

**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)

**OPENING BRIEF OF THE ALLIANCE FOR SOLAR CHOICE, SOLAR ENERGY
INDUSTRIES ASSOCIATION, CALIFORNIA SOLAR ENERGY INDUSTRIES
ASSOCIATION AND VOTE SOLAR**

CALIFORNIA SOLAR ENERGY
INDUSTRIES ASSOCIATION
Brad Heavner
555 5th Street, #300-S
Santa Rosa, CA 95401
Telephone: (415) 328-2683
Email: brad@calseia.org

*Policy Director for the California Solar
Energy Industries Association*

THE VOTE SOLAR INITIATIVE
Susannah Churchill
360 22nd St, Suite 730
Oakland, CA 94612
Telephone: (415) 817-5065
Email: susannah@votesolar.org

Regional Director, West Coast for Vote Solar

GOODIN, MACBRIDE,
SQUERI & DAY, LLP
Jeanne B. Armstrong
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: jarmstrong@goodinmacbride.com

*Attorney for Solar Energy Industries
Association*

KEYES, FOX & WIEDMAN LLP
Joseph Wiedman
Samuel Harvey
436 14th Street, Suite 1305
Oakland, CA 94612
Telephone: (510) 314-8202
Email: jwiedman@kfwlaw.com

Attorneys for The Alliance For Solar Choice

Dated: October 19, 2015

TABLE OF CONTENTS

| | Page |
|---|------|
| I. INTRODUCTION | 1 |
| II. SOLAR COST PROJECTIONS UTILIZED BY THE JOINT SOLAR PARTIES ARE REASONABLE AND ACCURATE REFLECTIONS OF REAL WORLD PRICES..... | 3 |
| A. Current Prices Are Consistent with Public Tool Assumptions..... | 5 |
| 1. Assumptions Are Supported by Data..... | 5 |
| 2. PG&E’s Price Conversions Are Inaccurate | 7 |
| 3. PPA Price Data Also Supports Public Tool Assumptions | 11 |
| B. Future Price Reduction Assumptions in the Public Tool’s Low Solar Cost Case Are Unreasonable..... | 12 |
| 1. PG&E’s Previous Analysis Supports the Base Solar Cost Case..... | 13 |
| 2. PG&E Fails to Show that Solar Companies Can Reduce Prices by Opting for Lower Profits..... | 14 |
| 3. Companies Will Strive to Reduce Soft Costs, But the Commission Must Not Overestimate Likely Reductions..... | 15 |
| C. The Highly Competitive California Solar Industry Exerts Downward Pressure on Prices | 15 |
| 1. Objective Data Demonstrate that the Solar Marketplace Is Competitive..... | 15 |
| 2. Solar Companies Base Pricing on Costs..... | 17 |
| III. INTERCONNECTION FEES SHOULD BE SET AT A LEVEL THAT WILL PROVIDE AN INCENTIVE FOR UTILITIES TO CONTINUE TO ADOPT BEST PRACTICES AND DRIVE DOWN LONG-TERM COSTS | 19 |
| IV. DISCRIMINATORY FEES AND RATES PROPOSED BY VARIOUS PARTIES ARE ILLEGAL UNDER CALIFORNIA AND FEDERAL LAW..... | 22 |
| A. State and Federal Law Require that a Separate Rate Structure for NEM Customers Be Based on a Substantial Showing that the Cost to Serve Such Customers Is Different..... | 22 |
| B. None of the Additional Charges Advanced for Imposition on NEM Customers Are Based on Cost of Service | 25 |
| 1. SDG&E’s and PG&E’s Proposed Non-Coincident Demand Charge | 25 |
| 2. SDG&E’s Fixed Charge | 27 |
| 3. SCE’s Proposed Grid Access Charge | 28 |
| 4. ORA’s Installed Capacity Fee | 31 |

TABLE OF CONTENTS
(continued)

| | Page |
|--|-------------|
| 5. NRDC's Proposed Coincident Demand Charge..... | 35 |
| V. FEES AND RATES PROPOSED BY VARIOUS PARTIES ARE INCONSISTENT WITH THE COMMISSION'S RATE DESIGN PRINCIPLES FOR RESIDENTIAL CUSTOMERS..... | 36 |
| A. SDG&E's and PG&E's Non Coincident Peak Demand Charge | 37 |
| B. SCE's Grid Access Charge | 40 |
| C. ORA's Installed Capacity Fee | 41 |
| D. NRDC's Coincident Demand Charge..... | 42 |
| VI. CONCLUSION..... | 42 |

TABLE OF AUTHORITIES

| | Page |
|--|---------------|
| Statutes | |
| Public Utilities Code Section 2827.1 | 34 |
| Public Utilities Code Section 2827.1(b)(1)..... | 5 |
| Public Utilities Code Section 2827.1(b)(7)..... | 22, 28 |
| Public Utilities Code section 453(c) (c)..... | 22 |
| Public Utilities Code Section 739.9 | 28 |
| Public Utilities Code Section 769..... | 30 |
| Decisions of the California Public Utilities Commission | |
| Decision 14-12-080..... | 29 |
| Decision 15-07-001..... | <i>passim</i> |
| Federal Energy Regulatory Commission Orders | |
| Sun Edison LLC, 129 FERC ¶ 61,146 (2009) | 24 |
| Other Authorities | |
| 18 CFR § 292.203(d) | 24 |
| 18 CFR § 292.303(c)..... | 24 |
| 18 CFR Sec. 292.305(a)(1)(ii) | 24 |
| 18 CFR Sec. 292.305(a)(2) | 24 |
| Cal Constitution Article XII, Section 4..... | 22 |

**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)

**OPENING BRIEF OF THE ALLIANCE FOR SOLAR CHOICE, SOLAR ENERGY
INDUSTRIES ASSOCIATION, CALIFORNIA SOLAR ENERGY INDUSTRIES
ASSOCIATION AND VOTE SOLAR**

Pursuant to the schedule established at the end of hearings on October 7, 2015 by Administrative Law Judge Anne Simon, The Alliance for Solar Choice (TASC), Solar Energy Industries Association (SEIA),¹ California Solar Energy Industries Association (CALSEIA) and Vote Solar (hereinafter Joint Solar Parties or JSP), submit their opening brief concerning the topics addressed at hearings on the net energy metering (NEM) successor tariff.

I. INTRODUCTION

The hearings in this proceeding were focused to bring a broader understanding to certain elements of the record which are crucial for the Commission to determine an appropriate NEM Successor Tariff -- *i.e.*, a tariff that will ensure the sustainable growth of the solar industry. To this end the Commission sought a deeper understanding of the basis for (1) projections of prices of rooftop solar installations; (2) the investor-owned utilities' proposed charges in the successor tariff for interconnection of small systems; and (3) any proposed demand charges, capacity fees,

¹ The comments contained in this filing represent the position of the Solar Energy Industries Association as an organization, but not necessarily the views of any particular member with respect to any issue.

standby charges, access fees, use charges, or other fixed charges for the successor tariff. As illustrated in this brief, the record of this proceeding clearly demonstrates that:

- The ability of solar installers to cut costs is narrow, and therefore the Commission should not make policy changes that are out of step with soft cost reductions that are actually achievable;
- Interconnection costs should be set at a constant level consistent with best utility practices across all the investor owned utilities (IOUs);
- Various charges and fees proposed by the IOUs and the Office of Ratepayer Advocates are discriminatory, illegal under state and federal law, and inconsistent with the rate design principles for residential rates adopted by the Commission in Decision 12-06-013.

In contrast, through our collective proposals and comments on parties' proposals, as well as the testimony presented at hearing, the JSP have clearly demonstrated that continuing NEM in its present form with a few adjustments meets all the requirements of Public Utilities Code Section 2827.1, as well as being consistent with the Commission's rate design principles. The Commission can help to ensure the continued sustainability of the solar industry in California, while also ensuring that the costs and benefits of net metered DG under the new tariff will be reasonably balanced for participating ratepayers (as required by PU Code Section 2827.1[b][3]) and for all ratepayers (as required by PU Code Section 2827.1[b][4]) through adoption of the JSP' proposal for a NEM successor tariff.

II. SOLAR COST PROJECTIONS UTILIZED BY THE JOINT SOLAR PARTIES ARE REASONABLE AND ACCURATE REFLECTIONS OF REAL WORLD PRICES

The Public Tool contains three scenarios for projections of future solar costs to customers.² These are termed the low case, the base case, and the high case. The historic prices are the same in each case through 2013, and are based on research by Lawrence Berkeley National Laboratory (LBNL) in the 2014 version of the annual “Tracking the Sun” report. Assumptions for 2014-2025 solar costs to customers differ for each case. The low case is based on achieving the U.S. Department of Energy (U.S. DOE) “Sunshot” goal of \$1.50/W-DC for residential and \$1.25/W-DC for commercial, in 2010 dollars. The base and high cases are derived by dividing the 2013 price into 60% cost and 40% margin, then reducing the cost by a learning curve of 23% for the base case and 15% for the high case, and reducing margin to 10% of total price in the base case and 15% in the high case.³ For all three cases, more of the reduction is assumed to occur in 2014-2017 than in 2018-2020, as shown in the annual percentage reductions in Table 1.

² In addition to the flaws in the Public Tool low solar cost case being unreasonable, the JSP continue to believe the Public Tool suffers from other serious flaws as discussed in our prior comments in this docket. *See*, Proposal for AB 327 Successor Tariff of The Alliance for Solar Choice, filed August 3, 2015 (TASC Proposal) pp. 31- 40 (explaining necessary changes to transmission avoided costs, assumed utility rate escalation, distribution capital expense scalars, and externalities, updated IOU rates, the adoption module, and the revenue requirement model within the Public Tool to address inadequacies in the Public Tool); Proposal of the Solar Energy Industries Association and Vote Solar for the Net Energy Metering Successor Standard Tariff, filed August 3, 2015, (SEIA/ VS Proposal) pp. 13-28 (explaining changes made to the adoption model); and Joint Solar Parties Opening Comments pp. 11-25 (discussing flaws in solar cost projections, rate escalation, sizes of adopted systems, utility cost errors, use of marginal CAISO costs, consistent use of marginal subtransmission and distribution costs, corrections to commercial rates).

³ Public Tool, Advanced DER Inputs tab, cells D116-D125.

Table 1. Price Reduction Assumptions in the Public Tool for Small Systems (Nominal Dollars)⁴

| | Price (\$/W-DC) | | | Reduction from Previous Year | | |
|------|-----------------|--------|--------|------------------------------|------|------|
| | Low | Base | High | Low | Base | High |
| 2014 | \$3.88 | \$4.50 | \$4.85 | 23% | 10% | 3% |
| 2015 | \$3.08 | \$4.08 | \$4.71 | 21% | 9% | 3% |
| 2016 | \$2.49 | \$3.73 | \$4.59 | 19% | 9% | 3% |
| 2017 | \$2.06 | \$3.44 | \$4.47 | 18% | 8% | 3% |
| 2018 | \$1.81 | \$3.25 | \$4.36 | 12% | 5% | 2% |
| 2019 | \$1.61 | \$3.09 | \$4.27 | 11% | 5% | 2% |
| 2020 | \$1.45 | \$2.94 | \$4.18 | 10% | 5% | 2% |
| 2021 | \$1.43 | \$2.81 | \$4.09 | 2% | 5% | 2% |
| 2022 | \$1.40 | \$2.68 | \$3.98 | 2% | 5% | 3% |
| 2023 | \$1.38 | \$2.55 | \$3.88 | 2% | 5% | 3% |
| 2024 | \$1.35 | \$2.43 | \$3.78 | 2% | 5% | 3% |
| 2025 | \$1.33 | \$2.32 | \$3.68 | 2% | 5% | 3% |

The Public Tool’s low solar cost case is a laudable goal but is not in keeping with the expectations of the California solar industry. Solar providers have every motivation to reduce costs and gain market share, but are limited by real world challenges, including the looming sunset of the Investment Tax Credit (ITC) in 2016. Even if cost reduction goals are met in the near term, they will not offset the looming reduction in the ITC. As described in CALSEIA’s opening testimony, there is a risk that reduced adoption rates due to policy changes will harm companies’ ability to reduce prices.⁵ It is essential that the Commission not “overshoot” in making policy changes that are out of step with soft cost reductions that are actually achievable. If efficiencies are lost due to reduced adoption rates, it may be difficult to take corrective action and expect the industry to quickly regain those efficiencies.⁶ Public Utilities Code Section

⁴ Solar costs are listed in the Advanced DER Inputs tab in cells D31:J48. This conversion from \$/W-AC to \$/W-DC uses a conversion rate of 0.87.

⁵ Exhibit 1 at p. 11, line 1 - p. 12, line 8.

⁶ Exhibit 1 at p. 11, line 1 - p. 13, line 22 (describing how declining sales volumes impacts installation efficiency, customer acquisition and financing).

2827.1(b)(1) requires the Commission to ensure that customer-sited renewable distributed generation continues to grow sustainably, and growth will not be sustainable or even achieved if solar providers cannot make business planning decisions based on sound expectations of customer activity and economic viability.

As shown below, evidence presented in this proceeding by the solar industry indicates that the Public Tool's high solar cost case may be the most realistic scenario. Nevertheless, the JSP have consistently supported using the base cost case in order to remain optimistic about future solar prices. In contrast, PG&E argues that the low solar cost case is the correct scenario to use for purposes of this proceeding. Its argument relies on two main points: (1) that current prices in the marketplace are lower than the Public Tool's 2015 base case prices; and (2) a belief that solar companies currently have large margins and could simply choose to reduce those margins without harming the companies' viability. As illustrated below these conclusions are based on an inaccurate price comparison and a fundamental lack of understanding of company margins. An accurate analysis of available data supports the Public Tool's base solar cost case.

A. Current Prices Are Consistent with Public Tool Assumptions

1. Assumptions Are Supported by Data

As mentioned previously, the Public Tool bases prices through 2013 on data from the annual "Tracking the Sun" reports, the most comprehensive study on the record that is specifically about solar pricing. Beyond this data, the record contains two strong data points for current pricing expressed in \$/watt. First, the Woodlawn study attached to the JSP rebuttal testimony, and referred to by JSP witness Contreras during cross-examination,⁷ analyzed the

⁷ Tr. Vol. 1 (CALSEIA-Contreras), p. 87, line 4 and line 11. (The transcript erroneously spells Woodlawn as "With Len.")

actual accounting ledgers of solar companies to determine average prices charged to customers. It found an average 2015 sale price of \$4.17/W-DC among six solar providers.⁸ The solar providers analyzed for the study are located both in California and other states, so the California prices are likely to be higher than this average.⁹ The average price determined by the Woodlawn study is higher than the \$4.08/W-DC 2015 price in the base case of the Public Tool, even before any adjustment for higher prices in California.¹⁰

Second, the “Summary of Solare Energy Pricing Examples” presented by PG&E in Exhibit 40 shows the base prices for four systems less than 10 kW which range from \$3.40/ W-DC to \$4.39/ W-DC, with an average of \$3.80/W-DC.¹¹ JSP witness Contreras repeatedly pointed out during cross-examination that these are base prices and average prices are considerably higher.¹² He stated:

So for instance, if we are installing an 8 kilowatt system on a home that has asphalt shingle roof, we are using modules that have a silver frame with a [white] back sheet, we are using a central inverter, and it is being in the County of San Diego permitting jurisdiction, our price for that would be \$3.36 per kilowatt DC, okay?

Contrasting to that, if we install a 3 kilowatt system that is in an area where either the HOA or homeowner for aesthetic purposes requires that we use modules that have a black frame with a black back sheet, and we are using microinverters, and it is in the [City of] Coronado that has much higher permitting fees and the permitting process requires additional inspections not required by other permitting jurisdictions, that price is going to be \$6.64 cents per kilowatt DC.

⁸ Exhibit 2 at p. 2 of Attachment A-2.

⁹ LBNL’s “Tracking the Sun” studies have consistently found prices in California to be higher than the national average.

¹⁰ Exhibit 1, Table 3 at p. 11.

¹¹ Exhibit 40 at p. 6. This is a simple average of the Pre-ITC prices for the four sample system sizes.

¹² Tr. Vol. 1 (CALSEIA-Contreras), p. 12, lines 6-15; p. 16, line 1 - p. 17, line 11; p. 22, lines 8-10; p. 90, lines 12-17.

So it is double. We make the same margin. The driver of that, of the doubling in the price, is in the cost associated with that specific project.¹³

Solare Energy's \$3.80/W-DC average base price is much closer to the Public Tool's 2015 base case price of \$4.08/W-DC than the Public Tool's 2015 low case price of \$3.08/W-DC. A weighted average price was not presented on the record, but considering that Solare Energy's prices for individual installations can be double the base prices, the weighted average price is certainly considerably higher than \$3.80/W-DC and likely higher than the Public Tool's \$4.08/W-DC base case price. Also, Solare Energy is the 13th most active company among more than 500 companies installing solar for SDG&E residential customers.¹⁴ Thus, with over 500 companies operating in SDG&E's service territory it is reasonable for the Commission to conclude that Solare Energy's prices are competitive.

2. PG&E's Price Conversions Are Inaccurate

PG&E claims that some prices observed in the industry today are lower than the Public Tool's 2015 base case price. PG&E also disputes the LBNL research on solar prices in the marketplace contained in the "Tracking the Sun" reports, despite its witness stating, "I think that they make a very strong effort to the best of their abilities to try to present the data in a way that is apples to apples."¹⁵ PG&E instead relies largely on information from an online "Quick Quote" marketing tool on the website of SolarCity.¹⁶ PG&E compares this information to PPA prices it derives from the Public Tool's Pro Forma module. This exercise is an "apples to oranges" comparison.

¹³ Tr. Vol. 1 (CALSEIA-Contreras), p. 16, line 17 - p. 17, line 11.

¹⁴ Exhibit 23, p. 2.

¹⁵ Tr. Vol. 2 (PG&E-James), p. 214.

¹⁶ All of the "PPA Year-1 Bid Price" data in Table 3-2 of Exhibit 20, PG&E's Rebuttal Testimony, is from the SolarCity "Quick Quote" online tool.

First, PG&E made a series of calculations to estimate \$/kWh LCOE values associated with the low and base scenarios of the Public Tool and attempts to compare those values to 20-year power purchase agreement (PPA) prices selectively picked from quotes. PG&E used the Pro Forma module of the Public Tool to convert solar prices from a \$/watt price to a 25-year \$/kWh LCOE.¹⁷ In so doing, however, PG&E failed to account for varying capacity factors built into the prices reflected in the Public Tool that lead to a very wide and likely lower range of \$/kWh values associated with each scenario.

The Public Tool calculates the LCOE \$/kWh values for different system sizes using the unique characteristics in each of the customer bins. Some of those characteristics, such as the directional orientation of the roof and the location, affect the productivity of the system, which can be measured as the capacity factor. Systems of varying productivity will result in different LCOEs, since PPA prices are a factor of kWh produced related to total system cost. The Public Tool then determines whether customers in that bin would adopt the DER technology of that size in the rate environment of that year. Therefore, the Public Tool has a range of LCOE values for a given dollar-per-watt installation cost. PG&E witness James agreed in cross-examination that the values presented by PG&E in its rebuttal testimony would more accurately be represented as ranges than absolute values due to differences in capacity factors in different bins.¹⁸

Second, PG&E provides a misleading summary of observed price quotes that understate the pricing generally available to prospective solar consumers, then understates the 25-year LCOE equivalents of those quotes by inappropriately discounting 20-year PPA prices when converting them to 25-year terms. PG&E witness James first converts the 20-year escalating

¹⁷ Exhibit 20, Table 3-1 at p. 3-5.

¹⁸ Tr. Vol. 1 (PG&E-James), p. 170, line 7 - p. 171, line 22.

PPA prices to 20-year non-escalating prices using a 10% discount rate.¹⁹ He then discounts the 20-year levelized price by about 10%, presumably to match the 25-year term of PPAs in the Public Tool. PG&E witness James appears to do this by finding a price that makes the NPV of a 25-year payment stream equal to the NPV of a 20-year payment stream, thus keeping the NPV constant while changing the term.²⁰ However, as PG&E witness James agreed in cross-examination, solar providers that offer 20-year PPAs have expectations of revenue beyond 20 years.²¹ PPA contracts include renewal clauses, and life expectancy of solar systems is at least 30 years.²² Therefore, a solar provider's PPA price reflects the expectation that customers will make payments based on this price beyond the initial term. It is inappropriate to discount the 20-year PPA as if no incremental NPV were expected from renewal. But this is what PG&E has done. Witness James merely assumes that the additional revenue beyond year 20 is zero, and he simply spreads the 20-year revenue over 25 years. The JSP recognize it cannot be assumed that all customers will renew at the same price, so a reduction must be applied to the 20-year PPA price to arrive at a 25-year PPA price. However, PG&E witness James effectively assumed a 100% reduction, and his data is therefore not informative.

Third, PG&E's sampling of 20-year PPA quotes is a misleadingly low presentation of prices available to solar energy consumers. In Figure 3-3 of its rebuttal testimony, PG&E

¹⁹ Exhibit 20 at p. 3-10, line 8. The original testimony stated that the discount rate used was "5-6 percent," and sensitivity analyses in the workpapers tested a 0% to 8% range. The figure was revised during direct testimony at the hearing to 10%. Further, James stated in cross-examination that the Public Tool uses a 14.2% discount rate (Tr. at p. 194, line. 15-16), but the weighted average cost of capital pre-loaded in the Public Tool is 8.25% (DER Pro Forma tab, cell H29).

²⁰ Exhibit 20 at p. 3-9, line 28 - p. 3-11, line 2. Note that James did not correctly describe the Joint Solar Parties' methodology within this section of testimony (Tr. at p. 171, line 23 - p. 172, line 26).

²¹ Tr. Vol. 1 (PG&E-James), p. 167, lines 9-28; p. 176, lines 23-26; p. 177, lines 19-27.

²² *Id.* p. 177, lines 11-13.

presents a marker presumably representing the pricing of SolarCity PPAs. However, on cross-examination it became clear that the value was an average of a price quote from the service territory of the Sacramento Municipal Utility District (SMUD) and the standard pricing in IOU territories.²³ It would be much more reasonable to use a value reflecting the pricing in IOU service territories, which represents the overwhelming majority of SolarCity's transactions, or at least an average that is weighted by relative market size. In the same figure, PG&E presents a midpoint of claimed signed contracts attributed to the SMUD website. Aside from the inappropriate reliance on the SMUD region to reflect pricing conditions statewide, there is no detail provided about what type of price this represents. It is not clear whether the prices reflect varying levels of down payments or whether prepaid leases are included. It is not clear whether LCOEs are properly calculated in which both payments and generated kWh are discounted, nor which discount rate was used. Nor is it clear whether this included cash sales, with the upfront cost spread over lifetime kWh generated without any discount rate applied at all. Also, PPAs are not all equal, with various non-price terms such as performance guarantees and warranties varying by provider.

In sum, because of the variation in capacity factor, the values in Table 3-1 of Exhibit 20 are mistakenly high.²⁴ The calculations treat all bins equally, and therefore ignore the fact that bins with higher rates of adoption are likely to have higher capacity factors and therefore lower PPA rates. At the same time, the pricing data shown in Figure 3-3 of that exhibit (which compares PPA prices in Public Tool to a sampling of prices) are mistakenly low because they do not present representative prices and the values are inappropriately discounted.

²³ Tr. Vol. 2 (PG&E-James), p. 242, line 6 - p. 245, line 16.

²⁴ Table 3-1 also rounds to 2 digits; PG&E's workpapers demonstrate that when 3 digits are used, the base case corresponds to 19.5 c/kwh and the low case to 15.2 c/kwh.

3. PPA Price Data Also Supports Public Tool Assumptions

Within PG&E's framework of looking only at PPA pricing, the strongest data points on the record for 2015 PPA/lease prices are SolarCity's standard price in California IOU service territories of \$0.15/kWh²⁵ and the base prices on the Solare Energy website.²⁶ Both have a 2.9% annual escalator. The SolarCity price is for a PPA with a 20-year term and the Solare Energy price is for a lease with a 25-year term. Converting from year one prices with escalators to levelized prices results in a 20-year PPA price of \$0.19/kWh for SolarCity²⁷ and a 25-year PPA price of \$0.23/kWh for Solare Energy.²⁸ For SolarCity, the revenue in years 21-25 is likely to be less than \$0.19/kWh, but it is not known how much less, so the \$0.19/kWh price should be rounded down by some amount.

According to PG&E's conversion of the Public Tool's solar prices from \$/watt to \$/kWh, the 2015 price is \$0.152 in the low solar cost case and \$0.195 in the base solar cost case.²⁹ As noted above, these estimates should be considered to be higher than what is used in Public Tool adoption module functionality. Thus, the base case of slightly less than \$0.195/kWh compares to slightly less than \$0.19/kWh for SolarCity and to \$0.23 for Solare Energy.

²⁵ Exhibit 20 at p. 3-19, lines 24-25 & p. 3-13, line 2. PG&E also finds that the SolarCity "Quick Quote" online marketing tool produces a year one PPA price of \$0.109/kWh for SMUD customers. However, it is not known how many systems SolarCity installs at that price. If SolarCity is not able to recover any of its overhead from those installations and does not do many SMUD installations, this is not a strong data point.

²⁶ Exhibit 40. The text below the price quotes in the screen shots in this exhibit is difficult to read. It includes the following statements: "Prices based on systems installed on asphalt shingle roof in County permitting area ... Year one leasing price shown based on 25 yr contract with 2.9% annual escalation and option to renew ... Results vary depending on electricity consumption and other specific home characteristics. Each home requires a custom assessment and proposal."

²⁷ See Exhibit 24, p. 2.

²⁸ Generated with the PPA Calculator in PG&E's workpapers to rebuttal testimony. Based on 4.64 kW system size. SCE using 5 kW to calculate its Grid Access Charge is the only data point on the record demonstrating 5 kW as a typical residential system size (Exhibit 16 at p. 18, line 6).

²⁹ Exhibit 20, Table 3-1 at p. 3-5, using the 3-digit values from the workpapers.

PG&E also cites an analysis from Kroll Bond Rating Agency that is recent enough to be considered current pricing.³⁰ The analysis found an average PPA/lease price of \$0.14/kWh and an average escalator of 2.02%. This translates to a levelized price of \$0.165/kWh, according to the PPA calculator from PG&E's rebuttal testimony workpapers. However, a majority of the contracts analyzed are in other states. Accordingly, the analysis from this agency is not indicative of California pricing.

B. Future Price Reduction Assumptions in the Public Tool's Low Solar Cost Case Are Unreasonable

As shown in Table 1 above, the Public Tool's low solar cost case assumes annual percentage price reductions of 10%-23% from 2014 through 2020, while the base case assumes reductions of 5%-10% and the high case assumes reductions of 2%-3%. In support of the low solar cost case trajectory, PG&E relies on two optimistic statements to investors from SolarCity and Sunrun on future installation costs. SolarCity has a target of \$2.50/W-DC in 2017,³¹ and Sunrun has stated, "By 2017, we expect to be in a cost structure place that looks similar to what the other scale companies have put forward. So something, in the 2.50 range."³² The Commission should not rely on cherry-picked statements from two companies. Instead, the Commission should rely on actual cost reduction potential discussed by witnesses at these hearings. Moreover, the statements themselves do not support PG&E's assessment of declining installation costs for residential customers. For example, the price cited by SolarCity is a blended price for residential and non-residential installations.³³ Also, it is clear from the

³⁰ *Id.*, p. 3-9.

³¹ *Id.*, p. 3-23, line 30.

³² *Id.*, p. 3-23, lines 14-16.

³³ Tr. Vol. 1 (PG&E-James), p. 143, lines 1-4.

SolarCity Q2 2015 investor presentation that the company accounts separately for the cost of sales associated with individual installations and broader marketing costs.³⁴ If the installation cost target does not include marketing overhead, it is not representative of the average cost of a system.

1. PG&E's Previous Analysis Supports the Base Solar Cost Case

Despite submitting testimony in support of the low solar cost case trajectory, in a previous submission in this proceeding PG&E presented projections of future solar cost reductions that support a very different position. Specifically, in its opening comments on party proposals, PG&E included a "NEM 2.0 and Distributed Solar Market Assessment Study."³⁵ Figure 2 of that study is "Residential and Commercial Rooftop Installed System Costs, 2012-2025 (Mid-Cost)." The annual cost reductions from this figure are shown in Table 2. These percentage reductions are far smaller than the percentage reductions in the Public Tool's low solar cost case shown in Table 1, and are even lower than the reductions in the base case. Thus, PG&E's own projections of future solar cost reductions support a trajectory between the base case and the high case.

³⁴ Exhibit 13 at p. 4: "Appendix A: Q2 2015 GAAP Statement of Operations." "Solar energy system and components sales" was an expense of \$22,087,000 in Q2, while "Sales and marketing" was an expense of \$113,160,000.

³⁵ PG&E, "Pacific Gas and Electric Company Comments on Party Proposals and Staff Papers," filed September 1, 2015, Appendix B.

Table 2. PG&E Estimated Annual Residential Solar Cost Reductions³⁶

| Year | Cost Reduction from Previous Year |
|------|-----------------------------------|
| 2014 | 6% |
| 2015 | 8% |
| 2016 | 6% |
| 2017 | 4% |
| 2018 | 3% |
| 2019 | 3% |
| 2020 | 3% |
| 2021 | 3% |
| 2022 | 3% |
| 2023 | 3% |
| 2024 | 3% |
| 2025 | 3% |

2. PG&E Fails to Show that Solar Companies Can Reduce Prices by Opting for Lower Profits

In rebuttal testimony, PG&E witness James states, “There is a great deal of information from solar vendors indicating that a number of them are setting their prices based upon utility rates, which implies that there is room for solar vendors to reduce prices in California simply by lowering their margins and more closely aligning price to cost structures.”³⁷ Throughout his testimony and in cross-examination, PG&E witness James was never clear whether this statement is intended to mean that solar companies have net profit that they can choose to reduce or that they should strive to reduce their overhead expenses. In cross-examination, PG&E witness James was confused by the difference between gross margin and net profit.³⁸

When margin is defined as net profit, companies can reduce their prices by lowering their margins only to the extent that there is substantial positive net profit among solar providers

³⁶ *Id.*, Figure 2 of Appendix B at p. 2 of Appendix B. Specific numbers obtained from the workpapers for the Figure.

³⁷ Exhibit 20 at p. 3-14.

³⁸ Tr. Vol. 1 (PG&E-James), pp. 140-141.

today. PG&E witness James did not demonstrate that solar providers have enough net profit to absorb changes to the Investment Tax Credit (ITC), even before considering potential changes to NEM.

3. Companies Will Strive to Reduce Soft Costs, But the Commission Must Not Overestimate Likely Reductions

When margin is defined as the difference between marginal installation cost and average installation cost including overhead, it can be reduced only to the extent that companies can reduce actual overhead expenses. The JSP agree that the Commission should assume some amount of soft cost reduction, but that the reductions in the Public Tool's low solar cost case are unreasonable. Overhead costs are actual expenses. They are costs that cannot be attributed to individual solar installations but must be recovered if a company is to avoid net losses. CALSEIA's opening testimony contains a description of the main categories of soft costs and the opportunities and challenges of reducing those costs.³⁹ They include installation efficiency, customer acquisition, financing, permitting and inspections efficiency, and interconnection efficiency. As shown in Table 2 above, even PG&E does not believe solar companies can reduce costs as much as the Public Tool's low solar cost case or base solar cost case assume.

C. The Highly Competitive California Solar Industry Exerts Downward Pressure on Prices

1. Objective Data Demonstrate that the Solar Marketplace Is Competitive

In opening testimony, CALSEIA presented the substantial number of companies currently installing solar for end use customers as one indicator of the intensely competitive California solar industry.⁴⁰ On rebuttal, PG&E witness James disagreed with the assertion that

³⁹ CALSEIA Opening Testimony at pp. 12-16.

⁴⁰ *Id.* at Appendix A.

the quantity of companies ensures competition and pointed out that a more complete metric of competition is the Herfindah-Hirschman Index (HHI),⁴¹ a measure of competition used by the U.S. Department of Justice (DOJ) to determine whether mergers will result in excessive market concentration.⁴² However, PG&E witness James provided no calculation of an HHI for any solar market in California. In response to this testimony, the JSP, on cross-examination, presented a calculation of the HHI for the SD&GE service territory. This calculation is based on interconnections of SDG&E residential customers from January 2015 through July 2015.⁴³ The calculation results in an HHI score of 632. DOJ does not consider a market to be moderately concentrated unless it has an HHI score of 1500 or more, and does not consider a market to be highly concentrated unless it has an HHI score of 2500 or more. Using PG&E witness James's preferred metric of competition, there is very strongly competition in SDG&E's service territory.

In an effort to distance himself from his previous recommendation of the HHI to determine whether a industry is competitive, on cross-examination, PG&E witness James claimed that residential solar is not a market unto itself but instead should be splintered into several different markets. As stated by James: "Some of these companies are selling very differentiated products. Some might be selling high-efficiency modules or microinverters. Some might be selling PPAs, or leases versus cash purchased systems."⁴⁴ The fact that there are various options does not divide the market into several different markets. For example, as PG&E witness James later agreed, most people who are considering solar are aware that they

⁴¹ Exhibit 20 at p. 3-17.

⁴² Exhibit 23. The JSP believes that interconnections of SDG&E customers is the best available data because it is a relatively small IOU in which certainly the largest solar companies, and likely nearly all solar companies in the region, serve customers throughout the utility territory.

⁴³ Tr. Vol. 1 (PG&E-James) p. 155, lines 25-28; p. 159, lines 4-5.

⁴⁴ *Id.*, p. 158, lines 21-28.

have the option to purchase a system or install a system via a PPA.⁴⁵ Witness James did not present any information suggesting that there are solar companies that do not offer microinverters or exclusively offer microinverters, or companies that only offer high-efficiency panels or exclusively offer high-efficiency panels. On cross-examination, PG&E witness James also characterized the solar industry as increasing in competition, with “a lot of innovation taking place with different financial products, different technologies” and presented evidence that new products are coming to the market to increase price transparency.⁴⁶ Hence, it is reasonable for the Commission to conclude that PPAs and purchased systems compete against each other as part of the same market. The irony of a monopolist arguing that the solar industry is not competitive enough should not be lost on the Commission particularly when the IOU business model is predicated on exclusion.

2. Solar Companies Base Pricing on Costs

Market concentration will increase if medium-sized and small companies go out of business because they are unable to match the prices of their competitors. SolarCity’s standard PPA price in IOU territories of \$0.15/kWh is less than they need to charge to compete against California utility prices of \$0.22/kWh - \$0.26/kWh.⁴⁷ If they did not have to compete against other solar companies, they presumably would charge customers a higher price in order to recover more of their overhead expenses. Smaller companies that have difficulty matching the lowest bids must offer cost-based prices with narrow margins in order to compete.

PG&E witness James asserts that value-based pricing is the dominant driver of solar

⁴⁵ *Id.*, p. 159, line 23 - p. 160, line 3.

⁴⁶ Tr. Vol. 2 (PG&E-James), p. 202, lines 22-25; Exhibit 20, p. 3-16, lines 9-20 (discussing EnergySage and Google offerings).

⁴⁷ Exhibit 20, Table 3-2 at p. 3-20.

pricing. However, the sentence on which Mr. James relies in written testimony is not in fact definitive, but has a qualifier.⁴⁸ During cross-examination, he stated separate “definitive evidence”⁴⁹ of the dominance of value-based pricing coming from a sentence from Exhibit 41. This exhibit is an NREL journal article that compares solar cash purchases, leases, and PPAs in 2010-2012 to evaluate which one produces the greatest savings for customers. A secondary finding of the study provides that:

“Installed prices reported to the CSI program declined by roughly \$2.00/W during 2010-2012. Over this same period, the CSI incentive declined by \$0.87/W, from a median of \$2.40/W in the first quarter of 2010 to \$1.53/W in the last quarter of 2012. That is, reported prices declined more rapidly than did incentives. However, the average price of contracts changed less over this period, with both lease and PPA prices *increasing* in 2010-2011, and then PPA prices decreasing in 2012, with lease prices remaining flat.”⁵⁰

This finding is unremarkable. 2010-2012 was a period when PPAs were just emerging and becoming widespread. SolarCity, the industry leading company offering PPAs to customers in California, has not been profitable.⁵¹ Charging customers similar prices while reducing expenses in that time period simply equates to companies reducing their losses. This in no way indicates that these individual companies or the solar industry as a whole would be able to reduce prices in 2016-2020 in response to changes in NEM structure.

⁴⁸ See discussion at Tr. Vol. 2 (PG&E-James), pp. 223-226; Exhibit 21, p. 3 (“States with higher incentives and/or higher electricity rates may have higher installed prices that would result in value-based pricing”).

⁴⁹ Tr. Vol. 2 (PG&E-James), p. 220, lines 9-10.

⁵⁰ Exhibit. 41 at pp. 7-8. PG&E witness James quotes a sentence in the last paragraph of the article with the same conclusion but less detail: “Our study indicates that, while installed PV costs have declined rapidly, the real contract price to the customer has remained largely unchanged.”

⁵¹ Exhibit. 13.

III. INTERCONNECTION FEES SHOULD BE SET AT A LEVEL THAT WILL PROVIDE AN INCENTIVE FOR UTILITIES TO CONTINUE TO ADOPT BEST PRACTICES AND DRIVE DOWN LONG-TERM COSTS

Each of the IOUs presented testimony concerning the basis for their proposed interconnection application charges. PG&E witness Waggoner proposes a \$100 application fee for systems 30 kW and smaller and a \$1600 application fee for systems above 30 kW. SCE proposes a \$75 application fee while SDG&E proposes a \$280 application fee for systems below 1 MW. As is readily observable, the IOUs asserted costs to process applications vary substantially and the variation is not adequately explained in their testimony. SDG&E's cost justification for a \$280 interconnection application fee is particularly troubling as JSP Witness Fulmer discussed.⁵² First, SDG&E included one-time expenses related to the development of its Distributed Interconnection Information System (DIIS) that the Commission has already recognized as having been recovered by SDG&E based on statements made by SDG&E representatives.⁵³ Once one-time costs of development of the DIIS are removed, SDG&E has an average cost per system of \$151.⁵⁴ SDG&E provides no justification for why its costs are dramatically higher than the other two IOUs. The JSP believe that it is important for the Commission to provide an incentive for the IOUs to pare down their costs by sharing best practices on lowering the costs of application processing while also providing customers across IOUs with a uniform fee. Thus, based on testimony from PG&E witness Waggoner and SCE witness Barsley, the JSP believe an interconnection application of \$75 is cost justified

⁵² Exhibit 2 (JSP-Fulmer), p. 52, lines 2 through p. 53, line 19.

⁵³ *Id.*, p. 52, lines 24 through p. 53, line 2.

⁵⁴ *Id.*, p. 53, lines 7-9.

particularly given PG&E's assertion that it expects interconnection application related costs to decline over time.⁵⁵

As noted above, PG&E proposes a \$1600 application fee for larger systems. However, PG&E does not provide any cost justification for this fee. The Commission should reject such a high fee as it would have a major impact on customers installing larger systems and PG&E has provided no justification for such a high fee in contravention of the requirement that it provide a basis for its proposed fees.⁵⁶

In addition to the NEM application fee, SDG&E proposes that customers with systems larger than 30 kW "be obligated to pay the cost of additional studies and/or system upgrade costs."⁵⁷ This is a significant requirement that could derail many potential solar installations. For projects on the lower end of the 30 kW - 1 MW range, distribution upgrades may be rare, but the uncertainty of not knowing whether a major expense will be involved would be extremely disruptive. If a customer proposing a small system does not know if that system will be what pushes the circuit past an upgrade threshold point, a wise investor would be wary to sign a contract with such significant uncertainty.

It is not known how often SDG&E would require a study or how it would be triggered. SDG&E witness Parks stated that SDG&E has not done any interconnection studies for NEM systems larger than 30 kW.⁵⁸ However, he did not state whether or not SDG&E has done any analysis to determine whether proposed systems would have impacts on the distribution system.

⁵⁵ Exhibit 2 (JSP-Fulmer), p. 53, lines 22-27; Exhibit 18 (PG&E-Waggoner), p. 1-3, lines 5-8.

⁵⁶ Exhibit 2 (JSP-Fulmer), p. 54, lines 1-4.

⁵⁷ "San Diego Gas & Electric Company Proposal for Successor Net Energy Metering Tariff," filed August 3, 2015, at p. A-78"

⁵⁸ Tr. Vol. (SDG&E -Parks), p. 107, lines. 3-7.

SDG&E has not had a reason to package such analyses into interconnection studies because NEM systems have been exempt from paying for such studies. The Commission can presume that analysis would have been written up as studies if customers had been responsible for paying for such studies. Saying that studies have not been done in the past implies that requiring customers to pay for such studies going forward would not be a major policy change. This cannot be assumed.

As the JSP have asserted in earlier comments, if a customer does not know at the point of signing a contract for a solar installation whether there will be added costs for interconnection studies or distribution system upgrades, it would be a major area of uncertainty. For this reason, the existing waiver facilitates streamlining by removing a step that would otherwise require further communication between the utility and the customer. Commission Staff have called the interconnection process for NEM customers “frictionless,” noting that extending NEM-type interconnection processes to other types of applicants can “level the playing field between utilities and prospective project applicants.”⁵⁹ It also recognizes the principle that with smaller systems, not all costs to upgrade the distribution grid are due solely to the next NEM customer. Maintaining this administrative efficiency will be important in achieving the goal of continued sustainable growth in DG deployment. On the balance, these benefits in fairness and ease to applicants should outweigh concerns over the small amount of resultant costs borne by other ratepayers.

⁵⁹ R.11-09-011, *Administrative Law Judge’s Ruling Setting Schedule for Comments on Staff Reports and Scheduling Prehearing Conference*, Attachment A, Staff Proposal on Cost Certainty for the Interconnection Process (July 18, 2014) 5, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M099/K767/99767928.PDF>.

IV. DISCRIMINATORY FEES AND RATES PROPOSED BY VARIOUS PARTIES ARE ILLEGAL UNDER CALIFORNIA AND FEDERAL LAW

The IOUs, as well as ORA and NRDC, are advancing the assessment of significant new charges on NEM customers alone, to the exclusion of other residential customers,⁶⁰ in the absence of a substantial showing, indeed any showing, that the costs to serve such customers are different than the costs to serve other residential customers. Without such a showing by the parties advancing these proposals for new charges, the Commission cannot find the charges to be just and reasonable under the applicable provisions of state and Federal law.

A. State and Federal Law Require that a Separate Rate Structure for NEM Customers Be Based on a Substantial Showing that the Cost to Serve Such Customers Is Different

State law requires that rates be non-discriminatory.⁶¹ Public utilities are prohibited from establishing any “unreasonable” differences as to rates and charges between classes of service. Therefore, consistent with state law, parties advancing disparate rate structures for NEM customers bear the burden of proving that proposed rates and classification are just, reasonable and nondiscriminatory. Section 2827.1(b)(7) added by AB 327 to delineate the NEM successor tariff, reiterates that “[t]he commission shall ensure customer generators are provided electric service at rates that are just and reasonable.” In this regard, it is critical to remember that, even after they install DG, customers on the NEM successor tariff will remain ratepayers of the utilities. In fact, most will still continue to pay a significant monthly utility bill. The record in this case shows that, for the average NEM customer, adding a typical solar DG system converts

⁶⁰ Both PG&E and SDG&E would allow non-NEM customers to voluntarily opt into the new rate schedules.

⁶¹ *See, e.g.* Cal Constitution Article XII, Section 4; Public Utilities Code section 453(c) (c) (“No public utility shall establish or maintain any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.”).

that customer from a larger-than-normal customer to a slightly-smaller-than-average one.⁶²

Accordingly, any proposed rate classification for NEM customers must overcome a significant burden of demonstrating that the cost of serving customers that self-supply electricity with on-site solar generation varies significantly from the cost of serving other residential customers that do not have solar, such that a different rate classification is justified.

As the Utah Public Service Commission (Utah Commission) recently recognized in rejecting calls for discriminatory fees merely because NEM customers decrease their purchases from their respective utilities:

Simply using less energy than average, but about the same amount as the most typical of PacifiCorp's residential customers, is not sufficient justification for imposing a charge, as there will always be customers who are below and above average in any class. Such is the nature of an average...[I]f we are to implement a facilities charge or a new rate design, we must understand the usage characteristics, e.g., the load profile, load factor, and contribution to relevant peak demand, of the net metered subgroup of residential customers. We must have evidence showing the impact this demand profile has on the cost to serve them, in order to understand the system costs caused by these customers.⁶³

The Utah Commission also recently found that NEM Customers are not “distinguishable on a cost of service basis from the general body of residential customers.”⁶⁴ Parties advocating for discriminatory treatment of NEM participants have offered no evidence that NEM participants are distinguishable from the general body of residential customers.

Similarly, federal law also requires that any separate rate structure for NEM customers must be based on a substantial showing that the costs to serve such customers are different.

PURPA requires utilities to interconnect “small power production facilities” that meet Federal

⁶² Exhibit 2, (JSP-Beach) p. 4, line 21 to p.5, line 3.

⁶³ *Id.*, pp. 67-68.

⁶⁴ Public Service Commission of Utah, *PacifiCorp dba Rocky Mountain Power 2014 General Rate Case*, Docket No. 13-035-184, Decision and Order (Aug. 29, 2014), p. 67.

Energy Regulatory Commission (FERC) eligibility requirements for qualifying facilities (QFs).⁶⁵ QF status automatically applies to on-site solar generators up to 1 MW,⁶⁶ and includes QF generators that participate in NEM.⁶⁷ The FERC’s regulations implementing PURPA requires that rates for electricity sales to QFs “[s]hall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.”⁶⁸ Differential rates for QFs are only considered to be non-discriminatory when they are “based on accurate data and consistent system-wide costing principles”⁶⁹ and only “to the extent that such rates apply to the utility’s other customers with similar load or other cost-related characteristics.”⁷⁰ Under current FERC regulations, nearly all current NEM systems in California automatically qualify as QFs because they are below 1 MW. Thus, the Commission must be cognizant of the requirements of federal law regarding imposition of fees on QFs.

In the instant docket, the IOUs, ORA and NRDC have provided *minimal to no* data concerning the basis for their rates based on NEM customer load or other cost-related characteristics necessary to justify their discriminatory fees. Simply put, none of the data these parties provide to the Commission illustrate that the cost to serve residential NEM customers varies from the cost to serve either the general body of residential customers or residential customers with similar load characteristics as NEM customers.

⁶⁵ 18 CFR § 292.303(c).

⁶⁶ 18 CFR § 292.203(d) (exempting facilities with net power production capacity up to 1 MW from certification requirement).

⁶⁷ Sun Edison LLC, 129 FERC ¶ 61,146 (2009) (recognizing onsite generators that participate in NEM as eligible for QF status even if they make no net sale of electricity to a utility).

⁶⁸ 18 CFR Sec. 292.305(a)(1)(ii).

⁶⁹ 18 CFR Sec. 292.305(a)(2).

⁷⁰ *Id.*

B. None of the Additional Charges Advanced for Imposition on NEM Customers Are Based on Cost of Service

1. SDG&E's and PG&E's Proposed Non-Coincident Demand Charge

The purported rationale behind PG&E's and SDG&E's proposed demand charges for NEM customers is to ensure such customers pay "an appropriate share of the infrastructure costs required to serve them."⁷¹ They assert that if distribution costs are collected only in volumetric energy (per kWh) rates, as they currently are for all residential customers, then a NEM customer that offsets most of its load pays very little for the distribution infrastructure necessary to serve them. However, as support for their proposed demand charges, neither PG&E nor SDG&E undertook any cost analysis to determine if there is a difference in the costs to serve residential NEM customers versus non-NEM residential customers, therefore rendering it impossible to determine what is the "appropriate share of infrastructure costs to serve [NEM customers]." A cost of service study is one of many crucial pieces to any ratemaking puzzle. Indeed, as recognized by SCE witness Behlihomji "if you had to be true to the process of constructing and designing like a design demand charge, you would have to include these [NEM] customers as part of their own rate class to do a proper cost allocation study and a costing study for these NEM customers."⁷² PG&E plainly did not conduct such a process as they readily admit that their proposal "does not attempt to develop rates that are based on unique cost of service considerations for NEM,"⁷³ while SDG&E's "back of the envelope" development of its NEM

⁷¹ PG&E August 3, 2015 Proposal, p. 14 ("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."). *See also* SDG&E August 3, 2015 Proposal, p. A-4 ("SDG&E's proposal eliminates hidden indirect subsidies and requires NEM customers to pay their fair share of infrastructure costs.").

⁷² Tr. Vol. 2 (SCE-Behlihomji), p. 380, lines 10-16.

⁷³ Exhibit 18, (PG&E-Pease) p. 2-1, lines 17-18.

demand charge proposal, clearly demonstrates that it did not perform a costing study for NEM customers.⁷⁴

Moreover, while SDG&E and PG&E advanced their proposed demand charges as being cost based, they are not. PG&E and SDG&E both propose a non-coincident demand charge covering distribution costs that would be based on the customer's maximum usage in any hour of the month, even if that maximum usage occurs in the early morning or late at night.⁷⁵ PG&E and SDG&E, however, design their distribution system based on the peak demand of the circuit;⁷⁶ they do not assume that all customers on the circuit peak at the same time.⁷⁷ As attested by SDG&E witness Fang, it is the customer's load at the time the distribution circuit reaches its peak that drives the costs to build the distribution system.⁷⁸ SDG&E has presented evidence that the majority of its distribution circuits peak in the afternoon⁷⁹ when solar output is at its strongest. PG&E has attested to a wide diversity of distribution system peak times across the service territory.⁸⁰ Thus, it is not cost-based to assess a demand charge on residential customers based on the customer's maximum use in *any* hour.⁸¹ A residential customer's maximum use at 2:00 a.m. simply is not a cost driver for the distribution circuit.

⁷⁴ Exhibit 26 (SDG&E-Fang), p. 9, line 12 to p.10, line 3.

⁷⁵ Tr. Vol. 2 (SDG&E-Fang), p. 281, lines 20-24; Tr. Vol. 2 (PG&E-Pease), p. 334, lines 8-16.

⁷⁶ Tr. Vol.2 (SDG&E-Fang), p. 286, lines 17-26.

⁷⁷ Tr. Vol. 2 (SDG&E-Fang), p. 270, line 21 to p.271, line 3; Tr. Vol. 2 (PG&E-Pease), p. 253, lines 8-15.

⁷⁸ Tr. Vol. 2 (SDG&E-Fang), p. 285, lines 24-28.

⁷⁹ Exhibit 28 (SDG&E-Fang), p. 4, Chart 1.

⁸⁰ Tr. Vol. 2 (PG&E-Pease), p. 353, lines 5-7.

⁸¹ Exhibit 2 (JSP-Beach), p. 39, lines 15-20.

2. SDG&E's Fixed Charge

SDG&E's proposed fixed charge is in direct contravention of the Commission's dictates in D. 15-07-001. SDG&E has proposed a fixed charge (a "System Access Fee") of \$14.34 per month to recover the customer-related cost portion of its distribution revenue requirement.⁸² Subject to the legislative constraint of a maximum fixed charge of \$10.00, this is the exact same proposal that SDG&E proffered in the RROIR proceeding.⁸³ The Commission's decision with respect to SDG&E's proposed fixed charge, as well as those of the other IOUs, was clear:

*As discussed in full below, we find that a fixed charge linked to costs that do not change as a result of individual customer usage is not appropriate unless certain requirements are met. These requirements include ensuring that the charge reflects appropriate costs, establishing a consistent methodology across utilities, and waiting until each utility has shifted to default TOU rates.*⁸⁴

In rendering this decision, the Commission did not exclude NEM customers from its determination that the imposition of fixed charges at this time is not appropriate. As none of the Commission imposed prerequisites for the assessment of a fixed charge have been met, SDG&E's proposal to impose a fixed charge on NEM customers is premature and cannot be approved.

SDG&E's reliance on AB 327 as the basis for ignoring the Commission's directives and proposing a fixed charge for NEM customers⁸⁵ is completely misplaced. While AB 327 does provide that "Any fixed charges for residential customer generators that differ from the fixed

⁸² Exhibit 26 (SDG&E-Fang), pp 10 - 11.

⁸³ Tr. Vol. 2 (SDG&E-Fang), p. 256, line 24, to p.257, line 1.

⁸⁴ Decision 15-07-001, p. 191. The specific requirements set forth by the Commission are (1) a GRC Phase 2 decision issues approving categories of fixed costs for possible inclusion in a future fixed charge; (2) for each IOU, a GRC Phase 2 decision issues that approves a calculation of fixed charges; (3) a decision in the IOU's 2018 Residential RDW that approves a new fixed charge request from the IOU and (4) Default TOU is implemented.

⁸⁵ Tr. Vol. 2 (SDG&E- Fang), p. 258, lines 4-8.

charges allowed pursuant to subdivision (f) of Section 739.9 shall be authorized only in a rulemaking proceeding involving every large electrical corporation,”⁸⁶ it does so with the caveat that “The commission shall ensure customer generators are provided electric service at rates that are just and reasonable.”⁸⁷ The Commission has just determined that the imposition on fixed charges on residential customers at this time is not just and reasonable. No exclusion was made with respect to NEM customers. It would be the very essence and definition of discriminatory rate treatment for the Commission to approve a fixed charge for NEM customers. SDG&E’s proposed fixed charge must be rejected.

3. SCE’s Proposed Grid Access Charge

Recognizing that imposition of a demand charge on NEM customers necessitates a cost-of-service study, SCE has proposed what it calls a “demand charge proxy” for the recovery of transmission and distribution costs from residential DG customers.⁸⁸ This Grid Access Charge (GAC) would be additive to the standard retail rate paid by NEM customers.⁸⁹ In essence, what SCE is attempting to do is to recover from DG customers a portion of the costs that they would have paid to the utility if they did not serve some of their own load.⁹⁰ SCE’s attempt to cost justify this recovery is inadequate.

The evidence which SCE proffers for its assertion that transmission and distribution costs do not decrease when a residential customer installs solar is an analysis that the Commission has already determined to be a deficient means to show to the difference between the “pre-solar” and

⁸⁶ PU Code Section 2827.1 (b) (7).

⁸⁷ *Id.*

⁸⁸ Exhibit 16 (SCE-Behlihomji), p. 5, lines 27-28.

⁸⁹ SCE August 3, 2015 Proposal, p. 27 (“the GAC charge is applied as an overlay rate structure to both tiered and TOU residential rates.”)

⁹⁰ Tr. Vol. 2 (SCE-Behlihomji), p.394, lines 6-16.

“post solar” demands of solar customers. Specifically, SCE attempts to assess the effect of customer sited DG on SCE’s distribution and transmission grid by comparing a typical demand of a sample of a thousand NEM customers before and after their installation of DG on SCE’s peak demand day in 2012 (the “pre-solar” day) and its peak demand day in 2014 (the “post-solar” day).⁹¹ Based on this comparison, SCE concludes that “the post-solar peak demand of these customers remains essentially at the same level as the pre-installation peak” and, therefore, “the installation of customer-sited DG has no present impact on NCP [non-coincident peak] demands and thus no impact on the allocation of SCE’s distribution costs to the residential class.”⁹² When presented with a similar analysis, however, the Commission has rejected the results.

In Application 12-02-002, SEIA compared certain customers’ loads during the peak hour of the year before they installed solar PV systems to their loads during the peak hour of the year following installation as basis for its assertion that the load reductions observed between pre- and post-installation demonstrate the substantial capacity provided by these customers’ solar PV systems. In response to SEIA’s analysis, the Commission stated:

We acknowledge that while the results of SEIA’s study suggest that solar PV systems provide significant peak capacity, its study was severely hampered by lack of access to the actual solar production data. The use of load differences as a proxy undermines the validity of the study, and consequently we do not give it much weight to reach our conclusions.⁹³

The same inadequacies are present in the SCE study. There are other factors besides solar installation which may have impacted the peak demands for the thousand customers

⁹¹ Exhibit 16 (SCE -Behlihomji) p.8, lines 1 to p.9, line 7.

⁹² *Id.*, p. 10, lines 1-5.

⁹³ D. 14-12-080, p.13.

on the two days which SCE analyzed. As recognized by SCE witness Behlihomji:

While we notice because of the difference in year, because of the difference in the date, there could be other factors that affect any variation that you're seeing in how this illustrative graph might depict the peak demand. But for the purposes of what we are discussing or what I am discussing in my testimony are basically assume them to be the same.⁹⁴

In addition to SCE's faulty analysis, the contention upon which SCE's GAC is premised -
- that transmission and distribution costs cannot be avoided when a customer installs DG --
disregards the entire premise of the Commission's Distributed Resources Proceeding and SCE's
own statements in its Distribution Resource Plan. As stated by the Commission:

The goal of these plans is to begin the process of moving the IOUs towards a more full integration of [distributed energy resources] DERs into their distribution system planning, operations and investment. Specifically, Section 769 requires that the DRPs must provide a roadmap for integrating cost-effective DERs into the planning and operations of IOUs' electric distribution systems with the goal of yielding net benefits to ratepayers.⁹⁵

To this end, in submission of its plan, SCE recognized that DG can provide capacity related reliability and resiliency benefits to the distribution system, as well as power quality and voltage support benefits.⁹⁶ It is disingenuous for SCE to now assert that the installation of DG results in no capacity related benefits through the reduction in coincident or non-coincident demand.

Finally, SCE argues that, even if DG did reduce the utility's coincident and non-coincident demand, it cannot be relied upon in system planning due to DG customers need to use the utility's grid for periods when their system fails or is operating at lower capacity.⁹⁷ As

⁹⁴ Tr. Vol. 2 (SCE-Behlihomji), p.389, line 23 to p. 390, line. 3.

⁹⁵ Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, R. 14-08-013 (August 20, 2014), p. 4.

⁹⁶ SCE Distributed Resources Plan, R. 14-08-013 (July 2, 2015), p. 62-63.

⁹⁷ Exhibit 16 (SCE-Behlihomji), p. 10, lines 12-15.

attested by JSP witness Beach,⁹⁸ however, and conceded by SCE's witness Behlihomji,⁹⁹ there are reasonable means to estimate the reductions in coincident and non-coincident demand that result from DG, and thus the amount of transmission and distribution capacity that DG avoids. Indeed, the Public Tool does so through the use of effective load carrying capacity (ELCC) and peak capacity allocation (PCAF) factors developed by E3 and widely used before this Commission in many types of resource valuation and rate design analyses.¹⁰⁰

4. ORA's Installed Capacity Fee

ORA proposed an Installed Capacity Fee (ICF) as an overlay on NEM customers rates which would begin at \$2 per kW of installed capacity once the 5% NEM cap is reached or July 1, 2017, whichever comes first, and would escalate when DG meets certain targets in the future based on installed capacity.¹⁰¹ To arrive at the ICF for each level of NEM penetration, ORA iteratively ran the Public Tool from \$1/kW/month to \$20/kW/month to observe cost of service results calculated in order to find ICF levels that resulted in recovery of full cost of service from DG customers.¹⁰² The revenues from the ICF would be used to reduce residential rates generally.¹⁰³ ORA's main rationale for the ICF is that it will mitigate a cost-shift from NEM customers to non-NEM customers. ORA also asserts that other sources of renewable generation

⁹⁸ Exhibit 2 (JSP-Beach), p. 32, lines 7-12.

⁹⁹ Tr. Vol. (SCE- Behlihomji), p. 390, line 27 to p.391, line 6.

¹⁰⁰ Exhibit 2 (JSP-Beach), p. 32, lines 10-12.

¹⁰¹ Exhibit 35 (ORA-Drew), p. 4, lines 13-21. (A \$5/kW/month would be imposed on new NEM customers after installed capacity reaches 6% of aggregate customer peak demand and, finally, a \$10/kW/month would be imposed on new NEM customers after installed capacity reaches 7% of aggregate customer peak demand).

¹⁰² Exhibit 35 (ORA-Drew), p. 26, lines 9-26.

¹⁰³ *Id.*, p. 4, lines 7-8,

are less expensive for non-participating customers than renewable DG. Both of these claims are erroneous.

As JSP witness Beach explained, ORA's reliance on the 2013 NEM Study as support for its allegations of a cost shift is misplaced as that study is decidedly dated due to rate design changes brought about by D. 15-07-001.¹⁰⁴ ORA witness Drew used the results of the study for the conclusions in his testimony even though he was aware that the study relied on rate structures far different from current policy.¹⁰⁵ ORA also supports its proposed ICF based on modeling from the Public Tool, particularly the scenarios presented by the Energy Division.¹⁰⁶ However, as the JSP explained in comments on parties' proposals, the Energy Division scenarios presented to parties were merely designed to show how to utilize the Public Tool and were not policy recommendations.¹⁰⁷ Most importantly, the proposals and opening comments of the JSP showed why modification of the assumptions made by the Energy Division are necessary to increase the accuracy of the Public Tool.¹⁰⁸ Once these modifications are made, the cost shift ORA purports to have found is significantly reduced or eliminated. Finally, ORA's reliance on its belief that utility-scale renewables procured to meet California's RPS are less expensive than customer-

¹⁰⁴ Exhibit 2 (JSP-Beach), p. 8, line 28-28 and p. 9, lines 1-2.

¹⁰⁵ Tr. Vol. 3(ORA-Drew), p. 428, line 17 - p. 429, line 1.

¹⁰⁶ See Exhibit 35 (ORA-Drew), pp. 6-8.

¹⁰⁷ *See, e.g.*, Joint Solar Parties' Opening Comments p. 10.

¹⁰⁸ *See*, TASC Proposal pp. 31- 40 (explaining changes made transmission avoided costs, assumed utility rate escalation, energy avoided cost locational multiplier, distribution capital expense scalars, and externalities, updated IOU rates, the adoption module, and the revenue requirement model within the Public Tool to increase the Tool's accuracy); SEIA/VS Proposal, filed August 3, 2015, pp. 13-28 (explaining changes made to the adoption model, DG/RPS Parity, inclusion of marginal costs of CAISO transmission, locational energy values, market price mitigation, and inclusion of societal benefits); and Joint Solar Parties Opening Comments pp. 11-25 (discussing solar cost projections, rate escalation, sizes of adopted systems, utility cost errors, use of marginal CAISO costs, consistent use of marginal subtransmission and distribution costs, locational benefits, corrections to commercial rates, and DG/RPS Parity).

sited renewable DG is equally inappropriate. SEIA/Vote Solar modeled scenarios where DG is assumed to replace utility-scale RPS resources on a one-for-one basis (DG/RPS Parity).¹⁰⁹ That modeling showed that renewable DG offers additional benefits that utility-scale renewables cannot provide such as avoided transmission and distribution costs and additional societal benefits.¹¹⁰ These added benefits counterbalance the lower costs of utility-scale renewables and present a valid economic justification for pursuing a balanced, diversified portfolio of renewable resources which includes both utility-scale renewable resources and customer-sited DG.¹¹¹

ORA's ICF proposal also suffers from a number of other critical flaws. First, JSP witness Fulmer demonstrated that ORA's proposed timeline estimating when the initial ICF and subsequent increases in the ICF would be imposed on NEM customers is defective as it assumes linear regression analysis when in fact, the historic installation trend for each IOU is exponential.¹¹² The end result of this mistake is that ORA's proposed ICF would be imposed much earlier than ORA predicts.¹¹³ JSP Witness Fulmer also provided analysis demonstrating that ORA's proposed ICF does not gradually increase similar to how the decline in CSI rebates operated as ORA asserts, but, instead, the ICF ratchets up at rates from 12-25% versus the gradual decline in CSI incentives of about 4% per year.¹¹⁴ JSP witness Fulmer also explained in great detail how use of the Public Tool to set ICF level is beyond the intent and ability of the

¹⁰⁹ Exhibit 2 (JSP-Beach), p. 9, line 8-14 *See, also*, SEIA/ VS Proposal pp. 22-23.

¹¹⁰ *Id.*, p. 9, line 8-14, *See also*, SEIA / VS Proposal.

¹¹¹ *Id.*, p. 8, line 14-16.

¹¹² Exhibit 2 (JSP-Fulmer), p. 12, lines 9 through p. 16, line 15.

¹¹³ *Id.*, p. 16, line 3-5.

¹¹⁴ *Id.*, p. 16, line 17 through p. 18, line 2.

Public Tool.¹¹⁵ In this section of his testimony, JSP witness Fulmer describes how the Tool is designed for estimating costs and benefits of NEM over the long-term and not for short-term ratemaking, how rates are typically set in GRCs wherein proposals receive deeper levels of scrutiny that are likely to unearth flaws that went uncorrected in the Public Tool, how use of the Public Tool by ORA to set the ICF results in counterintuitive results that could not be explained, and how reliance on the COS% metric within the Public Tool was particularly problematic, and how the PCT metrics within the Public Tool will always result in a PCT that will not fall below 1.0. Finally, JSP witness Fulmer provided analysis demonstrating that to the extent cost of service concerns are what is animating ORA to propose an ICF, a \$15 minimum bill would provide better cost of service recovery than a \$2 ICF.¹¹⁶ *Each one of these points was unrebutted by ORA during hearings.*

In the end, once ORA's ICF reaches its maximum, new NEM customers with a 5kW system would pay a fixed charge of \$50 per month for their choice to assist the state in meeting greenhouse gas goals.¹¹⁷ Such a proposal is far in excess of any reasonable estimate of customer-related fixed costs incurred by the utilities and should be rejected as extreme and inconsistent with the letter and spirit of Sec. 2827.1. This end-state would also result in a charge over 1400% higher than the ICF that Arizona Public Service (APS) put in place for new solar customers last year.¹¹⁸ APS filed a proposal to increase their ICF earlier this year, but has since

¹¹⁵ *Id.*, p. 18, line 3 through p. 23, line 2.

¹¹⁶ Exhibit 2 (JSP-Fulmer), p. 25, lines 1-3 (Table 5 showing results of the Public Tool model runs showing a COS% of 48% under ORA's \$2 ICF while a \$15 minimum bill under Energy Division's 20Tier High DG Value shows a COS% of 60%. Under TASC's Base Case a \$15 minimum bill has a COS% of 80%).

¹¹⁷ Tr. Vol. 3 (ORA-Drew), p. 409, line 13 through p. 410, line 1.

¹¹⁸ *Id.*, p. 420, lines 24-27.

moved to withdraw it amidst negative response from media and the public with a director at APS pointing out that “The fixed charge is a bit of a blunt instrument, and we would agree it’s not the cleanest and best price signal. We see it as if you can transition to something that has that price signal embedded in the rate, then you don’t need to have such a fixed charge sitting on top of the...rate design.”¹¹⁹

5. NRDC’s Proposed Coincident Demand Charge

NRDC’s proposed \$1 per kW coincident demand¹²⁰ charge on residential NEM customers is not based on *any* cost analysis. Rather NRDC relies solely on an article by the Regulatory Assistance Project to support its testimony that a \$1 per kW charge is “within the range of residential utility customer demand charges as proposed by nationally recognized rate design experts” and is sized to recover the cost for the local components of the distribution system (e.g. the meter, service drop, and line transformer).¹²¹ This is hardly cost justification for the proposed charge especially as the \$10 per month minimum bill approved by the Commission in D. 15-07-001, applicable to all residential NEM customers, will ensure that NEM customers will pay all, or at least a significant share, of the costs that are either independent of usage (metering and billing) or sized to an individual residential customer’s load (the service drop and final line transformer).¹²²

¹¹⁹ See Exhibit 37 title “APS Director: Fixed Charges Not the Cleanest and Best Price Signal”.

¹²⁰ NRDC calls their proposed a charge a “continuously variable demand charge” but it is equivalent of a coincident demand charge. Exhibit 32, p. 2.

¹²¹ Exhibit 31 (NRDC- Bull), p. 2, footnote 4; The Natural Resources Defense Council (NRDC) Reply to Party Comments in Response to Proposals for Determining a Net Energy Metering Successor Standard Contract or Tariff, R. 14-07-002 (September 15, 2015), p. 5, footnote 5,

¹²² Exhibit 2, (JSP-Beach), p. 46, line 7-12.

V. FEES AND RATES PROPOSED BY VARIOUS PARTIES ARE INCONSISTENT WITH THE COMMISSION’S RATE DESIGN PRINCIPLES FOR RESIDENTIAL CUSTOMERS

The IOUs’ argument that the Commission’s Rate Design Principles should be applied to the rates assessed NEM customers¹²³ and that such rates should provide NEM customers with the right price signals¹²⁴ work to *support* the JSP’s position that NEM customers should not be placed on separate rate schedules. Specifically, the IOUs argue that the Rate Design Principles established by the Commission in Rulemaking 12-06-013 should apply to the rates assessed NEM customers. The JSP agree. These rate design principles should apply to NEM and non-NEM customers alike. None of the IOUs proposals, however, achieve this result, while the JSP proposal to continue the present structure of net metering fully complies with the Commission’s Rate Design Principles. Under the current structure of NEM, all DG customers continue to see exactly the same price signals from rate design as non-NEM customers.¹²⁵ Thus, to the extent that the rate design for non-NEM customers, as adopted in D. 15-07-001, complies with the Commission’s Rate Design Principles, so too do the rates under the NEM tariff.¹²⁶ This “transparency” of the price signals under NEM is a strong reason to continue the present structure of NEM.¹²⁷

NEM customers, like other customers, can control their load in response to such signals. A NEM successor tariff rife with new demand and/or fixed charges could result in significantly reduced motivation for NEM customers to reduce usage and shift demand from high cost hours,

¹²³ See, e.g., Exhibit 28 (SDG&E -Fang) p. 5, lines 1-5.

¹²⁴ See, e.g., Exhibit 18 (PG&E-Pease), p. 2-12, lines 16-17. SCE Opening Comments p. 2

¹²⁵ Exhibit 2 (JSP-Beach), p. 5, line 25 to p.7, line 12; Tr. Vol. 3 (JSP-Beach), p. 479, lines 1-9.

¹²⁶ Exhibit 2 (JSP-Beach), p. 6, lines 24-26.

¹²⁷ *Id.*, p. 6, lines 26-28.

as acknowledged by SDG&E witness Fang.¹²⁸ As the Commission has noted, “the most important tool for balanced rate design is a price signal that customers can understand and respond to in a way that reduces the cost and environmental impact of energy use.”¹²⁹ The additional rate design elements proposed by other parties will result in very confusing and complex price signals which the average residential customer will not understand and therefore which will generate minimal to no response from the customer.

A. SDG&E’s and PG&E’s Non Coincident Peak Demand Charge

Customer understanding and acceptance was paramount to the Commission’s recent decision adopting residential rate design changes.¹³⁰ These precepts are embodied in Rate Design Principle No. 6, *i.e.*, “rates should be stable and understandable and provide customer choice,” and Principle No. 10, *i.e.*, “transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates.” The record in this proceeding illustrates that a residential demand charge based on a customer’s maximum kW demand in any 60-minute period over the billing cycle as proposed by SDG&E and PG&E is not likely to be understood by the average residential customer. Despite this fact, SDG&E and PG&E have not prepared any program to educate their customers on how demand charges work. Moreover, this lack of understanding by the customer will work against two additional Rate Design Principles that “rates should encourage conservation and energy efficiency” and “rates should encourage reduction of both coincident and non-coincident peak

¹²⁸ Tr. Vol. 2 (SDG&E-Fang), p. 288, line 23 to p.289, line 3 and p. 290 lines 15-19.

¹²⁹ D. 15-07-001, p. 4,

¹³⁰ *See, e.g.*, Decision 15-07-001, p. 31, 108, and 136.

demand, ” as both of these principles hinge on customer understanding of the price signal which it is being sent through the rate.¹³¹

Demand charges have never been part of residential rate design in California, are rare for residential customers elsewhere in the U.S., and to the JSP’s knowledge, have only once been mandated for a subset of residential customers. Salt River Project, in Arizona, levied mandatory demand charges on new solar customers starting in February 2015. As a result, solar installations fell by 96%, and never recovered.¹³² This is not surprising, as it has been only with the advent of smart meters that utilities have even been able to measure the demands of all individual residential customers. The result is a lack of customer understanding of demand charges. The IOUs are aware of this, as they commissioned a customer survey for the Commission’s RROIR which concluded that a demand charge “was confusing” to participants, who ended up making inaccurate comparisons to a fixed monthly service fee because they failed to comprehend that a demand charge “varies based on kW demand levels.”¹³³ This result was further reinforced by a survey that SDG&E conducted on customer preferences for NEM successor tariff rate design.¹³⁴ This survey concluded that the key drawbacks of the demand charge for NEM customers are that it is “confusing,” “unpredictable (may pay more),” and “can be difficult to change behavior.”¹³⁵ Despite these findings and the fact that the demand charge structure was only favored by 17

¹³¹ Tr. Vol. 2 (SDG&E- Fang), p. 262, lines 3-8 (agrees that in order for a rate to incent a certain type of behavior such as conservation the customer would need to understand the price signal that it's getting from the rate); Tr. Vol 2. (PG&E-Pease), p. 345, lines 22-26 (The “customer would have to understand how appliances use energy and how appliances when they -- when they're used at the same time can create a maximum demand that they would then be charged for.”)

¹³² See Joint Solar Parties Opening Comments, pg. 42-44.

¹³³ See Exhibit 2 (JSP -Beach). p. 34, lines 9-14 *citing* Hiner and Partners, Inc. “RROIR” Customer Survey, April 16, 2013, p. 22.

¹³⁴ Exhibit 29.

¹³⁵ *Id.*, p 24.

percent of the survey respondents, amazingly SDG&E advanced these survey findings as a basis for proposing a demand charge.¹³⁶ This activity appears to be par for the course with the IOUs. They engage in costly surveys to ask their customers what rate designs they find reasonable and then ignore the message their customers send. The JSP believe that California can do better than this.

On cross examination, SDG&E witness Fang and PG&E witness Pease both acknowledged that understanding of a demand charge requires an understanding of the difference between energy and capacity -- something which at the present time the average customer does not have.¹³⁷ Despite this acknowledged and documented lack of customer understanding, neither SDG&E nor PG&E have devised a customer education plan. As admitted by witness Pease “there is no outreach and education plan at this time.”¹³⁸ Similarly, witness Fang stated that SDG&E does not have an educational outreach plan to educate NEM customers or potential NEM customers with respect to demand charges.¹³⁹ This stands in stark contrast to the IOUs’ presentations in the RROIR. As admitted by witness Fang, at the time that SDG&E presented its proposed rate design changes to the Commission in the residential rate design proceeding, it had already prepared a customer education outreach program.¹⁴⁰

Moreover, even if a customer did understand the concept of a demand charge, it remains unclear as to how the customer would determine what its maximum demand is in any given

¹³⁶ Tr. Vol. 2 (SDG&E- Fang), p. 267, line 27 to p.268, line 4; San Diego Gas & Electric Company Proposal for Successor Net Energy Metering Tariff, R. 14-0-002 (August 3, 2015), pp. A-25 - A-26.

¹³⁷ Tr. Vol. 2 (SDG&E-Fang), p. 262, lined 9-20; (PG&E- Pease), p. 345, line 1 to p.346, line 7.

¹³⁸ Tr. Vol. 2 (PG&E-Pease), p. 347, lines 13-15.

¹³⁹ Tr. Vol. 2(SDG&E -Fang), p. 262, lines 22-26.

¹⁴⁰ Tr. Vol. 2 (SDG&E -Fang), p. 264, lines 3-8.

month. As attested by PG&E witness Pease, the information currently available to customers, even that information made available by a smart meter, is not assimilated in a manner which allows a customer to readily determine its maximum demand in a billing period.¹⁴¹ Moreover, the cross examination of witness Fang made it clear that SDG&E does not have a cogent plan for providing customers with demand data in a fashion which would allow them to act on it.¹⁴²

The bottom line is that both PG&E and SDG&E have proposed the imposition on NEM customers of a type of charge that they readily admit customers do not comprehend and, even if they did, customers do not have ready access to the information necessary to react to the price signal the charge is purportedly giving. The utilities are proposing to levy such charges without any proposed educational program to facilitate customers' understanding. Such proposals are the very antithesis of the Commission's Rate Design Principles.

B. SCE's Grid Access Charge

A rate designed to recover the costs that NEM customers would have paid to the utility if they did not serve their own load, such as SCE's GAC, runs counter to several of the Rate Design Principles. By being based on the amount of the customer's generation that serves the customer's own loads (*i.e.*, power that the customer self-supplies using its own equipment on its own premises and never touches the utility system) the GAC is contrary to Principle No. 6, which calls for customers to have choices in how they obtain their electric services. Moreover, the premise of the rate -- that a customer will be charged for power it does not receive from SCE -- is counterintuitive and not one that is readily explainable to the average customer. Yet nowhere in its proposal, comments or testimony does SCE address an educational plan for customers

¹⁴¹ Tr. Vol. 2 (PG&E-Pease), p. 348, lines 2-5.

¹⁴² Tr. Vol. 2 (SDG&E-Fang), p. 273. line 156 to page 275, line 8.

contemplating NEM. Finally, the GAC runs counter to the Commission's dictate that rates incent conservation and energy efficiency. If DG customers in the future use more of their power on-site, perhaps through smart-inverter technology or by installing on-site storage, then SCE would have a basis for raising the GAC. The result is penalizing self-consumption of self-produced energy.¹⁴³

C. ORA's Installed Capacity Fee

ORA's ICF, as a fixed charge,¹⁴⁴ is similarly at odds with Commission Rate Design Principles. The fundamental problem with fixed charges is that, counter to the rate design principle that rates should encourage conservation and energy efficiency, it is assessed regardless of the amount of energy the customer uses, i.e., the charge cannot be influenced via conservation and energy efficiency efforts.

Moreover, the ICF suffers from two structural defects which counsel against its adoption. First, as JSP witness Beach explained, a NEM customer cannot avoid the ICF unless they forego an investment in customer-sited DG or they "cut the cord" with their IOU and do not interconnect.¹⁴⁵ Both of these actions are directly at odds with California's long standing efforts to harness customer investment in DG to achieve greenhouse gas goals. Both also violate rate design principles which encourage and enable customers to take actions which benefit the grid as a whole.¹⁴⁶ Equally troubling is the fact that the ICF would not decrease for customers that take actions to increase the value their investment in customer-sited DG brings to the grid, such as

¹⁴³ Exhibit 2 (JSP-Beach), p. 26, line 30 to p.27, line 3.

¹⁴⁴ Tr. Vol. 3 (ORA-Drew), p. 410, lines 2-28.

¹⁴⁵ Tr. Vol. 3 (ORA-Drew), p. 411, lines 1-5; Exhibit 2 (JSP-Beach), p. 10, lines 14-16.

¹⁴⁶ Exhibit 2 (JSP-Beach), p. 10, lines 16-17.

facing their panels to the west instead of south to increase late afternoon output and capacity value or investing in smart inverters and/or energy storage.¹⁴⁷

D. NRDC's Coincident Demand Charge

The same problems discussed above in conjunction with the PG&E and SDG&E non-coincident demand charge proposals, in terms of the difficulties with customer acceptance, understanding, and access to demand data in time to take action, apply equally to NRDC's demand charge proposal.¹⁴⁸ While NRDC attests that customer education efforts will be paramount in helping NEM customers understand their bills and how they can take actions to reduce their bills,¹⁴⁹ NRDC has provided no details on the types of information that would be disseminated in such an education effort and how such dissemination would occur.¹⁵⁰ Like SDG&E and PG&E, NRDC's rate design proposal does not comport with the Commission's rate design principles.

VI. CONCLUSION

For the reasons stated herein and in the JSP comments on parties' proposals, the JSP urge the Commission to reject party proposals for discriminatory fees and charges that will undermine continued sustainable growth in customer-sited renewable DG as discussed extensively in the JSP's opening and reply comments on parties' proposals. Simply put, parties' proposals are illegal, not cost justified, and run roughshod over the Commission's Rate Design Principles. The discriminatory charges and fees proposed in this proceeding also chart a course that is at odds

¹⁴⁷ *Id.*, p. 10, line 30 through p. 11, line 17.

¹⁴⁸ *Id.*, p. 46, lines 14-18

¹⁴⁹ Exhibit 31 (NRDC-Bull), p. 3.

¹⁵⁰ Exhibit, 32, p. 5 ("We don't yet have details on the specific pieces of information. They will need to be developed.")

with the Commission's efforts in D.15-07-001 to orient utility rates towards those that are time of use based and encourage customer choice.

Respectfully submitted this October 19, 2015 at San Francisco, California.

GOODIN, MACBRIDE,¹⁵¹
SQUERI & DAY, LLP
Jeanne B. Armstrong
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
E-mail: jarmstrong@goodinmacbride.com

By: /s/ Jeanne B. Armstrong
 Jeanne B. Armstrong

Attorneys for the Solar Energy Industries
Association

3326/026/X176440.v1

¹⁵¹ In accordance *with* Commission Rule 1.8(d), counsel for the Solar Energy Industries Association is authorized to sign these comments on behalf of the members of the Joint Solar Parties.