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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON DRAFT VERSION OF THE NET ENERGY METERING PUBLIC TOOL

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I. INTRODUCTION

On April 15, 2015, Administrative Law Judge Anne Simon issued a Ruling Seeking Comment On Draft Version Of The Net Energy Metering (NEM) Public Tool (ALJ Ruling). Pacific Gas and Electric Company (PG&E) has reviewed the Public Tool extensively and appreciates this opportunity to provide our insights and suggestions.

The NEM successor tariff will have significant policy and economic implications (as much as $1 billion per year) for California. If, as expected, the policy design is contingent on the Public Tool, then it is critical to ensure that the Public Tool is fully functional and yields reasonable results. These comments provide specific proposed changes to help the Tool yield more meaningful results. In order to ensure this outcome, the Commission should permit parties to provide comments to Energy Division on further changes made to the Public Tool. This would not be an opportunity to reargue points previously made, but instead permit further review and comments on the changes made to the Public Tool once revisions from this round of comments have been integrated. There will be time for this work to continue as the parties move forward with specific NEM proposals and testimony.

PG&E appreciates that the Public Tool seeks to produce comparable results across Standard Practice Manual tests and can accommodate many stakeholder assumptions. However, portions of the Public Tool, as it now exists, cannot be used for its intended purpose because it contains several serious flaws that would inevitably result in poorly designed policies and predictions of market outcomes. In particular, the output of the current adoption module within the tool, which forecasts a 70% decline in adoption in 2017 due to the Investment Tax Credit (ITC) reduction, illustrates the folly of trying to use the Public Tool to forecast adoption and designing policy to yield a particular adoption target. Until these portions of the Public Tool are modified, they should not be used to inform public policy. Moreover, even with modification, the CPUC should not rely on it as a measure of whether a given proposed NEM successor tariff satisfies the Legislative criteria that eligible customer generation "continues to grow sustainably" that the CPUC is charged to meet.

As evidence of these flaws, the Public Tool currently generates illogical and counter-intuitive outputs, which if taken as the basis for policy making, would result in poorly designed policy. For example, the Public Tool "base case" produces the following results in PG&E's service territory:

- Solar PV adoption is shown to decline by over 70% in 2017 without any NEM or rate reform due to a reduction in the ITC from 30% to 10%.
- Even with an extension of the ITC to 30%, the model predicts that the CA solar adoption rate will decrease in 2017/2018 as the market begins to approach saturation.
- The projected 2017 levelized cost of energy (LCOE) for solar PV in CA are much higher than prices available today in California from some vendors, and up to 100% higher than LCOEs currently offered by solar vendors in states with lower energy prices.

- The model predicts that utility scale PV will become more costly than retail PV in within less than a decade.

These results are contrary to nearly every industry report, academic paper, financial analyst report, and vendor presentations to their investors pertaining to the California distributed generation market. The Commission and E3 must validate the output of any model by assessing plausibility of the scenarios produced and benchmarking to market forecasts, not simply ensuring that the mechanics of the model function properly.

PG&E has identified five major flaws that render portions of the Public Tool, in its current form, inappropriate to serve as a basis for assessing whether a given NEM successor proposal meets legislative criteria.

1. Adoption modeling method is outdated and does not reflect current market dynamics: The Public Tool uses an adoption model based indirectly on payback period to create an adoption forecast. The method drastically under-estimates customers' willingness to adopt relative to the size of customer savings. The most relevant research, based on California customers making decisions about solar PV installations, reveals that customers overwhelmingly make adoption decisions based on monthly bill savings, not payback, and that customer adoption is highly sensitive to this metric. The tool is not sufficiently sensitive to the DG value proposition to reflect current market dynamics. The CPUC must recognize this fact and implement a feature in the Public Tool that reflects actual adoption behavior based on a comparison of the cost of DG to monthly bill savings. PG&E has prepared such a modification and has shared it with E3; the same proposal is also discussed in detail below.

2. Equal application of technical potential to each customer group distorts the adoption forecast. The model assumes that the total technical potential for renewable customer generation is 35% of California customers. The technical potential is used to cap each of the customer groups as part of the adoption analysis. Whether or not this is the correct estimate of technical potential, it is incorrect to assume an equal percentage of adoption across each of the representative customer groups. Some of the characteristics of the customer groups (high usage, or home ownership) are also characteristics that drive the technical potential, which means the relative level of adoption should reflect these drivers. One would expect a higher technical potential for those customer groups, with a lower potential in others, even if the overall total potential for California is 35%. Using the same potential to cap adoption for each customer group means the adoption is significantly underestimated.

3. The Public Tool "Results" presentation infers adoption as the metric of market sustainability. As PG&E has previously noted, adoption forecasts are highly sensitive to input assumptions and methodologies and actual adoption is influenced by many factors exogenous to the CPUC's control. The appropriate method to determine whether a NEM successor tariff ensures sustainable growth is to compare the participating customer's bill savings under the NEM successor tariff to the actual "bottom-up" cost of the renewable generator, adding a user-defined profit margin (or using an implied margin when compared to modeled prices) for the vendor. So long as the assessment of the NEM successor tariff reveals that there is sufficient opportunity for customers to save compared to a forecast of their electric bills and sufficient margin for the vendor to offer the DG products and services under the new tariff, the CPUC should not place greater focus on speculative forecasts of future adoption. The Public Tool, as currently designed, fails to account for the supply-side (vendor) perspective on market sustainability. By assessing price in the absence of cost, there is no indication of whether vendors can achieve a sustainable return under different pricing scenarios. The sustainability of the margin available to vendors needs to be assessed by comparing costs to the various ranges of expected pricing scenarios under the successor tariff proposals. Only then can the CPUC evaluate whether sustainable growth is possible. For instance, if a NEM successor tariff prices an effective compensation rate that is above the vendor's cost, one can infer a negative margin, which would clearly not be sustainable. The CPUC must add DG cost forecasts to enable the CPUC to assess sustainability from both the customer and vendor perspective.

4. Treatment of Solar PV Price:

a. The Public Tool erroneously inflates solar PV price inputs by adding substantial and duplicative financing costs to referenced market prices, which already include financing. As a result, PG&E believes the CPUC should disable the Public Tool financing cost module.

b. The Public Tool is overly conservative in estimating the ability of the industry to reduce prices, which results in under-forecast of adoption. The model erroneously assumes price declines at rates that reflect conservative levels of cost declines from industry learning and technology advancements. However, price declines should also account for the ability of the industry to compress profit margins, which takes no "learning" and can be done immediately (as evidence by lower solar prices offered in other states).

c. The model needs a "Low" price solar PV scenario. As many researchers have repeatedly pointed out, the California market has much higher prices than elsewhere because vendors engage in value-based pricing against the utility rate, not because costs are commensurately higher in California. The substantial body of literature around this finding illustrates that prices can be disconnected from cost. Adding a low-price scenario would offer users a more balanced approach and would reflect prices that could be realized in California today.

5. Estimated avoided energy prices are erroneously high and stable. Energy prices, used to calculate the avoided energy cost as a benefit to ratepayers (RIM test) and California (TRC test), are too high, too flat, and do not reflect dynamic market behavior. This leads to avoided energy estimates that can be at least double what they should be. E3 chose to average energy prices in bins and to average prices over each month, however this choice misrepresents the true energy prices, at least for solar, because the energy produced by solar PV coincides with, and in fact drives the lowest future energy prices at mid-day. Averaging energy prices in the Public Tool does not adequately capture this significant mid-day dip, and erroneously attributes solar PV with high energy values from times at which the technology is not capable of producing energy.

PG&E compared the Public Tool estimate for energy prices for a typical day in March 2015 with the actual CAL ISO recorded prices last month. The Public Tool predicted that per MWh energy avoided costs for March 2015 would be $34.55; whereas the actual energy price last month for one MWh of electricity was $22.57.[1] This difference is exaggerated in the out-years of the model where the Public Tool estimate can be over 400% higher than expected energy values.

Below, PG&E provides comments and suggestions for addressing both the fundamental flaws listed above and the other issues identified during our examination of the model. We followed the order of questions provided in the ALJ Ruling, however two critical topics (Adoption and Solar Cost and Prices) cross several of the questions in the Ruling and are separately identified within each question.

PG&E summarizes our responses here to serve as a guide for the reader:

Question	**Issues**
Question 1	1. Additional documentation needed for the derivation of the adoption algorithm. 2. The terms "cost" and "costs" are used in various places in the Draft Tool to describe market pricing. The core input data is correctly described as "price"

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1 This uses the CAISO-side aggregate behind-the-meter PV profile provided by the CAISO in its 2014 LTPP Trajectory Case model. More information on this model is located here: https://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf.

	in the "Advanced DER Inputs" tab, but labeling is inconsistent throughout the Draft Tool.
Question 2	1. The data pulled from LBNL's "Tracking the Sun" report is not converted from DC to AC.
Question 3	1. User inputs for ITC in "Advanced DER Inputs" should also be applied to the RPS prices used for the RPS avoided cost. 2. The hardcoded PG&E DG adoption prediction for 2015 is flat relative to 2014. 3. Predicted PG&E DG adoption falls from 2016 to 2017, even if the 30% ITC is assumed to be extended and no changes are made to rate design or NEM. 4. The model currently assumes all residential customers are equally likely to be capable to installing rooftop solar. 5. Insurance cost is redundant and has a disproportionate impact on the PPA price (e.g., removing a 1% cost of insurance reduces the PPA price by 13%). 6. The Draft Tool's default user options result in DER pricing that is unsubstantiated and not representative of the market.
Question 4	1. The Draft Tool does not allow a user to select a "Low" price scenario.
Question 5	PG&E has no issues with Question 5 at this time
Question 6	1. The RPS prices used to calculate the RPS avoided in the model are too high. 2. Since the simplified stack energy price model uses monthly average profiles for load, wind and solar, it does not produce an accurate curtailment forecast. 3. The simplified stack model produces energy prices which are too flat and too high in the middle of the day. 4. The avoided T&D cost assigned to solar PV is erroneously high and should be reduced. 5. The model's historic adoption figures for PG&E do not match PG&E's actual

	adoption figures. 6. The Draft Tool's "Base" solar prices inputs represent the high end of the current pricing spectrum in California and are reflective of only a single study that uses a flawed top-down analysis method.
Question 7	1. The adoption algorithm is based on a payback curve, which is based on outdated research and unrealistically limits adoption. 2. Pricing declines used in the model are too conservative. 3. The Draft Tool underestimates the value of Federal incentives by using the "market" appraisal method, which is approved by the IRS, but rarely used by industry. 4. The Draft Tool provides policy-makers with a very limited perspective on DG solar pricing (one source) making it challenging to assess sustainability of this rapidly growing market from the customer (pricing) perspective. 5. The Draft Tool offers no insights into whether policy incentives are "right-sized" to stimulate the supply-side of the market. 6. The Draft Tool does not allow for modeling of a "transition path" from the current NEM tariff to the successor tariff. 7. The Draft Tool does not clearly illustrate the market/technical potential and where "on the S-curve" the current and predicted levels of adoption place the market.

II. PG&E'S RESPONSE TO THE QUESTIONS IN THE ALJ RULING

A. Question 1:

Please identify any input descriptions, or documentation materials, within the draft version of the Public Tool that should be expanded or modified. If yes, please provide tab and *row references to the description and/or materials, as well as a detailed description of each proposed expansion or modification.*

Response to Question 1:

ADOPTION

***Issue 1**: Additional documentation is needed for the derivation of adoption algorithm parameters.*

Location in Public Tool: Advanced DER Inputs, Cells E65:F67

Proposed solution: Please provide more documentation in the model regarding the derivation of each adoption parameter in the model. This would allow the user to update the tool in the future as more adoption research and data becomes available.

Rationale: The model is currently not transparent regarding the derivation of the adoption parameters. More documentation would build credibility and enable other parties to update the tool in the future as more adoption data becomes available. This would also enable the tool to be used on an ongoing basis for forecasting, rather than being limited to a one-time use aiding design of the NEM successor tariff in this proceeding.

SOLAR COST AND PRICES

***Issue 2**: The terms "cost" and "costs" are used in various places in the Draft Tool to describe market pricing. The core input data is correctly described as "price" in the "Advanced DER Inputs" tab, but labeling is inconsistent throughout the Draft Tool.*

Location in Public Tool: Cells B25 and B26 in the "Key Driver Inputs" tab list "costs." Similarly, cells B8, B9, and B11 in the "DER Pro Forma" tab describe DER "costs." In all cases, these are actually market prices for solar units.

Proposed solution: In the "Key Driver Inputs" tab, change cell B25 to "DER Market Pricing" and cell B26 to "Solar Pricing Case." In the "DER Pro Forma" tab, change cell B8 to "System Price", cell B9 to "System Price", and cell B11 to "Total System Price."

Rationale: The model uses reported solar pricing data as described in the Draft Tool's referenced LBNL report. Yet, the Tool erroneously describes this data as "costs" in select worksheets, which may cause confusion among users. The market pricing data in the "Advanced DER Inputs" tab is inclusive of all-in costs (including fixed and variable costs; legal and financing expenses; sales, general, and administrative expenses; and other overhead) and profit margins for third party solar providers. While these prices will be used as "costs" for participants, for all other Public Tool outputs, the price to the participating customer is not the cost.

LBNL clearly indicates that the numbers in its 2014 Tracking the Sun VII report reflect costs. In its report, LBNL states that "The data consist of prices paid to project developers or installers (prior to receipt of any incentives), and ...those prices may differ from the underlying costs borne by project developers or installers.... The reported market price data ... are based on whatever profit margin developers are able to capture or willing to accept. In markets with relatively high incentives and/or barriers to entry, developers may be able to price projects above the theoretically 'efficient' level."[2]

B. Question 2:

Please identify any computational errors in the draft version of the Public Tool or the Revenue Requirement that should be corrected. For each error identified, provide model and row references to identify each error, provide a proposed change that will correct the error, and provide specific reasons for the proposed change.

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2 LBNL ***Tracking The Sun VII*** Report, p. 7, available at http://emp.lbl.gov/sites/all/files/lbnl-6858e.pdf.

Response to Question 2:

<u>**SOLAR COST AND PRICES**</u>

<u>**Issue 1**</u>: **The data pulled from LBNL's *Tracking The Sun* report is not converted from DC to AC.**

<u>Location:</u> "Advanced DER Inputs" tab. Table Rows 32-49; Columns E-H.

<u>Proposed Solution:</u> Multiply the listed numbers by 1.15.

<u>Rationale:</u> The numbers in the LBNL report are in DC, and they are identical to the numbers listed in the Draft Tool, which are labeled AC.

C. Question 3:

Please identify any logical inconsistencies in the draft version of the Public Tool or the Revenue Requirement that should be resolved. For each inconsistency identified, provide model and row references to identify each inconsistency, explain why it is an inconsistency, provide a proposed change that will remove the inconsistency, and provide specific reasons for the proposed change.

Response to Question 3:

<u>Issue 1</u>: User inputs for ITC in "Advanced DER Inputs" should also be automatically applied to the RPS prices used for the RPS avoided cost.

<u>Solution</u>: There are two alternate solutions that could be implemented: 1) Limit the choices for ITC in cells K32-K49 of the Advanced DER Inputs and add those choices to the RPS prices in the RR Inputs worksheet of the Revenue Requirements spreadsheet (current input is at cells J75:AV282, or 2) Automatically populate the user input in these cells based on the difference between the base case ITC assumption and the user input.

For users that want to independently set the RPS prices, an additional table would need to be added below cells J75:AV282, which would over-ride the current input cells, which would then override the RPS base assumptions.

Rationale: As currently designed, the user can change ITC assumptions to calculate the various benefit-cost tests, but changing the ITC assumption does not affect the RPS price in the Revenue Requirements spreadsheet. As a result, the avoided cost of RPS does not change when the ITC assumption changes. PG&E is not aware of any indication that an extension or other change to the ITC/PTC would apply to behind-the-meter (BTM) resources only. They should also be reflected in the RPS price assumption.

ADOPTION

Issue 2*: *The hardcoded PG&E DG adoption prediction for 2015 is flat relative to 2014. The model infers a decrease in DG adoption in PG&E's service area, from 333 MW of DG in 2014, to 330 MW in 2015. However, through March 31, 2015, there have been 113 MW of DG interconnected in PG&E's territory, compared to just 73 MW for the same period in 2014, a 55% increase.

Location**:** Results tab (impacts all results)

Proposed solution**:** It is unclear whether the adoption module is calibrated based on inferred 2015/2016 adoption. If this is the case, then E3 should revisit the adoption algorithm to ensure model is calibrated appropriately.

Issue 3: **Predicted PG&E DG adoption falls from 2016 to 2017, even if the 30% ITC is assumed to be extended and no changes are made to rate design or NEM.** This result indicates that the adoption algorithm informing the hardcoded adoption figures for 2015 and 2016 is different from the one that is used within the model.

Location: Results tab (impacts all results)

Proposed solution: Revisit adoption algorithm and hardcoded forecasts to ensure continuity.

Rationale**:** If the model is already dramatically under predicting adoption this year, the forecast will be likely also be dramatically under predicting adoption in future years, resulting in inaccurate expectations of the impacts of different NEM successor tariff designs.

<u>Issue 4</u>: The model currently assumes all residential customers are equally likely to be capable to installing rooftop solar. The model appears to assume that a low usage apartment dweller in San Francisco has the same likelihood of being technically capable of installing solar (35%) as a high usage single family home dweller in Bakersfield. This is factually wrong, and will result in overstated adoption among low usage customers and understated adoption among high usage customers.

<u>Location</u>**:** Multiple locations; details in proposed solution below.

<u>Proposed solution</u>**:** Define the technical potential commensurate with actual customer capability to adopt the technologies using the relationship between energy usage and likelihood of being in a single family home, as described by PG&E below.

1) Add the table and data below to "Advanced DER Inputs"!U52:Y63. Column Y is a formula.

	U	V	W	X	Y
52	Residential Technical Potential Allocation				
53	Usage Decile	Minimum Usage	Maximum Usage	% Single Family	Technical Potential
54	1	-99999	2233	38%	22%
55	2	2235	3246	33%	19%
56	3	3246	4044	40%	22%
57	4	4046	4815	53%	30%
58	5	4815	5712	54%	30%
59	6	5712	6646	65%	36%
60	7	6647	7765	77%	43%
61	8	7766	9194	84%	47%
62	9	9195	11999	85%	48%
63	10	12005	99999	94%	53%

[3]

3 Source: E3 Draft Tool.

2) Starting in cell Y54, insert the following formula to allocate the 35% technical potential to each usage decile, according to single family home propensity:

=10*$E$54*X54/SUM($X$54:$X$63)

3) On the Adoption Module tab, extend the DER Controls table to row 22, and add the "Residential Usage Decile" field.

SOLAR COST AND PRICES

Issue 5: Insurance cost is redundant and has a disproportionate impact on the PPA price (e.g., removing a 1% cost of insurance reduces the PPA price by 13%).

Location: "DER Pro Forma" tab; cell E6.

Proposed solution: Drop insurance costs to 0% and disable users' ability to modify this cell. It is already embedded in the pricing data cited in the Draft Tool.

Rationale: Not only does the insurance expense in the DER Pro Forma represent double-counting, but it also has a disproportionate effect on the model's outputs, which appears to be an error. When a solar system is leased today, installation companies provide their own insurance for the asset, which is part of these companies' operating expenses that are included in pricing.[4] Since the Draft Tool uses reported market prices as inputs, and prices include all financing, insurance and other vendor costs, then it is redundant to add insurance costs to the price.

Issue 6: The Draft Tool's default user options result in DER pricing that is unsubstantiated and not representative of the market. According to an E3 response to questions, the Draft Tool's pro forma analysis adds an "appropriate return on invested capital [that] is a necessary

4 NREL. (2014). "Continuing Developments in PV Risk Management: Strategies, Solutions, and Implications." NREL/TP-6A20-57143. http://www.nrel.gov/docs/fy13osti/57143.pdf.

part of DER costs."[5] Yet, the pro forma model uses DER market prices as its base input, not DER costs, resulting in PPA/lease output prices that include two logical inconsistencies: (1) it represents duplicative financing costs that are already included in the referenced reported prices; and (2) the value of the (duplicative) financing costs in the pro forma are overestimated since they are calculated from a price basis, rather than a cost basis. Put another way, the Draft Tool *increases* the referenced data on DER market prices by adding an erroneous and duplicative financing cost.

Location: "DER Pro Forma" and "DER Advanced" tabs.

Proposed solution: Two solutions are possible: (1) zero-out and disable user manipulation of the financing cost inputs in the model; or (2) maintain this financing cost estimator, but only after the referenced market pricing data from LBNL is replaced with market cost data, less financing costs, from NREL. The second option is unnecessarily complex, however, because users would also need to calculate (or otherwise insert) a margin on top of all-in costs and several changes would have to be made to the Draft Tool. Therefore, we recommend the first proposed solution: to zero-out and disable user manipulation of the financing cost inputs in the model.

Rationale: California has some of the highest priced DG solar systems in the country, and this high pricing is driven in large part by local retail electricity rates and policy (as opposed to firms' costs).[6] Yet the Draft Tool inflates these costs further by adding financing and other costs that are already embedded in the price. The Draft Tool uses these "value based" market prices and then adds additional costs. The end result is not reflective of actual market pricing, and the methodology (adding costs to transaction

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5 Responses from E3 received by PG&E from Ehren Seybert by Susan Buller at 3:42 PM on April 16, 2015.

6 GTM/SEIA. (2015). "U.S. Solar Market Insight Report - 2014 Year-in-Review."

prices) is flawed. The Draft Tool's outputs represent artificially inflated lease/PPA prices that are not aligned with current market dynamics and literature on this topic, and this leads to a dramatic under-forecast of DG adoption by customers.

D. Question 4:

Please identify any assumptions on advanced user inputs tabs (e.g., Advanced Rate Inputs, Advanced DER Inputs, RR Inputs) that should be added to the "Key Driver Inputs" tab. Please provide a detailed description of each input that should be added, as well as supporting analysis demonstrating that the proposed input would have a significant impact on the outputs of the Public Tool.

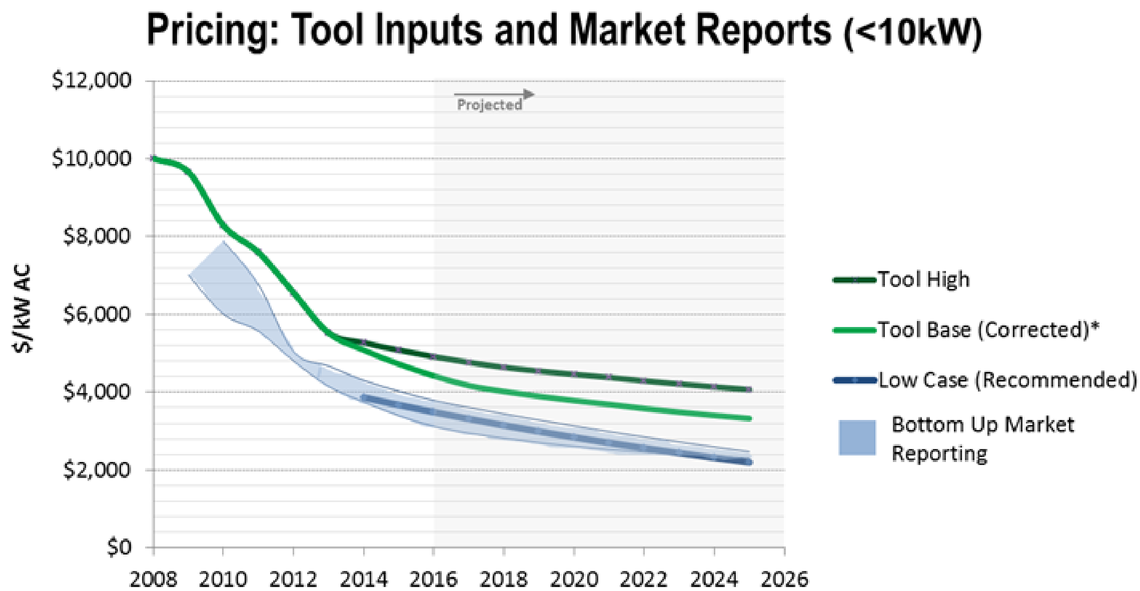
Response to Question 4:

SOLAR COST AND PRICES

Issue 1: The Draft Tool does not allow a user to select a "Low" price scenario.

Location: None. See "Advanced DER Inputs" tab.

Solution: The drop-down menu in cell C26 of the "Key Driver Inputs" tab should offer users more than just "Base" and "High" price scenarios. It should include a "Low" price scenario. Moreover, the current Base scenario itself appears to represent the higher end of the pricing spectrum in California based on bottom up cost and pricing research. PG&E recommends E3 adopt the "Low" price scenario shown below (dark blue line), which could fairly be described as the "Base" scenario, since it is the mid-range of bottom-up market pricing research.



* Tool Base and Tool High cases were converted from DC to AC.[7]

If the Draft Tool is run using this suggested price scenario (described as "Low Case" in the figure above) and the duplicative financing expenses are removed from the pro forma model (as explained in Issue 5 of Question 6), the Draft Tool's results appear much more rational, although other errors in the model obscure the full impact of this change.

7 Sources:

Bottom up market reporting (blue) are from 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

E3 Draft Public Tool. 2015. http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

LBNL, September 2014. "Tracking the Sun VII." http://emp.lbl.gov/sites/all/files/lbnl-6808e_0.pdf

Rationale: The Draft Tool offers users an incomplete and unbalanced perspective on DER pricing, which is skewed high. Since DG solar costs have declined rapidly and historical adoption forecasts have consistently underestimated actual deployments, it is important to include a more balanced approach to the model's inputs. Substantial evidence suggests that the Draft Tool's "Base" solar price input values are high, and by excluding any default options that are more aligned with actual market pricing or a "Low" price case, the model significantly underestimate adoption.

E. Question 5:

Please identify any changes or clarifications that should be made to the categorization of Societal Inputs on the "Key Driver Inputs" tab. For example, should a separate category be created for user-defined locational values that are anticipated to be produced in the Distribution Resources Plans addressed in Rulemaking 14-08-013? Please provide a detailed description of each input that should be added, as well as the specific reasons for each proposed change.

PG&E has no response to Question 5 at this time.

F. Question 6:

Please identify any erroneous or outdated data inputs used in the draft version of the Public Tool. For each such input, please provide a substitute value and a detailed rationale for the proposed change. Provide publicly available supporting material for the proposed change. If no publicly available material supporting the proposed change is provided, please identify any non-public information or material that has been used and explain why the relevant information is not publicly available.

Response to Question 6:

Issue 1: **RPS prices used to calculate the RPS avoided costs are too high**.

Solution: Reduce RPS solar PV prices by 25% and RPS wind prices by 5%, and re-balance the default RPS portfolio technology mix to reflect updated prices.

Rationale: It is unreasonable to use prices which are known to overvalue RPS resources by as much as 25%, as acknowledged by E3. The Draft Public Tool uses the same RPS price forecasts found in version 6.0 of the RPS calculator, and in a February 10 workshop on the RPS Calculator, E3 indicated that in future versions of the calculator those costs would be reduced by 25% for RPS solar PV and 5% for RPS wind (See slides 7 and 13 at the following URL: http://www.cpuc.ca.gov/NR/rdonlyres/5C8CA303-3E78-4B54-ABCF-1A65B4C0612C/0/RPSCalcWkshp_0202ResourceCostandPotential.pptx). Given that the need for a specific update has already been identified by E3, there is no reason to continue using forecasts which are demonstrably and significantly wrong.

Issue 2: **Since the simplified stack energy price model uses monthly average profiles for load, wind and solar, it does not produce an accurate curtailment forecast.** This significantly overstates the avoided RPS cost and understates the cost-shift associated with solar PV.

Solution: Calibrate the "minimum gas + qualifying baseload" input such that curtailment is observed in March, April and May under a 40% RPS. PG&E recommends using 19% for this input while setting qualifying baseload to zero for both nuclear and cogeneration.

Rationale: The CAISO provides PLEXOS results from its 2014 LTPP modeling efforts under various scenarios, including a 40% RPS in 2024 Scenario. Curtailment is observed in 2,825 hours of the year – approximately 32% of all hours. Daytime curtailment is observed in all months, but especially in March (24 of 31 days), April (29 of 30 days), May (28 of 31 days) and June (21 of 30 days). **To the contrary, under a 40% RPS, the draft public tool produces no curtailment in any hour.** In its own investigation of higher RPS levels, E3 found curtailment in 9% of all hours under a 40% RPS, largely due to the addition of solar generating resources.[8]

Issue 3: **The simplified stack model produces energy prices which are too flat and too high in the middle of the day.** This significantly overstates the avoided energy cost by up to 400% in 2020 and understates the cost-shift associated with solar PV.

Solution: Calibrate the simplified stack of marginal heat rates for 2015-2020 such that monthly average hourly prices created in Calculator for recent months reflects the shape of actual monthly average prices from the CAISO day ahead market. Beyond 2020, PG&E recommends calibrating the simplified stack of marginal heat rates such that the monthly average hourly prices created in the Calculator reflect the shape of monthly average hourly prices observed in the 2014 LTPP PLEXOS 33% RPS and 40% RPS models, which are publicly available from the CAISO.

Rationale: The comparison below between the Calculator price forecast for March 2015 and actual CAISO Day Ahead Market prices from March 2015 demonstrate that the simplified stack model produces prices which do not resemble the CAISO's "duck curve" and are significantly too high during the day. PG&E and other market participants anticipate that daytime prices will continue to fall as the amount of solar currently installed is more than doubled over the next 5 years, yet the simplified stack model continues to produce flat prices across much of the day in 2020. This flat price curve drastically over-values solar energy which results in an under-estimate of the cost-shift in the RIM test.

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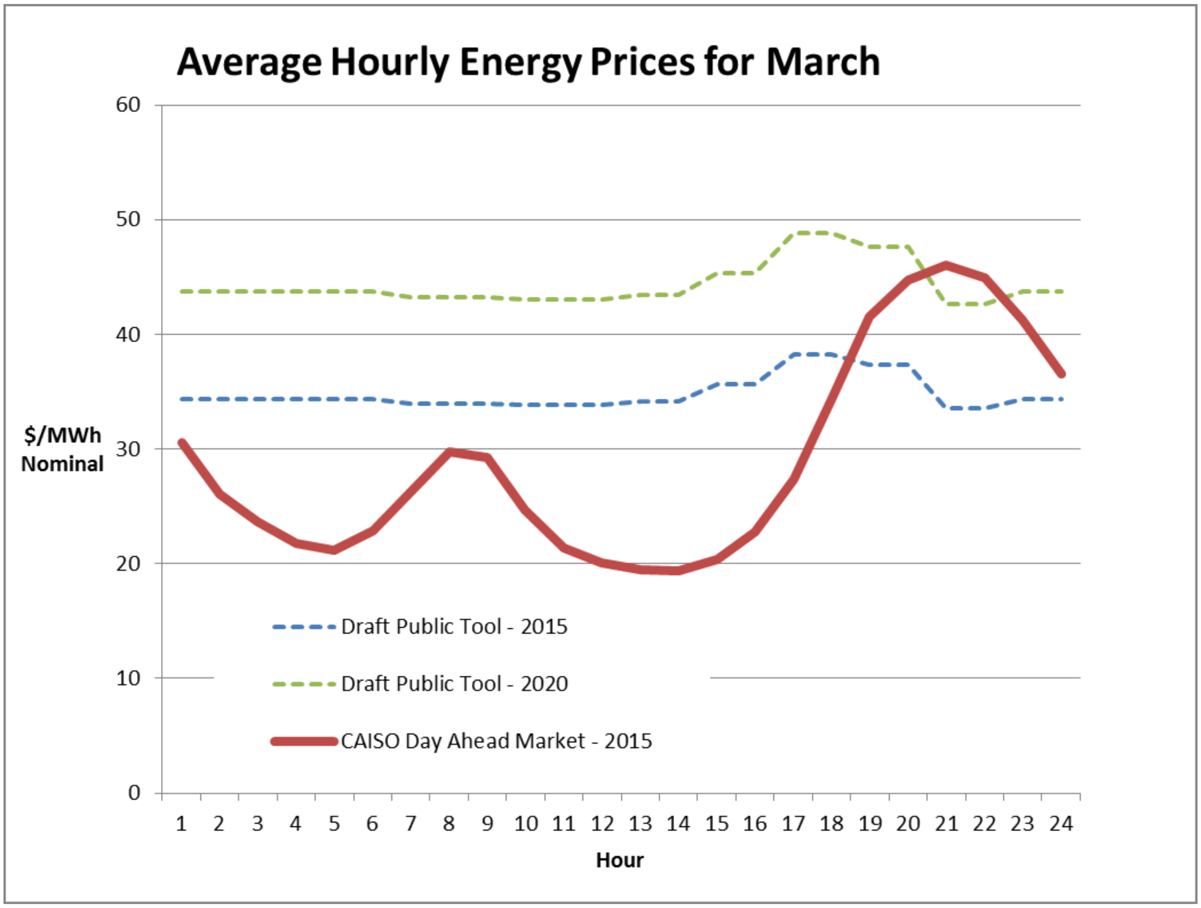
8 See Table 18 of CAISO Testimony in R.13-12-010 located here: https://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf.



Issue 4: **The avoided T&D cost assigned to solar PV is erroneously high and should be reduced.**

<u>Solution</u>: Replace PG&E T&D avoided cost with values from rigorous system-wide modeling performed by Navigant Consulting, Inc. (Navigant). The draft executive summary of this report is attached as Appendix A.

<u>Rationale</u>: 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 incremental, 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.

Prior to submission of PG&E's Distribution Resources Plan (DRP) and resulting General Rate Case and FERC T&D capacity addition cost forecasts, the attached Executive Summary by Navigant provides an 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, incremental net costs (2014, $Million) over the 10-year study horizon for the low, mid and high retail PV forecast. For the low and high retail PV forecast scenarios, the incremental, net costs for distribution system upgrades in 2024 are estimated to be $14/MWh and $23/MWh, respectively.

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

Figure 1. Total Cost of Incremental Distributed PV 2015-2024 [Pre-2014 capacity is not included]

The study methodology is based on the California Energy Commission's (CEC) Analytical Framework, but with additional detail and analytical rigor as outlined in the draft Executive Summary. 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.

ADOPTION

***Issue 5*: The PG&E historic PV adoption in the Model appears to be wrong.**

	Pre-2009	2009	2010	2011	2012	2013	2014
PG&E Model Adoption (MW)	221	69	102	152	171	221	334
Actual Adoption from PG&E EGI (MW)	246	75	109	161	180	260	331
% Difference	-10%	-8%	-7%	-6%	-5%	-15%	1%

Solution: Implement correct adoption number (or explain the discrepancy).

Rationale: The model is currently understating historic adoption due to the lower seed values and is incorrectly calibrated for forecasting of future adoption.

SOLAR COST AND PRICES

Issue 6: The Draft Tool's "Base" solar pricing inputs represent the high end of the current pricing spectrum in California and are reflective of only a single study that uses a flawed top-down analysis method. The top down analysis method has been demonstrated to be less accurate than widely accepted bottom-up methods. This issue is distinct from the proposal to add a low-price scenario (Issue 1, Question 4) in that it addresses the basis for all scenarios modeled in the Draft Tool.

Location: "Advanced DER Inputs" tab. Table Rows 32-49; Columns E-F.

Solution: Include at least one reference from a report that uses a bottom-up methodology in developing the price scenarios.

Rationale: Over the past few years, an increasing body of peer-reviewed literature and other reporting has documented that prices reported to incentive programs are often inflated and that the data offer an inaccurate perspective on actual market pricing.[9] The Draft Tool currently references a single study that uses a top-down method to estimate solar market pricing – i.e., LBNL's study is based on pricing reported to state incentive programs. *Given that the U.S. Department of Energy has funded NREL since 2011 specifically to provide a more accurate perspective on pricing through bottom-up analyses, and market reporting agencies such as GTM/SEIA, BNEF, and IHS have adopted this methodological approach, we recommend that the Draft Tool base its pricing information off a study that utilizes a bottom-up analysis method*.

Several reputable organizations have provided a strong rationale for why bottom up analysis methods are a more reliable indicator of actual costs and market prices. When GTM/SEIA transitioned to a bottom-up approach in 2013, they wrote the following: *"In an effort to ensure that the data reported is timely and accurate for industry assessments, we will be switching to a bottoms-up methodology based on tracked wholesale pricing of major solar components and data collected from major installers."*[10] The following year, GTM/SEIA emphasized the same point: "*As stated, these [top-down analysis] figures are subject to a number of factors that render the analysis insufficient for determining the actual industry costs during the quarter*

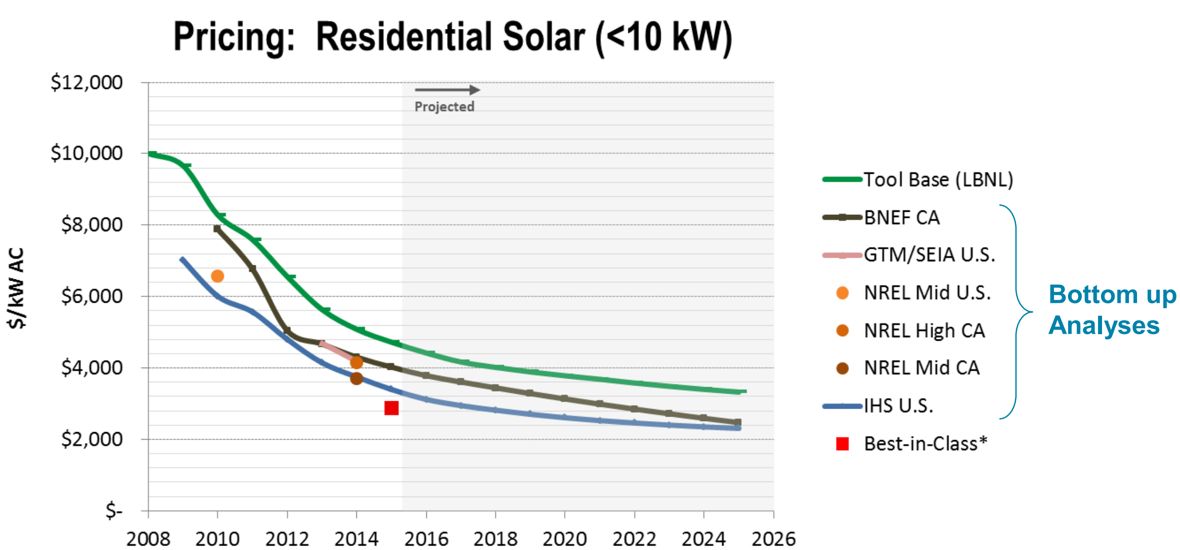
9 See *Environmental Research Letters.* (2015). "Exploring the market for third-party-owned residential photovoltaic systems: insights from lease and power-purchase agreement contract structures and costs in California." **10** 024006 doi: 10.1088/1748-9326-10-2-024006. http://iopscience.iop.org/1748-9326/10/2/024006; *Energy Policy.* (2013). "Evaluating the impact of third-party price reporting and other drivers on residential photovoltaic price estimates." Volume 62, November 2013, Pages 752-761. http://www.sciencedirect.com/science/article/pii/S0301421513007702; Photon. (2011). "Price wars – three solar CEOs allege that solar lease and PPA companies are abusing federal incentives." Page 38-45.

10 Page 64, GTM/SEIA. (2014). "U.S. Solar Market Insight Report – 2013 Year-in-Review."

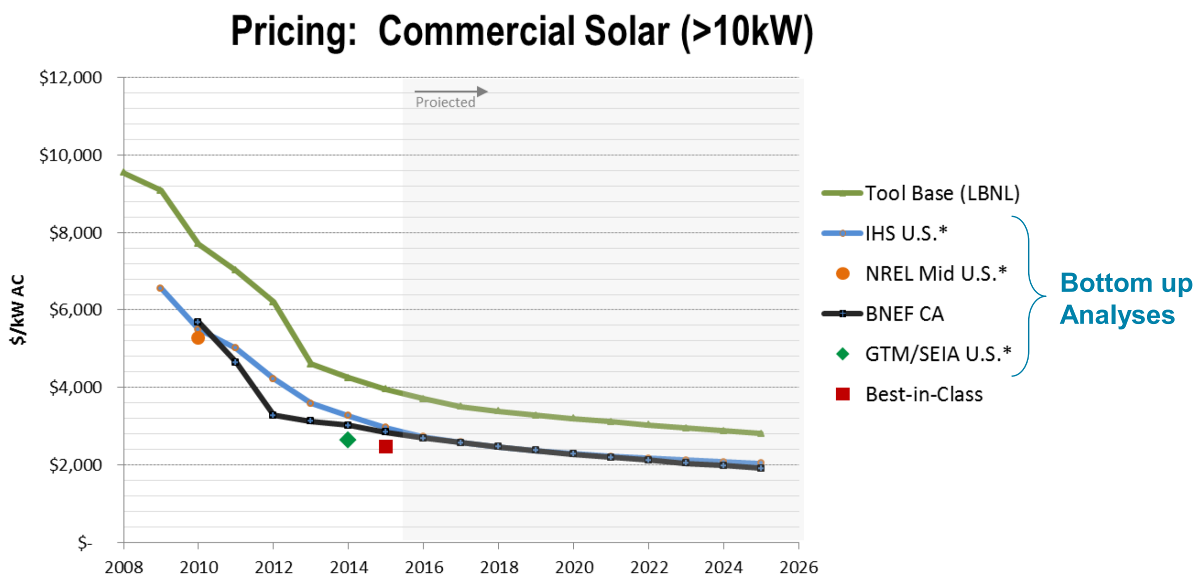
reported."[11] NREL and LBNL also publish a joint report in attempt to explain the gaps in pricing between top-down and bottom-up studies.

In short, top-down studies can still be useful for determining high-level market insights such as trends (e.g., solar prices continue to decrease), but these types of studies do not offer the most reliable information of market pricing for any specific period. As such, we strongly recommend basing the Tool's pricing inputs on a study that uses a bottom up methodology. At a minimum, the Tool should reference more than one publically available report.

There is consensus as to both methodology and findings in various studies about the use of this bottom-up methodology, as illustrated by the charts below:



11 Page 56-57. GTM/SEIA. (2015). "U.S. Solar Market Insight Report – 2014 Year-in-Review."



* Sources[12]

G. Question 7:

Please identify any other changes or modifications to the draft version of the Public Tool that are necessary (not merely desirable) to improve the functionality of the Public Tool for its intended use in this proceeding. Provide a detailed description and specific reasons for each proposed change. Provide publicly available supporting material for the proposed change. If no publicly available material supporting the proposed change is provided, please identify any nonpublic information or material that has been used and explain why the relevant information is not publicly available.

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12 Jigar Shah, co-founder and President of Generate Capital on pricing: GTM – *The Energy Gang.* "Debating the Solar Federal Tax Credit." March 26, 2015. Converted from DC to AC in figure. http://www.greentechmedia.com/articles/read/debating-the-solar-federal-tax-credit-will-expiration-kill-jobs-or-make-ins Bloomberg New Energy Finance (BNEF), January 2015. Solar Insight Service. "Data for 1H 2015 North American PV Outlook." GTM/SEIA, March 2015. "U.S. Solar Market Insight: 2014 Year-in-Review." NREL, 2014: "U.S. Photovoltaic System Prices, Q4 2013 Benchmarks." http://www.nrel.gov/docs/fy15osti/62671.pdf NREL, 2012. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States." http://www.nrel.gov/docs/fy12osti/53347.pdf

IHS Energy, October 2014. "Outlook for US Solar PV Capital Costs and Prices."

Response to Question 7:

<u>**ADOPTION**</u>

***<u>Issue 1</u>*: The adoption algorithm is based on a payback curve, which is based on outdated research and unrealistically limits adoption.**

<u>Description</u>: The current version of the model uses a payback curve to determine the market potential of each DG technology. While the underlying economic calculation is a benefit-cost ratio, this is translated into a payback time, which is then translated into a market potential using the functional form $e^{m*payback}$.

This methodology dates back to a paper regarding electric heat pumps (Kastovich 1982), which identified that many electric utility customers require very rapid payback times for investments that reduce utility bills. The implication of the study is that many customers use high internal discount rates for deciding whether to invest in energy saving investments, when faced with an upfront capital investment that is recovered over time via energy savings. Implicitly, if zero-down financing options (e.g., PPA/leases and some newer forms of loans) permit customers to avoid or reduce upfront costs and save money from day one, then the attractiveness of an energy saving technology would be much less sensitive to internal discount rates. This would result in increased market potentials at a given level of cost- effectiveness relative to the payback approach. In fact, this is exactly the phenomenon that has unleashed the recent, explosive growth in the PV market in California.

A recent study of nearly 2,000 California electricity customers has clearly shown that payback is no longer the dominant metric driving customers' decision making around DG. [13] Since 2012, over two-thirds of residential PV adoption has been through third

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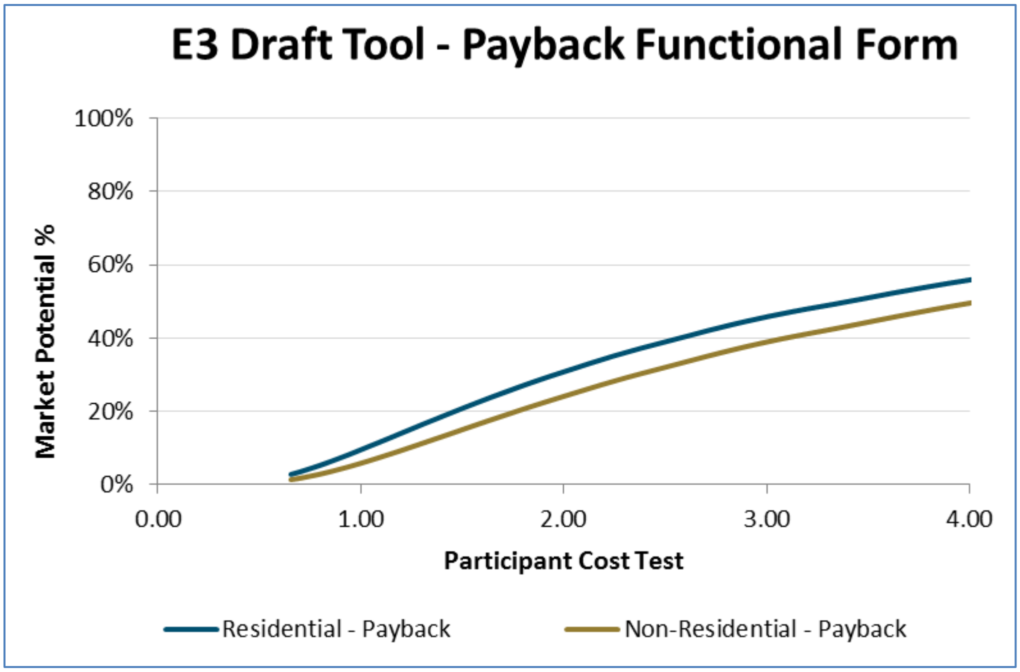
13 <u>Sources</u>: Sigrin B., Drury E., Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics, Energy Market Prediction: Papers from 2014 AAAI Fall Symposium.

party owned (TPO) arrangements. Of the remaining host owned market share, it is probable that some significant portion is financed. The result of broad access to financing for rooftop solar is that most adopters no longer use payback for their decision making (Sigrin 2014), and predominantly use monthly bill savings instead. As such, the functional form implied by payback curve research is obsolete and likely to result in a severe under-adoption of forecast at a given level of cost-effectiveness.

Solution: Implement a more representative "logit" based functional form to model customer decision making, per the instructions in Appendix B below. PG&E has implemented this solution in the draft Public Tool and found it to be a non-burdensome exercise.

Rationale: The existing functional form implies that the solar DG market will significantly shrink after the NEM cap is reached, even without any changes to NEM or residential rates. This result is driven by the existing functional form being inherently restrictive on adoption in the expected spectrum of solar benefit-cost ratios (BCR). Moreover, the functional form is unrealistically linear relative to the underlying variable, as seen in the graph below. Logically, moving from a world where solar does not have a positive NPV to one where it does should have a dramatic impact on market potential. However, this functional form essentially assigns no significance to this cost effectiveness threshold. The recommended approach allows for changing both the market potential at this threshold and the overall slope, which should allow the model to much more accurately capture the dynamics of DG economics and market potential.



SOLAR COST AND PRICES

Issue 2: Pricing declines used in the model are too conservative.

Location: "Advanced DER Inputs" tab.

Solution: Increase year-over-year projected rates of price declines to represent the ability to reduce costs not only via learning but also via competition (i.e., margin compression).

Rationale: Solar cost reductions over the past ten years have been striking, and the majority of analysts did not forecast such low costs for DG technologies in 2015. As a result, historical market forecasts have significantly underestimated price declines and levels of solar adoption. Even Greenpeace's "energy revolution" forecast in 2010 – based on assumptions of drastic structural, policy, and business changes – has proved conservative. IEA, a European-based agency, published European projections in 2000, 2006, and 2010, and all significantly under-forecasted adoption, as shown below.

The Draft Tool cites IEA's projected price declines, however, it may substantially underestimate the ability to reduce prices in California. IEA's solar adoption forecasts (below) are based largely on projected rates of solar price declines in Europe, and these projections are unlikely to apply to California's markets – where solar pricing is value-based and largely detached from costs. The second chart, below from an LBNL–NREL joint report last year, highlights how the current NEM tariff structure and relatively high volumetric rates have combined to enable relatively high, value-based pricing for solar in the United States when compared to Germany, while base costs are not widely different. In European markets, price declines are more likely to be incremental, but policy changes in the United States (and other factors such as increased competition) could change pricing more dramatically.

The ability for solar vendors to reduce margins in response to competition and/or lower compensation rates (i.e., lower utility retail rates) is clearly illustrated in the table below which compares prices PPA prices across states. The table illustrates that solar PPAs can be offered for as little as \$0.08/kWh in Arizona and other states where retail electricity rates are lower than in California. The Public Tool could be modeled to allow for similar pricing by allowing users to accelerate the price declines to reflect competition and margin compression. Unless there is a clear distinction in the cost basis between vendor operations in California and Arizona (of which PG&E is unaware), there is no policy basis for maintaining high prices and high vendor margins in California for the same commodity that is sold in Arizona at a much lower price. However, the model as currently designed, embeds this "value-based" pricing and the associated margin in the technology price and price reduction rates, which would yield a policy that perpetuates this overpayment and extraction of wealth from California rate payers.

Table 1. Comparison of Reported Residential PPA rates ($/kWh) in 2014

State	Quoted Residential PPA Rate[14]	Marginal, Highest Tier Electricity Rate	Average Retail Electricity Rate[15]
Arizona	$0.08	$0.17[16]	$0.12
California/PG&E	$0.15	$0.34[17]	$0.19[18]
Hawaii	$0.19	$0.41[19]	$0.36
Massachusetts	$0.10	$0.23[20]	$0.16
New Jersey	$0.12	$0.20[21]	$0.15
New York	$0.15	$0.20[22]	$0.19

In this context, the Draft Tool's incremental price reductions are too conservative. The model erroneously assumes price declines at rates that reflect incremental levels of cost declines stemming from industry learning and technology advancements. However, price declines should also account for the ability of the industry to compress margins in

14 Residential PPA rates quoted by leading TPO providers (with escalator tied to inflation, at 2.9% per year).

15 EIA Average Retail Electricity Rates, October 2014.

16 Arizona Public Service, Rate E-12. https://www.aps.com/library/rates/e-12.pdf

17 Pacific Gas & Electric Company, Rate E-1, Zone X. http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-1.pdf

18 PG&E October – December, 2014 Residential Retail Rates - http://www.pge.com/tariffs/electric.shtml

19 Hawaiian Electric Company, Rate R. Includes Energy Cost Adjustment charge of $0.055210/kWh. http://www.heco.com/vcmcontent/StaticFiles/FileScan/PDF/EnergyServices/Tarrifs/HECO/EFFRATESOCT2013.pdf

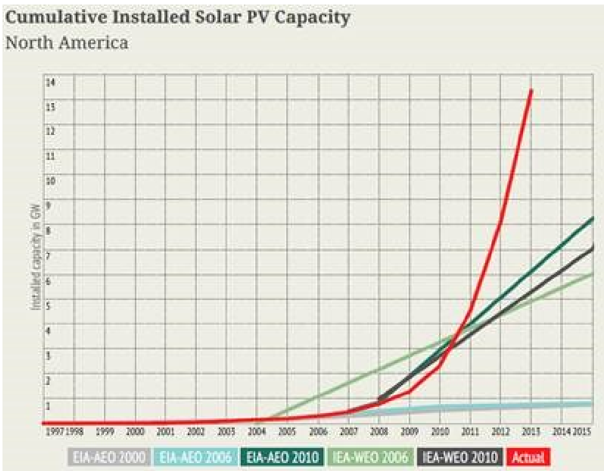
20 Eversource Energy, Rate R-1. https://www.eversource.com/Content/docs/default-source/rates-tariffs/190.pdf?sfvrsn=6

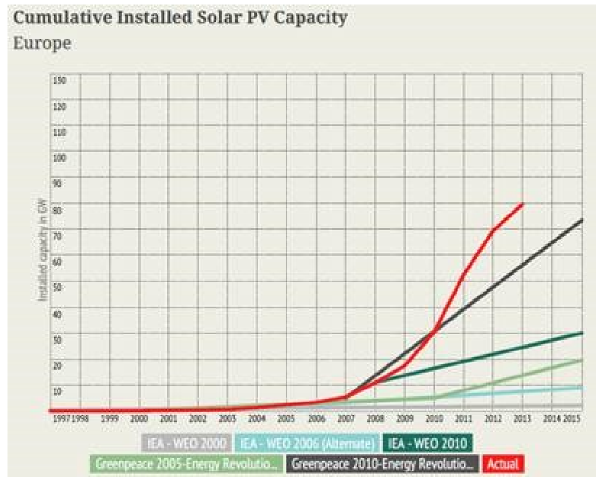
21 Public Service Gas & Electric, Rate RS. https://www.pseg.com/info/environment/ev/rlm-rs_rates.jsp

22 Consolidated Edison, Rate EL-1 and SC-1, Rate I. https://apps1.coned.com/csol/msc_cc.asp, http://www.coned.com/documents/elecPSC10/SCs.pdf

response to competition and policy changes which takes no "learning" and can be done immediately.

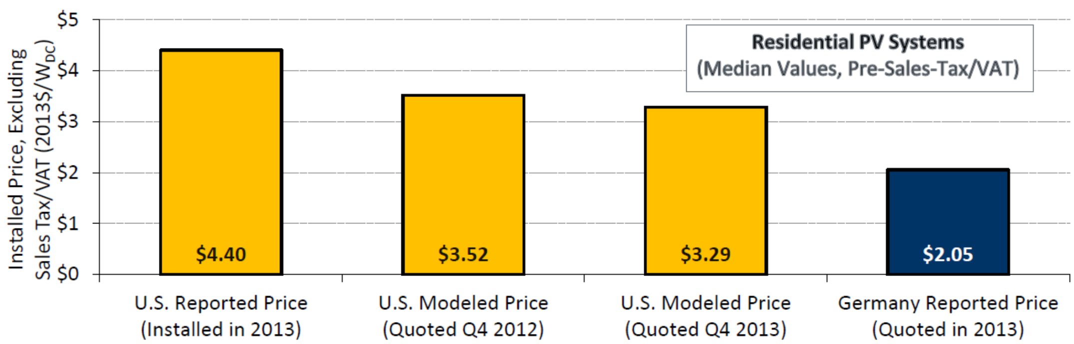
North America **Europe**





Source: Meister Consultants Group. (2015). http://infogr.am/the_renewable_energy_revolution; studies compared in the above figures are from EIA, IEA, and Greenpeace.

Installed Prices for Residential PV: United States vs. Germany



Note: The German data are based on price quotes for roughly 2,300 individual PV systems obtained by EuPD through its quarterly survey of German installers and provided to LBNL.

- Installed prices in the United States are high compared to many other major international PV markets; the disparity is particularly stark in comparison to Germany
- Hardware costs are fairly similar across countries; thus the gap in total installed prices must reflect differences in soft costs (including installer margins)
- Suggestive of a potential for near-term installed price reductions in the United States.

SunShot U.S. Department of Energy 24
energy.gov/sunshot

Source: NREL-LBNL. 2014. Page24. http://www.nrel.gov/docs/fy14osti/62558.pdf.

Issue 3: **The Draft Tool underestimates the value of Federal incentives by using the "market" appraisal method, which is approved by the IRS, but rarely used by industry.** This underestimates the ITC benefit and artificially inflates the price of DG technologies in the model, which in turn, puts downward pressure on adoption.

Location: "DER Pro Forma"

Solution: Use the "income" appraisal method.

Rationale: The IRS approved three methods to assess the "fair market value" of solar that can be applied towards available Federal incentives. These appraisal methods are described as the Income approach, the Cost approach, and the Market approach. Industry most often uses the Income approach because it results in the highest levels of incentives. These methods and key input variables to consider are available on pages 18-19, as well as in the appendices, of an NREL report available at: http://www.nrel.gov/docs/fy15osti/62671.pdf.

The U.S. Department of the Treasury has also provided guidelines on valuing Federal tax credits. Information can be found at the following URLs:

- http://www.treasury.gov/initiatives/recovery/Documents/N%20Evaluating_Cost_Basis_for_Solar_PV_Properties%20final.pdf
- http://www.treasury.gov/initiatives/recovery/Pages/1603.aspx

Issue 4: **The Draft Tool provides policy-makers with a very limited perspective on DG solar pricing (one source) making it challenging to assess sustainability of this rapidly growing market from the customer (pricing) perspective.**

Location: "Advanced DER Inputs" tab.

Solution: Include in the model a price option based on bottom up cost estimation plus a user defined margin. NREL's bottom up analysis of system prices less margin would serve as a basis for 2014 costs and this would be supplemented this with public reporting on costs from industry leaders and analysts. To establish a cost forecast for 2015-2024, E3 would then apply a reasonable annual estimated cost decline to develop a cost curve. To establish "price" E3 would simply add a user defined input for "margin". Adding two columns of estimated solar costs (one each for systems >10kW and <10kW) to the table in the "Advanced DER Inputs" tab.

Rationale: The Draft Tool offers an incomplete perspective to policy-makers about the sustainability of the solar industry because it only provides pricing inputs and is silent on system costs. Many valuable insights could be gained by adding a cost curve generated from publically available resources. This minor and easy-to-insert addition to the model would help advance the Tool so that it can be used to address the letter and intent of the legislation.

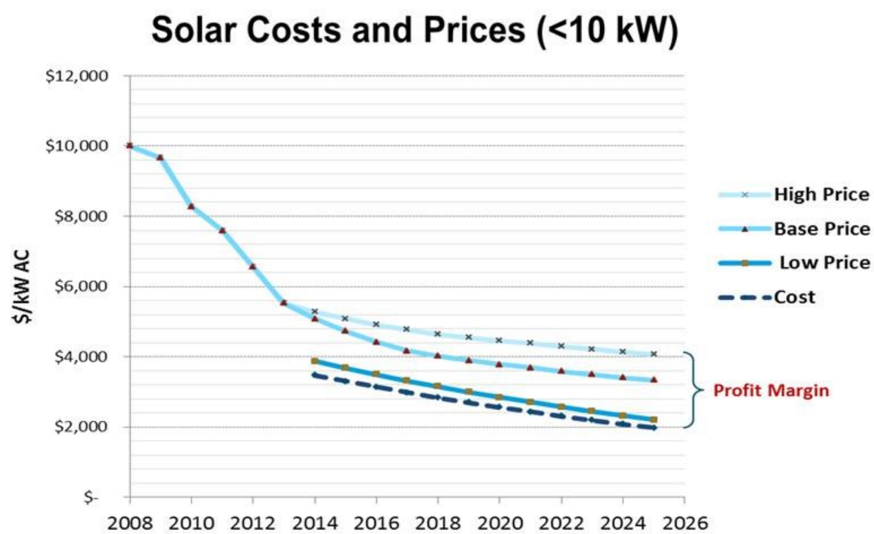
Issue 5: **The Draft Tool offers no insights into whether policy incentives are "right-sized" to stimulate the supply-side of the market.** The tool is incapable of estimating vendor or supply-side profit margins because no cost curve is presented. Including a cost curve against which to measure the margin implied by a given price would allow users to test whether pricing scenarios may be irrational (i.e., price is below costs) or may over-stimulate the market (i.e., price creates significant vendor surplus).

Location: DER Advanced Inputs tab.

Solution: Add both a solar cost trajectory (as described in a previous comment), and insert a basic chart that offers users a visualization of estimated margins for given pricing scenarios (e.g., Base or High) that are already in the model. For example, if a user chooses the Base scenario, they could go to the Advanced Inputs tab and see the estimated margin in a simple figure that is generated by the difference between the costs and prices (for a given scenario) in the table.

Rationale: Offering some perspective on costs and margins is essential. First, it will bound users' low-end pricing estimates and eliminates irrational (or at least unlikely) pricing scenarios. Second, it will offer insights into whether DG vendors have sustainable market opportunities. Lastly, this simple addition would not change the core function of the model, yet it would provide a number of stakeholders with important insights for a range of policy and pricing scenarios.

The illustrative chart below reflects changes that could be made to the Tool. The Tool would not have to illustrate these curves – it currently just lists pricing in a table – but a supplemental chart that shows estimated margins (difference between cost and price) for different scenario would provide significant value to many stakeholders.



***Issue 6*: The Draft Tool does not allow for modeling of a "transition path" from the current NEM tariff to the successor tariff.** This inevitably and artificially creates a convergence of factors in 2017 that appear to impact the economics of DG, including residential rate reform, NEM reform and ITC reductions. In turn, this is likely to inaccurately portray market impacts in

2017 as overly negative, given that the current Draft Tool predicts a decline of adoption of over 70% in 2017 for PG&E's service territory due to the ITC reduction alone.

Location: "Advanced Rate Inputs"

Solution: Include functionality to ramp in the new successor tariff or incentives over a user-specified period of time.

Rationale: Entities may desire to demonstrate the impact of gradually introducing reforms to mitigate any "market shocks" from the convergence of multiple market and policy initiatives in 2017.

***Issue 7*: The Draft Tool does not clearly illustrate the market/technical potential and where "on the S-curve" the current and predicted levels of adoption place the market.**

Location: "Results."

Solution: Include chart indicating market and technical potential and show trajectory over time as a result of forecasted adoption.

Rationale: The adoption rate implied by the model output is often counter-intuitive (e.g., showing a market slowdown despite improving economics), and is driven in large part by the market/technical potential. In order to better inform the user about the underlying driver of adoption rates a transparent display of the market/technical potential and the associated "s-curve" should be provided.

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III. CONCLUSION

PG&E appreciates this opportunity to address these issues as the Commission moves forward with this important work.

Respectfully submitted,

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