales and marketing tactics.

Consumer complaints have centered on all three of these issues. As with most industries, the vast majority of DG vendors engage responsibly with their customers; however, consumer protection efforts are warranted to protect against the small minority of vendors or "bad actors" who exhibit irresponsible behavior. Examples of "bad actors" in this space are similar to other more mature markets; however, consumers are at a greater disadvantage in DG markets due to lack of transparency and more limited consumer experiences, particularly with energy services/product pricing and utility rates. Actions by bad actors have included reports of impersonations,[65] predatory sales tactics (e.g., to elderly homeowners), harassing sales tactics (including door-to-door, repeated personal phone calls, and telemarketing robocalls), deceptive marketing materials, and limited cases involving product performance.

First, we recommend continuing an approved equipment list in compliance with SB 1 Guidelines, which has helped ensure consumer (and other stakeholders') safety, limited the market entry of poor quality products through minimum warranty requirements, and increased the transparency of hardware interconnected to distribution systems.

Second, efforts should be made to increase the transparency of homeowners' actual contractual terms with the third parties offering distributed generation solar, such as developing an aggregated repository of real contracts and standard definitions and presentment of contract terms and conditions. This would help advance consumer protections involving legal liabilities, value propositions, and may reduce deceptive sales and marketing tactics. PG&E recommends that the Commission consider requiring standardization of terms and disclosure of contract terms

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65 Homeowners in PG&E's territory have reported being contacted by solar providers claiming to represent the utility. Callers impersonating the utility have offered to install solar panels for free and tried to gain private customer data. Customers have also reported callers misrepresenting the California Green Energy Center as well as false solar energy initiatives and non-profit groups.

in a standard format that would empower customers and make prices and terms more transparent and comparable. This approach was successfully used to promote transparency and competition in the credit card industry, which was similarly opaque to customers.[66] We also recommend that the Commission require that installers use a reasonable, Commission-approved annual escalator for retail electricity rates (e.g., no more than 5% per year) for use in solar sales and marketing materials since much higher escalation rates (e.g., 6.0%) will likely overestimate consumer value propositions.

Third, California residents should have access to a consumer protection guide that is updated annually. Currently, utilities and state enforcement agencies are often contacted after negative incidents occur, and a focused solar consumer guide for distributed resources could help empower consumers and reduce the frequency of these incidents. This guidebook should focus exclusively on consumer protection issues and build upon related publications that discuss distributed solar considerations more broadly.[67] Residential solar should also be added to the State's Department of Consumer Affairs' Resource and Referral Guide.

Fourth, the Commission should promote education efforts such as online training and tools for consumers. In the past, PG&E and other utilities have helped lead these efforts,[68] and a number of stakeholders can play an important role to refine and expand the information that is already available at www.gosolarcalifornia.ca.gov.

Finally, we recommend that the Commission review relevant fines and penalties levied against solar stakeholders by the California State License Board. Reviewing the frequency and magnitude of penalties for licensed contractors and sales professionals operating distributed generation markets would help inform whether existing structures are effectively policing and deterring bad actors.

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66 http://www.consumerfinance.gov/credit-cards/.

67 http://www.consumerreports.org/cro/news/2015/02/when-going-solar-should-you-lease-or-buy/index.htm.

68 http://www.pge.com/en/mybusiness/save/solar/education.page.

### E. Legal Issues

#### 1. CPUC Jurisdiction and PURPA Compliance

FERC has addressed net metering on a number of occasions, addressing both the question of whether net metering is a sale for resale regulated by FERC, and whether FERC or the states have jurisdiction over the interconnection arrangements for such projects. FERC has agreed that states ordinarily have jurisdiction over the interconnection of projects receiving a bill credit under retail net metering arrangements. However, FERC stated that the rule is different if there is a net sale of energy:

> under most circumstances [FERC] does not exert jurisdiction over a net energy metering arrangement when the owner of the generator receives a credit against its retail power purchases from the selling utility. Only if the Generating Facility produces more energy than it needs and makes a net sale of energy to a utility over the applicable billing period would the Commission assert jurisdiction.

*FERC Order 2003-A*, 106 FERC ¶ 61,220 (2004) at pages 175-176, paragraph 746 (emphasis added). *See also MidAmerican Energy Co.*, 94 FERC ¶ 61,340 at 62,263 (2001); *FERC Order 2006* (2006), pages 125-26, paragraphs 476, 481.

Later, FERC again made a similar ruling There, FERC once again made the distinction between net metering projects that do and do not make a net sale of power to the utility, stating:

> Sun Edison asks the Commission to declare that in these circumstances [SunEdison selling solar power to a customer participating in net metering] there is no sale for resale. We agree that, where the net metering participant (i.e., the end-use customer that is the purchaser of the solar-generated electric energy from SunEdison) does not, in turn, make a net sale to a utility, the sale of electric energy by SunEdison to the end-use customer is not a sale for resale...

*SunEdison LLC*, 129 FERC ¶ 61,146 (Nov. 2009), paragraph 19.

As mentioned above, Assembly Bill 920 mandates that utilities give net metering customers the opportunity to elect to receive compensation for any net surplus electricity generated during the prior 12 month period, and PG&E proposes that this opportunity continue unchanged, except that netting would occur on a monthly, rather than annual basis.

In the AB 920 Decision, D.11-06-016, pages 7-12, the CPUC cited the FERC cases, and concluded that it had jurisdiction of regulate surplus kWh sales by treating such purchases as occurring under PURPA, and paying an avoided cost price. This issue does not need to be relitigated here. However, at the time, NEM was limited to projects 1 MW or smaller, and FERC had determined that renewable projects 1 MW and smaller did not need to file at FERC to obtain Qualifying Facility status. Now that projects bigger than 1 MW will be eligible for NEM status, if they wish to make surplus kWh sales, they will need to file at FERC to obtain Qualifying Facility status to make such sales, unless exempted from FERC regulation for other reasons.

### F. Other Issues

Related to the CPUC Jurisdictional issues discussed above, the CAISO Board of Governors approved, on July 16, 2015, a framework for expanding metering and telemetry options to enable distributed energy resources to participate in CAISO markets. PG&E reiterates here that behind-the-retail-meter DERs participating in NEM should be precluded from executing a DERP agreement until issues related to metering, interconnection agreements, and double compensation are resolved.[69]

## III. DETAILED DISCUSSION OF PG&E'S PROPOSAL FOR NEM FOR DISADVANTAGED COMMUNITIES

Attachment 2 to the ALJ Ruling dated June 4, 2015 described two proposals for expanding distributed generation in disadvantaged communities to meet the requirements of AB 327. PG&E instead proposes an alternative approach that we believe would better address the barriers faced by low income customers in disadvantaged communities to adopting solar.

In that Staff Paper, Energy Division proposed as one alternative that customers in disadvantaged communities be eligible for virtual net metering (VNM) under "the same compensation structure that the Commission adopts for the standard NEM successor tariff/contract." PG&E believes there are several issues that limit the viability of this option and

[69] PG&E's comments, on CAISO's draft final Expanding Metering & Telemetry Options Phase 2 Proposal are located at: https://www.caiso.com/Documents/PGEComments-ExpandingMeteringandTelemetryOptions-DraftFinalProposal.pdf.

therefore render it inadequate to best serve low income customers in disadvantaged communities. Staff's Neighborhood VNM proposal would be open to all customers, not just low income customers. PG&E believes it is unnecessary and duplicative to expand VNM to non-CARE customers, who can take advantage of the successor tariff without this added incentive. PG&E opposes expansion of virtual net metering as it has been demonstrated to significantly increase cost shifting to non-adopting customers. Moreover, as discussed above, to the extent it allows generation in one location to serve remote load, it is essentially a kind of de facto Direct Access, in which the energy supplier gets free wheeling service.

### A. Proposed Alternative to NEM Successor Tariff for Disadvantaged Communities

PG&E proposes that customers eligible for CARE located in areas designated by the CalEnviroScreen to be disadvantaged communities would be eligible to participate in its Solar CARE program. Solar CARE would be a new program which leverages key aspects of the Enhanced Community Renewables portion of PG&E's Green Tariff programs that were authorized by the CPUC in January 2015, by D.15-01-051. Solar CARE customers would remain on their regular rate schedule (e.g., Schedule EL-1); would enroll to have 100 percent of their annual usage covered by a local solar project; and would not pay any additional premium for this service. Additional premiums from the cost of solar generation would be subsidized through other non-CARE customers or through outside funding, such as general ratepayer rate increases or Greenhouse Gas Reduction Fund (GGRF) funding.[70]

Solar CARE will be limited to 28 MW of capacity with projects sized from 500 kW to 3 MW to be constructed in disadvantaged communities with the energy produced from these facilities available to benefit Solar CARE customers in said communities. The 28 MW will be in

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70 See California Air Resources Board Presentation, "Funding Guidelines for Agencies that Administer California Climate Investments, July 16, 2015, http://www.arb.ca.gov/cc/capandtrade/auctionproceeds/auction-proceeds-funding-guidelines-07-16-2015-workshop-presentation.pdf.

addition to the 45 MW of additional solar PV facilities reserved for service to customers in disadvantaged communities located in PG&E's service area under PG&E's Green Tariff Shared Renewables (GTSR) program approved by the Commission in D.15-01-051 pursuant to Senate Bill (SB) 43.[71] In addition, Phase IV of the Commission's GTSR proceeding will examine actions to provide additional support for GTSR facilities located in areas identified by the California Environmental Protection Agency (CalEPA) as the most impacted and disadvantaged pursuant to Public Utilities Code Section 2833(d)(1).[72]

PG&E considered several factors when determining the size of its Solar CARE program. PG&E followed the precedent set by the state legislature and CPUC which set original MASH and SASH funding levels at 10% of overall CSI funding.[73] The 28 MW proposed for Solar CARE represents approximately 10% of the 272 MW allotted to PG&E's Green Tariff Shared Renewables programs. Similar to the manner in which MASH and SASH complement the original California Solar Initiative, Solar CARE seeks to complement The Green Tariff Shared Renewables program to focus an amount of roughly 10% of the general market programs at boosting low-income customer adoption of the community solar model.

Another key factor in determining an appropriate program size is the amount of solar installed under the MASH and SASH programs to date. Solar CARE's 28 MW spread over a three year program enrollment period represents roughly twice the number of MW installed under the MASH program in PG&E territory through its entire seven and a half year life to date.[74] Throughout the entire state of California and over its seven and a half year program life,

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71 Public Utilities Code Section 2833(d)(1)(A).

72 D.15-01-051, p. 3.

73 Assembly Bill 2723 (AB 2723 or "the Pavley Bill"), which was signed by the Governor in September 2006, also describes requirements for low-income solar incentives. It requires the CPUC to ensure that "not less than 10% of the overall funds for the California Solar Initiative are utilized for the installation of solar energy systems, as defined, on low income residential housing." PU Code section 2852(c)(1)(later amended slightly).

74 As of July 15, 2015, PG&E has 13.3 installed or pending MW under the MASH program. See https://www.californiasolarstatistics.ca.gov/ for further detail.

the SASH program has installed 14.2 MW with 1.3 MW pending to date.[75] Taking these two programs together, the 28 MW of capacity proposed under PG&E's Solar CARE would roughly equal the combined total amount installed in California as a whole for SASH and in PG&E's territory for MASH in less than half the time. Furthermore, it can be assumed that only a portion of MASH/SASH projects have been installed in disadvantaged communities. Therefore, the increased solar capacity for low-income customers residing in these areas through Solar CARE will have a much larger impact on disadvantaged communities than MASH/SASH have had to date. This illustrates the program's alignment with the legislative intent of AB 327 to increase residential solar adoption in disadvantaged communities.

Perhaps the most striking data points that illustrate the impact Solar CARE's 28 MW can have on the left-behind low income and CARE customer market within disadvantaged communities are the adoption figures themselves. The disadvantaged communities that lie within PG&E's service territory make up approximately 17% of its land area and 19% of its customer count. According to PG&E's interconnection data, CARE customers residing in disadvantaged communities have installed less than 1.2 MW as of the end of May 2015. The 28 MW to be built in disadvantaged communities under Solar CARE represents roughly 23 times this amount and would be installed over three years.

### B. Eligibility

Solar CARE would only be available for customers eligible or currently on CARE rates in census tracts designated by the CalEnviroScreen to be disadvantaged communities. If a customer in such a census tract enrolls in the program and later moves out of a CalEnviroScreen census tract, that customer would still be eligible to carry their subscription with them. PG&E believes that the barriers to low income customers are high and likely prevent greater deployment of solar in the market as it is comprised today. Therefore, CARE customers located

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75 Ibid.

in disadvantaged communities stand the most to benefit from clean solar power at continued low (CARE) rates and will be the only customers eligible for the Solar CARE program.

### C. Customer Participation

PG&E would conduct outreach to CARE customers in disadvantaged communities to promote program participation and seek applicants in coordination with PG&E's outreach to low income and minority customers under its Green Tariff Shared Renewables Program (GTSR).[76] Specifically, PG&E will use a two-pronged approach to solicit CARE customers in eligible areas: 1) PG&E will leverage its relationship with CARE customers to market directly through existing communication channels such as billing while simultaneously 2) working with Community Based Organizations (CBOs) to identify and market to potential customers. CARE customers within disadvantaged communities will be able to sign up for Solar CARE until the earlier of: 1) reaching the 28 MW cap or, 2) three years after the program commences (e.g., if the program begins to take applicants on January 1, 2017, the application closing date would be December 31, 2019). Should a Solar CARE customer move to another location in a disadvantaged community, they will be able to remain on the rate until the program expires (date TBD and dependent on expected project life but likely 20-25 years after the solar projects are constructed and operational).

The outreach undertaken to promote Solar CARE will complement and leverage PG&E's GTSR outreach to low-income and minority customers. Per requirements of D.15-01-051, PG&E will promote the GTSR program to low-income and minority customers to expand access to renewable energy to all ratepayers to the extent possible. The low-income and minority customer outreach plan will primarily utilize one-on-one in-person communications to ensure customers fully understand the Green Tariff program and the associated costs for participating in the program. These community based outreach activities will include in-language support to

[76] PG&E Advice Letter 4638-E, Green Tariff Shared Renewables Marketing Implementation Advice Letter, May 13, 2015.

ensure non-English speaking customers are also fully informed of the program enrollment opportunities. PG&E will work to reach the low-income and minority customers segments through:

• Partnering with 64 community outreach contractors and 7 community-based organizations throughout the service territory that currently support PG&E's CARE program to drive awareness of program during the COC/CBO intake process as they drive awareness of CARE and other low-income programs. The community-based organizations offer services as a total network, supporting 32 languages.

• Partnering with community health outreach events, low-income home energy assistance program (LIHEAP) offices, and relief for energy assistance through community help (REACH) offices to drive awareness of the green tariff to Latino population at events and service offices as they conduct CARE outreach at service locations. The Community Health Outreach Worker project focuses on in-language and cultural relevant outreach and enrollment activities.

• Partnering with PG&E's local customer service offices to drive awareness of the green tariff at local offices while educating customers on PG&E's low-income programs in targeted cities in PG&E's territory.

• Conduct a targeted email campaign to CARE customers to explain the GTSR program and participation opportunities.

Using the outreach strategies already in place for its CARE and GTSR programs, PG&E's NEM 2.0 proposal will complement, leverage and not duplicate existing programs designed to increase the availability of cost-effective rooftop solar in disadvantaged communities.

### D. Solar CARE PV System Location and Sizing

PG&E, as the administrator of the Solar CARE program, would use the CalEnviroScreen and its customer database to determine a preliminary set of locations within disadvantaged communities that would be ideal for siting the community solar systems. In order to further determine the best places site community solar systems, PG&E will analyze whether there are areas that may be beneficial to the grid and ratepayers as a whole, or at least that have lower costs to interconnect.

Following the identification of locations within disadvantaged communities as described above, PG&E would then solicit input from members of these local communities, such as community based organizations, local leaders and other interested stakeholders for the best places to site such systems and to potentially engage in other related activities, such as education and job training. Customers would know that their participation in the program would directly support new renewables in their community. While specific locations are being finalized, PG&E would solicit and evaluate bids from solar companies to build and maintain community solar assets at the most cost effective price.[77] Consistent with the CPUC's ruling on PG&E's Enhanced Community Renewables portion of the Green Tariff Shared Renewables program, sizing for Solar CARE projects would be limited at 0.5 to 3 MW in size. The program's capped capacity of 28 MW would be in addition to the Green Tariff Shared Renewables 272 MW program cap and would similarly be ineligible to help meet PG&E's RPS obligations. This is consistent with the CPUC's ruling on PG&E's Green Tariff Shared Renewables program and ensures that the solar generation being procured for Solar CARE customers is above and beyond any RPS obligations PG&E may need to meet.

### E. Program Revenue and Cost

As mentioned in the overview, customers participating in the Solar CARE program would remain on the standard CARE rate. The program would be designed so that their total bill would be no different under CARE or Solar CARE. Generation revenue from participating customers will be used to offset the cost of the program. PG&E will leverage the cost structure from the Green Tariff Shared Renewables program such that costs for Solar CARE are equal to

[77] PG&E would explore as part of this process the advantages and disadvantages of utility-owned vs. third party owned PV projects for the Solar CARE program.

the adopted costs for the Green Tariff Shared Renewables program except where the Solar CARE program is unique. Specifically, the solar resource cost and the cost for administration and marketing will differ for the Solar CARE program. The table below offers a high level illustration of the program components:

| Component | Illustrative Pricing | Basis |
|---|---|---|
| Solar Charge | ~7 - 11 cents/kWh | Cost of delivering solar resource; depends on PV project cost |
| Program Charge | ~3 cents/kWh | Includes administrative, marketing and outreach costs. Also includes PCIA, RA, WREGIS and other components mandated by the CPUC as part of GTSR to ensure non-participants in that program are held indifferent |
| Generation Revenue from customer | (~ 9 cents)/kWh | Generation revenue received from customer as part of normal payment |
| Net Cost | 1 - 5 cent cost | Cost to be determined by net of above components |

Any cost in excess of the revenue from participants would be funded through other non-CARE customers or through outside funding, such as through Greenhouse Gas Reduction Fund (GGRF) funding. In the above table, PG&E estimates a 1-5 cent/ kWh premium that would be offset by one of the outside funding mechanisms mentioned above. Using the 28 MW program cap, PG&E estimates the range of first year program subsidy to be from a low of $500,000 to $2,500,000. Extrapolating these figures using a simple estimate that holds all of the components in the illustrative table constant for 20 years yields a net present value of the program cost (using a 6% discount rate) ranging from $5.6 to $28.1 million. Furthermore, on a per participating customer basis, PG&E estimates the cost of the program would range from $60 to $300 for the program's first year and $675 to $3,400 over 20 years. Using outside funding to cover the premium required will ensure that Solar CARE customers maintain their current level of CARE savings while enjoying the benefits of clean, distributed solar in communities deemed to be disadvantaged.

### F. Solar CARE Addresses Existing Barriers to Adoption

By authorizing Solar CARE in disadvantaged communities, the Commission could address the most significant barriers to customer adoption in such communities.

#### 1. Economic Barriers:

Solar CARE addresses the capital and credit barriers that remain significant hurdles for low income customers to adopt solar in today's solar marketplace. By allowing customers to remain on their CARE rate and using solar produced in a community solar project nearby, PG&E's Solar CARE removes the need for customers to secure capital to finance the system on their own or to maintain exceptional credit scores to receive a zero or low money down third party owned system.

#### 2. Property Ownership Barriers:

Solar CARE addresses the property ownership constraint by not requiring the customer to own property or by requiring incentives for the building owner to make an investment in solar. Under the program, CARE customers in disadvantaged communities can enjoy the benefits of solar power in their local communities by simply volunteering for the program, CARE customers residing in an apartment or a multi-family home (owned or rented) can sign up for Solar CARE just as they have signed up for CARE. The crucial difference between the two being that under the former customers would be assured that power equivalent to their annual usage would be produced by local community solar PV plants.

#### 3. Property Structure Barriers:

Since the community solar PV plants installed under the Solar CARE program do not need to be located on the enrolled customers' property, the issues of shading, insolation, roof condition, or roof orientation will not act as a barrier. PG&E, while working with concerned parties in disadvantaged communities (e.g., Community Based Organizations), will be able to locate these projects in as ideal locations as possible to ensure maximum efficiency and if possible, benefits to the grid and therefore overall ratepayers.

#### 4. Marketing, Outreach and Linguistic Barriers:

PG&E's experience as the CARE administrator ensures that it has the ability to provide outreach to customers that face marketing, outreach and linguistic barriers to adopting solar in today's marketplace. The Solar CARE program would directly benefit current CARE and CARE eligible customers by offering these customers the opportunity to easily sign up for and receive the benefits of locally produced solar energy at no additional cost. Importantly, PG&E's existing relationship with these customers will allow it to easily provide marketing and outreach through its multi-lingual customer care unit to help customers see the value in this program and wish to participate. Additionally, PG&E will seek assistance of Community Based Organizations (CBOs) to help ensure that CARE customers in disadvantaged communities are aware of the Solar CARE program, its positive impact on their communities and will therefore be more likely to sign up.

### G. PG&E's Solar CARE Program Meets Statutory Requirements

PG&E suggests that the Solar CARE proposal meets the statutory requirements in 2827.1.

Growth: Solar CARE is an alternative to the standard NEM successor tariff/contract that addresses the major barriers to adoption found for low income customers in disadvantaged communities today and will therefore promote growth in these communities.

Evaluating Costs and Benefits: From a purely economic standpoint, the CARE customer should remain indifferent as they will see no change in their bill when they join the Solar Care program. Depending on the exact funding source, non-participants may see an increase in rates to fund the program. As noted above, the subsidy required from non-participants in order to fund the 28 MW program is estimated to range from \$5.6M to \$28.1M. PG&E notes that this range represents only a small portion of the Greenhouse Gas Reduction Fund available for low income

GHG reduction projects, including rooftop solar, as intended by the California Legislature. PG&E believes that this amount is reasonable in order to aid low income solar adoption in disadvantaged communities consistent with the direction of AB 327.

### H. Administration of Solar CARE

Since customers will remain on their current CARE rate with only minor bill presentation adjustments additional administration costs should be low. Similarly, PG&E's longstanding relationship with CARE customers and leveraging its existing relationships with Community Based Organizations (CBOs) will also help to keep outreach and advertisement expenditure low.

### I. Evaluation of Solar CARE

PG&E agrees with Energy Division Staff's interpretation of the directive found in 2827.1 (b)(1) which states " the alternative to the standard NEM successor tariff/contract be "designed for growth among residential customers in disadvantaged communities." Staff suggests that this directive can be interpreted as different and distinct from the directive in 2827.1(b)(1) that the standard NEM successor tariff/contract "ensures that customer-sited renewable distributed generation continues to grow sustainably." PG&E agrees with the target as set out by Energy Division in its proposal to "promote growth beyond historic adoption levels among residential customers in disadvantaged communities," but believes the focus should be solely on CARE customers in these communities. PG&E foresees that the Solar CARE program would sufficiently meet this target.

To evaluate whether or not the program has met these goals, PG&E proposes evaluation criteria similar to that of Energy Division for its disadvantaged communities proposals, specifically that "the definition of 'growth' be based on installed capacity and be measured on an annual basis" and that " growth be defined as an increase in the total annual capacity installed by residential customers in disadvantaged communities…beyond the total annual capacity installed in the year prior to implementation of the alternative for disadvantaged communities. Staff suggests that the subsequent years also be held to the same growth requirements, wherein they benchmark against the year before the alternative was implements, rather than requiring an increase year-over-year." PG&E largely agrees with these criteria. However, PG&E recommends that its program be evaluated on the annual capacity installed by low-income (specifically CARE) residential customers in disadvantaged communities rather than staff's evaluation criteria proposal of annual capacity installed by all residential customers in disadvantaged communities. This is consistent with PG&E's belief that it is low income customers who face the greatest number of barriers that need to be addressed through an alternative to its standard NEM tariff proposal. Customers that are not low-income that reside in disadvantaged communities have a multitude of options to obtain solar, such as through the PG&E's proposed Standard NEM Successor tariff, PG&E's Green Tariff shared renewables program, or through the MASH and SASH programs. PG&E also agrees with Energy Division Staff's proposal which states "should the adoption target not be achieved in at least one year of the first three year period, Staff suggests that it may be appropriate for the Commission to revisit the alternative and consider whether an adjustment is warranted."

The Solar CARE program capacity cap of 28 MW allows room for growth among CARE customers to adopt solar over historical levels while ensuring that the amount of funding needed from outside sources to help offset program costs is limited.

## IV. CONCLUSION

PG&E appreciates this opportunity to address these issues, and encourages the Commission to adopt these proposals.

Respectfully submitted,

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August 3, 2015

## Appendix A

## Public Tool Results for PG&E's Proposed Tariff Using Modified Input Assumptions, And Description of Proposed Modifications

## APPENDIX A: Public Tool Results for PG&E's Proposed Tariff With Modified Input Assumptions And Description of Proposed Modifications

As required by section 1.B.1 of the June 4 Ruling, this attachment is transparently documenting, justifying and comparing PG&E's proposed inputs to the Public Tool to the "bookend cases."

PG&E's inputs to the Public Tool differ from Energy Division's bookend cases as described in Table A-1 below. If not specifically mentioned, PG&E's inputs do not diverge from the bookend cases. While in some cases PG&E may have disagreements with common assumptions in the bookends, these are not changed in PG&E's independent scenario due to the impacts on final results not being large enough to justify the added complexity of comparing results. Therefore, when responding to the input assumptions of other parties PG&E may argue that the most accurate or reasonable assumption varies from its own independent scenario.

**Table A-1. PG&E's Avoided Cost Inputs to the Public Tool**

| Public Tool Input Item | PG&E Input | High Renewable DG Value Bookend Case Input | Low Renewable DG Value Bookend Case Input |
|---|---|---|---|
| **2030 RPS Policy Target** | 50% | 33% | 50% |
| **Marginal Avoided Cost Treatment** | Non-Vintaged | Vintaged | Non-Vintaged |
| **EV Charging Scenario** | More Daytime Charging | More Daytime Charging | Less Daytime Charging |
| **ZNE Policy Scenario Selection** | Policy Goal | No ZNE | Policy Goal |
| **Carbon market costs** | Base | High | Base |
| **Resource Balance Year** | Model Will Calculate | 2017 | Model Will Calculate |
| **Marginal Avoided Energy Cost Locational Multiplier** | 100% | 100% | 100% |
| **Marginal Avoided Subtransmission Cost Multiplier** | 0% | 100% | 0% |

| | | | |
|---|---|---|---|
| **Marginal Avoided Distribution Cost Multiplier** | 0% | 100% | 0% |
| **Solar Cost Case** | Low Cost | Low Cost | High Cost |
| **Storage Price Selection** | High | Low | High |

PG&E's documentation and justification for these avoided cost inputs are described in the following sections.

## A. <u>2030 RPS Policy Target</u>

PG&E's Public Tool input for "2030 RPS Policy Target" is 50% versus a High Bookend of 33% and a Low Bookend of 50%.

PG&E assumes that California's mix of generation resources will continue to become cleaner over time, and does not anticipate that the amount of renewable generation on the California grid will remain fixed at the levels anticipated in 2020. While the timing and nature of future changes to RPS policy is uncertain, PG&E feels that the 50% RPS scenario, when considered over the long timeframe of the public tool model (out to 2050), is more appropriate than a scenario which maintains renewable generation on the California grid at or near the levels anticipated under current policy.[78]

## B. <u>Marginal Avoided Cost Treatment</u>

PG&E's Public Tool input for <u>"Marginal Avoided Cost Treatment" is Non-Vintaged</u> versus a <u>High Bookend of Vintaged</u> and a <u>Low Bookend of Non-Vintaged</u>.

PG&E asserts the Marginal Avoided Cost Treatment should be "Non-Vintaged" rather than "Vintaged." For purposes of doing cost-benefit analysis, it is fundamentally incorrect to "lock in" the values used to calculate generation capacity and RPS avoided cost from a PV

[78] Legislation pending in Sacramento may amend the existing RPS statute, including post-2020 RPS policy and the pace and timing of achieving interim targets. However, unless that legislation is enacted before this proceeding has concluded, PG&E's proposal reflects a 50% RPS scenario as described in Section A.

system's inaugural year for the 25-years that system is assumed to operate. Prior work by E3 has demonstrated that the actual ELCC and RPS curtailment impacts (and hence avoided costs) can vary significantly over that time period, especially when the penetration of solar and other renewables increases over time as in the scenarios considered in this proceeding.[79]

## C. EV Charging Scenario

PG&E's Public Tool input for "EV Charging Scenario" is More Daytime Charging versus a High Bookend of More Daytime Charging and a Low Bookend of Less Daytime Charging.

PG&E expects EV Charging behavior will use "More Daytime Charging" rather than "Less Daytime Charging." PG&E's knowledge of current EV charging behavior indicates that the current reality is closer to the "More Daytime" scenario. Moreover, as shown in the CAISO's TOU period analysis to address "high renewable" grid needs, the middle of the day—10 a.m. to 4 p.m.—is forecast to become the "Super Off Peak" period in the near future.[80] This is likely to drive additional daytime charging.

## D. ZNE Policy Scenario Selection

PG&E's Public Tool input for "ZNE Policy Scenario Selection" is Policy Goal versus a High Bookend of No ZNE and a Low Bookend of Policy Goal.

PG&E expects the ZNE Policy Scenario more likely will align with the "Policy Goal" rather than with "No ZNE" at all. PG&E recognizes the innovative efforts and thinking of the CPUC, CEC, and others who have helped shape California's ZNE goals for new and existing

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79 See for example, the February 10, 2015 CPUC Energy Division Presentation on RPS resource valuation, which discusses various saturation impacts on energy and capacity value, integration and curtailment cost, located here: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/RPS+Calculator+Home.htm. Similar impacts are discussed in the October 28, 2013 California Net Energy Metering Ratepayer Impacts Evaluation, located here: http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm

80 http://www.caiso.com/Documents/CaliforniaISO_Time_UsePeriodAnalysis.pdf. http://www.caiso.com/Documents/MatchingTimeOfUsePeriodsWithGridConditions-FastFacts.pdf.

buildings. The most recent progress on these goals includes the establishment of a regulatory ZNE definition in the CEC's 2013 Integrated Energy Policy Report[81] as well as the CPUC's draft New Residential Zero Net Energy Action Plan 2014-2020.[82] Recent research estimated over 300 megawatts (MW) of new distributed generation (largely solar PV) annually by 2020 and over 1 gigawatt (GW) annually by 2030 should California building codes adopt the ZNE goals measured with a Time Dependent Valuation metric.[83]

**E. Carbon Market Costs**

PG&E's Public Tool input for "Carbon Market Costs" is Base versus a High Bookend of High and a Low Bookend of Base.

PG&E expects Carbon Market Costs will be closer to the "Low" scenario than the "High" scenario. PG&E expects prices to remain at or near the floor price because both the market appears to be sufficiently supplied with allowances through 2020 and PG&E expects GHG emissions from many sectors to continue to decline.

**F. Resource Balance Year**

PG&E's Public Tool input for "Resource Balance Year" is Model Will Calculate versus a High Bookend of 2017 and a Low Bookend of Model Will Calculate.

The Public Tool should be allowed to calculate the Resource Balance Year rather than assume an out-of-date resource balance year of 2017. The source of the 2017 date[84] appears to

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81 California Energy Commission. (2013). Final 2013 Integrated Energy Policy Report (No. CEC-100- 2013- 001- LCF). Sacramento, CA. Retrieved from http://www.energy.ca.gov/2013publications/CEC-100-2013- 001/CEC-100-2013-001-LCF.pdf.

82 California Public Utilities Commission, & California Energy Commission. (2013). New Residential Zero Net Energy Action Plan 2014-2020. Retrieved from http://www.cpuc.ca.gov/NR/rdonlyres/D8EBFEE4-76A5-47AC-A8F3-6E0DAB3A9E5D/0/DRAFTZNE_Action_Plan_Comment.pdf.

83 "Technical Feasibility of ZNE Buildings in California (ZNE Technical Feasibility)", Arup, December 2012, Table 17, pp. 43. Retrieved from http://calmac.org/publications/California_ZNE_Technical_Feasibility_Report_CALMAC_PGE0326.01ES.pdf

84 As described in the documentation of E3's avoided cost calculator.

be a Joint IOU submittal on July 1, 2011, in the LTPP proceeding (R.10-05-006 track 1). It appears to reflect the middle load trajectory with 10,000 MW of imports, no demand response, and no incremental EE or combined heat and power after 2013. Embedded in this forecast is an assumption of once-through-cooling plants dropping off in 2017. This 2017 date was later reinforced by the CAISO's December 6, 2011 Report on Basis and Need for CPM Designation for Sutter Energy Center.

No recent major stakeholder process in California—e.g., LTPP, TPP—still advocates a need for flexible, fossil-fueled capacity as early as 2017.

## G. Marginal Avoided Energy Cost Locational Multiplier

PG&E's Public Tool input for "Marginal Avoided Energy Cost Locational Multiplier" is 100% versus a High Bookend of 100% and a Low Bookend of 100%.

While PG&E is using the default energy avoided costs, this is done primarily in the interest of maintaining consistency and comparability with other scenarios. PG&E has found that energy prices in the Public Tool are too flat and too high in the middle of the day during the period of maximum solar generation. This significantly overstates the avoided energy cost by up to 400% in 2020 and understates the cost-shift associated with solar PV. PG&E was unable to satisfactorily modify the model to achieve reasonable results in this regard, but notes that any energy avoided costs within the model should be considered an upper bound. Additional discussion on this issue is provided in PG&E's comments on the draft version of the public tool.[85]

See PG&E's prior comments on the NEM Public Tool dated April 28, 2015 (pp. 5-6, 18-21) for details of how this was calculated.

85 These comments are located here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K569/151569666.PDF.

## H. Marginal Avoided Subtransmission and Distribution Cost Multiplier

PG&E's Public Tool inputs for "Marginal Avoided Subtransmission and Distribution Cost Multipliers" are 0% versus a High Bookend of 100% and a Low Bookend of 0%.

A distribution investment can be deferred if and only if the sum of demand side and distributed generation resources can satisfy the minimum criteria of "the "right time, right place, right amount, right certainty" and right performance level." PG&E's assumption is the average amount of deferment is close enough to zero to call it that.

In late 2014, PG&E retained Navigant to conduct a Distributed Generation Photovoltaic (DGPV) Transmission and Distribution (T&D) Impact Study on its behalf. The study was designed to develop a rigorous and defensible range of T&D costs and benefits resulting from the integration of higher levels of DGPV on PG&E's electric grid. The study examines multiple DGPV penetration scenarios and separately attributes costs and benefits to retail and wholesale DGPV systems for the years 2015 through 2024.

The study by Navigant was included as Appendix A to PG&E's April 28 Reply comments on the NEM Public Tool. It provides a defensible alternative to prior statewide estimates of DG net value by using an approach that more accurately reflects costs and benefits for PG&E's grid. The following table illustrates the total net costs (2014, $ Million) over the 10-year study horizon for the low, mid and high retail PV forecast. For the low and high PV forecast scenarios, the net costs for distribution system upgrades in 2024 are estimated to be $14/MWH and $24/MWh, respectively.

Navigant's estimation of the value of transmission and distribution (T&D) deferral was developed from the ground up using individual feeder load data. These profiles were aggregated and compared to standardized PV profile in order to determine the contribution of the solar resource to T&D deferral. This contribution was subtracted from projected loads at each substation, and compared to T&D upgrade plans. The value of avoided T&D is the sum of the deferred investment costs. Using this methodology Navigant observed that a maximum of around six percent (6%) of planned substation investments potentially could be differed.

Navigant applied well-known analytical tools to predict costs and benefits at the feeder level. Study methods and assumptions are consistent with approaches and assumptions PG&E engineering and planning uses for its internal studies. The two primary analytical tools, the CYME distribution load flow and PSLF transmission network model, are the same as those used by PG&E and other California utilities. Model databases and criterion applied by PG&E also are used for evaluating PV costs and benefits.

The representative circuit methodology is designed to develop defensible, system-wide estimates of costs and benefits; but, it may not sufficiently granular to inform feeder-specific investment decisions, since it relies on representative circuit characteristics.

| PV Forecast (MW) | 2024 PV Capacity (MW) | | | 2024 Costs & Benefits | | | | |
|---|---|---|---|---|---|---|---|---|
| | Retail | Wholesale | Total PV | Costs | Benefits | Net Cost | ($/kW-PV) | ($/MWH) |
| Low Retail | 1,160 | 1,385 | 2,545 | $ 37 | $ 7 | $ 30 | $ 26 | $ 14 |
| Mid Retail | 4,353 | 1,385 | 5,738 | $ 125 | $ 13 | $ 112 | $ 26 | $ 14 |
| High Retail | 6,778 | 1,385 | 8,163 | $ 309 | $ 17 | $ 293 | $ 43 | $ 23 |

The study methodology is based on the California Energy Commission's (CEC) Analytical Framework, but with additional detail and analytical rigor. The primary assumptions about upgrade costs, triggers and values were informed by PG&E and are more conservative (i.e., result in lower costs) in nature than those used in the previous CEC study for Southern California Edison. The following steps highlight the overarching methodology applied by the Navigant team, in consultation with the PG&E team:

1. Select representative set of 20 feeders as the basis to model PG&E's entire distribution system containing over 3,000 individual feeders.

2. Develop three (high, mid, low) system level retail and wholesale PV capacity forecast scenarios for 2015 through 2024 (forecasting conducted by PG&E).

3. Allocate system-level forecast to each of over 3,000 distribution feeders (allocation of retail forecast conducted by PG&E; allocation of wholesale forecast conducted jointly).

4. Conduct parametric studies of distribution impacts and costs via simulation models for each scenario.

5. Estimate upgrade costs for all PG&E feeders based on parametric studies of representative feeders; upgrade cost methodology, triggers and values informed by PG&E.

6. Calculate distribution capacity deferral benefits at the feeder level based on the ELCC methodology for distribution assets.

7. Conduct transmission impact analysis for PG&E service territory via PSLF simulation model for each scenario.

8. Develop net costs and benefits for each scenario & PV forecast (9 total).

## I. Solar Cost Case

PG&E's Public Tool input for the "Solar Cost Case" is the "Low Price" scenario because the resulting PPA prices align with current reporting and market trends as illustrated in the figures below. The Public Tool's price input options listed in the "Advanced DER Inputs" tab were the focus of many parties' comments on the Draft Tool, yet these values are not used to simulate DG transaction pricing and adoption. Instead, the Public Tool uses these values as inputs in a *pro forma* analysis that calculates fixed-rate PPA prices after adding several additional expenses and an additional margin (The PPA values calculated in the Public Tool are listed in the "DER Pro Forma" tab, cells D46 to W46). As such, the structure of the Public Tool only simulates one type of DG solar transaction: a third-party lease arrangement. That is, for every year over the next decade, the Public Tool is "designed to mimic a third party lease" transaction for 100% of DG solar system sales.[86] And, the assumptions embedded in the *pro*

[86] Page 21 of the Energy Department's "Public Tool Updates and Questions on the Tool." http://www.cpuc.ca.gov/NR/rdonlyres/D8E05965-F612-4355-91A1-C07B45F62904/0/PublicToolQA7172015.pdf.

*forma* add significant premiums to the default solar price input options listed in the Advanced DER Inputs tab, which skew the PPA values high.

We disagree that all DG solar systems over the next ten years will be sold as leases due in large part to the high costs associated with these structures and the increasing availability of other options (e.g., loans) that offer better value to consumers. In this regard, PG&E's views are aligned with leading solar industry participants that envision a future with fewer third-party-owned transactions.[87] As reported by a solar industry trade magazine in December 2014: "Ultimately, the shift to more loans and less third-party solar is not driven by any external change, but as part of the evolution of the solar industry and the ongoing reduction in PV costs, including financing."[88] This change is likely to be accelerated by the reality that whether it is for an automobile or a DG solar energy system, leasing goods for 25 years – as it is calculated in the Public Tool – is often very expensive compared to market alternatives. Yet, the Public Tool only models these types of third-party transactions, which inflate PPA values for the given user price input options. Thus, we strongly believe the *pro forma* analysis in the Public Tool adds superfluous costs that are unlikely to characterize DG solar markets in the future.

In this context, PG&E chose to model the "Low Price" scenario since it results in PPA pricing that is best aligned with current pricing and market trends. Alternatively, numerous changes to the Public Tool's *pro forma* analysis could be offered – many inputs do not represent the documented costs of today's third party providers and are inappropriately conservative for 2015 let alone 2025 – and then paired with other pricing scenarios, such as the Public Tool's

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87 Greentech Media. "SolarCity CEO: Solar Loans Could be Half of New Business by End of Year." October 2014. http://www.greentechmedia.com/articles/read/SolarCity-CEO-Half-of-New-Business-by-End-of-Next-Year-Could-Be-Solar-Loan. Solar Industry Magazine. "How To Make The Pitch That Owning Residential Solar Beats Leasing." November 2014. http://www.solarindustrymag.com/e107_plugins/content/content.php?content.14808. Why Lease Solar When You Can Buy." WholeSale Solar. http://www.wholesalesolar.com/solar-information/solar-leasing-option.

88 PV-Magazine. "Loan or Lease." December 2014. http://www.pv-magazine.com/archive/articles/beitrag/loan-or-lease-_100017388/618/#ixzz3g4vgyBWH.

"Base Price" scenario; however, it may complicate other parties' ability to replicate the analysis as more input options and functionality of the Public Tool are changed. Therefore, PG&E has chosen to not modify any inputs in the Public Tool's *pro forma* analysis tab and instead select the "Low Price" user input scenario because it results in very feasible PPA prices calculated by the Tool over the next decade (as illustrated below). In further support of the Low Price scenario, increasing numbers of market participants are announcing that they will achieve the Department of Energy's *SunShot* solar price targets, which were the basis for this trajectory in the Public Tool.[89] We strongly believe the "Base" and "High" price scenarios will significantly underestimate levels of DG deployments and associated cost shifts.

To use the Public Tool's low DG value scenario (and/or other high price scenarios) as the basis for setting the compensation terms for future DG markets would result in excessive and severe bill impacts to other ratepayers.

As many researchers have repeatedly pointed out, the California market has historically experienced much higher prices than in other states, especially in residential markets. This is because vendors engage in value-based pricing against the utility rate, not cost-plus-margin, competitive pricing.[90] This illustrates how disconnected price can become from cost, and it is important to note since the base of the Public Tool's solar price forecasts start from this inflated, high-margin market context in California.

As noted in comments filed about the Draft Tool, residential solar prices in states like Arizona have been documented at fixed rates of less than $0.10/kWh in 2015.[91] By comparison, the Tool's 2015 fixed-rate PPA price is $0.152/kW (25 year term) in the "Low Price" scenario. The market rates currently available in other states are not achieved until about 2018–2019, and thereafter the Tool's PPA prices only decline a small amount. We strongly believe that a

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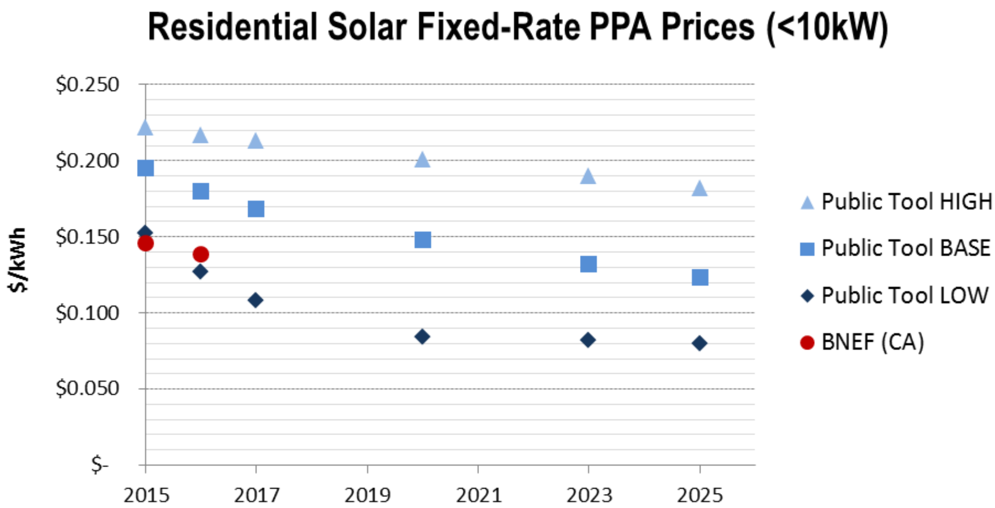
89 "America Will Achieve Its Sunshot." Forbes. June 21, 2015. http://www.forbes.com/sites/jeffmcmahon/2015/06/21/america-will-achieve-its-sunshot/.

90 MIT. "The Future of Solar Energy," page 92, 2015. http://mitei.mit.edu/futureofsolar.

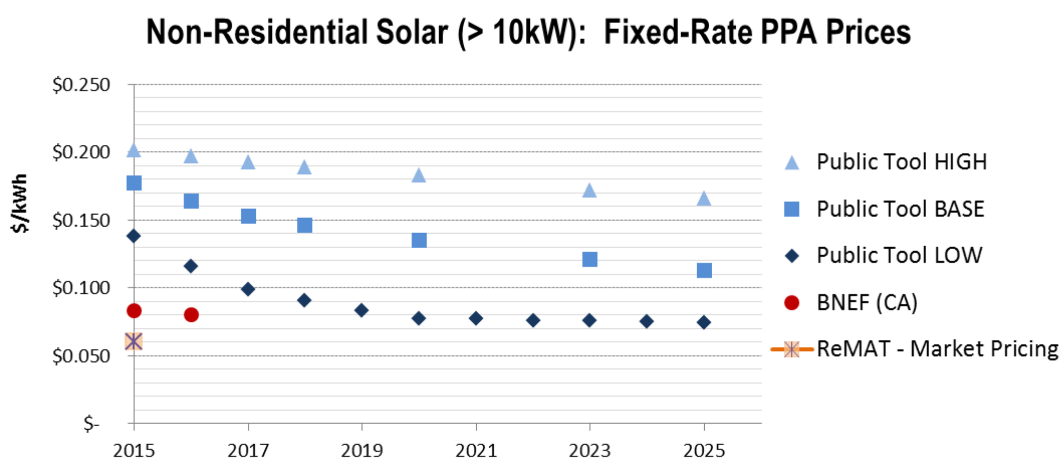
91 Bloomberg Energy Finance. "H1 2015 US Residential PV PPA Survey." April 6, 2015.

reformed policy environment that is more tailored to the DG solar industry's current status – in addition to continued trends of lowering costs, increasing levels of competition, and rising customer awareness – will drive alignment of pricing with other states, and this can be achieved in California's residential DG solar market by 2018. In the non-residential market segment (">10 kW"), the Public Tool's DG solar PPA prices are high, even in the model's "Low Price" scenario. Select competitively bid DG solar programs such as the Renewable Market Adjusting Tariff (Re-MAT) in California offer insights into achievable prices levels in the non-residential solar market. Recent pricing in Re-MAT has been as low as $0.056/kWh, as shown below,[92] and this pricing aligns with competitive market pricing in other states. In contrast, the fixed-rate PPA rates from the Public Tool's Low Price scenario do not reach today's market prices for this segment until 2025. The Tool's calculated fixed-rate PPA prices are $0.138/kWh in 2015 or more than two times current market rates. In other words, the Tool's calculated PPA rates from the "Low Price" scenario are *very* conservative (i.e., high) for the non-residential DG solar market segment.

92 http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page



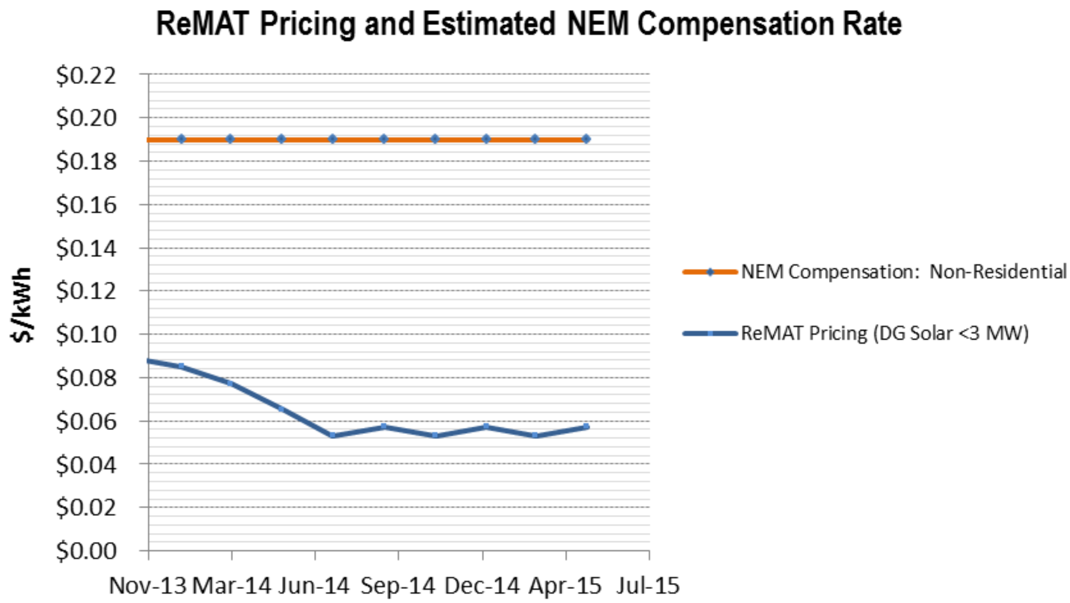

Note: This figure illustrates a 30% ITC across all scenarios to enable comparisons among the outputs as well as to current PPA prices.[93]




Note: This figure illustrates a 30% ITC across all scenarios to enable comparisons among the outputs as well as to current PPA prices.[94]

93 Bloomberg New Energy Finance (BNEF). "H1 2015 North American PV Outlook." January 2015.

94 Ibid. And, ReMAT data is available at http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page




Note: The estimated NEM compensation line illustrated above is from a public tool developed for the CPUC's 2013 study titled, "California Net Energy Metering Ratepayer Impacts Evaluation." Note that the ReMAT program is designed to limit gaming of the bid process and to ensure that winning bids (that are subsequently accepted by applicants) represent projects that will be built. For example, to bid into the ReMAT program, developers must submit an application fee of $2 per kW, and they must also provide collateral of $20 per kW to accept awarded projects. Applicants must also have passed Fast Track interconnection screens (or completed Phase 1 or System Impact studies), and guarantee that any required network upgrade costs will be $300,000 or less.[95]

## J. Storage Price Selection

PG&E's Public Tool input for "Storage Price Selection" is High Cost versus a High Bookend of Low Cost and a Low Bookend of High Cost.

PG&E believes storage prices will be closer to the High price scenario than the Low price scenario. Based on 2015 market trends from SolarCity and Tesla announcements, PG&E has projected the 2015 starting price of the Tesla Lithium Ion battery energy storage for retail

95 Detail of the ReMAT program and CPUC's NEM Ratepayer Impacts Evaluation Study are available on-line: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page and http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm.

customers to be between $900 and $1000 per kWh.[96] When this price is converted into a price per kW (assuming a 2-hour battery), this projects the 2015 price to be roughly $1,800 - $2,000 per kW. PG&E notes that this 2015 figure is closer to the 2015 Low case in the Public Tool, but nonetheless believes the High case should be used in both Bookend cases, because the Tesla and SolarCity announcements represent the lowest-price storage available on the market. This cost does not reflect the potentially higher price of storage offered to customers by new market entrants or the price of emerging technologies in energy storage, such as advanced flow batteries. Furthermore, PG&E views the price declines in both the Low and High to be overly aggressive, and so over time, the High price case more closely reflects a reasonable market forecast.[97] As a long-term low-end benchmark for energy storage pricing, PG&E notes that Tesla's reported future price for a commercial Powerpack storage device is $250/kWh ($500/kW assuming a 2-hour storage device).[98] However, this listed price would include favorable economies of scale for larger energy storage systems that are not the typical small-scale NEM –paired systems, and does not include the balance of system costs, including permitting, design and interconnection fees, and does not include a developer margin. Therefore, PG&E does not believe that the price of energy storage will fall below $500/kW, as the Low case does. The High case in the Public Tool is the most reasonable case for a long-term storage price.

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96 Randall, T. *SolarCity Taking Orders for Tesla Batteries Starting at $5,000,* Bloomberg New Energy Finance. Retrieved 6/24/15 from http://www.bloomberg.com/news/articles/2015-05-01/solarcity-taking-orders-for-tesla-batteries-starting-at-5-000. Note that the full non-PPA price of the 10 kWh storage is $7,140. PG&E assumes that the 7 kWh storage price is more reflective of the true use case of storage, because the 7kWh storage device is meant for daily discharge, whereas the 10 kWh device is intended for backup. Since Tesla is selling the 7 kWh storage offering for $500 less than the 10 kWh storage device, PG&E assumes the same markdown for SolarCity. This puts the overall storage price at roughly between $900 and $1000 per kWh.

97 Based on 2010-2015 information from the Self Generation Incentive Program, the average rate of decline in storage reported costs for two of the major storage developers in California is 8.8%.

98 Wesoff, E. *Tesla Battery Bottom Line: $3,500 for a 10-Kilowatt-Hour Storage System*, Greentech Media, retrieved 6/22/15 https://www.greentechmedia.com/articles/read/Reporting-Live-From-the-Tesla-Mystery-Product-Unveiling

## K. DER Renewable Energy Credit (REC) Scenario

PG&E's Public Tool input for "DER Renewable Energy Credit (REC) Scenario" is "DER Does Not Count for Bucket 1," which is unchanged from the High Bookend and Low Bookend of scenarios.

While the independent scenario has the same value for this input as both CPUC-defined bookend scenarios, there are several important issues to highlight related to this input. Specifically, while this simplification illustrates how rooftop solar is currently treated in practice under the existing RPS paradigm, it does not reflect the nuance[99] of existing rooftop solar REC eligibility and accounting under the RPS. Moreover, legislation currently pending in Sacramento may influence how rooftop solar RECs are counted towards RPS requirements. As part of its decades-long commitment to solar, in that legislation, PG&E is advocating in that legislation that the RPS program should value new in-state rooftop solar generation by counting it fully toward meeting RPS requirements, regardless of whether the energy is used on-site or exported to the grid. The DER REC treatment inputs may therefore need to be revisited based on the outcome of this legislation.

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99 Currently, "net surplus" power at annual true up, as described above, is eligible to count towards RPS requirements as a PCC1 energy product. In addition, on-site use of rooftop solar power may generate RECs that can be purchased as are considered as PCC3. However the ability to count both of these RECs is complicated by the requirements to meter the quantities and to register with the CEC and WREGIS.