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ALJ	:	Anne Simon
Witness	:	Tim Drew

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Opening Testimony of the Office of Ratepayer Advocates On The Basis For Net Energy Metering Successor Tariff Capacity Fees

San Francisco, California
September 21, 2014

154483666

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1. INTRODUCTION AND SUMMARY OF THE BASIS FOR ORA'S PROPOSED CAPACITY FEES

This exhibit sets forth the testimony of the Office of Ratepayer Advocates (ORA) to support the basis for ORA's proposed Installed Capacity Fee (ICF) for the successor to the existing Net Energy Metering (NEM) tariff. ORA submitted a Proposal for a Successor Tariff on August 3, 2015 (ORA Proposal).[1] Pursuant to the *Administrative Law Judge's Ruling Setting Evidentiary Hearings and Setting Schedule for Further Activities Prior to Evidentiary Hearings*, dated September 1, 2015, this testimony is limited to describing the policy basis for the ICF and ORA's analysis of the forecasted effects of the ICF.

By design, the ICF would be introduced gradually, with a three step glide-path. The amount of the fee is based on the installed capacity of the Distributed Generation System, and the fee will increase as milestones for installed capacity within a utility service are met. ORA proposes the following approach:

- $2/kW/Month, when qualifying NEM installed capacity in a utility territory surpasses 5%,
- $5/kW/Month, at 6%, and
- $10/kW/ at 7%.

The three-step approach is shown in Figure 1.

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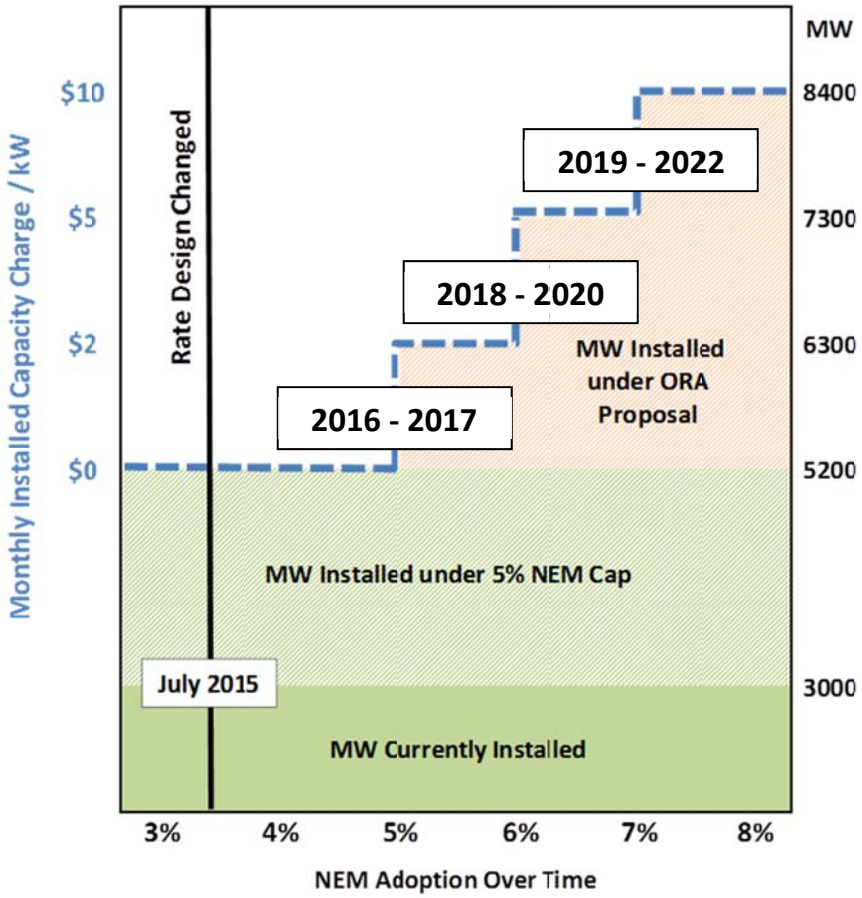
[1] See ORA Proposal, dated August 3, 2015. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K058/154058222.PDF.

Figure 1: Illustration of the ORA Installed Capacity Fee for Residential Customers



Under the existing NEM tariff, there is a cross-subsidization or cost-shift between NEM participants and non-participants. The cost-shift is a result of NEM participants who are able to avoid a portion of utility costs associated with serving them. These avoided costs are ultimately paid by non-participants, who are responsible for funding the NEM program. The ICF is necessary in order to address the cost-shift between NEM participants and non-participants. Lowering the cost of the NEM program to all ratepayers through a simple mechanism like the ICF is also prudent in light of the availability of other similar but less expensive and competitively procured renewable energy.

ORA's proposed ICF has numerous benefits. The ICF is ready to implement with minimal additional regulatory processes. An ICF is easy for customers to understand. It is a simple mechanism that has been successfully implemented in other parts of the country. It continues the existing NEM tariff design that has worked well for solar customers and the

solar industry, while gradually addressing the cost-shift created by the existing NEM tariff. The ICF is fair to solar customers and non-participants and is necessary to address Public Utilities Code Section 2827.1(b)(4) which requires that the total benefits of the NEM successor tariff to all customers and the electrical system are approximately equal to the total costs.

The design of the ICF glide-path is based on benefit-cost and adoption metrics produced by the Public Tool, which was accepted into the record and provided to parties in R.14-07-002 by the Administrative Law Judge (ALJ)[2] on June 4, 2015 for parties to use in evaluating proposals for the successor tariff.

Program designs similar to ORA's proposed ICF glide-path have been successfully implemented in the past, such as the California Solar Initiative (CSI), which implemented declining incentives along a pre-determined schedule of solar adoption. ORA's proposed ICF glide-path starts with a modest fee that the public tool shows to have little impact on the participants' economics of adopting (Distributed Generation) DG. ICF increases to the ICF occur only after NEM adoption grows. The ICF remains unchanged if DG adoption slows. Through this design, ORA's proposed ICF ensures that customer-sited renewable distributed generation continues to grow sustainably and that the total benefits of the tariff to all customers and the electrical system are approximately equal to the total costs.

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[2] *Administrative Law Judge's Ruling Setting Specifications for the Final Version of the Public Tool and Accepting into the Record the Final Version of the Public Tool*, dated June 4, 2015.

2. WHAT IS THE FEE THAT ORA PROPOSES?

ORA proposes a successor tariff for residential utility customers that is a continuation of the existing NEM tariff (at full retail rate), with an additional fee to be levied on customer generators who interconnect after a utility reaches the 5% NEM cap for its territory or July 1, 2017, whichever comes first.[3] ORA's proposed fee, referred to throughout this testimony as an Installed Capacity Fee (ICF), is based on the installed capacity of the distributed generator. The utilities will credit the ICF revenues directly to residential electricity customers in rates. To maintain market certainty, ORA proposes to introduce the ICF gradually with a three step glide-path, as shown in Figure 1, above. Each subsequent ICF step change is triggered as NEM adoption milestones are reached. By tying ICF increases to NEM adoption milestones, ORA's proposal ensures that increasing fees do not outpace the rate of adoption and that the tariff adjusts to actual adoption, rather than theoretical adoption.

- The **first step** will be a fee of **$2/kW/Month** that will begin implementation when a utility surpasses **5%** of its aggregate customer peak demand, or July 1, 2017, whichever comes first.[4]
- The **second step** will be a fee of **$5/kW/Month** that will begin implementation when the proportion of existing NEM and successor tariff interconnected capacity surpasses **6%** of a utility's aggregate customer peak demand.
- The **third step** will be a fee of **$10/kW/Month** that will begin implementation when the proportion of existing NEM and successor tariff interconnected capacity surpasses **7%** of a utility's aggregate customer peak demand.

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[3] ORA's proposal is specific to residential NEM customers, only. At this time, ORA is not proposing any changes to the existing commercial and industrial (non-residential) customer NEM tariff. The 2013 NEM Ratepayer Impacts Evaluation found that non-residential NEM customers already pay 112% of their cost of service, suggesting that cost-shifting is not an issue for commercial/industrial NEM customers. Also many non-residential NEM customers already face demand charges of some sort. *See* California Net Energy Metering Ratepayer Impacts Evaluation (2013 NEM Ratepayer Impact Evaluation), dated October 2013, http://www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf.

[4] ORA proposes that the proportion of aggregate peak demand continue to be calculated as described in D.14-03-041.

3. BASIS FOR IMPLEMENTING A CAPACITY CHARGE

Public Utilities Code Section 2827.1(b)(4) requires that the total benefits of the NEM successor tariff to all customers and the electrical system are approximately equal to the total costs. The existing NEM tariff creates a cross-subsidization, or cost-shift, between NEM participants and non-participants. The cost-shift is a result of NEM participants who are able to avoid a portion of utility costs associated with serving them. These avoided costs are ultimately paid by non-participants, who wind up responsible for funding the NEM program. The necessity to implement changes in the NEM successor tariff is demonstrated by the following three findings:

- The California Public Utilities Commission (Commission) Energy Division report *California Net Energy Metering Ratepayer Impacts Evaluation*, published in October 2013 (2013 NEM Ratepayer Impact Evaluation) documented that the current NEM structure creates a cost shift,

- The Public Tool baseline scenarios showed a cost shift, and

- The NEM program has a higher cost to ratepayers than similar market alternatives.

a. The 2013 NEM Ratepayer Impact Evaluation Shows There is a Cost-Shift

The 2013 NEM Ratepayer Impact Evaluation documented that the current NEM structure creates a cost shift. The 2013 NEM Ratepayer Impact Evaluation performed a cost of service analysis to estimate the percent of the utilities' cost to serve NEM customers and what those NEM customers pay through their utility bills. The study described a cost-shift as follows: if the customer bill savings resulting from NEM are greater than the corresponding reduction in utility costs, NEM will create a cost shift from NEM customers to other non-participating customers as utilities adjust their rates to compensate for the shortfall.[5] This study showed that residential NEM customers paid only 81% of their full cost of service, thus requiring non-participating customers to make up the costs not paid by NEM participants.[6] Additionally, the 2013 NEM Ratepayer Impact Report also forecasted that costs associated

[5] 2013 NEM Ratepayer Impact Evaluation, p. 17.

[6] *Id.*, pp. 6-10.

with all NEM generation will be approximately $1.1 billion (calculated in 2012 dollars) per year by 2020, or approximately 3.1% of the forecasted utility revenue requirement.

b. The Seven Baseline Scenarios of the Public Tool all Show There is a Cost-Shift

Energy Division Staff and their consultant who prepared the 2013 Report, Energy + Environmental Economics (E3), have developed a spreadsheet calculator known as the Public Tool, which was accepted into the record and provided to parties to use in evaluating NEM successor proposals.[7]

A separate ALJ ruling provided parties with specifications for seven baseline Public Tool baseline scenarios: The Existing Rate-Design Policy, Future Two-Tier Rate Design, Time-of Use (TOU) 4-8PM, and TOU 2-8PM.[8] Each baseline scenario except the Existing Rate-Design Policy was executed under a high Distributed Generation (DG) value case and a low DG value case. Table 1, provides the Public Tool Standard Practice Manual (SPM)[9] Ratepayer Impact Measure Test (RIM, also referred to as the Non-Participant Test)[10] and Cost of Service (COS) outputs for all of the ED Staff baseline scenarios as replicated by ORA. Each of these baseline scenarios produces results that demonstrate severe cost-shifting from NEM participants to non-participants. Under all baseline rate designs, the non-participant RIM benefit/cost test results are substantially less than 1. This indicates that the existing NEM tariff will increase prices for all customers under all rate design futures.[11]

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[7] *Administrative Law Judge's Ruling Setting Specifications for the Final Version of the Public Tool and Accepting into the Record the Final Version of the Public Tool*, dated June 4, 2015.

[8] *Administrative Law Judge's Ruling Providing Further Instructions For Parties' Proposals and Accepting Into the Record Certain Updates to the Public Tool*, dated July 20, 2015.

[9] Available at: http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf

[10] The Standard Practice Manual the RIM is defined as follows: "The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels." *Id.* at 13.

[11] "The Commission has a well-established history of using the RIM test to evaluate the costs and benefits of NEM." Energy Division Staff Paper on the AB 327 Successor Tariff or Standard Contract (Staff NEM Successor Whitepaper), dated June 3, 2015, p. 1-10. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M152/K410/152410786.PDF

Similarly, under all baseline rate designs, NEM participants' COS contribution results are all less than 50%,[12] indicating that under the existing NEM tariff and under all default rate design futures, NEM participants do not pay their share of utility costs. Both the RIM test results and COS results provide a strong indication that the current NEM tariff needs to be modified to comply with Public Utilities Code Section 2827.1(b)(4).

Table 1: Current NEM Creates Cost-Shift to Non-Participating Customers Under All Baseline Rate Designs (RIM All Generation)

					Residential COSR	
Renewable DG Case	**Default Residential Rate**	**Forecasted Installations 2017-2025 (MW)**	**Average Non-Participant Benefit/Cost Ratio**	**Ratepayer Impact/Bill Increase (% of Res. RR)**	**Without DER**	**With DER**
Existing	4-Tiered	11,293	0.44	7%	120%	45%
High	2-Tiered	16,047	0.49	10%	120%	31%
Low	2-Tiered	11,985	0.25	15%	110%	29%
High	TOU1	14,707	0.47	11%	121%	39%
Low	TOU1	11,771	0.24	18%	112%	31%
High	TOU2	15,622	0.49	11%	121%	38%
Low	TOU2	12,098	0.25	17%	111%	29%

c. NEM Costs are Double Those of Market Alternatives

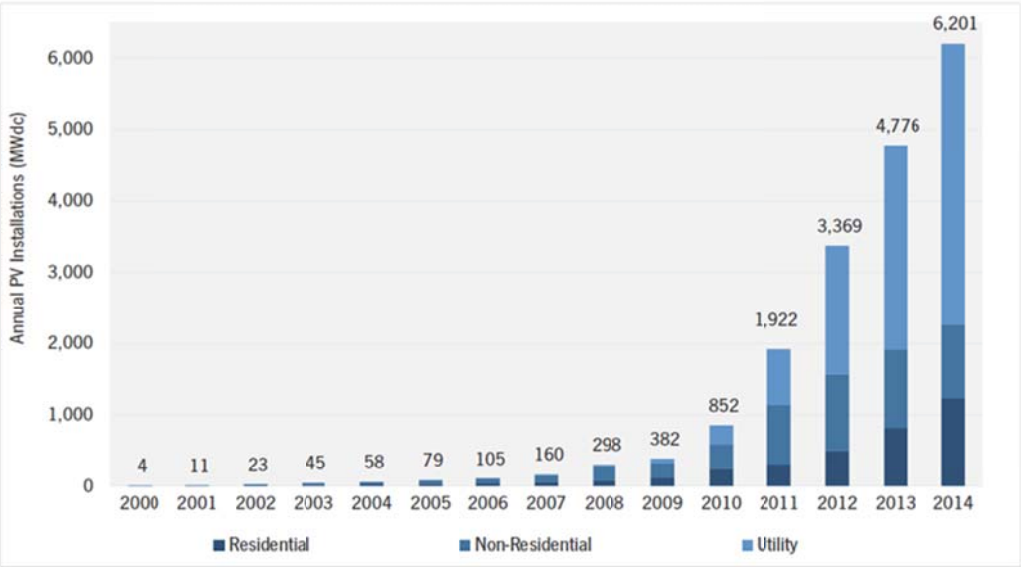
The existing NEM tariff was originally established in California in 1995 with the adoption of Senate Bill 656 (Alquist, Stats. 1995, ch. 369) and codified in § 2827 of the Public Utilities Code.[13] Since then, the NEM tariff has remained largely unchanged. But in these same twenty years, the solar photovoltaic (PV) industry has experienced phenomenal growth (see Figure 2). Also, in these twenty years, the cost of solar PV has dropped dramatically (see Figure 3). The Solar Energy Industries Association (SEIA) reports that

[12] A COS value of 100% indicates that a customer pays their full share of utility costs.

[13] *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*, dated July, 17, 2014, p. 1.

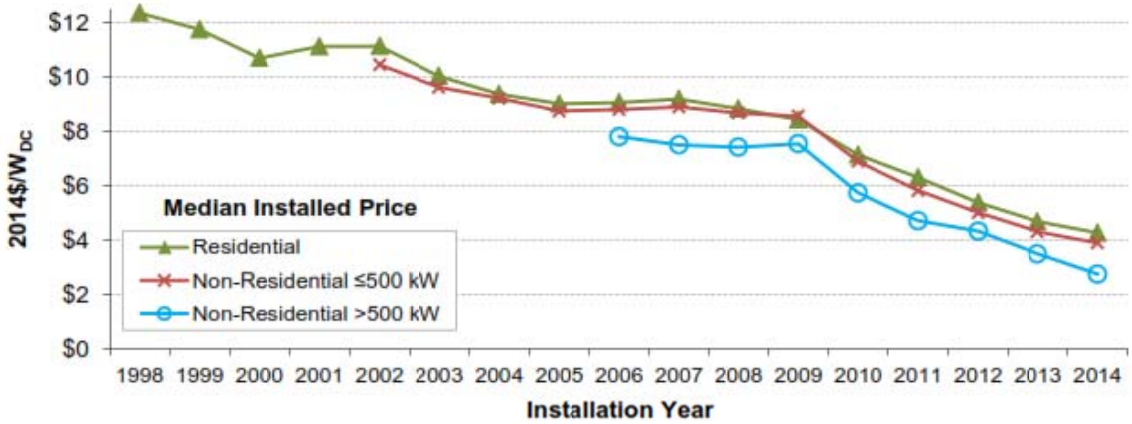
since 2006, the cost to install solar has dropped by more than 73% and since 2010 residential solar costs have dropped by 45%. Unfortunately, these steady solar PV cost decreases have not translated to lower NEM costs for ratepayers. This is one of the fundamental problems with the existing NEM tariff. Specifically, solar PV cost decreases are not passed on to non-participating ratepayers through lower NEM program costs. This problem is in contrast to the declining costs for solar resources procured by the utilities on behalf of all ratepayers through competitive mechanisms, which are passed on to ratepayers through lower power purchase agreement prices.

Figure 2: Annual United States Solar PV Installations, 2000-2014



Source: Solar Energy Industries Association (SEIA) Solar Market Insight Report 2014 Q4

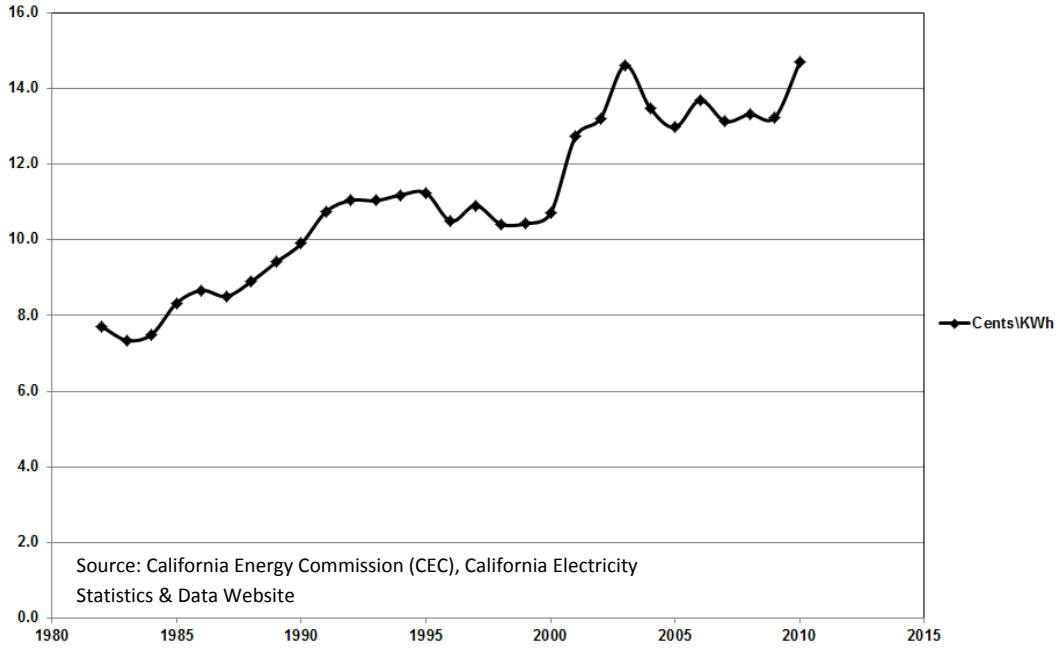
Figure 3: Installed Price of Residential & Commercial PV Has Steadily Declined Since 1998[37]



Source: Lawrence Berkeley National Laboratory/DOE Sunshot, *Tracking the Sun VIII*, August 2015

A second flaw with the existing NEM tariff is that the solar customer's underlying electricity rate, not solar costs, drives NEM program costs for all ratepayers. Retail rates in California are on the rise, and are likely to continue in the future (see Figure 4). Currently, as retail rates increase, NEM compensation increases, which is a perverse incentive for a declining cost resource. The existing NEM tariff is a mechanism that doesn't account for the explosive growth of solar, the declining costs of solar, the rising California retail rates, and the need for solar customers to share in the costs of the distribution system. Assembly Bill (AB) 327 (2013 Perea) recognized the importance of resolving this problem with two inter-related tasks: 1) reforming residential rates and 2) designing a new NEM tariff. The first step, residential rate reform, has been completed with the Commission approval of Decision (D.) 15-07-001.[14] ORA's proposal can be implemented to complete the second task set out by AB 327, which is to design a NEM successor tariff.

Figure 4: California Average Retail Electricity Prices Continue to Rise



[14] D.15-07-001, *Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates*, dated July 13, 2015.

For the benefit of all ratepayers, the NEM successor tariff should be based on solar cost reductions achieved over time, rather than on maintaining unnecessarily high subsidies for the minority of utility customers who are able to afford to install solar. The reductions in solar costs are observable in competitively-procured solar resources. California is an experienced buyer of solar PV systems of all sizes. California buys large-scale solar through the renewable portfolio standard (RPS) program, medium-scale solar through the Renewable Auction Mechanism (RAM), and small-scale solar (similar in scale to NEM) through the Investor Owned Utility (IOU) Solar PV Programs, Feed-in Tariffs, and the Renewable Market Adjusting Tariff (ReMAT). Through each of these competitive procurement mechanisms, California ratepayers benefit from steady price decreases that reflect the declining cost of solar. The NEM successor tariff should also reflect the declining cost of solar.

There is a wide disparity between the cost to ratepayers of residential NEM solar in juxtaposition to comparable-sized competitively-procured solar. Figure 5 shows this distortion in cost to ratepayers between NEM and ReMAT. The 2013 Ratepayer Impact Evaluation estimates the levelized cost to ratepayers of NEM to be $200 per Megawatt hour (MWh). This is in stark contrast to comparable-sized ReMAT program projects built and under development which are less than $100 per MWh.[15]

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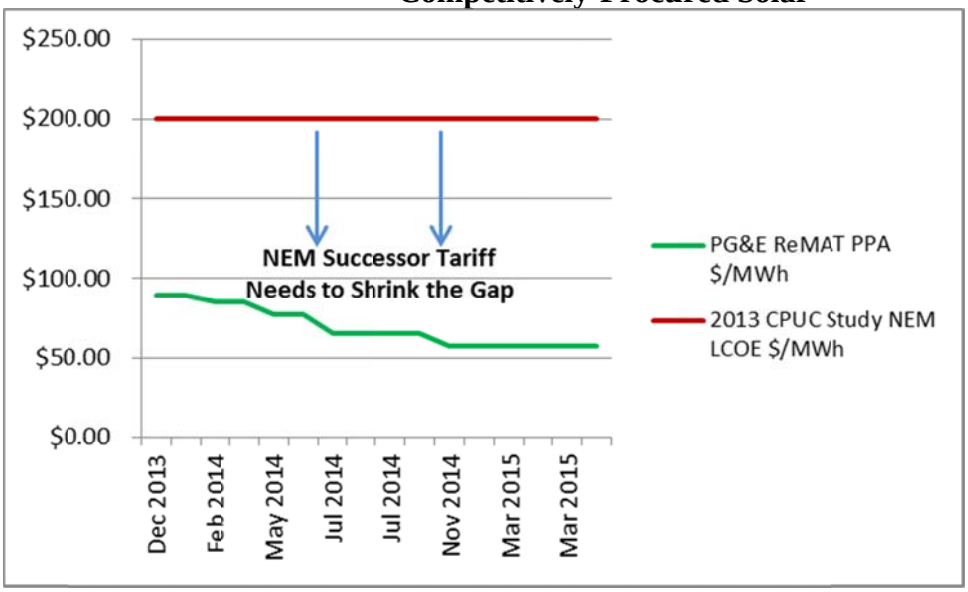
[15] The ReMAT prices are from PG&E's July 2, 2015 ReMAT report in compliance with Public Utilities Code Section 399.20(m). Available at http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page, scroll down to "10-Day Reporting Requirement."

Figure 5: NEM Resource Costs are Double those of Small-Scale Competitively-Procured Solar



California NEM is currently limited to solar resources no greater than 1 MW while ReMAT is limited to solar generators no greater than 3 MW, so there is not a complete overlap of system sizes between the two programs.[16] Because of this scale difference, NEM costs may not completely converge with comparable competitively procured solar resources, but the NEM successor tariff needs to close this gap. In a sustainable market, ratepayers would be indifferent to funding competitively-procured solar or NEM solar since both types of resources should have comparable costs. But the current situation, where NEM solar cost is double that of similar-sized competitively-procured solar, is not sustainable. ORA's NEM successor tariff proposal addresses this discrepancy by gradually reducing this price gap.

A 2015 study from the Massachusetts Institute of Technology titled The Future of Solar Energy (MIT Solar Study) discusses similar cost findings and reports that the levelized cost of energy (LCOE) for California residential solar is approximately double that of utility-scaled solar.[17] The MIT Solar Study also finds numerous issues with the residential solar market in general, including:

[16] Section 2827.1(b)(5) of the Public Utilities Code conditionally allows projects greater than 1 MW under the NEM successor tariff so the size overlap between NEM and ReMAT projects will become even more comparable.

[17] Attachment A: Excerpts from *The Future of Solar Energy*, The Massachusetts Institute of Technology, p. 118, dated May 2015. Complete text available at: https://mitei.mit.edu/futureofsolar

- NEM at Retail Rate + Distribution Grid Costs collected thru Volumetric Rates is problematic.[18]

- Utility-scale PV is Competitive (Estimated Cost ~ Reported prices) while residential PV is not.[19]

- If the objective of deployment support policies is to increase solar generation at least cost, favoring residential PV makes no sense.[20]

- Residential PV generation should not continue to be more heavily subsidized than utility-scale PV generation.[21]

Another recent peer-reviewed solar study by the Brattle Group also finds residential solar to be double the cost per kilowatt-hour of utility scale solar.[22]

The comparison of NEM costs to ReMAT prices presented in this testimony demonstrates that ratepayers funds procure renewable power from small competitively procured solar for far less than NEM resources cost. This comparison is not intended to suggest that small scale solar and NEM should be identical in price, but at the least, ReMAT and NEM resources should have comparable costs. ReMAT resources provide similar benefits as NEM resources do. Specifically, PG&E's E-ReMAT tariff specifically requires that ReMAT projects be physically located within PG&E's electric service territory and be interconnected to PG&E's electric distribution system.[23] Furthermore, in order to be eligible

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[18] *Id*., p. 220; "In broad terms, the economically obvious solution is to move away from the prevalent design of distribution network charges that recovers fixed distribution costs via volumetric (per-kWh) charges."

[19] *Id*., pp. 81-86; "A bottom-up estimate of cost for utility scale PV installations yields a result that is very close to the average reported price per peak watt, indicating active competition in that segment of the PV market. In the residential sector, by contrast, a large difference exists between contemporary reported prices and estimated costs."

[20] *Id*., p. 223.

[21] *Id*., pp. 225-226; "Residential PV generation should not continue to be more heavily subsidized than utility-scale PV generation. Eliminating this uneconomic disparity will require replacing per-kWh distribution charges with a system for recovering utilities' distribution costs that reflects network users' impacts on those costs."

[22] Attachment B: Excerpts from *Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area*, prepared for utility-scale solar provider, First Solar, by The Brattle Group, dated July 13, 2015. Complete text available at: http://www.brattle.com/news-and-knowledge/news/study-by-brattle-economists-quantifies-the-benefits-of-utility-scale-solar-pv.

[23] PG&E E-ReMAT Tariff, D.1. http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_SCHEDS_E-

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for PG&E's ReMAT tariff, all projects are required to demonstrate that the most recent interconnection study or interconnection agreement affirmatively supports the project's ability to interconnect without requiring transmission system upgrades that exceed $300,000.[24]

4. WHY A CHARGE BASED ON INSTALLED CAPACITY?

The Commission should adopt a capacity-based fee to begin the process of reducing NEM program costs and the cost shift created by the current NEM structure. ORA's proposed successor tariff, which includes a capacity based fee, is superior to other mechanisms that could be adopted to reduce the cost shift because it is simple and effective.

The ORA successor tariff is ready to implement with minimal additional regulatory processes. The ICF is simple, and can be added to any tariff structure. The additional revenue collected through the ICF should be included in the utility residential distribution balancing accounts, which in turn will reduce the overall residential revenue requirement the following year. Once a Commission decision adopting the successor tariff is passed at the end of this year, remaining implementation details such as updates to the tariff sheets, establishment of balancing accounts to track the ICF revenue, and the calculation of aggregate customer peak demand can be managed through the Advice Letter process.

The ORA successor tariff is easy for customers to understand. Because the ICF is based on the installed capacity of a customer's NEM generator, customers and their installers will be able to precisely forecast monthly cost as a result of the successor tariff, which will help customers make informed decisions about adopting solar. The ICF does not require any additional metering equipment, does not require the customers to understand additional complicated billing formulae, and does not depend on residential customers to understand demand based charges. If the grandfathering provisions recommended by ORA are adopted, the customer's ICF will remain unchanged for 10 years once a customer is on the successor tariff.

A capacity based fee such as ORA's proposed ICF is a simple design that has already been implemented for DG customers in other jurisdictions. For example, net metered

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REMAT.pdf

[24] PG&E E-ReMAT Tariff, D.5.a.

customers of the utility company, Arizona Public Service (APS), have been required to pay a $0.70/kW fee since the end of 2013. During that time, the solar market in APS's territory has continued to grow at a heathy rate.[25] The Arizona Corporation Commission is now considering an increase of the capacity fee up to $3/kW[26] [27] From this evidence, it is clear that a $/kW solar fee can be a successful mechanism for recovering revenue under-collections.

The ICF is the only major modification that ORA is proposing to make to the existing NEM tariff. ORA proposes to continue the existing NEM tariff design that has worked well for solar customers and the solar industry, while also gradually balancing the cost-shift through a capacity based fee. This design achieves the balance that the Legislature sought with the passage of Assembly Bill 327.

Finally, the ICF will be phased-in along a glide-path for the purpose of transitioning solar customers onto the successor tariff while also providing opportunities for the solar industry in California to adapt to policy changes. The glide-path is driven by actual adoption so that if adoption accelerates, the ICF will be increased sooner; or, if adoption slows, the ICF will not increase until NEM adoption milestones are achieved. ORA's proposal is the only proposed tariff that is explicitly designed to provide a glide-path to sustainability that is driven by actual solar adoption. ORA proposes that the ICF begin at $2/kW, which as discussed elsewhere in this testimony, is not expected to have a significant impact on the growth of solar in California.

[25] "Before May of this year, APS averaged 1000 DG applications per month. In May and June, APS received approximately 1,300 applications, respectively. In July, the number grew to 1,533. By comparison, APS received 7,800 applications in all of 2014." Arizona Corporation Commission, DOCKET NO. E-01345A-13-0248. ARIZONA PUBLIC SERVICE COMPANY'S EXCEPTIONS TO RECOMMENDED ORDER, p.3. Aug 12, 2015. http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=18039

[26] Arizona Corporation Commission, DOCKET NO. E-01345A-13-0248. Decision 75251. Aug 31, 2015. http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=18039

[27] Arizona Corporation Commission, DOCKET NO. E-01345A-13-0248. ARIZONA PUBLIC SERVICE COMPANY'S EXCEPTIONS TO RECOMMENDED ORDER. Aug 12, 2015. http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=18039

5. ORA'S BASIS FOR THE SPECIFIC INSTALLED CAPACITY FEE STEPS AND THE GLIDE-PATH IS SOUND

Under ORA's proposal, the ICF will be gradually increased as California solar adoption milestones are achieved. Solar adoption will be measured using the same methodology currently used by the Commission to track solar penetration for the purposes of evaluating progress towards the current 5% NEM cap.[28] On July 1, 2017, or when the aggregate NEM generator peak capacity in each utility service area reaches the current NEM cap of 5% penetration, whichever occurs first, the utilities will begin collecting a fee of $2/kW/Month from all new residential customer generators. When a utility reaches 6% NEM penetration level, the ICF will be increased to $5/kW/Month. When a utility reaches 7% NEM penetration level, the ICF will be increased to $10/kW/Month. Figure 6 provides an illustration of the mechanics of ORA's proposal. ORA has performed two separate analyses to estimate when the utilities will reach the 5%, 6%, and 7% NEM penetration, which are discussed in section 5.a. of this testimony.

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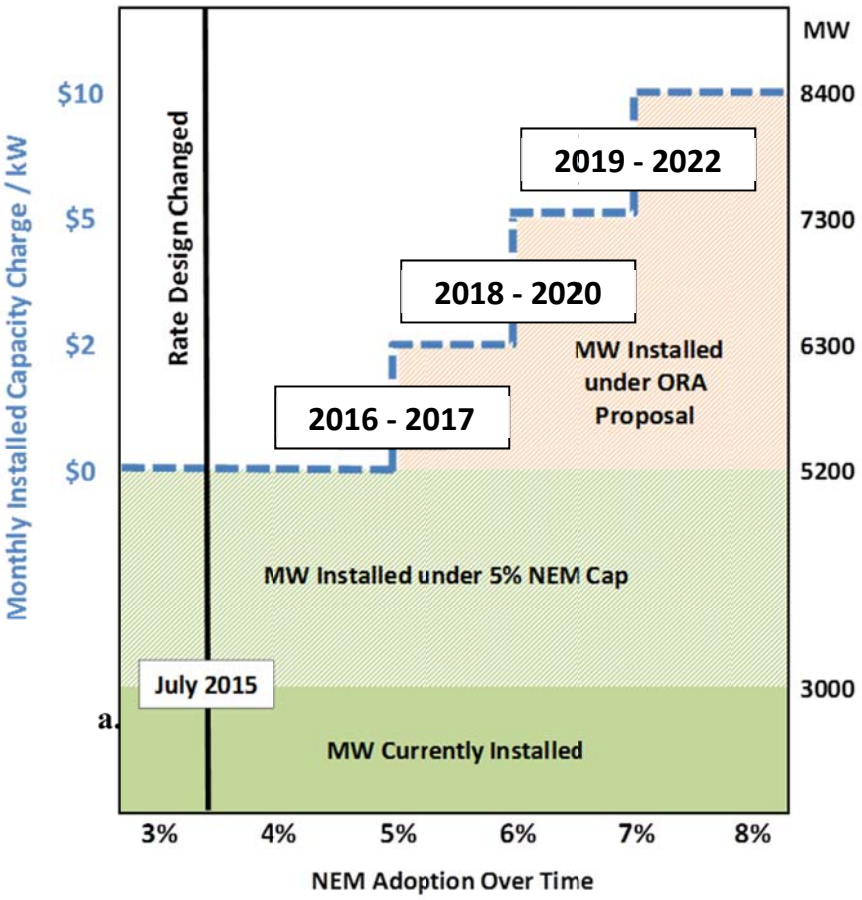
[28] As documented in D. 14-03-041, *Decision Establishing a Transition Period Pursuant to Assembly Bill 327 For Customer Enrolled in Net Energy Metering Tariffs*.

Figure 6: Illustration of the ORA Installed Capacity Fee for Residential Customers



In Section 9.b. of ORA's proposal[29] ORA presented the results of a regression analysis used to estimate when the penetration of renewable distributed generation will reach 5%, 6%, and 7% of aggregate customer peak demand. That regression analysis used historical installed capacity data for NEM installations through June 2015 submitted by PG&E, SCE, and SDG&E per Public Utilities Code §2827(c)(4)(C)[30] and responses to data requests made by ORA and CALSEIA.[31] For this testimony ORA provides the same analysis, but with the addition of monthly installed capacity data for July and August 2015.

[29] ORA Proposal, p. A-42.

[30] These data are submitted via Advice Letter filings on the 10th of every month.

[31] ORA relied on PG&E Data Response "NetEnergyMetering-Tariffs_DR_ORA_002-Q01" Question 1 and 16, February 27, 2015; SCE Data Response "R.14-07-002-ORA-SCE-003-NEM-003", Question 1 and 16, February 13, 2015; SDG&E Data Response "ORA-SDG&E-DR-02," Question 1 and 16, February 24, 2015, which are voluminous data responses, to form its work papers. ORA's work papers are available at http://www.ora.ca.gov/general.aspx?id=3195.

In addition, ORA prepared an alternate analysis using the public tool to forecast adoption as ORA's proposed tariff escalates through the ICF glide-path.

1. Regression Forecast

Figures 7 shows the cumulative MW installed under the NEM program since 1996 with a trajectory drawn for each utility from January 2011 to Aug 2015.[32] Figure 8 shows the NEM interconnected capacity as a percent of aggregate customer peak demand (defined as the highest sum of all customers' non-coincident peak demands that occurs in any calendar year). As of Aug 2015, the proportion of NEM interconnected capacity (i.e. penetration) for PG&E, SCE and SDGE are at 3.4%,[33] 2.81%,[34] and 3.79%[35].

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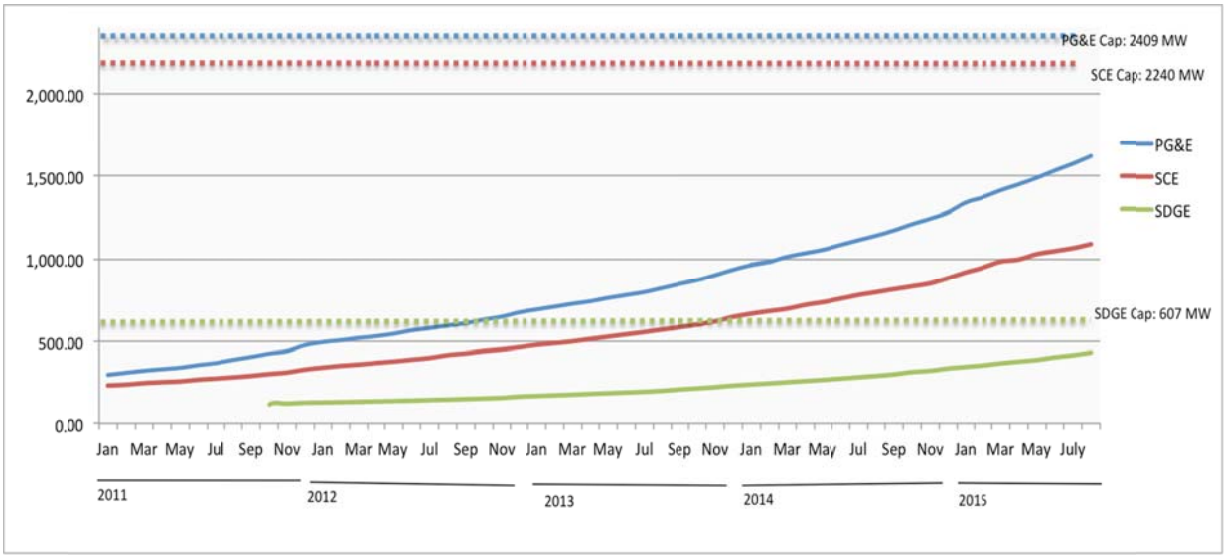
[32] Source: PG&E, SCE, and SDG&E Information-Only Advice Letter Filings Regarding Net Energy Metering Monthly Transition Reporting in accordance with D.14-03-041.

[33] PG&E Advice Letter 4701-E.

[34] SCE Advice Letter 3270-E.

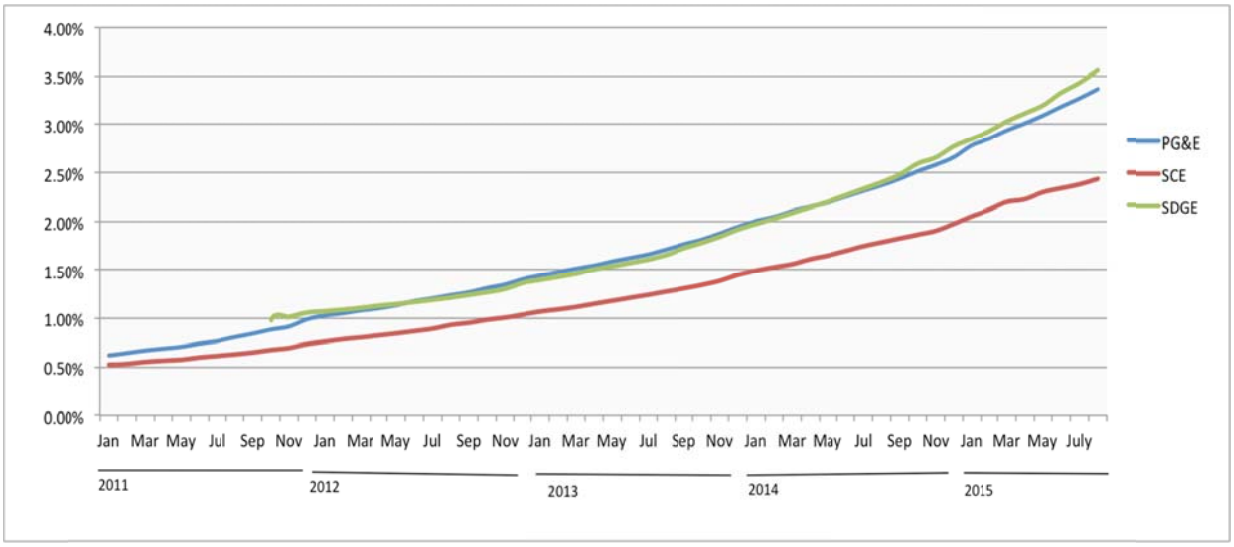
[35] SDG&E Advice Letter 2785-E.

Figure 7: Cumulative NEM Installed Capacity (MW)



Source: PG&E, SCE, and SDG&E Information-Only Advice Letter Filings Regarding Net Energy Metering Monthly Transition Reporting in accordance with D.14-03-041.

Figure 8: Cumulative NEM Installed Capacity (% Penetration)



Source: PG&E, SCE, and SDG&E Information-Only Advice Letter Filings Regarding Net Energy Metering Monthly Transition Reporting in accordance with Decision (D.) 14-03-041.

Using this historical data, ORA developed a forecast using an ordinary least squares (OLS) regression analysis to estimate the month and year when utilities can be expected to reach penetration levels of 5%, 6%, 7% and 8%. The regression was run using STATA with monthly cumulative NEM installed capacity (in MW) treated as the dependent variable and

the months as independent variable. Table 2 presents the result of the regression of cumulative NEM installed on months for each utility.

The regression output for each utility shows a strong linear trend in cumulative growth of NEM installations over time with a robust R squared statistic of 94.8% for SDGE and about 97% for PG&E and SCE.

Table 2: Regression of Cumulative NEM Installations in MW on month

Variable	PG&E	SCE	SDGE
Constant	171.625***	134.069***	76.824***
	(17.526)	(12.314)	(6.272)
Month	22.865***	15.388***	6.497***
	(.535)	(0.376)	(0.227)
R-squared	0.971	0.969	0.948
Observations	56	56	47
Standard errors	***p<0.01	**p<0.05	*p<0.1

On the basis of the above regression, we forecast the time period when each utility is expected to reach a penetration level of 5%, 6%, 7% and 8%, given the historical trends. The results are presented in Table 3.

Table 3: Month and Year Estimates for Solar Penetration Milestones

Penetration	PG&E	SCE	SDGE
5%	Feb 2019	May 2021	Jul 2018
6%	Nov 2020	Oct 2024	Jan 2020
7%	Aug 2022	Mar 2027	Aug 2021
8%	May 2024	Aug 2029	Mar 2023

Scatter plots in Figures 9 – 11 below show the actual trend (dotted line) versus the predicted regression line (solid line). As seen, the historical trend follows a near linear path except for the recent months where growth in MWs installed has increased. Hence, while our forecasts are based on the assumption of linear growth, the penetration levels might be reached sooner if the steep trend continues, presumably in anticipation of the policy changes like the expiration of the federal investment tax credit and changes to NEM.

Figure 9: PG&E Regression Plot

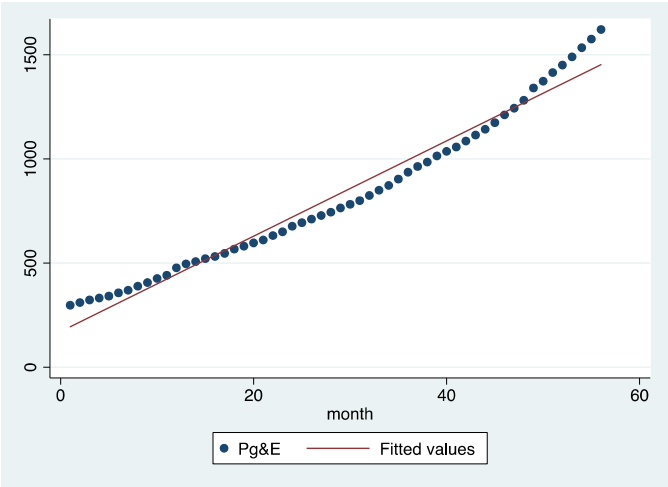


Figure 10: SCE Regression Plot

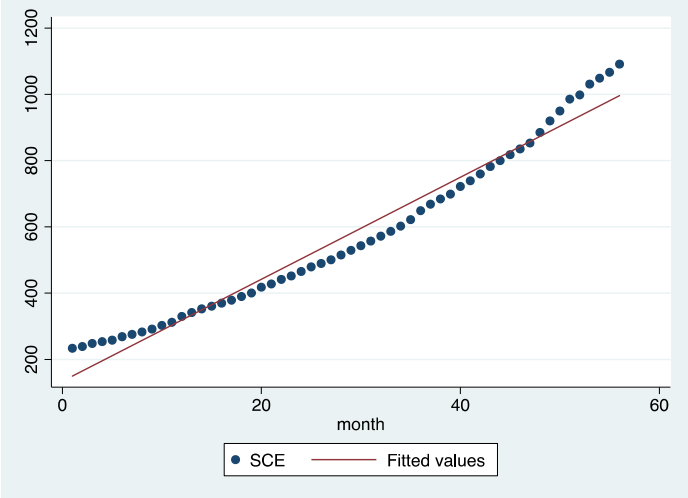


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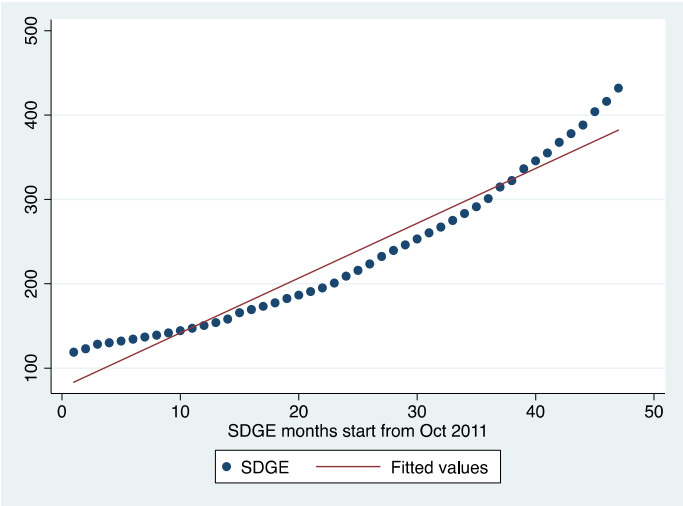
Figure 11: SDG&E Regression Plot



2. Public Tool Forecast

In addition to a regression analysis used to estimate when the penetration of renewable distributed generation will reach 5%, 6%, and 7% of aggregate customer peak demand, ORA constructed an adoption forecast using the annual adoption results for the $2/kW, $5/kW, and $10/kW ICFs from ORA's public tool simulations.

ORA constructed annual adoption tables through 2025 for each of the IOU service territories and for each of the high and low DG value bookends – for a total of six tables. The pre-2009 and 2009-2016 annual adoption estimates that are seeded in the public tool form the base of each of the six tables. The 2017 capacity installation estimate for each IOU/DG value combination from ORA's public tool scenarios forecasting adoptions with a $2/kW ICF were then added to the tables. The capacity installation estimate for each IOU/DG value combination from the $2/kW ICF public tool simulation then was added to each subsequent year until the cumulative annual capacity installations surpassed the 6% milestone that would trigger a step to the $5/kW ICF.[36] Once the 6% milestone was exceeded, the annual adoption estimate based on the $5/kW ICF public tool simulations was added to each subsequent year until the cumulative annual capacity installations surpassed

[36] For the purpose of this analysis ORA used the static aggregate peak demand described in D. 14-03-041 to calculate the 6% and 7% aggregate peak demand milestones that would trigger a step up to the $5/kW and $10/kW ICFs. The aggregate peak demand milestone for 6% is 2891 MW for PG&E, 2688 MW for SCE, and 728 for SDG&E. The aggregate peak demand milestone for 7% is 3372 MW for PG&E, 3136 MW for SCE, and 849 for SDG&E.

the 7% milestone that would trigger a step to the $10/kW ICF. After the 7% milestone was exceeded, the annual adoption estimates based on the $10/kW ICF public tool simulations were added to the remaining years. All the annual adoption estimates used to build these tables from 2019 through 2025 were based on the public tool simulations using the TOU rate design with a peak period of 4PM to 8PM.

The adoption trajectory based on the public tool results, shown in Table 4 estimates that the installed capacity will reach the end point of the ICF glide-path between 2019 and 2020.

Table 4: Year Estimates for Solar Penetration Milestones / Low DG Value

Penetration	PG&E	SCE	SDGE
5%	2017	2017	2017
6%	2019	2019	2018
7%	2020	2020	2019
8%	2022	2021	2020

b. Increases in the ICF are Dependent on Adoption

Parties have pointed out the many challenges of forecasting renewable DG adoption.[37] While the Energy Division has earnestly addressed many of these comments on the draft public tool with modifications incorporated into the final version of the public tool,[38] the outstanding concern that renewable DG adoption cannot be accurately forecasted persists. In designing the successor tariff proposals, all parties are faced with answering the question - *What will be the economic effect of the successor tariff?* Designing the successor tariff based on adoption forecasts has the potential to either be too aggressive, resulting in an undesirable suppression of the solar market; or not aggressive enough, resulting in a tariff that has little effect on addressing the cost shift. ORA's proposed tariff does not need to answer this question. ORA's tariff is designed around a mechanism that allows the ICF to increase as solar adoption increases, or to remain unchanged if adoptions slow. By starting with a modest fee added to the existing NEM tariff, with fee increases dependent on

[37] For Example: ORA Comments on Draft Version of Public Tool, April 28, 2015, p. 1; PG&E Comments on Draft Version of Public Tool, April 28, 2015, p. 2; Solar Parties Comments on Draft Version of Public Tool, April 28, 2015, p. 3; IREC Comments on ALJ Ruling Seeking Post-Workshop Comments, Oct 1 2014, p. 14.

[38] *Administrative Law Judge's Ruling Setting Specifications for the Final Version of the Public Tool and Accepting into the Record the Final Version of the Public Tool*, Attachment 1, p. 1.

adoption, ORA's tariff all but guarantees that the Commission will get the desired results. For evidence of this effect, the Commission need only review the considerable success of the CSI program, which was designed around a similar mechanism. The Energy Division's 2015 CSI Annual Program Assessment describes this mechanism most succinctly:[39]

> The CSI program's financial incentives decline in steps as more capacity is installed. The declining incentives, required by PU Code Section 2851, are intended to help the program meet its goal of creating a self-sustaining solar industry by reducing rebates as the solar industry grows. Each step has an installed MW target that triggers the subsequent step down in incentive level.

By linking ICF increases to NEM adoption milestones, ORA's proposal ensures that increasing fees do not outpace the rate of adoption and that the tariff adjusts to actual adoption, rather than theoretical adoption.

Experience with CSI indicates that the introduction of the ICF would not harm the solar industry. The CSI general market program was closed in PG&E's service territory on December 12, 2013, and the deployment of solar continued to grow. Since 2013, the cumulative capacity of NEM installations in PG&E's service territory has grown from just under 1000 MW to over 1500 MW, a 50% installed capacity increase in the 18 months since the CSI program closed. NEM capacity grew by approximately 500 MW in PG&E's service area during 2012 and 2013, the last two years of the CSI program. This data demonstrates that the embedded subsidy in the existing NEM tariff can begin to be reduced with ORA's proposed ICF glide-path without disrupting the solar market.

A total of 1051 MW[40] of distributed generation will be installed across all the utilities under each of the $2/kW and $5/kW ICF steps. For comparison, 1051 MW is just slightly

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[39] California Public Utilities Commission, Energy Division, *The Energy Division's 2015 CSI Annual Program Assessment*, p. 21. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/8E158382-9114-4756-B0C7-AA6CA1A110A4/0/CSI_2015AnnualReport_FINAL.pdf, p. 21.

[40] The 1051 MW estimate is based on the aggregate customer peak demand used to calculate the current utility specific 5% NEM caps published in § 2827(c)(4)(B)(i) – § 2827(c)(4)(B)((iii). These values are 48,177 MW for PG&E, 44,807 MW for SCE, and 12,134 for SDG&E. ORA calculated the difference between 5% and 6% of these aggregate customer peak demand estimates, which is 1051 MW.

less than the total NEM capacity that was installed in SCE's service territory during the first 18 years of net energy metering.[41] Only after 1051 MW of solar adoption is accomplished under the $2/kW ICF would the ICF increase to $5/kW. And here again, another 1051 MW of distributed generation would be installed across all the utilities under the $5/kW ICF step.[42] Counting from August 2015, the total DG capacity that would be installed before the $10/kW fee is triggered is 4000 MW,[43] which is more solar capacity than has ever been interconnected under the NEM tariff since its inception in 1996.[44] To get to the $10/kW fee, the installed capacity would have more than doubled from the capacity installed today, and the state will have installed more than 7,000 MW of cumulative capacity under the NEM and successor tariff programs alone, which is more than half of the Governor's goal for developing 12,000 MW of local renewable energy. Figure 12 provides a graphical representation of the stack of MWs installed to date up to the 12,000 MW goal.

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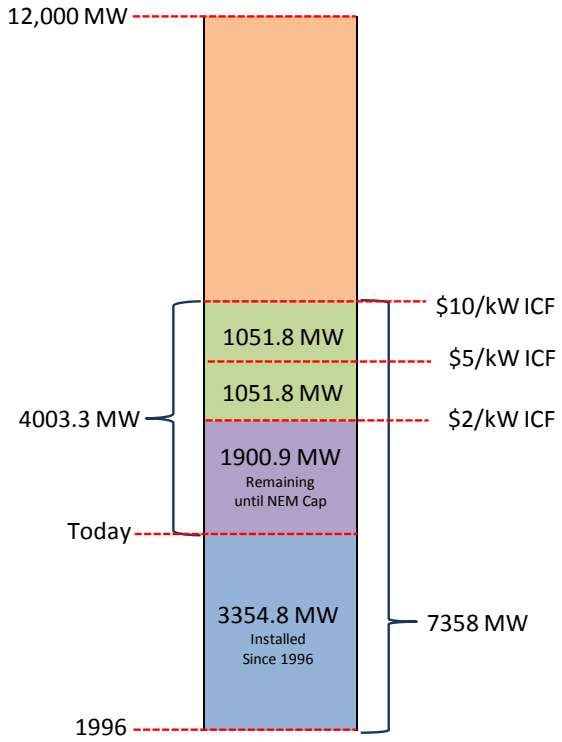
[41] 1088.3 MW of NEM capacity was installed between 1996 and April 2015 in SCE's service area, SCE Advice Letter 3217-E.

[42] The $5/kW ICF starts when the utility reaches a 6% NEM penetration and continues until the utility reaches a 7% NEM penetration. The number of MWs to go from the 6% NEM cap to 7% NEM penetration is also approximately 1051 MWs.

[43] 4003 MW will be installed prior to reaching the 7% aggregate customer peak demand milestone. This estimate is based on the capacity remaining under the 5% cap for each utility taken from SCE Advice Letter 3270-E, PG&E Advice Letter 4701-E, SCE Advice Letter 3270-E, plus the estimate of capacity available between the 5% and 6% and the 6% and 7% aggregate customer peak demand milestones described in footnote number 29 (above).

[44] According to the Advice Letters SCE 3270-E, PG&E 4701-E, SCE 3270-E, 3,355.1 MW has been installed under the existing NEM or is in the NEM queue.

Figure 12: NEM MW Capacity Installed to Date, Through the ORA Proposed ICF Glide-Path, up to the Governor's 12,000 MW Goal



Under ORA's proposed successor tariff, a modest fee of $2/kW will be instituted only when the utility surpasses 5% of its aggregate customer peak demand, or July 1, 2017, whichever comes first. As of August 31, 2015, SDG&E is at 3.79%,[45] PG&E is at 3.4%,[46] and SCE is at 2.81%[47] of the aggregate customer peak demand used to measure progress towards the current 5% NEM cap. Parties in this proceeding have made different projections as to when each of the utilities will reach the 5% cap. These projections and the public tool adoption forecasts involve some degree of speculation as they require assumptions regarding a multitude of factors that can influence near term changes in California's distributed solar market. Under ORA's proposed ICF glide-path, it may be immaterial if the installed capacity accomplishments forecasted under the successor tariff occur more quickly than anticipated. For example, if the ICF milestones were achieved earlier than forecast, and the$5/kW fee

[45] SDG&E Advice Letter 2785-E.

[46] PG&E Advice Letter 4701-E.

[47] SCE Advice Letter 3270-E.

were triggered sooner than expected, this would mean that residential solar industry would have installed more capacity during this unexpectedly short transition period than was interconnected under the NEM tariff during the 19 years between 1996 and 2015. In fact, such a quick transition though the glide-path and unprecedented acceleration of solar adoption would be a signal that the solar market can readily absorb an increase to the $10/kW fee without adversely affecting the potential for future demand.

c. Method for Using Public Tool to Calculate What Installed Capacity Fee Is Necessary to Recover the Full Cost of Service

To determine when costs are approximately equal to benefits, ORA used the public tool to estimate the ICF values that would allow the ICF revenues to be equal to the under-collection that results from successor tariff customers receiving retail rate based export credits and offsetting their own load. ORA tested the estimated ICF values that would be required to cover the cost shift in the public tool and found that fees of such a magnitude have an unacceptable effect on adoption. ORA then used the public tool to systematically test installed capacity fees ranging from $1 to $20 to determine the appropriate fees to be implemented at the final step of ORA's proposed glide-path. Based on this experimentation, ORA concludes that a $10/kW/Month fee would be an appropriate fee to ultimately charge customer generators, since it is expected to have a significant effect on balancing the cost shift and reducing bill impacts on non-participants, all while maintaining an average payback below 10 years and a participant cost test (PCT) ratio above 1.0.

The public tool characterizes the cost of service in terms of the percentage of cost of service recovery for each customer class, for each utility, and for both participants and non-participants. ORA used the cost of service results from the base case public tool simulations to calculate the ICF that would be required in order to recover the full costs to serve DG customers. This method able to identify the approximate upper limit for capacity fees that would be needed to recover the full cost to serve successor tariff customers.

ORA's method for determining the ICF ensures that the under-collection in cost of service recovery from residential customers through the NEM rate would instead be recovered through the ICF. ORA reviewed the 2-tiered, TOU 1, and TOU 2 base case scenarios and used the information in Cell AS53 of the Results tab to determine the embedded subsidy for residential customers. The Public Tool presents this embedded

subsidy as a percentage of cost of service revenue recovery. The monetary value of the percentage of cost of service recovery can be calculated by deducting the denominator of the equation from the numerator. This is the Net Present Value (NPV) of installations through 2025. ORA focused on the embedded subsidy for participants from 2017 to 2025 by selecting the "Include Only NEM Successor Participants" filter in the cost of service results data area in the public tool Results tab. ORA selected this time frame since the successor tariff is intended to address the embedded subsidy going forward rather than attempting to recover revenue under-collections caused by customers on NEM 1.0.

ORA then determined the cumulative installed capacity from 2017 to 2025 for residential participants by adding the MW value from the "Annual Incremental Capacity Installations by Class" chart of the Results tab for 2017 through 2025. This ensures that the embedded subsidy is aligned with the installed capacity forecast in the same time period (2017 to 2025) as the filtered cost of service results. Dividing the NPV value of the embedded subsidy by the MW of installed capacity provides the under collection of cost of service per MW of installed capacity from 2017 to 2025.

To translate this to a monthly kW fee, ORA divided the under collection of cost of service per MW of installed capacity from 2017 to 2025 by 9 (to convert to an annual value), by 12 (to convert to a monthly value) and by 1000 (to convert from MW to kW). The equation below summarizes the calculation:

$$\begin{aligned} &Embedded\ Subsidy\ from\ Cell\ AS53 \\ &\qquad \div Cumulative\ Capacity\ from\ 2017\ to 2025\ in\ MW\ \div\ 9\ \div 12\ \div 1000 \\ &\qquad = \$\ per\ kWh\ per\ month\ ICF \end{aligned}$$

The results of this calculation, performed on all 6 base case public tool scenarios are provided in Table 5 below:

Table 5: Estimates of the Installed Capacity Fees Required to Recover the Full Cost of Service from Residential Successor Tariff Participants

Base Case Public Tool Model	NPV Value of Cost of Service Recovery Under Collection for Residential NEM Participants (2017-2025)	Cumulative Installed Residential Capacity (2017-2025)	Cost of Service Under Collection per MW	Installed Capacity Fee Needed to Recover Cost of Service Under Collection
2 Tiered High DG Value	$ 13,455,368,693	10,515	$ 1,279,582	**$ 11.85**
2 Tiered Low DG Value	$ 26,575,532,029	9,697	$ 2,740,689	**$ 25.38**
TOU 1 High DG Value	$ 15,280,386,390	9,176	$ 1,665,238	**$ 15.42**
TOU 1 Low DG Value	$ 28,352,687,246	9,477	$ 2,991,582	**$ 27.70**
TOU 2 High DG Value	$ 13,496,614,410	10,091	$ 1,337,546	**$ 12.38**
TOU 2 Low DG Value	$ 26,416,265,589	9,809	$ 2,693,133	**$ 24.94**

ORA tested the Installed Capacity Fee estimates by running a sample of base case public tool scenarios with the estimated fees. The test results are provided in Table 6.

Table 6: Residential Cost of Service Recovery Results for Installed Capacity Fee Estimates

		Residential Cost of Service Results with Fee Estimate			
Base Case Public Tool Model	Installed Capacity Fee Needed to Recover Cost of Service Under Collection	PG&E	SCE	SDG&E	All IOUs
2 Tiered Low DG Value	**$ 25.38**	94%	106%	139%	104%
TOU 1 Low DG Value	**$ 27.70**	96%	112%	138%	108%
TOU 2 Low DG Value	**$ 24.94**	79%	98%	107%	92%

d. Rationale for the Specific Fee Steps

The initial $2/kW/Month ICF was selected as a modest initial fee based on the assumption that a fee of this size can begin reducing the embedded subsidy in a meaningful way while ensuring that California solar incentives remain robust. The results of ORA's public tool scenarios also show that a $2/kW/Month ICF has minimal impacts on indicators of the financial proposition for participating customers, specifically the Participant Cost Test (PCT) and the implied payback period for customer-sited renewable generators. Table 7 compares Energy Division's base case public tool scenarios to ORA's $2/kW/Month ICF

scenarios.

Table 7: Comparison of base case public tool scenarios to $2/kW/Month ICF scenarios.

		ED Base Case Scenarios		ORA $2 ICF Scenarios	
Renewable DG Case	Default Residential Rate	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG systems (Years)	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG systems (Years)
High	2-Tiered	16,047	5.01	16,775	5.18
Low	2-Tiered	11,985	7.13	12,581	7.40
High	TOU1	14,707	4.77	15,313	4.96
Low	TOU1	11,771	6.72	11,951	6.99
High	TOU2	15,622	5.05	16,778	5.25
Low	TOU2	12,098	7.18	12,398	7.51

None of ORA's proposed ICF values modeled in the public tool result in PCT ratios that fall below 1.0, indicating that all of the ICF values in ORA's proposed successor tariff will remain economically attractive to participating customers. Similarly, all of the public tool scenarios proposed as part of the successor tariff are estimated to have payback periods of less than 10 years. As Table 8, indicates below, the $2 installed capacity fee has a small effect on the RIM and payback period, and has a positive effect on adoption.

Table 8: Public Tool Results; Adoption, PCT, and Payback; $2/kW/Month ICF scenarios.

Renewable DG Case	Default Residential Rate	Installed Capacity Fee (ICF $/kW-month)	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG systems (Years)	Average Participant Benefit/Cost Ratio (PCT)
High	2-Tiered	2	16,775	5.18	1.90
Low	2-Tiered	2	12,581	7.40	1.33
High	TOU1	2	15,313	4.96	1.98
Low	TOU1	2	11,951	6.99	1.41
High	TOU2	2	16,778	5.25	1.87
Low	TOU2	2	12,398	7.51	1.31

The ICF is increased to $10/kW/Month when NEM penetration in an IOU service area reaches 7%. ORA only analyzed the TOU 2 base case with a $10 ICF based on the assumption that default TOU rates will be implemented by the time the ICF is raised to $10. The public tool results for the $10 ICF with low DG value assumptions shows a noticeable drop in adoption in 2017, a rapid increase between 2019 and 2020, and a steep recovery to 2024. ORA's proposed successor tariff would not implement the $10 ICF until solar penetration in an IOU service area reaches 7% of aggregate peak demand, which ORA estimates to occur between 2019 and 2021. Therefore the Commission should focus on adoption of a $10 ICF beginning in 2019 when contemplating the effects of the $10 ICF on adoption under low DG value assumptions, which is also when the public tool predicts an increase in adoption under implementation of the $10 ICF .

The cumulative installation forecast, PCT, and payback for each of ORA's public tool scenarios are shown in Tables 9 through 11, and the Cost Impacts to non-participating customers for systems installed from 2017 to 2025 (RIM All Generation Case) are shown in Tables 12 through 14.

Table 9: Public Tool Results; Adoption, PCT, and Payback; $2/kW/Month ICF scenarios.

Renewable DG Case	Default Residential Rate	Installed Capacity Fee (ICF $/kW-month)	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG systems (Years)	Average Participant Benefit/Cost Ratio (PCT)
High	2-Tiered	2	16,775	5.18	1.90
Low	2-Tiered	2	12,581	7.40	1.33
High	TOU1	2	15,313	4.96	1.98
Low	TOU1	2	11,951	6.99	1.41
High	TOU2	2	16,778	5.25	1.87
Low	TOU2	2	12,398	7.51	1.31

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Table 10: Public Tool Results; Adoption, PCT, and Payback; $5/kW/Month ICF scenarios.

Renewable DG Case	Default Residential Rate	Installed Capacity Fee (ICF $/kW-month)	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG systems (Years)	Average Participant Benefit/Cost Ratio (PCT)
High	2-Tiered	5	16,570	5.71	1.72
Low	2-Tiered	5	11,199	8.05	1.22
High	TOU1	5	16,591	5.28	1.86
Low	TOU1	5	12,069	7.48	1.31
High	TOU2	5	16,596	5.77	1.70
Low	TOU2	5	11,142	8.19	1.20

Table 11: Public Tool Results; Adoption, PCT, and Payback; $10/kW/Month ICF scenarios

Renewable DG Case	Default Residential Rate	Installed Capacity Fee (ICF $/kW-month)	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG systems (Years)	Average Participant Benefit/Cost Ratio (PCT)
High	2-Tiered	10	15,255	6.78	1.45
Low	2-Tiered	10	8,262	9.14	1.07
High	TOU1	10	15,962	6.18	1.59
Low	TOU1	10	9,609	8.52	1.15
High	TOU2	10	15,265	6.91	1.42
Low	TOU2	10	8,067	9.31	1.05

Table 12: Public Tool Results; Cost Impacts on Non-Participating Customers for Systems Installed 2017-2025 (RIM All Generation Case); $2/kW/Month ICF scenarios

Renewable DG Case	Default Residential Rate	Installed Capacity Fee (ICF $/kW-month)	Average Non-Participant Benefit/Cost Ratio	Forecasted Installations 2017-2025 (MW)	Ratepayer Impact/Bill Increase (% of Res. RR)
High	2-Tiered	2	0.50	16,775	11%
Low	2-Tiered	2	0.25	12,581	16%
High	TOU1	2	0.48	15,313	12%
Low	TOU1	2	0.24	11,951	18%
High	TOU2	2	0.51	16,778	13%

Low	TOU2	2	0.25	12,398	17%

Table 13: Public Tool Results; Cost Impacts on Non-Participating Customers for Systems Installed 2017-2025 (RIM All Generation Case); $5/kW/Month ICF scenarios.

Renewable DG Case	Default Residential Rate	Installed Capacity Fee (ICF $/kW-month)	Average Non-Participant Benefit/Cost Ratio	Forecasted Installations 2017-2025 (MW)	Ratepayer Impact/Bill Increase (% of Res. RR)
High	2-Tiered	5	0.55	16,570	10%
Low	2-Tiered	5	0.28	11,199	13%
High	TOU1	5	0.51	16,591	14%
Low	TOU1	5	0.25	12,069	19%
High	TOU2	5	0.55	16,596	12%
Low	TOU2	5	0.28	11,142	15%

Table 14: Public Tool Results; Cost Impacts on Non-Participating Customers for Systems Installed 2017-2025 (RIM All Generation Case); $10/kW/Month ICF scenarios.

Renewable DG Case	Default Residential Rate	Installed Capacity Fee (ICF $/kW-month)	Average Non-Participant Benefit/Cost Ratio	Forecasted Installations 2017-2025 (MW)	Ratepayer Impact/Bill Increase (% of Res. RR)
High	2-Tiered	10	0.65	15,255	9%
Low	2-Tiered	10	0.34	8,262	9%
High	TOU1	10	0.59	15,962	13%
Low	TOU1	10	0.30	9,609	13%
High	TOU2	10	0.66	15,265	10%
Low	TOU2	10	0.35	8,067	9%

e. Public Tool Scenarios

To analyze the ICF, ORA executed 25 scenarios including i) the existing NEM under 4-tier residential rates, ii) base case scenarios for adopted two-tier residential rates and two TOU periods (TOU 1 with a peak from 2-8pm and TOU2 with a peak from 4-8pm) for high and low bookend cases and iii) the 6 base case scenarios with $2, $5 and $10 /kW-month installed capacity fees. ORA used the public tool published on July 17, 2015 (as indicated in cell B13 on the public tool cover page) as required by the July 20, 2015 ALJ Ruling.[48] Since

[48] *Administrative Law Judge's Ruling Providing Further Instructions for Parties' Proposals and Accepting Into the Record Certain Updates to the Public Tool*, dated July 20, 2015.

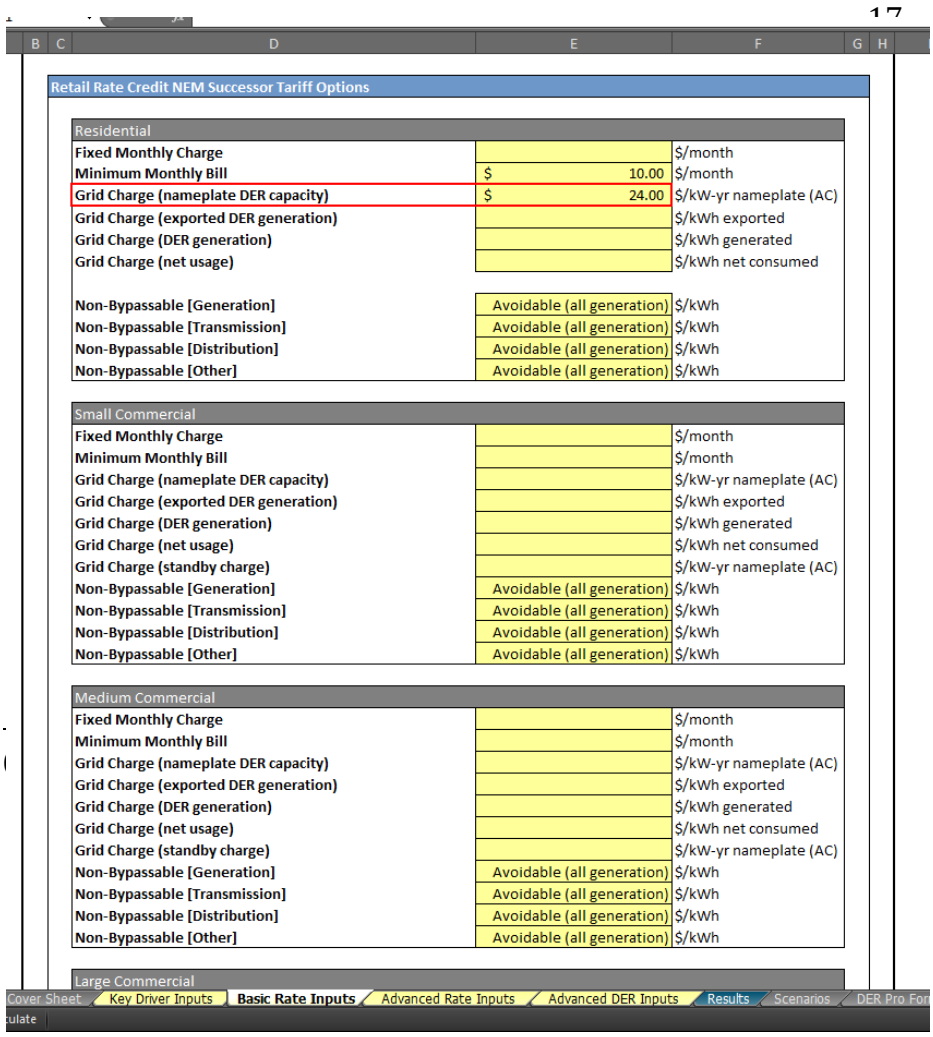
(continued on next page)

the public tool does not have the functionality to simulate charges or fees that escalates over time when solar penetration milestones are achieved, ORA ran scenarios with different installed capacity fees for the entire period from 2017-2025.

In order to run these scenarios with the proposed ICF, ORA used the base scenarios (i.e. two-tiered and TOU1 and TOU2 for high and low bookend cases) as provided by the Energy Division Staff in the public tool and input the ICF rate to be tested under the "Grid Charge (nameplate DER capacity)" for the residential customer class (input cell E46) on the Basic Rate Inputs, as shown in Figure 13. The ORA successor tariff proposal and this testimony refers to a *monthly* ICF, however, the public tool is designed to analyze annual capacity fees so each proposed fee tested by ORA was multiplied by 12 when entered into input cell E46 on the Basic Rate Inputs tab of the public tool.

Aside from simulating $2, $5, and $10 /kW-month installed capacity fees for residential customers, input into the July 17, 2015 version of the public tool as described above, ORA made no other changes to the key driver inputs, rate design assumptions, DER assumptions, or other underlying data and calculations in the public tool.

Figure 13: Inputs made to the Public Tool to simulate runs with ICF



Retail Rate Credit NEM Successor Tariff Options

Residential		
Fixed Monthly Charge		$/month
Minimum Monthly Bill	$ 10.00	$/month
Grid Charge (nameplate DER capacity)	$ 24.00	$/kW-yr nameplate (AC)
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated
Grid Charge (net usage)		$/kWh net consumed
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh
Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh

Small Commercial		
Fixed Monthly Charge		$/month
Minimum Monthly Bill		$/month
Grid Charge (nameplate DER capacity)		$/kW-yr nameplate (AC)
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated
Grid Charge (net usage)		$/kWh net consumed
Grid Charge (standby charge)		$/kW-yr nameplate (AC)
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh
Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh

Medium Commercial		
Fixed Monthly Charge		$/month
Minimum Monthly Bill		$/month
Grid Charge (nameplate DER capacity)		$/kW-yr nameplate (AC)
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated
Grid Charge (net usage)		$/kWh net consumed
Grid Charge (standby charge)		$/kW-yr nameplate (AC)
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh
Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh

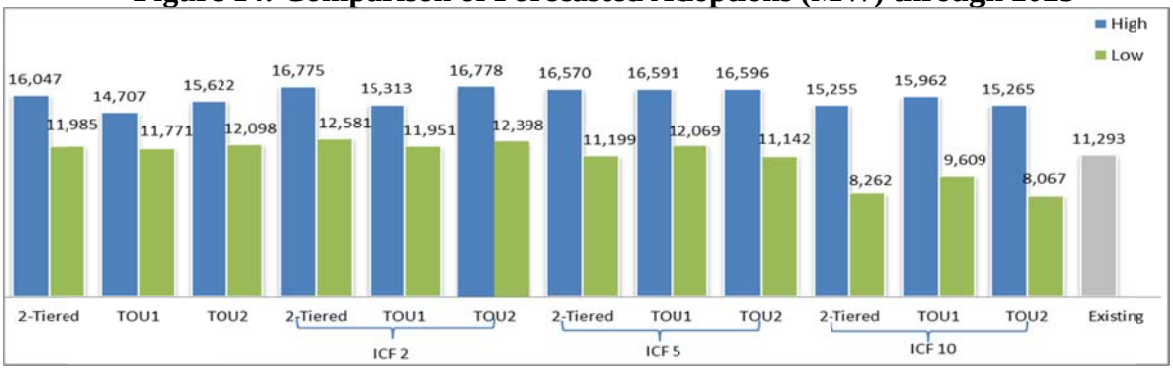
Large Commercial

Cover Sheet | Key Driver Inputs | Basic Rate Inputs | Advanced Rate Inputs | Advanced DER Inputs | Results | Scenarios | DER Pro For

Figures 14-16 and Table 15 provide all model results for Forecasted Cumulative Installations, Average Implied Payback, the Participant Cost Test ratio, the Ratepayer Impact Measure test ratio (for both Export only and All Generation), Residential Bill Increases (for both Export only and All Generation), Cost of Service results, the Total Resource Cost test ratio, and the Societal Cost Test ratio.

Figure 14 shows the forecasted capacity through 2025 under each scenario. Adoption rates for all ICF values under the high- and most low- DG value cases are higher than the forecasted capacity estimated by the existing policy pre-set in the public tool. The adoption rates are lower for the low DG value case with the $10 ICF for all the three rate structures (Tier2, TOU1 and TOU2) compared to the existing policy scenario.

Figure 14: Comparison of Forecasted Adoptions (MW) through 2025



The average implied payback of renewable DG systems and the Participant Cost Test ratio (PCT) are provided in Figures 15 and 16. The payback period for distributed generators is under 10 years for all the scenarios. The difference between the payback period of 6.55 years estimated for existing policy and the payback period for systems under a $2 or $5/kW-month tariff are within the 1-2 year maximum difference recommended by ED.[49] The $10 ICF results in a difference greater than 2 years, but the $10 ICF would not be implemented in the near-term and are thus less important than the near-term payback period. All of the scenarios modelled by ORA return a PCT ratio greater than one, as shown in Figure 16, indicating that a successor tariff remains economically attractive to participating customers with the introduction of the ICF.

[49] *Id.*. Attachment 1, pp. 1-9.

Figure 15: Comparison of Average Implied Payback Period under Existing NEM with current 4-Tier Residential Rates to NEM under the adopted 2-Tier and TOU rates with Installed Capacity Fee

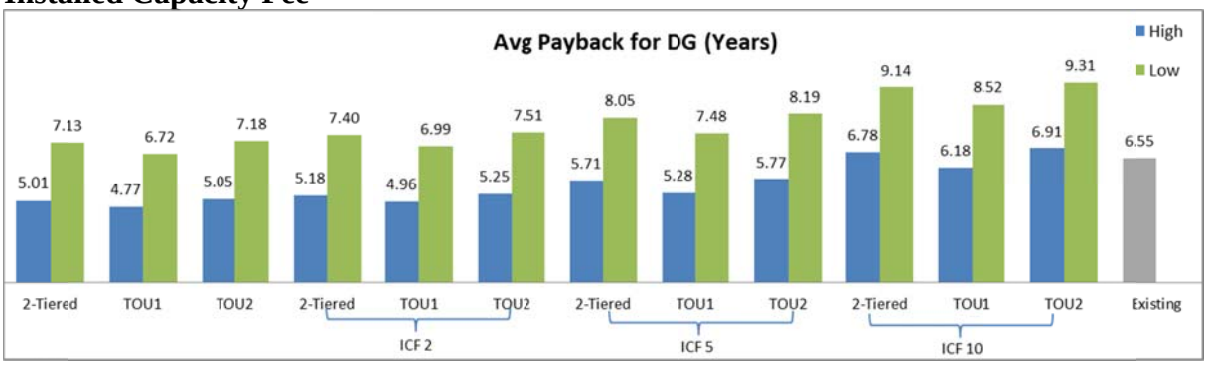


Figure 16: Comparison of Participant Benefit under Existing NEM with current 4-Tier Residential Rates to NEM under the adopted 2-Tier and TOU rates with Installed Capacity Fee

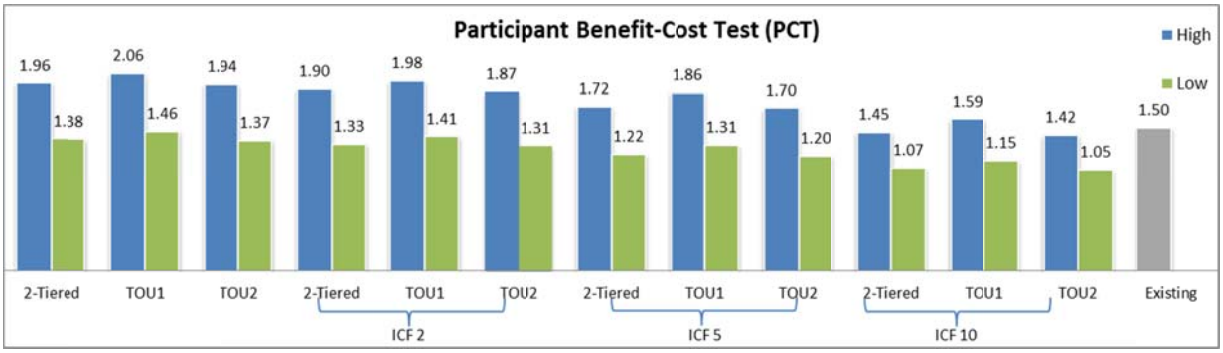


Table 15 shows the results of the two RIM tests (export only and all generation), the Total Resource Cost Test, and the Societal Cost Test. The $2 ICF has very little effect on these tests. However, these tests improve modestly with the higher ICF rates of $5 and $10.

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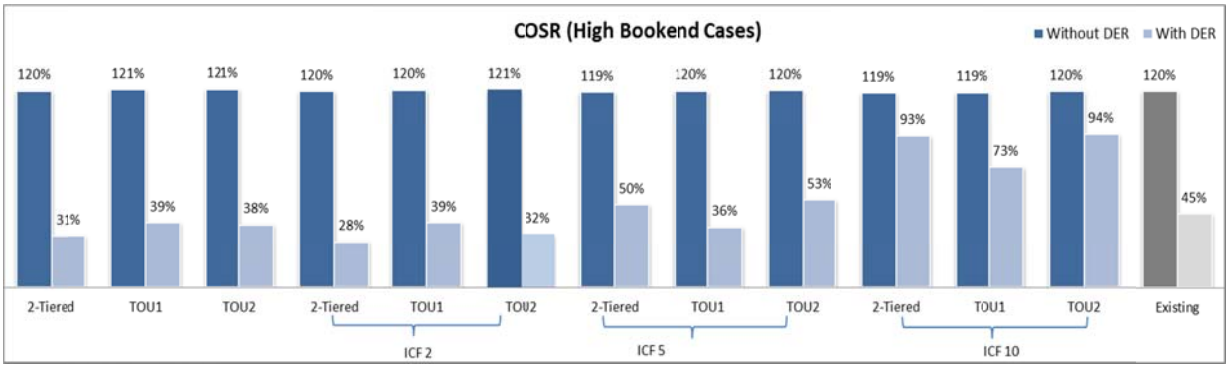
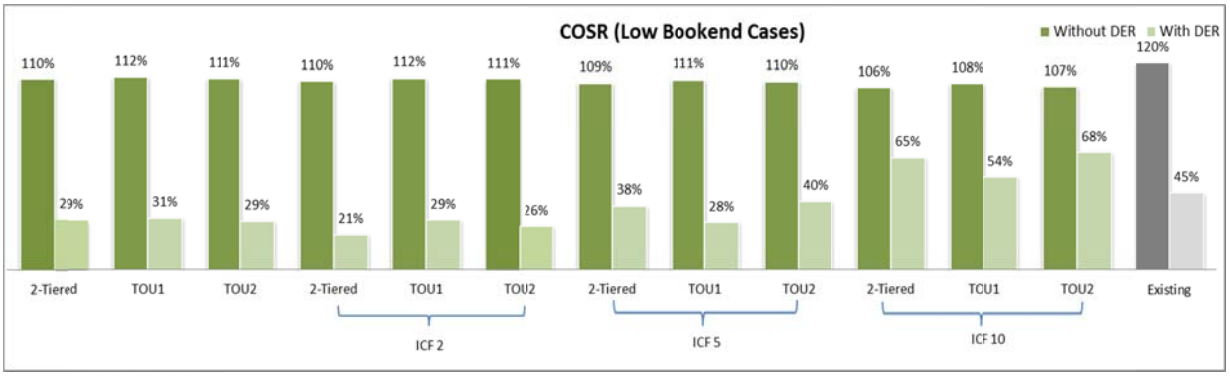
Table 15: Cost Impacts of NEM to Non-Participating Customers for Systems Installed 2017-2025

				Cost Impact to Non Participant Customers					
				RIM Export Only		RIM All Generation Case			
Renewable DG Case	Default Residential Rate	Installed Capacity Fee (ICF $/kW-month)	Forecasted Installations 2017-2025 (MW)	Average Non-Participant Benefit/Cost Ratio	Ratepayer Impact/Bill Increase (% of Res. RR)	Average Non-Participant Benefit/Cost Ratio	Ratepayer Impact/Bill Increase (% of Res. RR)	Total Resource Cost Test	Societal Cost Test
Existing			11,293	0.42	7%	0.44	12%	0.72	0.74
High	2-Tiered		16,047	0.39	10%	0.49	13%	0.95	0.97
Low	2-Tiered		11,985	0.18	15%	0.25	19%	0.46	0.45
High	TOU1		14,707	0.34	11%	0.47	13%	0.96	0.98
Low	TOU1		11,771	0.15	18%	0.24	20%	0.46	0.45
High	TOU2		15,622	0.36	11%	0.49	12%	0.95	0.97
Low	TOU2		12,098	0.17	17%	0.25	19%	0.45	0.45
High	2-Tiered	2	16,775	0.39	11%	0.50	13%	0.94	0.97
Low	2-Tiered	2	12,581	0.18	16%	0.25	19%	0.45	0.45
High	TOU1	2	15,313	0.34	12%	0.48	12%	0.95	0.98
Low	TOU1	2	11,951	0.15	18%	0.24	20%	0.46	0.45
High	TOU2	2	16,778	0.36	13%	0.51	12%	0.94	0.97
Low	TOU2	2	12,398	0.17	17%	0.25	19%	0.45	0.45
High	2-Tiered	5	16,570	0.41	10%	0.55	10%	0.94	0.97
Low	2-Tiered	5	11,199	0.20	13%	0.28	15%	0.47	0.47
High	TOU1	5	16,591	0.33	14%	0.51	12%	0.95	0.97
Low	TOU1	5	12,069	0.15	19%	0.25	19%	0.46	0.45
High	TOU2	5	16,596	0.37	12%	0.55	10%	0.95	0.97
Low	TOU2	5	11,142	0.18	15%	0.28	15%	0.47	0.47
High	2-Tiered	10	15,255	0.43	9%	0.65	6%	0.96	0.99
Low	2-Tiered	10	8,262	0.23	9%	0.34	10%	0.51	0.51
High	TOU1	10	15,962	0.35	13%	0.59	9%	0.95	0.98
Low	TOU1	10	9,609	0.18	13%	0.30	13%	0.49	0.49
High	TOU2	10	15,265	0.40	10%	0.66	6%	0.96	0.98
Low	TOU2	10	8,067	0.22	9%	0.35	9%	0.51	0.51

The Cost of Service Recovery (COSR) results are provided in Figure 17. The COSR estimates for residential customers with DER under the low DG value for the base case scenarios is approximately 30%. The COSR at the end of the tariff glide-path is over 50% for the low DG value scenarios and 70% to 90% for the high DG value scenarios.

Figure 17: Cost of Service Recovery for Residential NEM Successor Participants





f. Aggregation of Public Tool Adoption Results to Estimate the Glide-Path

The public tool was not designed to model charges or fees that adjust over time, so ORA constructed an adoption forecast that is an aggregation of public tool results from the $2, $5 and $10 /kW-month installed capacity fee scenarios. The purpose of constructing an aggregated adoption forecast is to simulate the annual adoptions from 2017 to 2025 with the ICF increases from $2 to $5 and $10. The aggregated adoption forecasts based on the regression forecast assumption described in section 5.a.1., under both the low and high DG value assumptions, are displayed in figures 18 and 19. The aggregated adoption forecasts based on the public tool forecast assumption described in section 5.a.2., under both the low and high DG value assumptions, are displayed in figures 20 and 21.

Figure 18: Aggregation of Low DG Value Adoption Assumptions (MW) Based on Regression Forecast Assumptions

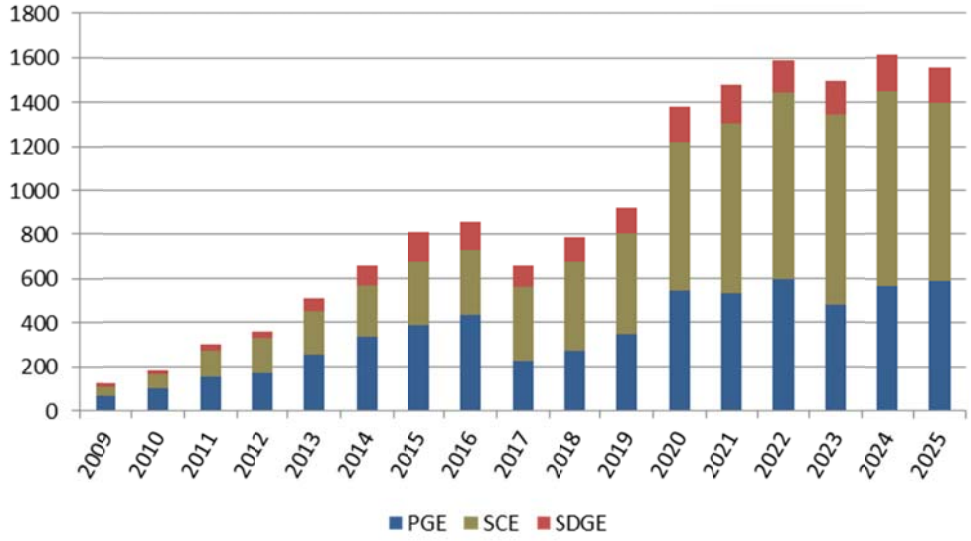


Figure 19: Aggregation of High DG Value Adoption Assumptions (MW) Based on Regression Forecast Assumptions

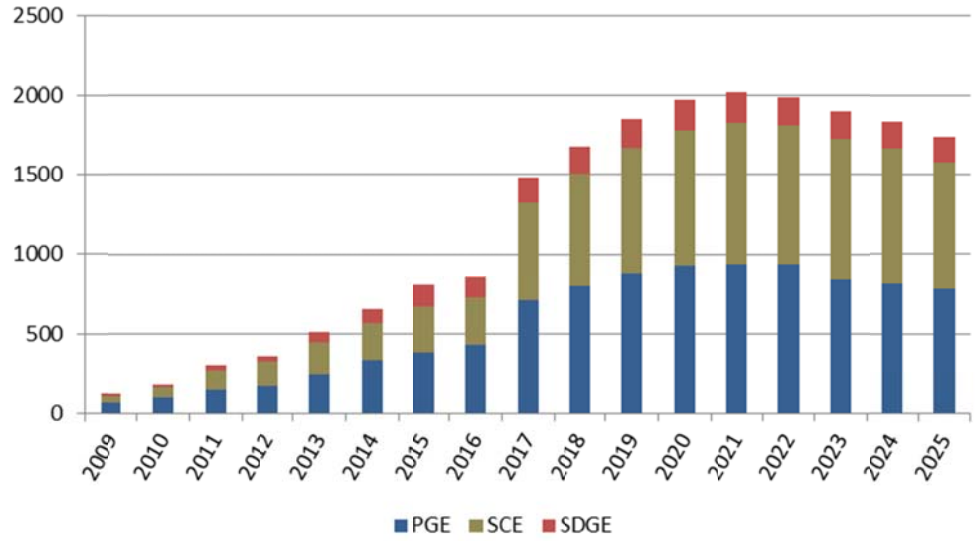


Figure 20: Aggregation of Low DG Value Adoption Assumptions (MW) Based on Public Tool Forecast Assumptions

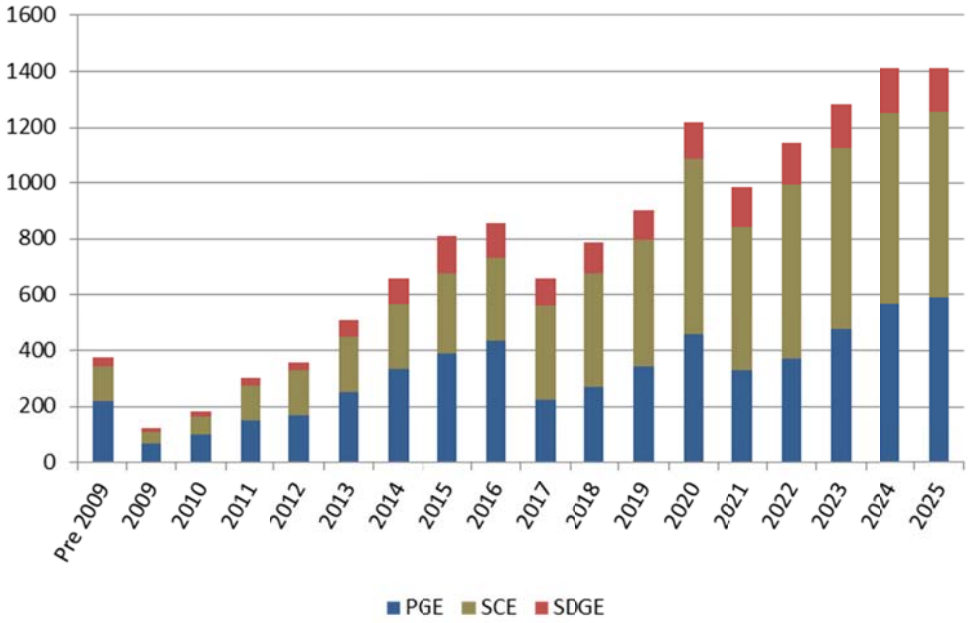
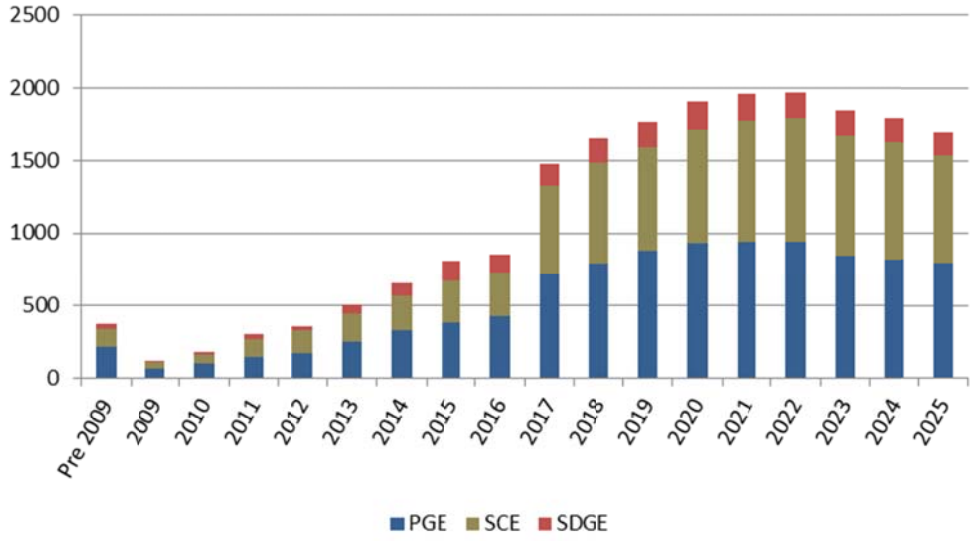


Figure 21: Aggregation of High DG Value Adoption Assumptions (MW) Based on Public Tool Assumptions



ATTACHMENT A

ATTACHMENT B

ATTACHMENT C - QUALIFICATIONS

QUALIFICATIONS AND PREPARED TESTIMONY
OF
TIM DREW

Q.1. Please state your name and address.

A.1. My name is Tim Drew. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission in the Electricity Pricing and Customer Programs (EPCP) Branch of the Office of Ratepayer Advocates (ORA) as a Public Utilities Regulatory Analyst.

Q.3. Please provide a brief description of your educational background and professional experience.

A.3. I received a Master of Public Administration degree from the Evan's School at the University of Washington, Seattle, in 2001. I received a Bachelor of Arts degree in Environmental Studies from the University of California, Santa Cruz, in 1995. I received a Certificate in Quantitative Evaluation Methods from the Evaluator's Institute at George Washington University, Washington D.C., in 2011.

I was employed by the Energy Division of the California Public Utilities Commission from June 2001 to September 2014. My responsibilities in the Energy Division included oversight and evaluation of energy efficiency, demand response, and customer generation programs and analysis of the California Public Utilities Commission's policies for demand-side management programs.

In September 2014, I joined ORA where my responsibilities have been to support ORA's advocacy within the NEM successor tariff, distributed generation, community solar, and integrated demand side resources proceedings.

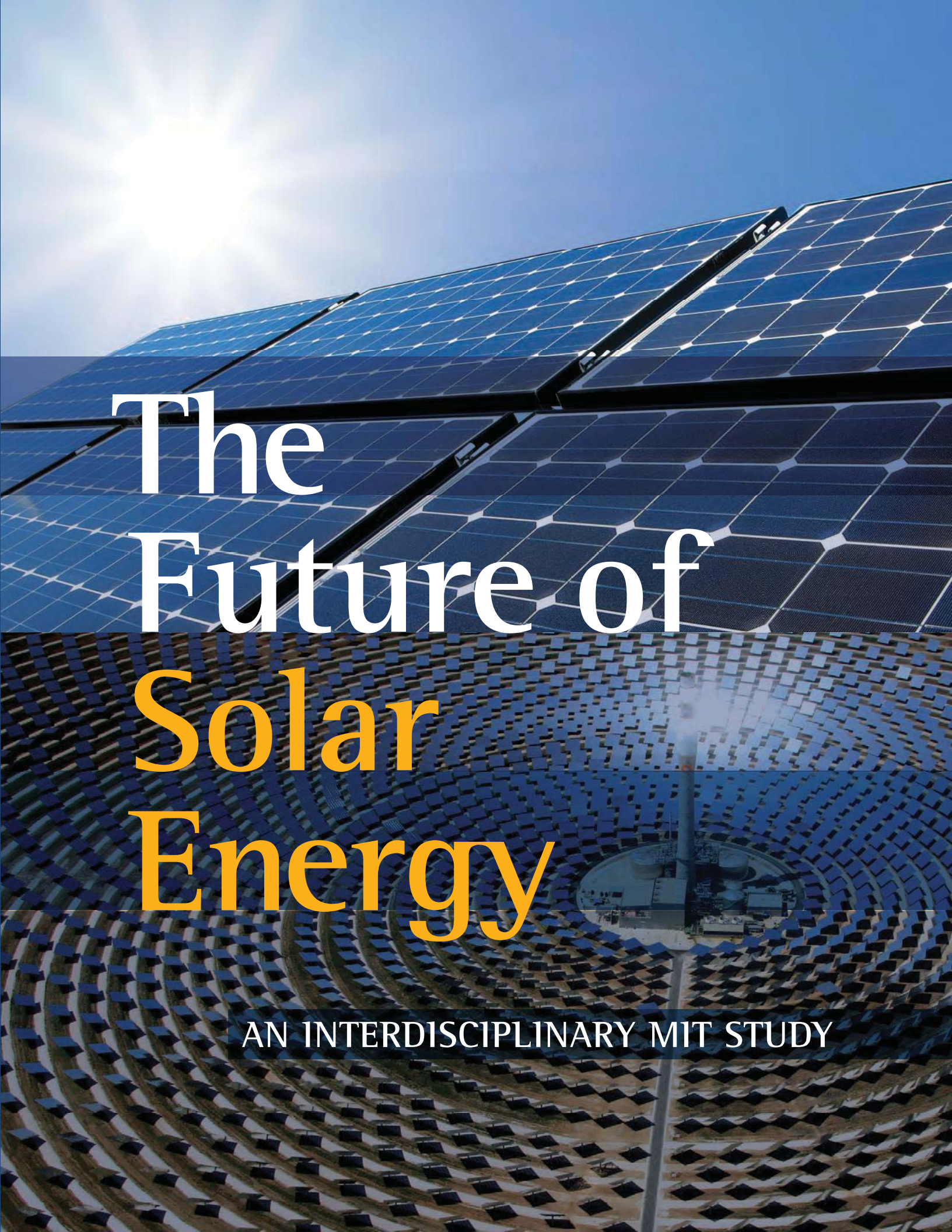
Q.4. What is the area of your responsibility in this proceeding?

A.4 I am sponsoring Opening Testimony of the Office of Ratepayer Advocates on the basis for Net Energy Metering Successor Tariff Capacity Fees.

Q.5 Does this conclude your prepared direct testimony?

A.5 Yes, it does.

ATTACHMENT A



The Future of Solar Energy

AN INTERDISCIPLINARY MIT STUDY

Chapter 5 – Economics of Solar Electricity Generation

In Chapter 4 we presented data on the total investment cost of residential- and utility-scale photovoltaic (PV) installations, and in Appendix D we presented data on the investment cost of utility-scale concentrated solar power (CSP) plants. In this chapter we first use those data, along with other information, to compute estimates of the cost of electricity generated at: (1) a 20-megawatt (MW) utility-scale solar PV project; (2) a 7-kilowatt (kW) residential rooftop PV installation, and (3) a 150-MW utility-scale CSP project. We consider hypothetical facilities at two U.S. locations for which reliable insolation data are available: the town of Daggett in southern California's San Bernardino County and the city of Worcester in central Massachusetts.[i] The southern California location is much sunnier on average than the Massachusetts location: Daggett receives approximately 5.8 kilowatt-hours of solar radiation per square meter per day (kWh/m^2/day) whereas Worcester receives approximately 3.8 kWh/m^2/day. Together, this pair of sites helps illustrate the range of costs produced by geographic variation. We assume identical investment costs for the two locations, but account for differences in insolation and other location-specific factors discussed below. We then compare generation costs at these sites to each other and to the cost of electricity from a new natural gas combined cycle plant with and without a carbon tax, where the carbon tax is set equal to the social cost of carbon dioxide (CO_2) emissions used by federal agencies in recent regulatory impact analyses.[1]

Data on average hourly wholesale electricity prices in the two locations are used to shed light on the average value of power generated by our hypothetical solar installations, taking wholesale prices as given.[ii] We then look at the impact of a number of factors on the cost of solar electricity from our hypothetical facilities. To highlight the importance of balance-of-system (BOS) costs for PV installations, we compute generation costs assuming that module prices decline by 50%. And because, as we stress in Chapter 4, the residential PV market is immature, we present estimates of levelized cost assuming that residential BOS costs in the United States fall to a level commensurate with those in Germany. Finally, we analyze the effects of the main federal subsidies on generation costs in the United States. As discussed below, it was not possible for us to measure the effects of state-level policies (known as "renewable portfolio standards") that oblige utilities in both California and Massachusetts to acquire a certain percentage of their electricity from renewable sources, or

[i]Our insolation data are from the National Renewable Energy Laboratory (NREL), which provides hourly insolation data for individual years (1991–2010) and for the typical meteorological year for 1,454 locations in the United States through the National Solar Radiation Database. Insolation and local meteorological conditions are either directly measured at ground stations or modeled based on a combination of satellite and ground-based data. Here we select locations designated as Class I stations, which have a complete record of solar and meteorological data for all hours for 1991–2010 and the highest-quality modeled solar data. From this we constructed a series for the typical year.

[ii]For our southern California data, we used hourly day-ahead locational marginal prices from the California Independent System Operator (CAISO) for the two major transmission intersections closest to Daggett, and averaged them. We are indebted to Gavin McCormick and Anna Schneider at WattTime for providing this data. For our central Massachusetts data, we used Independent System Operator-New England (ISO-NE) hourly day-ahead locational marginal prices for West-Central Massachusetts, made available in convenient form by GDF SUEZ Energy Resources.[2] In both cases, we constructed a series for a typical year by averaging over the years 2010–2012.

the effects of an array of additional state- and local-level renewable energy policies in these and other states.

Before turning to the details and results of our quantitative analysis, it is useful to begin with a general discussion of how the cost and value of electricity from particular generating facilities can be measured.

5.1 MEASURING THE COST AND VALUE OF SOLAR ELECTRICITY

A metric that is widely used to compare alternative generating technologies is the levelized cost of electricity (LCOE).[iii] Given a stream of capital and operating costs incurred over the life of a facility and a corresponding stream of electricity production, the LCOE is defined as the charge per kWh that implies the same discounted present value as the stream of costs. The discounting is done using a cost of capital appropriate to the type of project being considered. Put another way, the LCOE is the minimum price a generator would have to receive for every kWh of electricity output in order to cover the costs of producing this power, including the minimum profit required on the generator's investment. More detail on the calculation of LCOE is presented in Appendix E.

One important limitation is that the LCOE implicitly values all kilowatt-hours of power produced the same, regardless of when they are generated. But the incremental cost of meeting electricity demand is higher during peak periods.

Renewable electricity generated in peak hours is more valuable than electricity generated in off-peak hours.

The Cost of Capital

A critical component of the LCOE is the cost of capital. As described in detail in Appendix E, our basic analysis assumes a weighted average nominal cost of debt and equity capital of approximately 6.67%, along with an expected inflation rate of 2.5%.[iv] A 6.67% nominal cost of capital may seem high, given the extremely low interest rates that prevailed as this report went to press, but it is likely to be quite reasonable in more normal times.

Value versus Levelized Cost

Estimating the LCOE is only a starting point for evaluating the economics of a solar project, or of any other power generation project. One important limitation is that the LCOE implicitly values all kilowatt-hours of power the same, regardless of when they are generated. But the incremental cost of meeting electricity demand is higher during peak periods, like hot summer afternoons, than during off-peak periods, like comfortable spring evenings. During peak periods, incremental demand is typically met by employing fossil-fuel generating units that are operated for only a few hours a year. Since it is expensive to keep large amounts of capital idle most of the time, these units generally have low capital costs and, as a consequence, relatively high marginal costs. Thus renewable electricity generated in peak hours is more valuable than electricity generated in off-peak hours because it permits a larger reduction in fossil generation costs at the margin. In competitive wholesale power markets, this fact is at least partially reflected in higher prices for electricity during peak hours as compared to prices during off-peak hours. The price of electricity also varies over the course of the calendar year for

[iii] See, for example, NREL.[3,4]

[iv] Background on the weighted average cost of capital can be found in, for example, Brealey, Myers, and Allen.[5]

similar reasons. Other limitations of the LCOE arise when this metric fails to reflect a project's ability to provide capacity to meet uncertain demand, its ability to provide ramping capability, and other distinguishing attributes, some of which are discussed in more detail in Chapter 8.

To keep our analysis simple and because the value of the time profile of generation is so critical for a non-dispatchable resource like solar, we address only the average-price limitation of the LCOE.[v] Specifically, we use the time profile of wholesale electricity prices as the best available measure of the time profile of the social value of power. If more solar generation occurs when the hourly location-specific price is above average than when the price is below average, solar generation is more valuable per kWh than baseload generation. In this case, a solar plant selling at hourly location-specific prices would be viable at a lower unweighted average price than a baseload power plant with the same LCOE.[vi] Hirth introduced the term "*value factor*" to denote the ratio of a facility's output-weighted average price to its corresponding unweighted average price.[12]

Dividing a facility's LCOE by its value factor produces what we call the *value-adjusted* LCOE — in other words, it gives the minimum unweighted average price per kWh that would cover the generator's cost, given the observed temporal pattern of prices.

At least at low levels of solar penetration, one would expect solar facilities to have value factors above one, since wholesale prices tend to be higher in the day than at night. For our hypothetical PV facilities, we computed value factors using the typical-year insolation data described in Footnote i and the typical-year hourly price data described in Footnote ii. The value ratio for the southern California location was 1.13 and for the central Massachusetts location was 1.10. These values are roughly consistent with results obtained by Schmalensee (forthcoming)[13] using 2011 data.[vii] For the CSP facilities, without taking advantage of energy storage, the value ratio for the southern California location was 1.08; for central Massachusetts it was 1.11. This differs from the value ratio for our hypothetical PV project primarily because a certain amount of

[v]The U.S. Energy Information Administration (EIA) recently introduced another metric, the levelized avoided cost of energy (LACE) that can be used along with the LCOE to address this same limitation. See the presentation by Chris Namovicz.[6] See also two papers available at the same website.[7,8] LACE is closely related to the value factor defined below, except that it includes capacity payments available through wholesale markets. The Minnesota Department of Commerce, Division of Energy Resources recently undertook an alternative, similarly inspired effort to augment the LCOE.[9]

For a recent, much more ambitious — and controversial — attempt to quantify all the costs and benefits of a set of generating technologies that includes solar PV, see Charles R. Frank, Jr.[10] and Amory Lovins.[11]

[vi]Output from solar facilities is often sold under fixed-price, long-term contracts, not on the day-ahead hourly market. Absent a subsidy, however, one would not expect a buyer to pay more under a long-term contract than the (discounted) expected value of future hourly prices, since the buyer is bearing all the price risk. Indeed, many solar power purchase agreements adjust payments according to the hours in which power is actually delivered, specifying a higher price for power in some hours than in others. In any case, the value of a solar facility's output will surely influence the price it will command in the market.

[vii]An earlier version is Schmalensee's 2011 value factors, which are calculated for nine PV facilities, three of which were at unknown locations in California and three of which were at unknown locations in New England.[14] All nine solar value factors were above one. (In contrast, 22 of 25 value factors for wind generators were below one.) Value factors for the three California PV plants clustered tightly around the average of 1.13, which is exactly the value factor we find here for our southern California location at Daggett. For the three New England plants, Schmalensee found value factors of 1.18, 1.11, and 1.08, for a combined average of 1.12. This is higher than the 1.10 value factor we find here for our central Massachusetts location at Worcester, but well within the range of the data.

within-day inertia in the timing of electricity production is inherent in CSP, since the temperature of the medium that stores solar-derived thermal energy is relatively insensitive to short-term fluctuations in insolation.

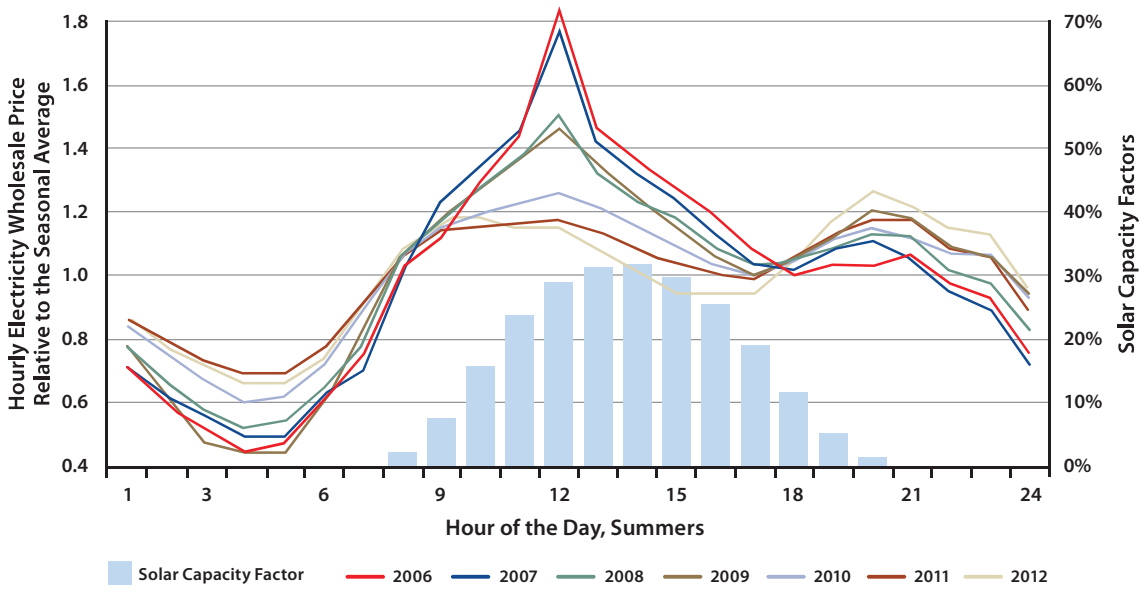
In a system with lots of solar generators that can profitably sell power in the short run at almost any positive price, wholesale prices might be lower at noon than at midnight.

However, taking optimal advantage of energy storage opportunities that would allow a CSP facility to accumulate thermal energy during hours of low electricity prices and generate at maximum capacity during hours of high electricity prices (so long as either insolation or stored thermal energy is available), the value ratios for the hypothetical CSP facilities increase to 1.12 and 1.16 at the southern California and central Massachusetts locations respectively. We use these higher values to calculate a value-adjusted LCOE for the CSP facilities.

Unfortunately, the value factor for any solar project is likely to decline dramatically with increased penetration of solar generation in the overall power mix as a result of basic supply and demand dynamics. Simply put, increasing the amount of zero-marginal-cost generation available during hours of high insolation will drive the price down in those hours. In a system with lots of solar generators that can profitably sell power in the short run at almost any positive price, wholesale prices might be lower at noon than at midnight.

Hirth finds considerable evidence for declining value factors in European data over several years of increasing solar penetration.[12] Figure 5.1, taken from Hirth, shows how the daily electricity price structure in Germany

Figure 5.1 Summertime Hourly Electricity Wholesale Prices Relative to Seasonal Average Price in Germany 2006–2012



Note: Lines show hourly wholesale prices relative to the seasonal average price for different years for the period 2006–2012, a time when installed solar capacity in Germany increased by 30 GW. The bars show the time profile of solar generation in Germany measured as the capacity factor for installed generation for 2006 to 2012.[12]

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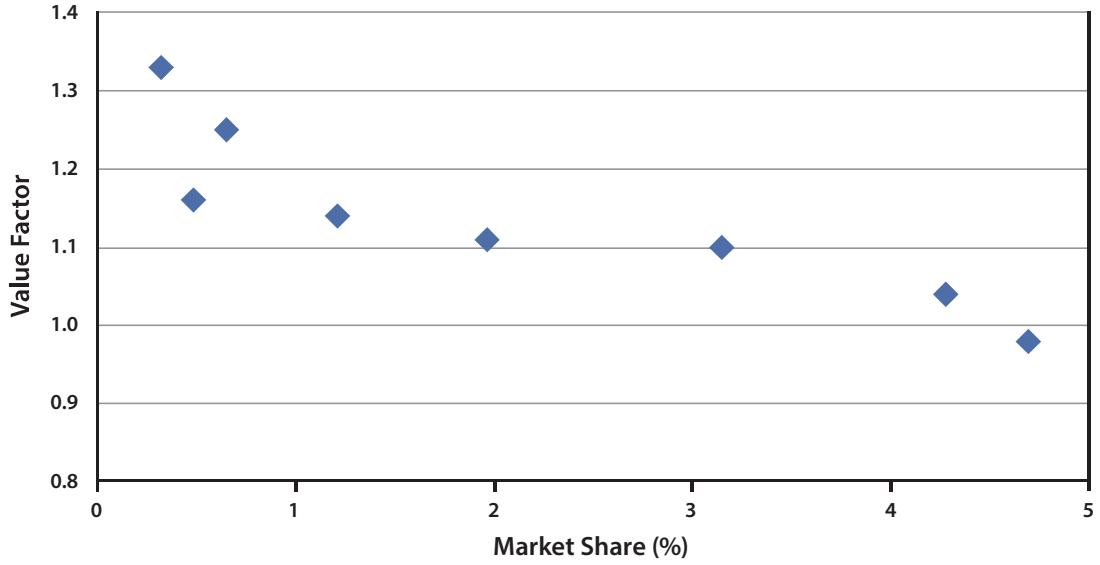
Figure 5.2 Value Ratio for Solar Generation in Germany with Changing Market Share[12]



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during summer hours changed between 2006 and 2012 as solar capacity increased by 30 gigawatts (GW). In 2006, the price at noon was 80% higher than the average price, while in 2012 it was only about 15% higher. Consequently, the value ratio for solar power declined dramatically over the same time. Figure 5.2, also taken from Hirth, shows this decline as a function of solar generation's increasing market share. It follows that currently observed value factors provide only a rough upper bound to expected future value factors for intermittent generators in the same market, using the same technology.

5.2 UTILITY-SCALE PV

Our analysis begins with the solar electricity generating technology that enjoys the most favorable economics today. As noted above, we consider hypothetical solar PV plants in California and Massachusetts with a nameplate direct current (dc) peak power rating of 20 MW.[viii] The project life is assumed to be 25 years, with output from the modules degrading at a rate of 1% per year, so that output in the 25th year equals approximately 79% of output in the first year.

Following Chapter 4, we assume a fully loaded module cost (i.e., including associated installer overhead) of 65 cents per watt ($0.65/W), which — when multiplied to reflect a 20 MW, utility-scale facility — yields an up-front investment cost of $13 million for the modules. Besides the cost of the modules, the complete installation requires the purchase of inverters, brackets, and wiring, as well as additional expenditures on engineering, construction and project management, sales taxes on materials,

[viii] These projects are assumed to be ground-mounted, fixed-tilt arrays using multicrystalline silicon PV modules with a dc peak power of 310W and a power conversion efficiency of 16%. The direct-current-to-alternating-current (dc-to-ac) derate factor of approximately 0.86 was estimated following NREL. The total dc-to-ac derate factor of 0.86 includes inverter and transformer inefficiencies (0.977), module-to-module mismatch (0.980), blocking diode and connection losses (0.995), dc wiring losses (0.980), ac wiring losses (0.990), soiling loss (0.950), and system downtime (0.980). We do not include losses due to nameplate rating error, shading effects, and tracking error. For further discussion, see NREL.[15]

and other charges. Together these are known as BOS (balance-of-system) costs. Again following Chapter 4, we assume a BOS cost of $1.15/W. At the 20 MW scale, this yields an additional up-front investment cost of $23 million. Together, the module and BOS costs add to a total investment of $36 million. Module cost and BOS costs account for 36% and 64%, respectively, of this total.

A given project may also incur additional indirect costs associated with grid integration. These indirect costs depend on many factors.

After the initial investment, our hypothetical project incurs annual operation and maintenance (O&M) costs, which we assume equal $0.02/W per year.[16] We assume O&M costs escalate with inflation. So, in the first year of operation, the O&M cost is $410,000. In addition, the project's inverters will need to be replaced in the twelfth year of operation at a cost of $3 million (before accounting for inflation).

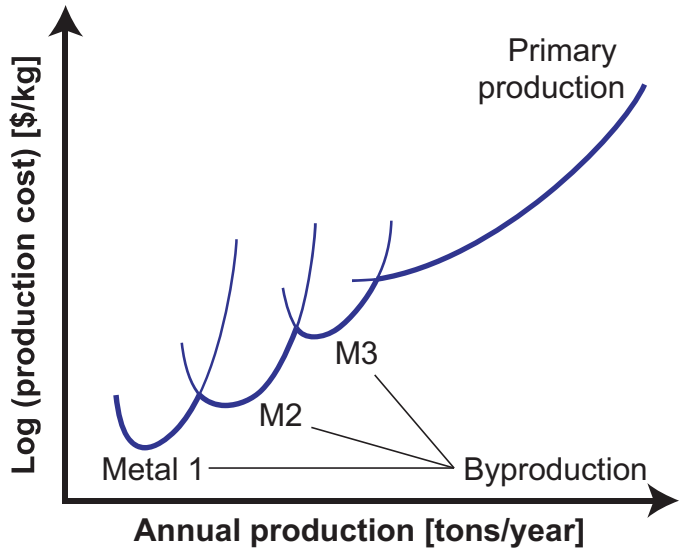
Investment cost plus O&M costs constitute all direct costs. However, a given project may also incur additional indirect costs associated with grid integration. These indirect costs depend on many factors, including the institutional rules governing the region where the project is located. For example, the intermittency of the solar resource may force the grid manager to maintain additional flexible resources to ensure system reliability, and some of these costs might be imposed on the solar facility.[ix] In addition, depending on the location of the project and applicable cost allocation rules, there may be costs associated with installing a transmission line to deliver power from the solar facility to the existing grid. Our calculations do not include any charges for these or any other indirect costs.

We apply the same investment cost and O&M cost assumptions to both the southern California and the central Massachusetts plants. Given the typical insolation at our southern California location, this plant should generate approximately 36,000 megawatt-hours (MWh) of electricity in the first year of operation, with output in subsequent years declining gradually over the life of the project. In contrast, lower levels of insolation at the central Massachusetts location mean that the same plant can be expected to generate approximately 24,000 MWh in its first year of operation, one-third less electricity than the southern California project using the same equipment. Because of this difference in output, the LCOE of the central Massachusetts project is 15.8 cents per kilowatt-hour (¢/kWh), 50% higher than the 10.5¢/kWh LCOE of the southern California project. These figures assume no subsidies. Figure 5.3 provides a convenient visual display of these LCOEs, together with some of the further results discussed below. These results are also summarized in Table 5.1, which appears at the end of the chapter.

As described above, we calculated value factors for the California and Massachusetts locations to account for the fact that peak solar output is likely to occur at times when demand is high and prices for electricity are above average. Dividing by these value factors lowers the LCOE of the southern California project by 12% and lowers the LCOE of the central Massachusetts project by 9% (see Table 5.1). As we noted previously, value factors will tend to decline as the share of solar energy in the overall generation mix increases. This in turn would raise the value-adjusted LCOEs of future solar projects. At a certain level of penetration, value factors for solar generators are likely to decline below 1, so that the value-adjusted LCOE rises above the unadjusted LCOE.

[ix]See Chapter 8 of this report and Gowrisankaran, Reynolds, and Samano.[17]

Figure 6.6 Cost versus Production for a Hypothetical Energy-Critical Element



Note: Figure 6.6 shows a hypothetical cost versus production curve for an energy-critical element (ECE) that is initially obtained as a byproduct of major metal extraction. Each joint production curve shows an initial decrease as the new byproduction technology becomes established, followed by a plateau and a slow increase as rising production requires progressively more heroic efforts to capture the critical element, and finally a sharp increase when by production capacity is saturated. Eventually, primary production is the only remaining alternative, with a more conventional cost–production function.

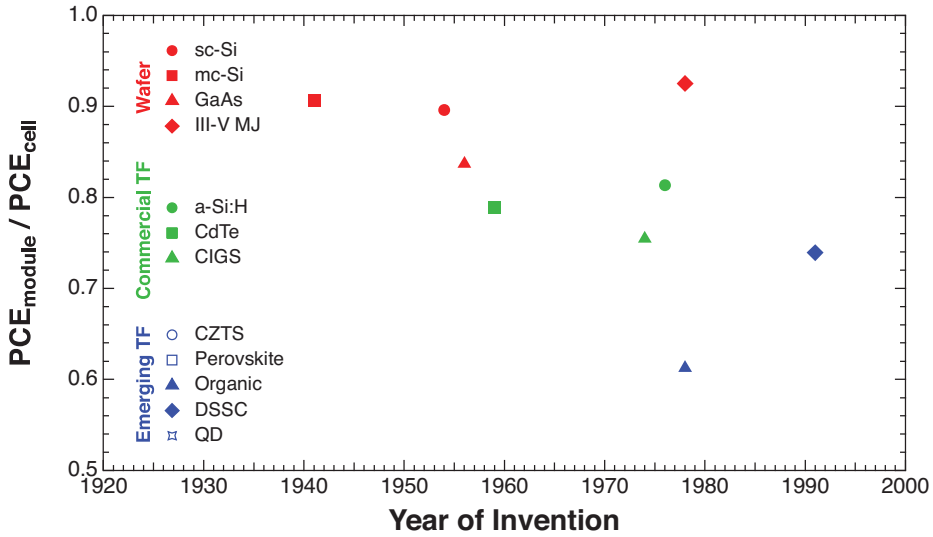
The aggressive increase in annual PV deployment required to meet 50% or 100% of projected global electricity needs with PV would necessitate similarly aggressive growth in the production of certain materials.

Growth in Yearly Production [tons/year per year]

Just as there may be limits to the cumulative or yearly production of a material, there may also be limits to the rate at which production of this material can grow. The aggressive increase in annual PV deployment required to meet 50% or 100% of projected global electricity needs with PV would necessitate similarly aggressive growth in the production of certain materials (particularly materials that do not see wide use in other sectors, such as tellurium). Following the analysis method of Kavlak et al.[61,62] (presented in more detail in an associated white paper[63]), we estimate the rate of growth in the production of PV-critical elements that is necessary to achieve these PV deployment targets and compare these growth rates with historical precedent. This analysis provides insight into the feasibility of terawatt-scale deployment of different PV technologies that employ these elements.

Figure 6.7 shows production data for 35 different metals over the last century.[39,44] To determine the historical rate of growth in production as a function of time, we fit lines to the natural logarithm of production in overlapping 36-year periods (equal to the time remaining to achieve our 2050 deployment targets), using the slope to determine the annual growth rate over that period. We find that the median annual growth rate of production for these 35 metals over 36-year periods between 1900 and 2012 is

Figure 10.5 Effect of Development Time on Record Efficiencies of Solar Cells and Modules



Note: The figure shows that record module efficiencies tend to be closer to record cell efficiencies for older technologies. For each technology, the year of invention refers to the date of the first peer-reviewed publication or patent reporting the solar cell design in question. Some emerging thin-film technologies (e.g., CZTS, perovskites, and QDPV) are omitted because few or no modules of that type have been demonstrated.

In part due to the availability of combustion turbines, demand management, and geographic averaging, current levels of PV penetration across the United States have not yet reached the point where the absence of large-scale storage capability is constraining further deployment.[iii] Therefore, the appropriate balance of government support for storage technologies should emphasize fundamental research over deployment at the present time. Given the importance of energy storage for long-term, high-penetration deployment of solar and other intermittent generation technologies, support for storage technologies within the DOE RD&D research portfolio should be a high priority.

RECOMMENDATION

Research on bulk energy storage should be strongly supported at a level commensurate with its importance as a key enabler of intermittent renewable energy technologies.

The appropriate balance of government support for storage technologies should emphasize fundamental research over deployment at the present time.

[iii] Pumped hydro is a mature and efficient energy storage technology, but it is only applicable in specific geographic regions, most of which have already been exploited in developed nations.

High-Efficiency Solar Energy Collection and Receiving Systems

As discussed previously, the most expensive and second least efficient component of a typical CSP plant is the collector/receiver, which gathers solar energy in the mirror field and converts it to thermal energy. Key RD&D priorities for the mirror field include lower cost manufacturing and installation, less costly and more accurate tracking systems, more efficient mirrors, and engineered surfaces to prevent fouling in desert environments — all improvements that would enable future plants to achieve tighter light focusing and higher temperatures. Basic research at universities on surface modification and thin films may lead to breakthroughs in the latter two areas, and applied research undertaken by universities, national laboratories, and industry researchers can lead to lighter-weight, easier-to-manufacture mirror designs. Most of the applied research to reduce mirror weight and manufacturing costs, however, will appropriately fall to industry as it scales up new CSP technologies.

As described in Chapter 3, a point-focus CSP architecture (e.g., solar tower) can generally achieve higher power conversion efficiencies than the older trough technology, since point-focus designs deliver a higher-temperature heat source to the power block. Based on this inherent efficiency advantage, we recommend that most future CSP research target point-focus technologies or new, novel configurations rather than incremental improvements to trough designs.

Although a higher-temperature heat source increases the heat-to-electricity conversion efficiency of CSP systems, it also creates material-related challenges. One such challenge is to develop suitable receiver materials and heat transfer fluids that are capable of handling high temperatures without degrading and can also get through the night without freezing. Another challenge is to develop construction materials and designs for components such as pumps and pipes that are capable of withstanding exposure to high temperatures. These challenges point to important new directions for basic and applied research in this field.

Key RD&D priorities for the mirror field include lower cost manufacturing and installation, less costly and more accurate tracking systems, more efficient mirrors, and engineered surfaces to prevent fouling in desert environments.

RECOMMENDATION

Future CSP RD&D should emphasize high-temperature, point-focus technologies that hold promise for improving system efficiency and cost-effectiveness.

Efficient and Cost-Effective Thermal Energy Storage Systems

One of the unique characteristics of CSP technologies is that they offer easy and cost-effective opportunities to incorporate significant thermal energy storage. Many problems in thermal storage must be addressed, however, to exploit this synergy fully. Much recent research has focused on developing molten salt compositions suited to parabolic trough and point-focus applications. This work leverages extensive past research on molten salts for high-temperature nuclear reactors.[17] Progress with molten salts has enabled operation at higher temperatures and provided for greater thermal energy storage density. However, problems with freezing at the low-temperature end of the process and thermal decomposition at the high-temperature end of the process may

Novel CSP Design, Integration, and Hybrid Configurations

Research on novel CSP configurations can exploit the inherent advantages of CSP technology — namely, that it allows for the natural integration of energy storage and easy hybridization with fossil power plants — and may enable the efficiency limitations of current systems to be overcome. In particular, novel configurations can provide a platform for integrating innovations in the three research opportunity areas discussed previously (i.e., high-efficiency collection and receiving systems, efficient and cost-effective energy storage systems, and advanced power cycles). An example is the direct solar-to-salt design described in Chapter 3 (Section 3.6 and Figure 3.12), which — by combining the traditional elements of receiver and thermal energy storage container — simultaneously addresses several issues with respect to efficiency losses, materials design challenges, thermal storage, and operational temperature.

Finally, numerous research opportunities exist for exploiting the thermal energy collected in CSP plants to provide energy for thermochemistry and process heat. Because this study is focused on solar electricity generation, we do not discuss these applications in detail other than to note that by stopping short of the electricity production step, they eliminate power block losses altogether. An example is the use of steam produced by concentrated solar thermal plants for enhanced oil recovery. In such applications, the thermal energy collected by the solar plant can either supplement fossil energy sources or replace them. Concentrated solar thermal energy can also be used as a heat source for reforming, cracking, and gasification processes. With potential advances in the future, it might also be used for water splitting[18] to produce hydrogen.[vii]

There are a variety of ways in which the thermal energy collected by CSP plants might be exploited efficiently in thermochemical and other thermal processes. These processes and designs need to be considered for further development and possible commercialization as part of a broader CSP RD&D portfolio.

10.5 DEMONSTRATION SUPPORT FOR SOLAR TECHNOLOGIES

The federal government has long provided support for energy technology demonstration, including for early light water nuclear reactors, and more recently for efforts to demonstrate carbon capture and sequestration. The demonstration of new PV and CSP technologies at appropriate scale is a critical step in the progression to large-scale deployment. Exactly what scale of demonstration project is necessary to build confidence in a technology and move it through the development cycle will vary. In the case of PV systems, where technical performance is largely insensitive to scale (*economic* performance, it should be noted, is sensitive to scale, even for PV systems), confidence can be gained even from very small-scale demonstrations. By contrast, the *technical* performance of CSP systems is inherently sensitive to scale and proving out these systems requires demonstration projects that are at least pilot-scale in size.

The demonstration of new PV and CSP technologies at appropriate scale is a critical step in the progression to large-scale deployment.

[vii] Water splitting could be achieved through solar thermolysis or a solar thermochemical cycle.

Loan Guarantee Programs

Over the past several years, the loan guarantee programs administered by DOE's Loan Programs Office (LPO) have been held up as an important example of demonstration support for solar PV and CSP technology.[19,20] Fourteen individual solar projects have received LPO support, all as part of the Section 1705 Loan Program. In total DOE has provided $5.85 billion in loans for CSP projects (including $5 billion as the sole lender) and $4.74 billion in loans for PV projects (including $3.28 billion as the sole lender). All of the CSP and PV loans are currently in good standing. DOE has also provided $1.085 billion in loans for solar manufacturing; of this total, $596 million is classified as discontinued (including $528 million drawn by Solyndra Inc.), which indicates termination of the loan or guarantee, an ongoing bankruptcy proceeding, or (possibly pending) sale of the guaranteed note.[21]

A key objective of any technology demonstration program should be to develop insights regarding, among other things, the cost, technical performance, and reliability of new technologies when deployed at commercial scale. Sharing this information with the private sector should build confidence in the technologies being demonstrated and help reduce perceived technology risks to the point where private capital becomes available to support deployment. While DOE loan guarantees have certainly enabled the development of several very large (i.e., commercial-scale) PV and CSP installations, with combined capacity totaling 1,200 megawatts (MW), it is not clear that the current loan program has been effective in achieving desired technology demonstration objectives, particularly since DOE has not produced any comprehensive public reporting on the costs and performance of the technologies the program has supported.

A key objective of any technology demonstration program should be to develop insights regarding, among other things, the cost, technical performance, and reliability of new technologies when deployed at commercial scale.

FINDING

Many of the solar projects supported by DOE's loan guarantee programs to date are of a scale well beyond that needed for effective commercial demonstration; moreover, very high loan repayment rates suggest an overly conservative loan guarantee project portfolio.

The fact that only 2.2% of DOE's PV and CSP generation loan book is now in default indicates that the risk profile of projects supported by the federal loan program has been very conservative. Furthermore, several projects that have received federal loan guarantees, including several PV generation projects, significantly exceed the project size needed for effective technology demonstration.[22]

RECOMMENDATION

DOE should assess what has been learned regarding cost, performance, and reliability for solar technologies that have received support in the form of federal loan guarantees and make this information available to the private sector.

Moving forward, DOE has stated that its loan guarantee programs will no longer be available to the types of large-scale PV and CSP facilities they have supported to date.[23] We believe this change is appropriate.

ATTACHMENT B

Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area

PREPARED FOR

PREPARED BY

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Sanem Sergici
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Jens Schoene (EnerNex)

July 2015

THE Brattle GROUP

Xcel Energy Colorado was chosen for this study because it is reasonably representative of a midsize utility system in the Western U.S. from a number of perspectives, including, among others, the size of system, load profile, and the current level of penetration of residential-scale systems in its service territory. Xcel Energy Colorado's service territory is also reasonably representative of investor-owned utilities in the West in terms of the mix of urban and rural load and distribution feeders. We employed an increment of 300 MW of PV because this level of addition is consistent with Xcel Energy Colorado's currently planned addition of utility-scale resources in 2019.[3] This level of incremental solar capacity is large enough to produce a useful cost comparison but is not so large as to cause a complete reconfiguration of its existing resource plan.

In this study, we have analyzed a Reference Case and five scenarios with varying ITC, PV cost, inflation, and financing parameters. We provide brief descriptions of the Reference Case and the scenarios below, with more details provided in Section III. In each of these scenarios, costs for residential-scale PV systems are considered in two ways: as a simple system purchased and owned by customers [our base case] or modeled as a leased system.

Reference Case uses the projected installed PV costs for 2019; assumes that the ITC is at 10%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale lease systems. Residential-scale purchases do not receive any ITC credits in 2019, consistent with the current tax code.

Scenario 1 (2019 ITC at 30%) uses the projected installed PV costs for 2019; assumes that the ITC remains at 30%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale lease systems. In this scenario, residential-scale purchases are also assumed to take advantage of the 30% ITC.

Scenario 2 (2019 Developer absorbing ITC) uses the projected installed PV costs for 2019; assumes that the ITC is at 10% and developers (as opposed to third-party tax equity) absorb the ITC credits for both utility- and residential-scale lease systems.

---

[3] Xcel Energy Colorado plans on adding 170 MW of utility-scale PV into their system by 2019.

Scenario 3 (2019 Higher Inflation) uses the projected installed PV costs for 2019; assumes that the ITC is at 10%; tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale systems; and inflation is higher at 4%. Residential-scale purchases do not receive any ITC credits in 2019, consistent with the current tax code.

Scenario 4 (2019 Lower PV Cost) scales down the projected installed PV costs for 2019 by 20%; assumes that the ITC is at 10%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale systems. Residential-scale purchases do not receive any ITC credits in 2019, consistent with the current tax code.

Scenario 5 (2014 Actual PV Cost) uses the actual installed PV costs for 2014; assumes that the ITC is at 30%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale lease systems. Residential-scale purchases are also able to take advantage of the 30% ITC credits, consistent with the current tax code.

The results of our analysis demonstrate clearly that the generation costs per MWh of PV electricity from 300 MW of utility-scale systems are roughly one-half the costs of an equivalent amount of PV electricity from 60,000 residential-scale systems when added to the Xcel Energy Colorado system in 2019. The projected levelized cost of energy from utility-scale PV in 2019 ranges from $66/MWh to $117/MWh (6.6¢/kWh to 11.7¢/kWh) across the scenarios considered, while residential-scale PV energy costs $123/MWh to $193/MWh (12.3¢/kWh to 19.3¢/kWh) for a typical residential-scale system owned by the customer and even more if the residential-scale system is leased.[4] The generation cost difference between the two is 6.7¢/kWh to 9.2¢/kWh solar across the scenarios. To put this in perspective, national average all-in retail residential electric

[4] Today about 70% of residential systems are leased from third party owners. Industry reports and our own calculations, reported below, indicate that the cost of solar power to residential customers from leased systems is typically larger than the cost of solar power from otherwise-identical systems that are customer-owned. The calculated per-MWh difference between utility- and residential-scale leased systems, as shown in Table 2, is therefore even larger than the difference between utility- and residential-scale owned systems. However, the cost of power from residential-scale leased systems also varies substantially by solar provider, finance and tax assumptions, region, and lease provider. In addition, industry reports indicate that customer ownership is likely to overtake leasing in the next several years. Because our target year is 2019, customer ownership is the more logical benchmark for comparison.

rates in 2014 were 12.5¢/kWh.[5] One reason for this difference in electricity cost between utility- and residential-scale systems is that the utility-scale system produces almost 50% more electrical energy per year than an equal capacity of residential-scale systems.[6]

Table 2: Levelized Cost of Utility- and Residential-scale PV ($ per Solar MWh)

No	Scenario	Utility-scale	Residential-scale Purchase	Cost Difference (Res-Utility)	Residential-scale Lease
Reference	**2019 ITC @ 10%**	**83**	**167**	**83**	**182**
Scenario 1	2019 ITC @ 30%	66	123	**57**	140
Scenario 2	2019 Developer absorbs ITC	66	N/A	**N/A**	140
Scenario 3	2019 Higher Inflation	95	187	**92**	206
Scenario 4	2019 Lower PV Cost	69	137	**67**	149
Scenario 5	2014 Actual PV Cost	117	193	**76**	237

Notes:
1-All Scenarios other than Scenario 2 assume there is a tax equity partner.
2-In Scenario 1, 30% ITC assumption has been applied to all three cases uniformly.
3-Scenario 2 is only relevant to the utility- and residential-scale leased systems and does not to impact residential-scale purchases.

Table 2 and Figure 1 show our comparison of the levelized costs for utility- and residential-scale PV systems, customer-owned residential-scale systems (residential purchase), and leased residential-scale systems. As these results indicate, the large generation cost advantage of utility-scale PVs does not change with differences in other factors that normally affect costs to costumers such as tax credits, use of tax equity, renewable energy certificate (REC) prices, inflation, or a more rapid decrease in the price of PV panels.

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5 EIA Electric Power Monthly, January 2015, Table 5.3.

6 As discussed later in the report, utility-scale solar PV would yield an annual 597,000 MWh and residential-scale PV would yield 400,000 MWh.

ATTACHMENT C - QUALIFICATIONS

QUALIFICATIONS AND PREPARED TESTIMONY
OF
TIM DREW

Q.1. Please state your name and address.

A.1. My name is Tim Drew. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission in the Electricity Pricing and Customer Programs (EPCP) Branch of the Office of Ratepayer Advocates (ORA) as a Public Utilities Regulatory Analyst.

Q.3. Please provide a brief description of your educational background and professional experience.

A.3. I received a Master of Public Administration degree from the Evan's School at the University of Washington, Seattle, in 2001. I received a Bachelor of Arts degree in Environmental Studies from the University of California, Santa Cruz, in 1995. I received a Certificate in Quantitative Evaluation Methods from the Evaluator's Institute at George Washington University, Washington D.C., in 2011.

I was employed by the Energy Division of the California Public Utilities Commission from June 2001 to September 2014. My responsibilities in the Energy Division included oversight and evaluation of energy efficiency, demand response, and customer generation programs and analysis of the California Public Utilities Commission's policies for demand-side management programs.

In September 2014, I joined ORA where my responsibilities have been to support ORA's advocacy within the NEM successor tariff, distributed generation, community solar, and integrated demand side resources proceedings.

Q.4. What is the area of your responsibility in this proceeding?

A.4 I am sponsoring Opening Testimony on the Office of Ratepayer Advocates Net Energy Metering Successor Tariff Basis for Capacity Fees.

Q.5 Does this conclude your prepared direct testimony?

A.5 Yes, it does.