Rulemaking: 14-07-002
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Date: September 30, 2015
Witness(es): R. Thomas Beach
Mark Fulmer
Jose Luis Contreras

JOINT SOLAR PARTIES

NET ENERGY METERING SUCCESSOR TARIFF

REBUTTAL TESTIMONY

September 30, 2015

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EXECUTIVE SUMMARY OF RECOMMENDATIONS

This testimony presents the rebuttal testimony of the Joint Solar Parties (JSP) – the California Solar Energy Industries Association (CALSEIA), the Solar Energy Industries Association, the Alliance for Solar Choice, and Vote Solar – in this rulemaking proceeding to determine the successor tariff for net energy metering (NEM) in California.

In Chapter 1 of this testimony, the JSP review the proposals of other parties for new rate design elements that would be included in the NEM successor tariff. We assess these new rate design elements in terms of whether they would advance the Commission's Rate Design Principles and would comply with the policies for residential rate design which the Commission recently adopted in Decision 15-07-001 in the comprehensive Residential Rate Design OIR (RROIR).

The JSP's recommend retaining the current NEM structure. As demonstrated in the JSP's testimony, the current NEM tariff complies with the Commission's Rate Design Principles to exactly the same extent as the underlying rate design. One of the strengths of the current NEM tariff is that it is completely "transparent" to the rate design under which NEM customers take service, By "transparent," we mean that a residential customer who has installed solar under the current NEM tariff continues to see exactly the same rate design, and the same resulting price signals, that the customer faced before installing solar. It is particularly important to retain the transparency of the current NEM tariff at a time when residential rate design is undergoing significant changes. If the NEM successor tariff has a very different and more complex structure and rate design, as several parties have proposed, the transition to new rate designs for both regular residential customers and for customers who install DG would become unworkably complex.

ORA and SCE have proposed new fixed charges based on installed DG capacity that would be additive to the rates paid by customers who install renewable distributed generation (DG). On the record of this proceeding the JSP have disputed the rationale underlying the need for new fees or rate design changes; nonetheless, the JSP appreciate that the ORA's ICF (as an overlay to the current NEM tariff) is simple to understand from a customer perspective and would continue to convey the same price signals as the underlying rate design. At the same time, the JSP are certain that the timeline, ramp up and proposed ICF fees would significantly reduce solar consumer savings and thus damage the market in a time of uncertainty. Simply put, ORA presents very unrealistic estimates of when their adoption targets will be reached. ORA claims that its proposal is based on the gradual reductions in solar incentives under the California Solar Initiative (CSI), yet ORA fails to realize that step changes in CSI incentives were very gradual, while the upcoming step-down of the federal Investment Tax Credit plus the phase-in of ORA's ICF would cause much larger and more severe impacts on solar economics than the CSI step changes. Finally, the ICF is a monthly fixed charge that DG customers are powerless to change or to reduce once it has been imposed; thus, it will present an unavoidable barrier to the continued growth of renewable DG in the state.

SCE tries to justify its fixed, $3 per kW-month Grid Access Charge as cost-based, and as based on the transmission and distribution (T&D) costs which a DG customer will not pay because it can use its own DG production to serve at least a portion of the on-site load. In other words, SCE argues that the installation of DG does not allow it to avoid any T&D costs because it must continue to stand by to serve the pre-solar loads of all DG customers. This position is contrary to SCE's own Distribution Resource Plan and its longstanding distribution marginal costs, and is not supported by the data that the utility provides. The data on when distribution circuit reach their peak loads show that the majority of these peaks occur during the hours of maximum solar output. As a result, although solar DG may not be able to avoid distribution capacity costs on all distribution circuits, it does have the potential to avoid distribution costs on a majority of circuits. Finally, we explain how the small size, large numbers, and diversity of residential and small commercial customers means that the utility does not need to maintain T&D facilities to serve the pre-DG loads of all DG customers. As a result, SCE's attempt to cost-justify its Grid Access Charge is misplaced.

PG&E and SDG&E take another approach – they would re-design the rates applicable to DG customers to include significant demand charges, and, in SDG&E's case, a large fixed charge as well. The complexity of the resulting rate designs is further increased by the utilities' proposals for a much lower rate that would apply to power exported to the grid. The result is that residential and small commercial DG customers would face a very complex and difficult-to-understand new rate design that might be appropriate for a large industrial complex, but that is not workable for small customers. These proposals clearly run counter to the Commission's Rate Design Principles that emphasize customer understanding and acceptance. Customer surveys show that customers do not understand or favor demand charges, and no party to the RROIR even dared to propose a residential demand charge such as the ones that PG&E and SDG&E now advance for DG customers. The implementation of residential demand charges would require a completely new customer education effort that would detract from the focus of the RROIR's education efforts on time-of-use rates. Neither PG&E nor SDG&E propose any details for this outreach. Further, we show that the proposed demand charges applicable to a customer's maximum usage in any hour would not be cost-based and, particularly when applied to solar customers, would bill customers for demand in off-peak hours or on low-demand days when their usage does not cause the utility to incur costs. Finally, the large fixed charge that SDG&E proposes is both unneeded given the $10 per month minimum bill adopted in D. 15-07-001, and conflicts with the deliberative process that the Commission has established in the RROIR for the further consideration of the role of fixed charges in residential rate design.

The final section of Chapter 1 focuses on NRDC's proposed rate design for DG customers, which also features a small demand charge. Although NRDC's demand charge is marginally better than those of PG&E and SDG&E because it would apply only to on-peak usage, the same problems with customer understandability and acceptance arise with NRDC's proposal. In addition, NRDC has not fully described the basis for the size of its charge, the modeling that supports why it is needed, or how the charge would affect the other elements of NRDC's rate design.

Chapter 2 of the JSP’s rebuttal testimony address assertion made by ORA that the solar market is not competitive. The JSP illustrate that the study utilized by ORA to support their assertion is based on a faulty methodology which produced erroneous results.

Finally, in Chapter 3 the JSP’s address the IOUs’ proposed interconnection fees. Through this testimony the JSP illustrate that by including one-time costs in its proposed fee, SDG&E has proposed an unreasonable fee. In addition, the JSP note the discrepancies between the proposed fees of the IOUs and recommend that the Commission incentivize the IOUs to share best practices and efficiencies by adopting the lowest interconnection fee proposed by one of the IOUs.

JOINT SOLAR PARTIES

Chapter 1

PROPOSED CHARGES AND FEES

Witnesses: R. Thomas Beach[1]

Mark Fulmer

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1 Witness qualifications are attached in Exhibits A-1 and B-1.

I. INTRODUCTION - Witness Beach

Q: On whose behalf is this rebuttal testimony being offered?

A: This rebuttal testimony is submitted on behalf of the Joint Solar Parties – CALSEIA,[2] SEIA, [3] The Alliance for Solar Choice[4] (TASC), and Vote Solar[5] – in this rulemaking proceeding to determine the successor tariff for net energy metering (NEM) in California. The Joint Solar Parties submitted their proposals for a NEM successor tariff on August 3, 2015, and have commented extensively on the proposals submitted by other parties.

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[2] CALSEIA is a 501(C)(6) not-for-profit solar industry trade association with more than 300 company members involved in the solar energy business in California. CALSEIA is an active participant in a number of Commission proceedings addressing state policy and electric utility rates. Changes to the tariffs for NEM have direct economic impacts on the current and prospective customers of CALSEIA's member companies and may help or hinder the companies' ability to market solar energy products.

[3] SEIA is the national trade association of the United States solar industry. Through advocacy and education, SEIA and its 1,000 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. SEIA's members have a strong interest in the adoption and implementation of innovative, forward-looking policies and programs that will accelerate the movement toward a low-carbon economy and stimulate the development and use of zero-carbon, renewable energy technologies such as solar photovoltaic (PV) generation. The views contained in this testimony represent the position of SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

[4] TASC leads advocacy across the country for the rooftop solar industry. Founded by the largest rooftop companies in the nation, TASC represents the vast majority of the rooftop solar market. Its members include: Demeter Power, Geostellar, Inc., Silveo, SolarCity, Solar Universe, Sunrun, Verengo, and Zep Solar. These companies are responsible for more than one hundred thousand solar installations serving businesses, residents, schools, churches and government facilities across the United States.

[5] Vote Solar is a nonprofit (Internal Revenue Code §510[c][3]), grassroots organization with active members throughout California and the United States. Vote Solar's mission is to address global warming, energy independence, and economic development by bringing solar energy into the mainstream and making solar systems affordable for residential and non-residential customers. Vote Solar's members include ratepayers as well as present and prospective solar energy system owners. Vote Solar has been an active stakeholder in the development of solar energy and Renewable Portfolio Standard (RPS) programs in California.

Q: What is the purpose of this rebuttal testimony?

A: Chapter 1 of this testimony responds to the direct testimony served on September 21, 2015 which addresses the third set of issues that Administrative Law Judge Simon set for hearing in her Ruling dated September 1, 2015:

> 3. The basis for any proposed demand charges, capacity fees, standby charges, access fees, use charges, or other fixed charges for the successor tariff that are different from the assumptions used in the Public Tool (NRDC; ORA; PG&E; SCE; SDG&E).

The September 1 Ruling, at page 3, specifically states that testimony on these issues should not seek to re-litigate issues resolved in D. 15-07-002, the Commission's recent order in the RROIR.

Specifically, this rebuttal testimony responds to the September 21 testimony served by the three IOUs (PG&E, SCE, and SDG&E), the Office of Ratepayer Advocates (ORA), and the Natural Resources Defense Council (NRDC). Generally, the parties have advocated the adoption of new rate design elements – new fixed and demand charges – in the rates for residential and small commercial customers who choose to invest in renewable distributed generation (principally solar photovoltaic [PV] systems). The following **Table 1** summarizes the proposals of ORA, SCE, PG&E, SDG&E, and NRDC for new rate elements in the NEM successor tariff, and also shows the other key attributes of their proposals.

Table 1: *Proposals for New Fixed or Demand Charges on NEM Customers*

Party	New Rate Elements	Other Key Attributes
Parties proposing Additional Charges on NEM Customers		
ORA	Installed Capacity Fee $ per kW of installed DG	ICF increases in pre-defined steps when specific adoption targets are hit.
SCE	Grid Access Charge $ per kW of installed DG	Export rate is limited to generation rate component, about 8 c/kWh.
Parties proposing to Re-design Existing Rates		
PG&E	Noncoincident maximum demand charge	• Export rate limited to generation rate component, about 9.8 c/kWh • Monthly netting
SDG&E	System Access Charge (fixed $ per month) plus Grid Charge (noncoincident demand charge)	Export rate at market price for energy alone, about 4 c/kWh.
Unspecified Proposals		
NRDC	Demand charge ($ per kW of maximum hourly On-peak demand)	NEM customers required to use TOU rates; non-bypassable PPP rate

II. KEY BACKGROUND – Witness Beach

A. Statutory Constraints and Standards

Q: What are the statutory constraints on including new rate design elements, such as new fixed and demand charges, in the NEM successor tariff?

A: AB 327, the legislation which is the statutory basis for the NEM successor tariff, also made significant changes to residential rates design in California, and was the impetus for the Commission's residential rate design rulemaking. AB 327 included (1) P.U. Code Section 739.9(f) which limited the fixed or demand charges in the residential rates of the IOUs to no more than $10 per month (plus an inflation adjustment beginning in 2016), and (2) Section 2827b.1(b)(7), which specifies that the NEM successor tariff can have fixed and demand charges that are not subject to the constraints of Section 739.9(f), but only if they are set in "a rulemaking proceeding involving every large electrical corporation" and are just and reasonable. This is the standard that the new rate elements proposed by the IOUs, ORA, and NRDC must meet.

Q: PG&E and SDG&E argue that the residential and small commercial rates which they have proposed for NEM customers, including new fixed and demand charges, are cost-based and are simply cost-based re-designs of their current rates. SCE makes arguments that its $3 per kW Grid Access Charge (GAC), which would be a new charge added on top of the regular retail rate, is reflective of the higher cost of service for NEM customers. Is the statutory standard for NEM successor tariff that any charges included in the tariff must be strictly cost-based?

A: No. The standard for the NEM successor tariff in Section 2827.1[b] focuses not on whether the elements of the tariff are cost-based, but on whether the costs <u>and benefits</u> of net metered DG under the new tariff will be reasonably balanced for participating ratepayers (Section 2827.1[b][3]) and for all ratepayers (Section 2827.1[b][4]), such that DG will "continue to grow sustainably" (Section 2827.1[b][1]). This balance can be assessed using the Public Tool, because that analysis considers both the costs and benefits of renewable DG. Public Tool analyses have been addressed extensively by the parties in their proposals and comments in this docket but are not within the scope of this testimony on the third issue that the ALJ set for hearing.

Q; How should the Commission evaluate the new rate design elements which the IOUs, ORA, and NRDC have proposed?

A: Section 2827.1[b][7] of AB 327 clearly requires that the Commission must find that these new rate elements are just and reasonable for the ratepayers who will pay them. In this regard, it is critical to remember that, even after they install DG, customers on the NEM successor tariff will remain ratepayers of the utilities. In fact, most will still continue to pay a significant monthly utility bill. The record in this case shows that, for the average NEM customer, adding a typical solar DG system converts that customer from a larger-than-normal customer to a slightly-smaller-than-average one. For example, PG&E's analysis of bill savings for a representative residential solar customer, using the rates approved in D. 15-07-001, indicates that the customer will offset 54% of its load with solar generation, resulting in 39% bill savings. PG&E indicates that the average monthly bill for this average NEM customer would decrease from $163 per month to $99 per month, for a bill savings of $64 per month.[6] This compares to the average monthly bill for PG&E non-CARE residential customers of about $110 per month.[7] Thus, bill for an average residential solar customer on the PG&E system is only 10% smaller than the bill for the average non-CARE residential customer.

The key point is that NEM customers, on average, remain significant utility customers even after installing DG, with close to average usage from the utility system. Accordingly, the same rate design principles and policies that the Commission has adopted for non-NEM customers also should apply to the rate design used for the NEM successor tariff. Obviously, the Commission has just completed an extensive rulemaking on residential rate design (the RROIR), with the results set forth in D. 15-07-002. Thus, the proposals to implement new rate structures and charges for NEM customers should be evaluated in light of both the Commission's Rate Design Principles and its findings and conclusions from D. 15-07-002.

B. Under NEM at the Full Retail Rate, DG Customers Would Continue to See the Same Rate Design Signals as Non-NEM Customers.

Q: What is the general proposal of the JSP for the NEM successor tariff?

A: The JSP support the continuation of NEM under the present framework, where customers who install net-metered DG would continue to take service under a standard retail rate applicable to their class of service, with a retail rate credit for the power that they export to the grid when their production exceeds their on-site use.

Q: Would a NEM successor tariff that continues the present structure of net metering fully comply with the Commission's Rate Design Principles?

A: Yes, it would. It is important for the Commission to recognize that, under net metering

[6] See the August 26, 2015 PG&E motion to file corrections to its August 3, 2015 proposal, at pp. 1-2.

[7] PG&E's website, at www.pge.com/nots/rates/tariffs/ResElecCurrent.xls, indicates that its average non-CARE residential rate is about 20.5 cents per kWh for E-1 customers. Assuming average usage of 535 kWh per month, this is about $110 per month.

as it exists today, a customer who installs a DG system will continue to see, on the margin, exactly the same rate design signals that he would see if he were a non-NEM customer. This is true regardless of whether the solar customer is importing or exporting power at any moment.

For example, at my home I take service as a NEM customer under PG&E's E-7 residential TOU rate, which has two pricing periods, on-peak and off-peak. If I consume power from the PG&E system during the summer on-peak period of noon to 6 p.m., I pay for that power at the high E-7 on-peak rate. My west-facing PV system at times produces more power than my home consumes during PG&E's on-peak period, and I export this power back to PG&E, which the utility then uses to serve my neighbors and for which I receive a credit at the full E-7 on-peak rate. Yet even when my system is exporting, I retain a strong incentive to shift any available loads out of the on-peak period – if I do not run appliances between noon and 6 p.m., I send additional solar kWhs out to the grid, earning additional net metering credits at the E-7 on-peak rate. This is no different than the price signal I face when I am importing on-peak power. In the mornings, evenings, and on weekends, I pay the much lower E-7 off-peak rate when I run appliances, and I also earn lower NEM credits for exports during these off-peak hours. Thus, even as a solar customer, I continue to see exactly the same TOU price signal as non-solar customers on the E-7 rate, and I continue to have the same incentive to shift my loads to off-peak periods.

Thus, under the current structure of NEM, all DG customers continue to see exactly the same price signals from rate design as non-NEM customers. Thus, to the extent that the rate design for non-NEM customers, as adopted in D. 15-07-001, complies with the Commission's Rate Design Principles, so too do the rates under the NEM tariff. The JSP submit that this "transparency" of the price signals under NEM is a strong reason to continue the present structure of NEM.

Even more important are the simplicity and continuity of the rate design price signals under NEM. Customers find it easy to understand that the same incentives which they have under the regular rate design will continue unchanged if they install a NEM system. This also means that the utilities and the solar industry do not have to educate NEM customers about rate design in any way that is different than with non-NEM customers. For example, informing customers about TOU rates will be the same regardless of whether the customer has a NEM system or not. This will further Rate Design Principles Nos. 6 and 10:

- 6. Rates should be stable and understandable and provide customer choice.

- 10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

As I will explain below, the additional rate design elements proposed by other parties will result in very confusing and complex price signals to residential customers, and will conflict in important ways with the Commission's Rate Design Principles.

C. Characterizing the Design of the New Fixed and Demand Charges

Q: How would you characterize the design of the new fixed and demand charges that other parties have proposed for the NEM successor tariff?

A: The other parties have designed these new charges in two ways:

1. **Additional charges.** ORA and SCE have proposed new charges that simply would be added to the existing rates paid by NEM customers, thus generating more revenue from NEM customers. Only SCE has tried to justify these higher charges as based on a higher cost-of-service for NEM customers. NRDC's proposed demand charge also may fall into this category, although NRDC's proposal is not clear on this point.

2. **Re-design of an existing rate to include new fixed and/or demand charges.** PG&E and SDG&E have re-designed residential TOU rate designs from the RROIR or from their current rates to include new fixed and/or demand charges.

This results in a reduction in the volumetric portion of these rates. These rates clearly would result in more revenue from NEM customers, although the rates are designed to be revenue-neutral if they were applied to the entire class.

Table 1 above categorizes the other parties' proposals in this way. This testimony responds first to the proposals from ORA and SCE for additional charges, then to the PG&E and SDG&E proposals which would re-design an existing rate, and finally to NRDC's proposal.

III. PROPOSALS FOR ADDITIONAL CHARGES

A. ORA's Installed Capacity Fee – Witness Beach

Q: ORA is proposing an additional fixed charge for NEM customers, an Installed Capacity Fee (ICF) based on the installed capacity of the DG system. The fixed ICF would begin at $2 per kW of installed capacity when the 5% NEM cap is reached, and would escalate when certain DG adoption targets are reached: to $5 per kW at 6% DG penetration and finally to $10 per kW at 7% DG penetration. The revenues from this fee would be used to reduce residential rates generally.[8] **How does ORA justify this new, added charge on NEM customers?**

A: ORA bases its proposal primarily on the argument that NEM causes a cost shift to non-participating ratepayers and that such a fee is necessary to mitigate this cost shift. ORA also makes the secondary argument that other sources of renewable generation are less expensive for non-participating ratepayers than renewable DG.[9]

Q: Have the JSP responded to ORA's cost shift allegations in their proposals and comments?

A: Yes, and this testimony will not repeat those arguments in detail. ORA first relies on the 2013 NEM Cost-effectiveness Study, which is clearly dated. That study used the 4-

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[8] ORA Testimony, at p. 4.

[9] Ibid., at p. 5.

tiered, increasing block residential rate design with steep tier differentials, a rate design from which the Commission has moved away decisively in the RROIR. ORA next cites Public Tool modeling, relying heavily on the scenarios presented by the Energy Division, which were intended simply to show how to use the Public Tool, not as policy recommendations. The proposals and opening comments of the JSP showed why significant assumptions used in the Energy Division's scenarios should be modified. When these changes are made, the Public Tool results show that any cost shift from NEM has been significantly reduced or eliminated. Finally, with respect to ORA's argument that utility-scale RPS renewables are less expensive than DG, the JSP have modeled scenarios in which DG is assumed to replace utility-scale RPS generation on a one-for-one basis (DG/RPS Parity). This modeling shows that renewable DG offers additional benefits that utility-scale renewables do not provide, including avoided transmission and distribution (T&D) costs and additional societal benefits. These added benefits compensate for the lower costs of utility-scale renewables. This is the economic reason why the state should pursue a robust, diversified portfolio of renewable resources that includes both DG and utility-scale generation.

1. ORA's Proposal runs Counter to Commission's Rate Design Principles

Q: ORA's proposal would retain all of the present elements of NEM, including the retail rate credit, and would add only the additional ICF, which would be set and known at the time a customer decides to invest in a DG system and which would increase only when certain adoption targets are reached. Please comment on these structural aspects of the ORA proposal in light of the Commission's Rate Design Principles.

A: The JSP strongly disagree with ORA that the Public Tool results show a need for an ICF, and certainly not at the levels that ORA has proposed. However, in comparison to the IOU proposals, the ORA proposal is simpler and more understandable for the DG customer, who, at the time of purchase of the DG system, will know the ICF that will apply to the system for its full life. ORA's proposal also retains the simplicity of NEM and ensures that both NEM and non-NEM customers will see the same price signals from rate design. Thus, with respect to meeting Rate Design Principles #6 and #10, the ORA proposal is superior from a customer perspective to the IOU proposals which are impossible to understand from a customer perspective as I will discuss below.

In addition, ORA's linkage of increases in the ICF to actual increases in DG adoption is another important way in which the ORA proposal is better than the IOU or NRDC proposals.[10] This feature helps to align the ORA proposal with the statutory requirement that the NEM successor tariff must continue to allow renewable DG to grow sustainably, but the extreme jump in the ICF over the course of ORA's timeline raise serious issues as discussed below.

Q: In what way does the ORA ICF run counter to the Commission's Rate Design Principles?

A: The major problem with the ORA ICF is that it is a fixed charge which a DG customer can do nothing to avoid except by (1) not installing DG or (2) adopting DG but not interconnecting to the grid, i.e. "cord cutting." Neither result is economically beneficial for the state, for the electric system as a whole, or for other ratepayers. A central theme that runs throughout the Commission's Rate Design Principles is that rates should encourage and enable customers to take actions that benefit the grid as a whole; all of the following Principles reinforce this theme:

- 4. Rates should encourage conservation and energy efficiency.
- 5. Rates should encourage reduction of both coincident and non-coincident peak demand.
- 6. Rates should be stable and understandable and provide customer choice.
- 9. Rates should encourage economically efficient decision-making.

Assuming for argument's sake that there is a cost shift from DG, there are significant steps that DG customers could take, both when installing a DG system and after the

[10] The JSP emphasize our support only for ORA's concept of linking NEM changes to DG adoption, not for ORA's specific numbers. For the reasons set forth in the accompanying testimony of Mark Fulmer, the JSP do not agree with how ORA has modeled adoption using the Public Tool.

system is operating, to increase the value of this generation for the grid and other ratepayers, and thus to reduce the cost shift. These include, at the time of installation, steps such as:

1. if possible, **facing the panels to the west** instead of the south to increase late afternoon output and capacity value,

2. **smart inverters** that provide grid support benefits and may enable greater coordination between the customer's generation and loads, and

3. **storage** that firms the intermittent solar output and significantly increases its value to the system.

ORA's proposal would not reduce the ICF should the customer take any of these steps that would reduce any purported cost shift. Once the DG system is operating, the ORA proposal provides no additional incentive for the DG customers to shape its load in ways that also might reduce a cost shift, such as by shifting loads out of peak periods.

ORA's proposed fixed charge is surprising, given ORA's strong and consistent opposition over many years to the use of fixed charges in retail rate design, and ORA's strong support for time-sensitive rates that allow customers to take actions that benefit the system as a whole. For example, Chapter 2 of ORA's opening testimony on residential rate design in the RROIR, served on September 15, 2014, described in detail ORA's reasons for opposing the implementation of fixed charges.[11] ORA expressed the opinion that fixed charges are difficult to reconcile with Commission longstanding policy of basing rates on marginal costs. ORA found that competitive markets do not use fixed charges to recover fixed costs, and argued that it is the purpose of marginal cost-based pricing in utility ratemaking to mimic pricing that would occur in a competitive market. ORA's RROIR testimony noted that, in competitive markets, the most common approach to recovering fixed costs is to mark up the wholesale cost of production, which is similar to what the Equal Percent of Margin (EPMC) process in utility ratemaking achieves. ORA's RROIR testimony concluded that fixed charges which lock customers into one

[11] See the September 2014 "Opening Testimony of ORA On 2015 Rates and Beyond" in R. 12-06-013, at pp. 2-1 to 2-3.

supplier are anti-competitive. Applying the logic of ORA's own RROIR testimony to its ICF proposal in this case, ORA's proposed large fixed charge on solar customers is likely to lock many potential customers out of the solar market and into full service from the utility.

2. ORA's Year Estimates for Solar Penetration Milestones Are Highly Incorrect – Witness Fulmer

Q. As noted above, ORA's proposal calls for the transition to a $10 ICF to be accomplished in only three steps triggered by adoption levels of 5%, 6%, and 7%. In its testimony ORA presents estimates of when those steps will occur. Are those estimates correct?

A. No, First, ORA estimates that SDG&E will not reach its 5% program limit for the current NEM tariff until July 2018.[12] This estimate is not reflective of current data. As of August 31, 2015, SDG&E had 147 MW of capacity remaining in the current NEM tariff and is receiving 20 MW per month (or more) of new applications.[13] At this rate, the cap will be met in March 2016. If there is an increase in customer activity due to the coming deadline, the cap will be met earlier. Similarly, PG&E had 772 MW of capacity remaining at the end of August and received 89 MW of new applications in August. If this pace were to continue, PG&E would meet the cap in May 2016. Even if the pace of new applications is consistent with the June - July application rate of 61 MW, the cap for PG&E would be met far before 2017.

Q. How does ORA arrive at the SDG&E 5% conclusion, as well as the timelines for the other IOUs and for future milestones?

A. ORA uses a linear regression of a growth curve that is obviously not linear. Data clearly show that the rate of solar installation has been increasing steadily over time. ORA pretends this is not the case, stating, "the historical trend follows a near linear path except for the recent months where growth in MWs installed has increased."[14] Removing "recent

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[12] SDG&E Opening Testimony, Table 3, at p. 19.

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

[14] ORA Opening Testimony at p. 19, lines 14-15.

months" and analyzing 2012-2014 monthly installations, the following figures demonstrate that the historical trend has not been linear. Instead, exponential trend lines fit very closely to the actual data.

Figure 1. PG&E 2012-2014 NEM Installations

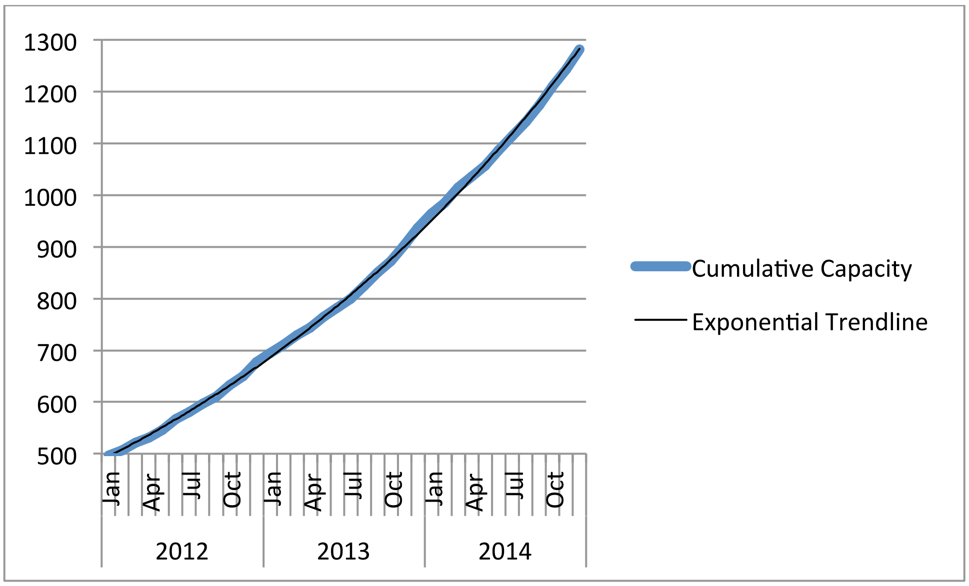


Figure 2. ORA Regression Plot for PG&E

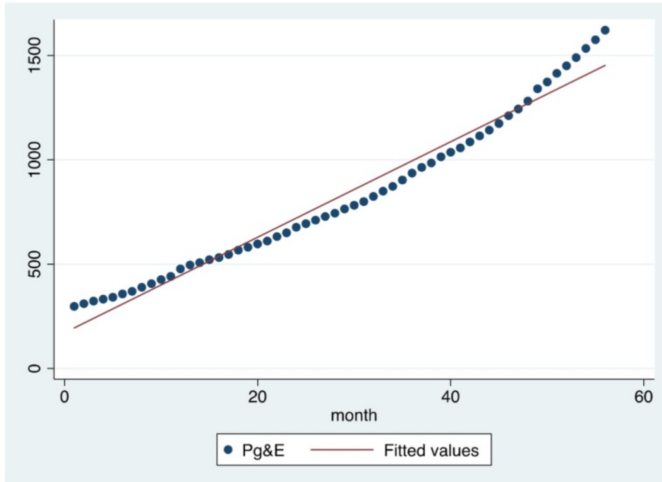


Figure 3. SCE 2012-2014 NEM Installations

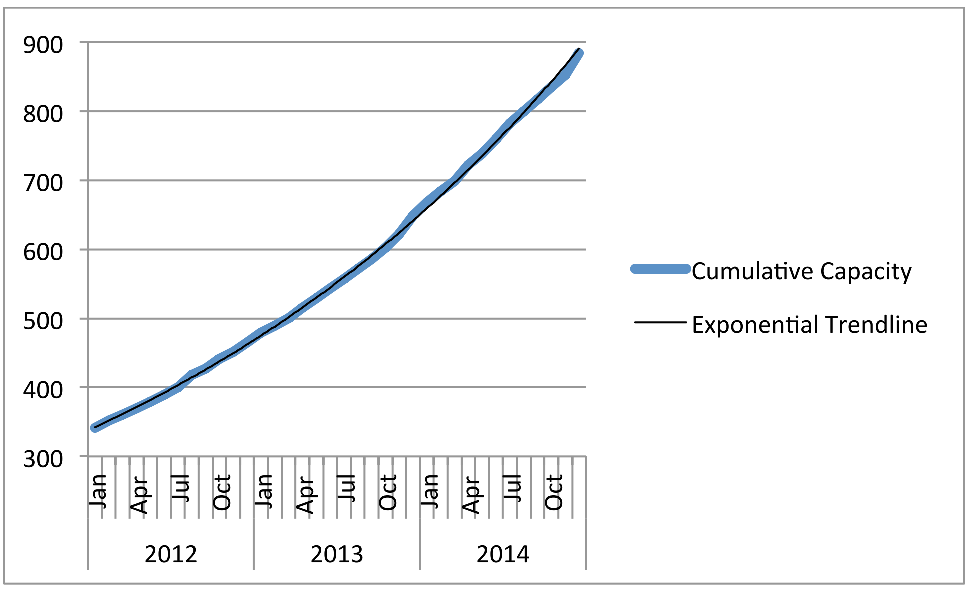


Figure 4. ORA Regression Plot for SCE

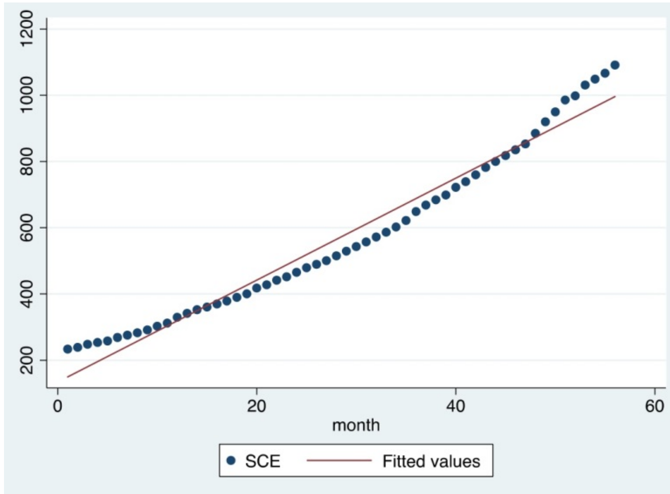


Figure 5. SDG&E 2012-2014 NEM Installations

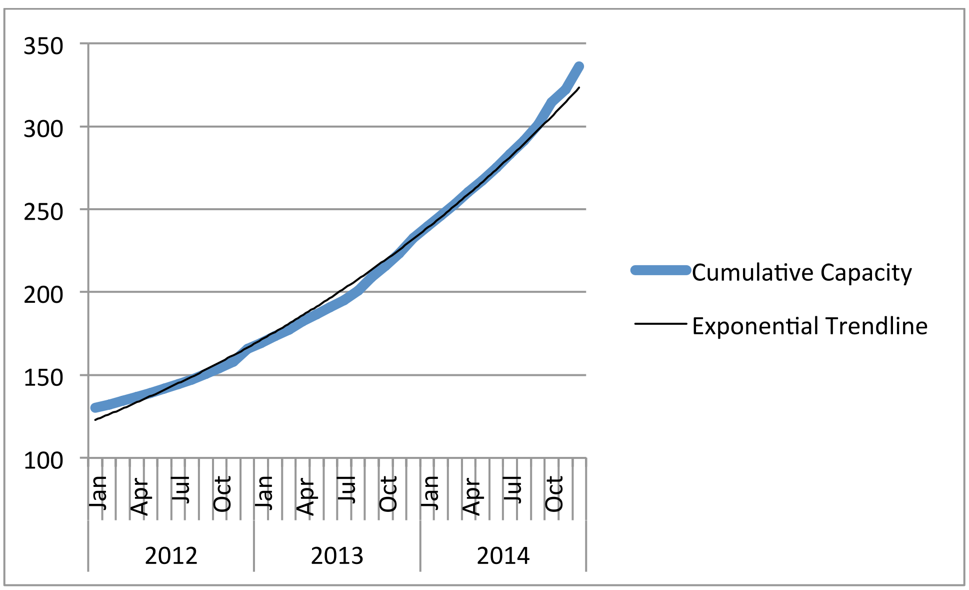
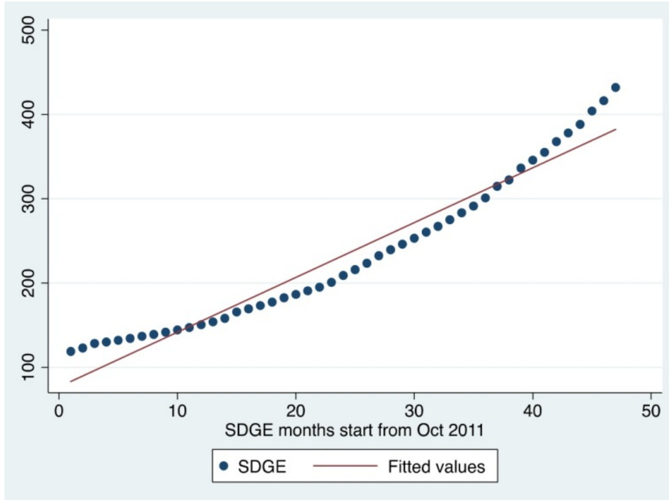


Figure 6. ORA Regression Plot for SDG&E



Because of this faulty methodology, the Commission should not rely on the month and year estimates for solar penetration milestones in Table 3 of ORA's Opening Testimony. The Commission should understand that those milestones will be met much sooner.

Q. Does ORA use any other methodology to support their estimates of solar penetration milestones?

A. Yes. ORA also uses the Public Tool to predict the time when solar penetration milestones will be achieved. This is an inappropriate use of the Public Tool. E3 has been clear that the 2017 start date for the successor tariff was not based on market penetration but on creating a uniform starting point for the IOUs. In the frequently asked questions document explaining the Public Tool, E3 states, "in order to simplify the model, we assume that the new residential rates and the successor tariff(s) to NEM do not go into effect before 2017."[15]

3. CSI Steps Were Gradual; the Upcoming ITC Change and the ORA Proposal Are Not – Witness Fulmer

Q. ORA states that the California Solar Initiative (CSI), with its phased reduction in rebates, was a success, and, therefore, since its proposed ICF is also phased-in, it is

[15] "Documentation on adjustments to the Draft Version of the Public Tool to produce the Final Version of the Public Tool," available at http://www.cpuc.ca.gov/NR/rdonlyres/DFBEB5B7-B28D-4A2F-BDBC-41B5E5A0BDEF/0/PublicToolQA8182015.pdf

also sure to be a success. Can you please comment?

A. ORA's argument ignores that the CSI had ten steps and the impact on solar economics was much more gradual than ORA's proposal. Table 2 shows that CSI step changes impacted the price of solar to customers by only 1%-7%. In contrast, as shown in Table 3 the ITC changes will impact the solar price by 29%-43%. This change is so severe that adding further reductions in solar benefits to customers in the years following the ITC changes would be on a scale far different from the CSI step changes. Furthermore, as shown it Table 4, the phase-in steps of the ORA proposal on their own would also have impacts far larger than the CSI step changes.

Table 2. Impact on Customer Cost of CSI Step Changes[16]

Step	Rebate	Price Without Rebate	Price With Old Rebate (and ITC)	Price With New Rebate (and ITC)	Percentage Reduction in Subsidized Price
2	$2.50				
3	$2.20	$9.27	$4.74	$4.95	4%
4	$1.90	$9.27	$4.95	$5.16	4%
5	$1.55	$9.13	$5.06	$5.31	5%
6	$1.10	$7.98	$4.50	$4.82	7%
7	$0.65	$7.98	$4.82	$5.13	7%
8	$0.35	$7.46	$4.77	$4.98	4%
9	$0.25	$6.57	$4.35	$4.42	2%
10	$0.20	$6.57	$4.42	$4.46	1%

Table 3. Impact on Customer Cost of ITC Changes

ITC Before	ITC After	Year of Change	Price With Old ITC	Price With New ITC	Change in Price
30%	10%	2017	2.77	3.56	29%
30%	0%	2017	2.77	3.96	43%

[16] Tables 2 and 3 use the prices in the Public Tool base solar cost case. All prices are in $/W-AC. The prices in this table are for the year of the step change when averaging the residential step change dates of the three IOUs.

Table 4. Impact on Customer Cost of ORA Proposed ICF Changes

ICF Before	ICF After	NPV of ICF Change ($/W)	Year of Change	Price With Old ICF ($/W)	Price With New ICF ($/W)	Change in Price
$0.00	$2.00	0.36	2016	3.00	3.36	12%
$2.00	$5.00	0.53	2017	3.96	4.49	13%
$5.00	$10.00	0.89	2018	3.74	4.63	24%

4. ORA's Incorrect Use of the Public Tool – Witness Fulmer

Q: How does ORA use the Public Tool in relation to its proposed ICF?

A: In addition to evaluating alternative NEM successor tariffs, ORA uses the Public Tool to calculate ICF values that would result in its desired revenue collection from NEM users. More specifically, "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 [is] able to identify the approximate upper limit for capacity fees that would be needed to recover the full cost to serve successor tariff customers."(sic)[17] ORA then ran the tool with incrementally increasing ICFs, from $1/kW-month to $20/kW-month, to observe the Public Tool's cost of service ("COS") outputs. 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."[18] In other words, ORA used the Public Tool not just for evaluating a successor tariff, but also to derive specific rate values.

Q: Is this beyond the intent and ability of the Public Tool?

A: Yes. As stated in the Order Instituting Rulemaking, the Public Tool is for ***estimating*** costs and benefits of NEM successor tariff options. And as ORA rightly argued, the Public Tool takes a long-term view. But a model designed to evaluate alternative policies

[17] ORA at 26.

[18] ORA at 26.

in the long-term should not be used for shorter-term rate-setting.

Q: Setting specific rates is typically addressed in General Rate Cases ("GRCs"). How are the models used in those cases treated by ORA and other intervenors?

A: Cost of service, cost allocation and rate design models in GRCs undergo months of scrutiny by intervenors. All aspects of the models are reviewed, with many assumptions and calculations challenged openly in testimony and hearings.

Q: Did the Public Tool get this level of scrutiny?

A No. While the Public Tool was subject to a series of workshops and rounds of comments, the model was in the hands of the users for whom it was intended (the public) for only about 4 months from when the first review draft version of the model was released to when parties' proposals where due.[19] (Or only 2 weeks if you count from when the final "final" draft was released.)[20] Furthermore, its designers were not subject to the scrutiny that the utilities face with their rate design models. The Public Tool designers did not have the burden of justifying their inputs or algorithms to the same degree they would have if it were a GRC.

Q: Can you provide a concrete example of this?

A: Yes. Through the approved channels, I pointed out that there was an error in how the Public Tool accounted for the possible retirement of PG&E's Diablo Canyon nuclear power plant. With respect to the Public Tool's double-counting of assumed Diablo Canyon capital expenditures, the consultants producing the Public Tool agreed and corrected the error. However, when asked to correct an associated error—that Diablo Canyon's O&M should not continue at the same level as it would if the plant were operating if it is closed in perpetuity —the concern was disregarded:

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[19] The first draft version of the Public Tool was released March 26, 2015. Parties proposals using the Public Tool were served August 3, 2015.

[20] The final "Final" version of the Public Tool was released July 17, 2015.

> **83. Looking at PG&E, it appears that adjustments to the generation O&M would also need to be made to account for the retirement of Diablo Canyon described in question 76 above.**
> E3 did not make this adjustment because we assume that some level of O&M costs will continue after nuclear plant retirement.[21]

As is being seen now with the retirement of San Onofre, while O&M at a non-generating nuclear plant continues, it is at a much lower level than when the plant was operating.[22] Furthermore, as more time progresses, much of the remaining O&M will be covered through funds from the decommissioning trust. But in the Public Tool, even if the user assumes Diablo Canyon retires at the end of its current license, its O&M costs will continue in perpetuity at the same level as if it were operating. This is an obvious error that could have been corrected easily to increase accuracy of all modeling runs. I highly doubt that this would happen in a GRC as the result is a significant overstatement of O&M costs.

Q: Please provide examples of why the Public Tool is not up to the standard for models used in proceedings where rates are set.

A: First, the Public Tool relies upon assumptions that are taken from utility applications that have not been approved. For example, the Southern California Edison revenue requirements are from its filed Phase I GRC (A.13-11-003).[23] ORA knows well that utilities' GRC requests are rarely granted in full. While TASC attempted to address this problem in its modifications to the model, simply accepting an IOU's revenue requirement without scrutiny would never happen in a rate setting proceeding.

Second, it does not reflect actual rate designs. D.15-07-001 introduced, among other things, a "Super-User Electric Surcharge," which is effectively a very high third tier. This new rate simply cannot be modeled by the Public Tool. While for planning purposes, and given the timing of the D.15-07-001, it is reasonable to ignore this new third-tier, it would not be acceptable to ignore it for calculating an actual rate.

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[21] Documentation on adjustments to the Draft Version of the Public Tool to produce the Final Version of the Public Tool (Proceeding R.14-07-002). Updated July 15, 2015.

[22] I.12-10-13, Southern California Edison, *SONGS OII Phase II Testimony Providing Ratemaking Proposal,* August 14, 2013 at 2.

[23] Ibid, answer to question 28.

Q: Please provide an example of what results from ORA using the Public Tool beyond its capacity.

A: Table 7 on page 29 of Mr. Drew's testimony compares the forecast installations and implied payback under the "ED Base Case" and "ORA $2 ICF" scenarios using six rate design and renewable DG cost combinations. In every case, there was more installed DG capacity but with a lower average implied payback with the $2/kW-month ICF than without it. Thus, according to the ORA analysis, adding ~$120 (5 kw x 12 x 2) per year to the cost of DG will induce *additional* DG adoption. This result is counterintuitive, to say the least. Furthermore, ORA notes that "[t]he 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."[24] Reducing the residual revenue requirement would reduce (or at least put downward pressure on) residential per-kWh rates, decreasing the potential rate savings associated with installing a DG system. Thus, according to ORA's modeling, not only does the ICF increase the DG users' monthly costs, it reduces the rate savings while at the same time increases penetration. This fallacious result simply points to underlying flaws in the Public Tool's adoption module. Or, perhaps more charitably, it points to the fact that the model is not capable of the level of precision the ORA is asking it to do when using it to set ICF rates.

Q: What about basing a rate upon the cost-of-service percentage (COS%) metric included in the Public Tool?

A: I find that to be particularly problematic. The COS% is not a good metric for evaluating the impacts of a policy, let alone for ratemaking. As noted in the ED report:

> Finally, a Cost of Service (COS) analysis can provide a valuable perspective in addition to the Commission's Standard Practice Manual tests. A COS analysis provides an indicator of whether DG customers are 'paying their fair share,' and can further inform the results of a RIM test by highlighting existing subsidies built into utility rate structures. However, as indicated in the 2013 NEM study, because a COS analysis doesn't capture how much participating customers should

[24] ORA at 13.

> be paying relative to nonparticipating customers, and also because the results of a COS analysis are inextricably linked with broader rate design issues designed to support numerous Commission policies, ***caution should be applied when interpreting the results of this analysis***.[25]

By relying on the COS% metric to set explicit rates, ORA is going well beyond ED's caution only to use the COS% "when interpreting results." ORA goes well beyond this admonition, by using the COS% to set rates that actual customers would be pay.

Q. Besides ORA's use of the Public Tool to calculate ICF values that would result in its desired revenue collection from NEM users, does ORA incorrectly use the Public Tool with respect to its proposed ICF?

A. Yes. ORA models its ICF levels in the Public Tool and uses the implied payback and Participant Cost Test (PCT) results to argue that solar adoption will not suffer from its proposal. ORA states that PCT does not fall below 1.0 and the implied payback is never more than ten years.[26] In fact, the Public Tool never creates a PCT below 1.0 and the adoption curve restrains the implied payback. The reason is that the Public Tool calculates PCT and implied payback only among adopters. It is not measured across all customers or across some set of typical customers. By only measuring payback and cost-benefit for customers for whom solar is economic, these metrics are self-fulfilling prophecies. To demonstrate this, the Figure 7 was created using the unlikely scenario of a $15/kW ICF plus a grid access fee of 9 ¢/kWh. Adoption is minimal, but the PCT is still 1.07 and the implied payback is 9.2 years. The PCT and implied payback as calculated in the Public Tool are practically meaningless.

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[25] Energy Division Staff Paper on the AB 327 Successor Tariff or Standard Contract," June 3, 2015 at 1-12 – 1-13.

[26] ORA Opening Testimony at p. 26, lines 19-20; p. 29, lines 11-15.

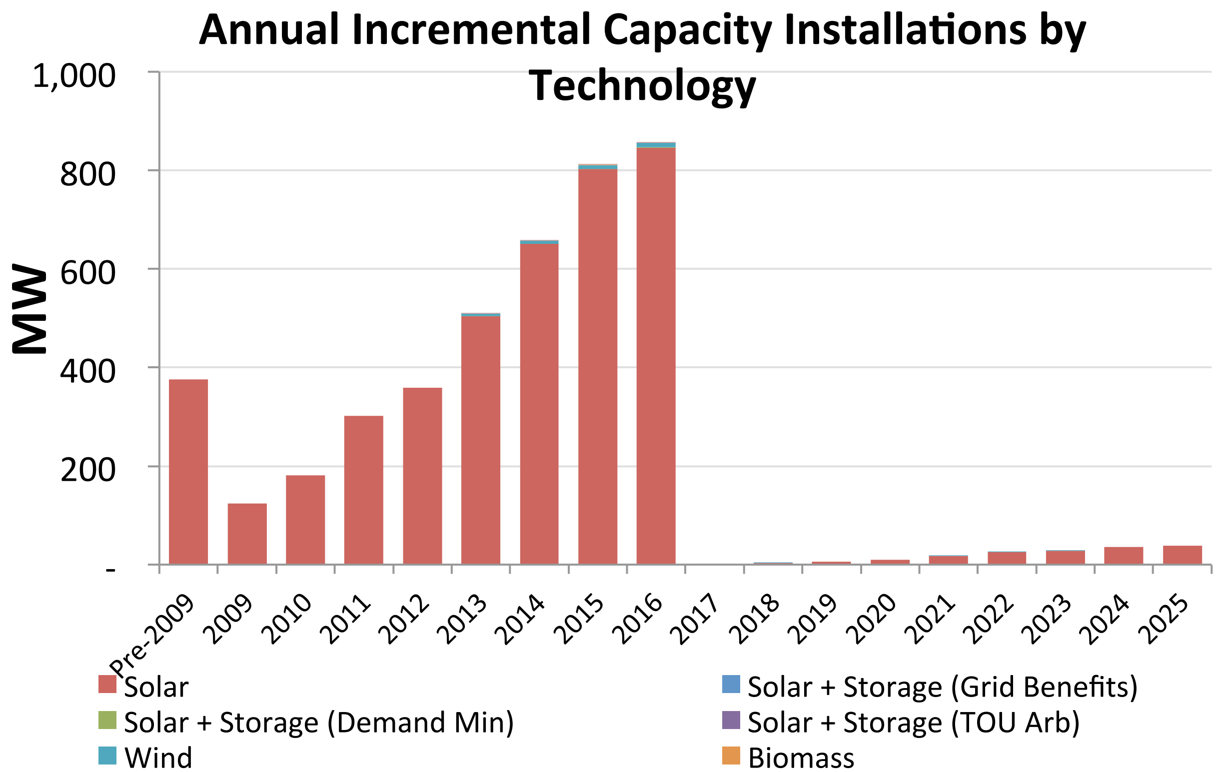


Figure 7. Extreme Scenario with Minimal Annual Capacity Installations

Q. Do you have any comments regarding ORA's proposed ICF impact on solar financing?

A. Yes, ORA also proposes that the level of the ICF only be set for ten years. Because many projects are financed based on a defined amount of revenue over 20 years, this would create major problems for solar financing. Lenders can be expected to build risk into their rates, and costs to customers would therefore increase. ORA should be seeking to reduce costs for customers, not increase them unnecessarily.

Q: Please summarize your concerns with ORA's use of the Public Tool.

A: ORA is using a high-level, long-term, "what if" tool designed to compare scenarios to do ratemaking. This is inappropriate. If the Commission chooses to move forward with an ICF, then an additional phase of this proceeding would be necessary to order to set a specific ICF rate.

5. A Minimum Bill of $15 Results In Significantly Better COS% For Solar Customers than a $2 ICF - Witness Fulmer

Q. In addition to the concerns raised in the previous section that the Public Tool is not capable of the level of precision ORA is seeking from it and that the results from the Public Tool are inappropriate for ratemaking purposes, do you have any other concerns about the rate structure ORA has proposed?

A. Yes. ORA largely justifies the ICF structure based on how it improves the COS% metric. However, based on the Public Tool results, a $2 ICF actually can have a negative impact on the COS%. In the Energy Division's unmodified 2-Tier High DG Value NEM case, the COS% is 49% for residential customers. After implementing ORA's proposed $2 ICF, the COS% actually decreases to 48%. This means that, according to the Public Tool results, implementing this rate would lead to the average solar customer contributing a smaller portion of its cost of service than under full retail NEM with no fixed charges. This counterintuitive result is further evidence that using the Public Tool to set rates in this way is inappropriate. It also calls into question whether the ICF structure is the most effective way to improve the COS% (assuming of course that the COS% is an appropriate measure to begin with).

Q. Are there other rate structures that do a better job of improving the COS% metric?

A: Potentially, yes. For example, a modest increase in the minimum bill for NEM customers would improve the COS% far more than the $2 ICF according to the Public Tool results. A $15 minimum bill for NEM customers under the same ED 2-Tier High Value DG NEM case would increase the COS% from 49% to 60% for residential customers. A $15 minimum bill was modeled by TASC as a sensitivity in its Proposal filed on August 3, 2015.

Table 5: Impact of Rate Proposals on Residential Cost of Service Recovery Fraction

Case Name	**COS%**
Energy Division 2-Tier High DG Value Unmodified	49%
Energy Division 2-Tier High DG Value With ORA's $2 ICF	48%
Energy Division 2-Tier High DG Value With $15 Minimum Bill on Solar Customers	60%
TASC Base Case With $15 Minimum Bill	80%

While the JSP continue to believe that the Commission has never stated that individual customers have a unique responsibility, compared to ratepayers overall, to ensure recovery of utility costs, the Commission has stated in D.15-07-001 that a minimum bill can address cost recovery from low usage customers while also avoiding negative impacts to conservation stemming from fixed charges. This is a finding we continue to support fully.[27] Moreover, as D.15-07-001 recognizes, ORA was among the parties that supported utilizing a minimum bill rather than fixed charges to help ensure that the utilities have an opportunity to recover their costs.[28]

[27] See D.15-07-001 at pg. 225 ("The minimum bill would ensure that all customers contribute some amount toward the cost of the system to which they remain connected. It also avoids any potential negative impact on conservation associated with a fixed charge, and it protects lower-usage customers whose fixed costs might be lower.")
[28] See D.15-07-001 at pg. 218.

B. SCE's Grid Access Charge - Witness Beach

Q: SCE also proposes a new fixed charge based on the installed capacity of a DG unit, a $3 per kW Grid Access Charge (GAC). This charge would apply only to residential customers who install DG. Does this proposed charge present similar issues as ORA's ICF?

A: Yes. Like ORA's ICF, SCE's proposed GAC would be additive to the standard retail rate paid by DG customers. Revenues from the GAC would not reduce directly the other elements of the rates applicable to DG customers. It is purely a rate designed to recover what NEM customers would have paid to the utility if they did not serve their own load, e.g. a departing load charge. As we will discuss in more detail below, SCE explicitly designs the GAC based on the amount of the DG customer's generation that serves the customer's own load. This is power that the customer self-supplies using its own equipment on its own premises, and is power that never touches the utility system. Fundamentally, customers should not have to pay for utility services which they do not use. California policy does not charge customers who install other types of preferred resources, such as energy efficient lighting and appliances, for the revenues that the utility loses as a result of such actions; instead, we encourage customers to take such steps through incentives, and thank them when they do so. Many, if not most, of these energy efficiency programs do not pass the RIM test and result in higher rates for non-participating ratepayers.

Q: Are there other ways in which SCE's GAC, in combination with other elements of SCE's proposal. will work at cross purposes to continued sustainable growth in renewable DG?

A: Yes. Unlike ORA, SCE also proposes a rate for NEM exports (about 8 cents per kWh) that is much lower than the retail rate (approaching 20 cents per kWh for non-CARE residential customers). This low export rate would send a strong signal to future DG customers to use as much of their DG generation as possible on-site. Yet SCE has designed the GAC based on the amount of power which the customer uses on-site. So if DG customers in the future use more of their power on-site, perhaps through smart inverter technology or by installing on-site storage, this would provide SCE with a basis for raising the GAC, thus penalizing such self-consumption and shifting the private benefit of such self-consumption to other ratepayers.[29] Thus, the structure of SCE's GAC, combined with its low export rate, would discourage innovations such as smart inverters and on-site storage that have such promise and potential to increase the value of DG. Like the ORA ICF, the GAC is a fixed charge that the DG customer can do nothing to avoid, except by not installing renewable DG.

Q: In addition to its Public Tool modeling, SCE tries to cost-justify the GAC based on an argument that certain costs, principally T&D costs, cannot be avoided when a customer installs DG. Please respond to SCE's justification for the GAC.

A: There are a number of reasons why the Commission should give little weight to SCE's supposed "cost justification" for the GAC.

First, as the JSP noted in their September 1 comments (at pages 57-59), SCE's own statements in its Distribution Resource Plan recognize that DG can provide capacity-related reliability and resiliency benefits to the distribution system, as well as power quality and voltage support benefits.[30] It is the basic purpose of the DRP proceeding to unlock those benefits, and thus to assume now that these benefits are zero presumes that the DRP process will fail. In addition, SCE's rates have been based for decades on marginal costs, including marginal distribution capacity costs, which assume that in the long-run a reduction in non-coincident demand, for any reason including the installation of DG, will lower the utility's distribution capacity costs.[31] Although SCE's FERC-regulated transmission rates are not based on marginal costs, they are based on monthly

[29] SCE has proposed to update the GAC in future general rate case (GRC) rate design proceedings. SCE Testimony, at p. 2, footnote 2.

[30] SCE DRP, at pp. 62-63.

[31] PG&E's calculation and allocation of its marginal distribution costs have long recognized that a portion of its distribution system, principally the higher-voltage circuits and substation where there is significant load diversity, are driven by coincident system peak demand rather than non-coincident customer loads. A pending settlement on marginal costs and revenue allocation in SCE's current GRC Phase 2 proceeding (A. 14-06-014) includes a provision that SCE will study the time-dependence of its distribution system costs.

coincident peak demand. Thus, DG can avoid transmission costs to the extent that it reduces coincident demand.

SCE's testimony attempts to argue that its T&D costs do not decrease when a residential customer installs solar because the key drivers of T&D costs, the customer's coincident and non-coincident peak demands, do not decrease when solar is installed. For example, in Figure II-2 of SCE's testimony, SCE presents load profile data on the system peak day from a sample of NEM customers; SCE alleges that this data are representative of these customers' demands before and after solar installation, and show little change from adding solar.

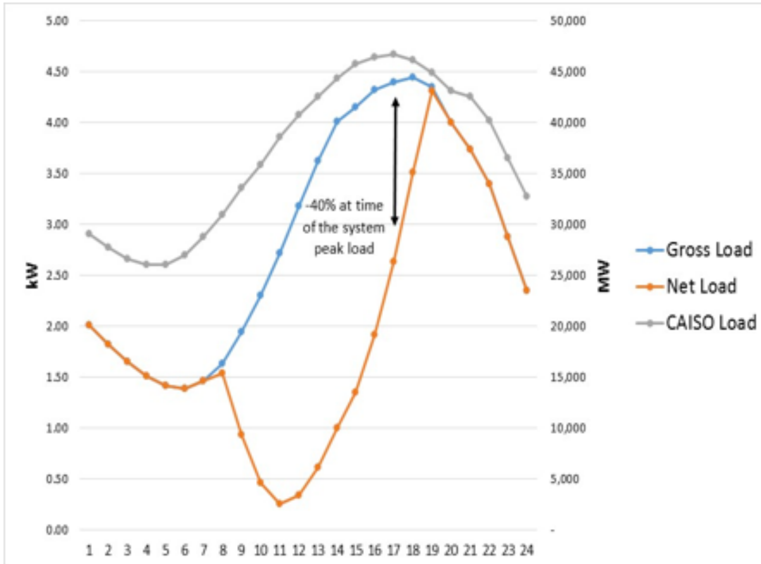
SCE's comparison is flawed, first, because SCE's comparison looks at customer load on the dates of the CAISO system peak load in two different years. The "pre-PV" peak load day is August 13, 2012, and the "post-PV" peak load day is September 15, 2014. The Commission has already found the use of load data from peak days in different years to be an unconvincing way to show the difference between the "pre-solar" and "post-solar" demands of solar customers. In the rate design window proceeding (A. 12-12-002) that reviewed whether PG&E should implement Option R rates with reduced demand charges for solar customers, SEIA presented "pre-solar" and "post-solar" peak day demand data on 71 solar customers with "pre-solar" and "post-solar" peak days from different years, exactly as SCE has done here. PG&E criticized the SEIA data set because there could be many other factors, in addition to solar installation, which could cause these customers' peak day demands to vary from one year to another year. In Decision 14-12-080, the Commission accepted PG&E's criticism, and, as a result, the Commission based its decision on other data which did not have this problem.[32] SCE's analysis here has the same problems that SEIA's did in A. 12-12-002. Peak CAISO load on the SCE transmission system, in the hour ending at 5 p.m. PDT, was 2% were higher on

[32] D. 14-12-080, at pp. 12-13. On this issue, the order states: "We acknowledge that while the results of SEIA's study suggest that solar PV systems provide significant peak capacity, its study was severely hampered by lack of access to the actual solar production data. The use of load differences as a proxy undermines the validity of the study, and consequently we do not give it much weight to reach our conclusions."

September 15, 2014 (the “post-solar” peak) than on August 13, 2012 (the “pre-solar” peak). In addition, by 8 p.m. on September 15, 2014, which is the time when SCE claims the post-PV load showed the largest increase versus pre-PV load, SCE area CAISO loads were 10% higher on September 15, 2014 than on August 13, 2012. Confirming this result, NOAA data on hourly temperatures for downtown Los Angeles were 12 degrees F warmer at 5 p.m. on September 15, 2014 than at 5 p.m. on August 13, 2012. These results show that other factors besides PV output, such as higher temperatures on the “post-solar” peak day, could have affected the load difference comparison SCE is attempting.

Presented below is a figure that shows the impact of correcting SCE’s figure so that load differences from different dates are not used. The figure shows, in gray, CAISO system load on August 13, 2012, which peaked at hour ending 5 p.m. PDT at about 46.7 GW. The gross load profile (in blue) in the figure is SCE’s “pre-PV” hourly loads for the sample of solar customers on that date. To model a sample PV system serving these loads, we used actual solar insolation data for August 13, 2012 from Clean Power Research’s Solar Anywhere data base, combined with the NREL Solar Advisor Model solar PV simulation tool. The orange line in the figure portrays net load, equal to the difference in each hour between gross customer load and solar generation on this date. Because the gross customer load peaks at hour ending 6 p.m. just before the end of the solar generation cycle, the customer’s reduction in non-coincident demand on this date is small, just 3%. However, in the hour ending at 5 p.m. when the system load peaks, the customer’s net load is 40% lower than gross load. Thus, the solar customer does contribute to a significant reduction in coincident peak demand on this peak day. It is not correct to argue that solar does not provide peak load reductions, in particular reductions in coincident peak loads that drive generation and transmission capacity costs.

Figure 9. SCE Gross and Net Loads for PV Customer Sample, August 13, 2012



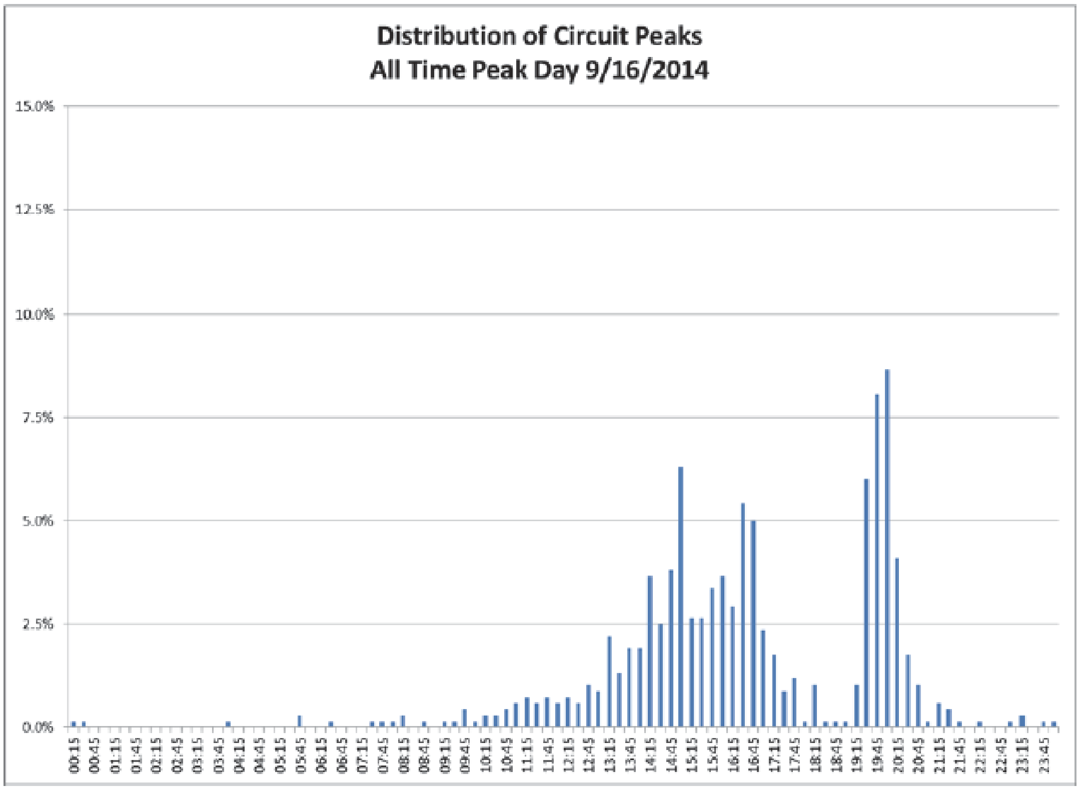
Q: SCE's data, even when adjusted as you have just explained, suggests that DG may not result in a significant reduction in residential DG customers' non-coincident loads; for example, if DG customers' loads peak in the evening as shown above and in SCE's Figure II-2. SCE allocates its distribution costs on the basis of non-coincident peak (NCP) demand. Does this mean that residential DG cannot avoid distribution costs?

A: No. The key point that SCE's testimony does not discuss is that the peak demands on its distribution circuits also are non-coincident, in other words, they do not necessarily coincide in time with the system peak, with each other, or with the evening peak in the sample of residential customers discussed above. As a result, unless one looks in detail at the load profiles of the elements of SCE's distribution system on a more granular, circuit-by-circuit basis, and compares those profiles with solar DG output, one cannot draw blanket conclusions about whether residential DG can or cannot avoid distribution capacity costs, such as SCE's assertion in its testimony that "the installation of customer-sited DG has no present impact on NCP demands and thus no impact on the allocation of SCE's distribution costs to the residential class."[33] The IOUs themselves have presented evidence on the record of this case which contradicts this claim, showing that their

[33] SCE Testimony, at p. 10, lines 4-5.

distribution circuits peak at a variety of times during the day, with a majority of circuits peaking in the afternoon when there is significant solar production. For example, here is the distribution of circuit peaks for SDG&E, from its September 15 reply comments.

Chart 3: Distribution of Circuit Peaks on All-Time Peak Day



SCE itself has stated that its distribution circuits peak at 3 p.m. in the summer (i.e. even earlier than the system peak), with 70% of distribution circuit peaks occurring during the hours of maximum solar output.[34] The JSP do not contend, and have never contended, that solar DG will be able to avoid distribution capacity costs on all distribution circuits. But DG does have the potential to avoid distribution costs on a significant fraction of circuits. Thus, the Commission should disregard SCE's claim that solar DG cannot avoid distribution costs, such that the portion of distribution costs avoided by a DG customer self-supplying their own load should be included in the GAC.

[34] SCE September 15 reply comments, at p. 22, footnote 53.

Q: SCE also make the argument the energy efficiency measures permanently reduce loads while DG does not.[35] How do you respond to this?

A: The JSP agree that it is more difficult to model the impact of variable DG generation on the loads that the utility must serve with its T&D infrastructure than it is to model load reductions from energy efficiency. Obviously, solar DG is a variable resource and will reduce coincident and non-coincident loads on the utility system by only a portion of the installed DG capacity. However, there are reasonable means to estimate the reductions in coincident and non-coincident demand that result from DG, and thus the amount of T&D capacity that DG avoids. The Public Tool does so through the use of effective load carrying capacity (ELCC) and peak capacity allocation (PCAF) factors developed by E3 and widely used before this Commission in many types of resource valuation and rate design analyses. What would be unreasonable would be for the Commission to accept SCE's assertion that hundreds of thousands of operating DG systems in California, with a generating capacity in excess of 5.4 GW located at points of end use, will result in zero reduction in the coincident and non-coincident loads that must be served from SCE's T&D system.

Q: SCE's position suggests that its T&D system must stand by with T&D capacity to meet the original loads of all NEM customers.[36] Is this a reasonable assertion?

A: No. This suggestion assumes that all NEM systems would fail at the same time. This is extraordinarily unlikely given the very large numbers of DG systems and the low forced outage rate of today's modern solar DG systems. The Commission should recognize that a residential DG system on a distribution circuit with hundreds or thousands of other customers is very different than a large industrial customer with self-generation who today is required to pay T&D costs through a standby charge. The industrial customer is likely to be served through a dedicated circuit, or to represent a significant fraction of the load on the circuit that serves it. Thus, the industrial customer requires a significant portion, or even 100%, of the capacity of that circuit to maintain service should its on-site

[35] SCE Testimony, at p. 10, lines 6-19.

[36] SCE Testimony, at p. 6, lines 19-20: "…grid facilities remain necessary for SCE to serve peak loads of DG customers when their DG installation is not generating electricity."

generator fail. This justifies a standby reservation charge to collect T&D capacity costs for the "backup" capacity that the industrial customer requires when its generator is out of service. In contrast, the failure of a 4 kW DG system on a distribution circuit serving several thousand customers is very unlikely to cause a change in loads on that circuit that is beyond the normal fluctuations in load on such a circuit. As the penetration of residential DG increases in California, the impacts of residential DG on the distribution system may become more complex, but today there is no basis for assessing "standby" T&D costs on residential or small commercial DG customers through fixed charges.

IV. PROPOSALS FOR NEW CHARGES WITHIN CURRENT RATE DESIGNS – Witness Beach

A. PG&E's and SDG&E's Non-coincident Demand Charges

Q: PG&E and SDG&E propose that residential NEM customers must take service under a TOU rate that includes a non-coincident demand charge. PG&E's demand charge would be $3.00 per kW-month; SDG&E's would be $9.19 per kW-month. The revenues from the demand charge would reduce the TOU energy rates. Has the Commission ever approved or even considered residential demand charges?

A: No. A residential demand charge based on a customer's maximum kW demand in any 15- or 60-minute period was not even proposed by any party to the Commission's comprehensive RROIR. The closest proposal in R. 12-06-013 to a demand charge was SDG&E's proposal for an optional residential rate with a demand-differentiated fixed charge designed to recover distribution and other demand-related costs. This proposal featured a schedule of increasing monthly fixed charges, with the applicable fixed charge based on the customer's maximum demand in the prior month. Such a proposal would not be as complex as a standard industrial demand charge based directly on a customer's maximum monthly kW of usage. The Commission rejected the SDG&E proposal, even for inclusion in TOU pilot programs, as beyond the present scope of residential rate design and as potentially distracting from the Commission's central focus on expanding the use of TOU rates.[37]

Q: Are demand charges likely to be confusing to residential customers who are considering installing DG?

A: Yes. The potential for confusion is high, for the following reasons:

- **Customers do not understand demand charges.** Demand charges have never been part of residential rate design in California, and are rare elsewhere in the U.S. The IOUs know this – they commissioned a customer survey for the Commission's RROIR which concluded that a demand charge "was confusing" to participants, who ended up making inaccurate comparisons to a fixed monthly service fee because they failed to comprehend that a demand charge "varies based on kW demand levels."[38] Consumers have experience with their energy use, in kilowatt-hours, because that is the basis on which they are billed. They do not have experience with the concept of demand, measured in kW, which is the rate at which a customer uses energy as a function of time. In mathematical terms, it is the derivative of energy use with respect to time.

- Such confusion is not surprising, given that **demand data for typical home energy uses** is not readily available. Energy usage data for home appliances is typically expressed in term of the annual kWhs of energy use, for example, as in Energy Star ratings for appliances. Ratings are not given in terms of the maximum power use, in kW. As a result, consumers do not have accurate information today to make intelligent decisions to reduce their maximum kW demand.[39]

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[37] See D. 15-07-001, at pp. 182-184 and Finding of Fact 160.

[38] Hiner and Partners, Inc. "RROIR" Customer Survey, April 16, 2013, p. 22.

[39] For example, PG&E's website on home energy use (http://www.pge.com/en/myhome/myaccount/usage/index.page) lists the typical energy use of home appliances and equipment in terms of $ per month, $ per hour, or $ per use. These metrics are all based on the energy (kWh) use of appliances. PG&E does not explain (and, today, does

- Indeed, **data on each residential customer's maximum hourly demand only became available recently**, with the advent of smart meter data. To my knowledge, residential customers are not informed what their maximum 60- or 15-minute demand is today or when it occurs. Indeed, there is no reason to do so, given that residential customers have never been billed on the basis of their maximum kW of demand. There has been no customer education to date from the IOUs on what a kW of demand means, how to determine maximum demand from smart meter data, or how maximum demand charges work. Real-time data is not readily available to residential customers about their real-time demand or about what their maximum demand has been thus far in a billing period; such real-time information would be important if customers are to take actions to reduce their current demand. Even if such data becomes widely available through new technology, it is unlikely that customers will be able easily to alter their behavior so as to impact the level of their maximum kW of demand, which only occurs in one 15- or 60-minute period each month.

- **No education of residential customers on their kW of demand, or on demand charges, has occurred or is planned as part of RROIR.** As specified in D. 15-07-001, the California utilities will be focusing their customer education on promoting the use and understanding of TOU rates. The IOUs and interested parties are developing TOU pilots that explicitly will not include residential demand charges or even demand-differentiated fixed charges such as SDG&E proposed. If the Commission were to adopt a residential demand charge as part of the NEM successor tariff, this education plan would have to be supplemented and expanded to also educate customers on the demand charges that would apply to a customer who installs solar. As noted above, customers find the concept of demand charges confusing; the addition of demand charges to the residential rate structure thus could complicate the already-significant customer education effort that will need to be undertaken in the coming years.

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not need to explain) that the maximum kW demand of a home is the maximum, 15- or 60-minute, cumulative usage of multiple appliances at the same time.

- **Modeling of customer savings from solar under a demand-charge structure would be much more complex**, and would require data on both the hourly solar generation and the customer's hourly load profile, in order to calculate the impacts of the new demand charges. Today, the solar sales process can use monthly usage data, for example, from the last year of the potential customer's paper utility bills. Obtaining hourly smart meter data will be significantly more complex, as will the analysis to predict customer bill savings. Obviously, the software exists to perform these more complex calculations, but the customer is unlikely to be able to verify the math and may have much greater difficulty understanding and trusting the salesman's estimate. This will significantly complicate the solar sales process and impact the sustainability of the solar industry in California.

The complexity and confusion that demand charges will introduce are unlikely to support Rate Design Principles 6 and 10, which call for rates that are "stable and understandable and provide customer choice" and that "emphasize customer education and outreach that enhances customer understanding and acceptance of new rates." This conclusion is reinforced by a survey that SDG&E conducted of customer preferences for NEM successor tariff rate design.[40] This survey only looked at possible new structure for the NEM successor tariff, and did not include a continuation of the current NEM structure. The possible new structures tested included a feed-in tariff with a set price for all DG output, a demand charge, and an installed capacity charge. Significantly, the relatively simple feed-in tariff structure (although not as simple as NEM) was favored over demand charges or installed capacity charges by wide margins – by 3-to-1 over a demand charge and by 4-to-1 over an installed capacity charge. The JSP obtained the detailed survey results in discovery, and the survey concluded that for customers the key drawbacks of the demand charge are that it is "confusing," "unpredictable (may pay more)," and "can be difficult to change behavior."[41]

[40] SDG&E discussed this survey and the results in its August 3 proposal, at pages A-24 to A-26.
[41] Hiner & Partners, *Final Report: Solar (NEM) Rate Preferences Survey Results* (June 2015), at Slide 8.

Q: A key focus of the Commission's Rate Design Principles is that rates should send accurate, understandable, and actionable price signals to consumers. This focus is inherent in many of the Commission's principles, specifically Nos. 2, 3, 4, 5, 6, 9, and 10. Would the rate structure that PG&E and SDG&E propose for the NEM successor tariff achieve this overarching goal?

A: No. The problem with the PG&E and SDG&E rate structure for the NEM successor tariff can be illustrated by comparing the price signals that a NEM 2.0 customer will face under both (1) continued full retail NEM and (2) the PG&E/SDG&E rate structure with TOU volumetric rates, low rates for exported energy, and maximum demand charges.

- **Continued full retail NEM.** As noted above, with a continuation of NEM at the full retail rate, a solar customer will continue to see exactly the same price signals they received before solar installation. For example, the same TOU price signal to shift load will still apply if a customer on a TOU rate installs solar DG. Thus, the state's planned focus on educating customers about TOU rates will be equally effective and important for all customers, both those who install DG and those who do not.

- **PG&E / SDG&E's structure** of TOU volumetric rates, low export rates, and non-coincident maximum demand charges.
  - During summer on-peak period, under PG&E's proposed rates, the value of customer-generated power can swing from 9 cents/kWh to 30 cents/kWh from hour to hour, depending on whether the DG customer is exporting power or is importing power to meet a net on-site load. The value of summer, on-peak, customer-generated power for an SDG&E DG customer would vary from 31 c/kWh to as low as the DLAP market price of about 4 c/kWh. As a result, a DG customer will have great difficulty assessing what the marginal value of reducing or shifting his energy use will be.
  - For PG&E, this complexity will be increased further by the utility's monthly netting proposal. In months where a customer exports more

power than it imports, the net exports would be paid yet a third rate, the low rate for net surplus compensation. This means that, in a single TOU period during one billing cycle, a PG&E DG customer could face three different rates that each would be applicable at different times – one for imports, another for exports up to the amount of imports, and a third for net exports above the level of imports.

- Overlay on that complexity the fact that the customer also has to try to manage a maximum demand charge applicable to the premise's maximum hourly usage in any hour of the month.

The very complex rate structures that PG&E and SDG&E would impose on residential DG customers are similar to those for large commercial, industrial and institutional facilities, and then add the further complexity of different import and export rates. Large commercial and industrial customers have long experience with both their TOU energy usage and their maximum monthly demand, have the metering to track both energy use and demand in real time, and can pay facility managers dedicated to managing those demands and costs. But such a structure is not understandable or workable for residential or small commercial customers who spend only a few minutes a year focused on their utility bills. Imposition of such a rate structure on NEM customers will implement a major barrier to the adoption of behind-the-meter DG and will not contribute to the sustainable growth of customer-sited renewable DG, as required by AB 327.

Q: Given the newness of residential demand charges and the complexity of the rate structure that PG&E and SDG&E seek to impose on residential DG customers, have the utilities proposed to undertake significant customer education efforts to inform customers about the new rate elements and structure?

A: No, they have not. PG&E proposes that the Commission require DG customers to sign a statement acknowledging that rates may change over time; the utility says that such a statement would "aid in the education process."[42] PG&E then recommends that the Commission and "a number of stakeholders" should expand the information available for

[42] PG&E August 3 proposal, at p. 51.

potential DG customers.[43] Page A-28 of SDG&E's proposal observes that customer outreach and education are "critical" for "customer understanding of any new rate structure," without specifying what SDG&E would do to provide such education to its customers. This contrasts with the substantial detail (including a multi-year budget) that SDG&E provides on the marketing, education, and outreach efforts that the utility proposes as part of its Disadvantaged Communities proposal.[44]

Q: But don't the PG&E / SDG&E proposals to implement a residential demand charge advance Rate Design Principle No. 5, by providing the customer with an incentive to reduce non-coincident demand?

A: The incentive that the PG&E and SDG&E demand charges would provide is not likely to be understood or effective, for the reasons discussed above. Nor will such a demand charge be cost-based, for the following reasons.

First, PG&E and SDG&E propose a maximum demand charge covering distribution costs that would be based on the customer's maximum usage in any hour of the month, even if that peak occurs in the morning or at night. However, as shown in the figure for SDG&E presented above, most of SDG&E's distribution circuits peak in the afternoon or evening. Thus, it is not cost-based to assess a demand charge on residential customers based on the customer's maximum use in any hour. NRDC's September 15 reply comments provide a good explanation of the problem with a residential demand charge applicable in any hour:

> Our original proposal to use a 15-minute demand interval assessed at any time (i.e., non-coincident), would be unintentionally unfair for residential customers. Though a non-coincident 15-minute interval demand charge is standard practice across many utilities for larger, more sophisticated commercial and industrial customers, a single residential customer load is too small to dramatically affect local and system capacity to the same degree that a larger commercial or industrial customer would have on the system. A residential customer could hit a monthly peak demand in the morning getting ready for work and school when local and system-wide capacity is "off-peak." Thus, a non-coincident 15-minute demand charge

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[43] *Ibid.*, at p. 53.

[44] SDG&E August 3 proposal, at pp. B-15 to B-18 and B-25 to B-26.

interval is not a good fit for residential customers whose use does not necessarily impact the system.[45]

The JSP agree fully with NRDC's assessment.

Second, there is a level of diversity on residential circuits with many small customers such that the utility does not have to plan to size residential circuits to serve the sum of the non-coincident demands of all residential customers on the circuit. Such diversity does not exist to the same extent on circuits serving larger customers, and thus non-coincident demand charges are more reasonably a part of commercial and industrial distribution rates. As a result, it would be reasonable to collect distribution costs from residential customers based on their average demand during a summer on-peak TOU period that covers just the hours when the circuit is most likely to peak. This can be accomplished through a volumetric TOU charge to recover distribution costs during these peak hours. A customer's kWh usage over the peak period would measure the customer's contribution to the average demand during those hours and would be a reasonable, cost-based charge.

Finally, the record in A. 12-12-002 concerning Option R rates for large commercial solar customers on the PG&E system shows that, in California load centers such as the Bay Area and San Diego, solar customers on demand charges are likely to reach their maximum demand for the month on cool, overcast days when their solar systems are operating at low levels. However, these are "off-peak" days when overall demand at the system or distribution levels is not high. On the hot, sunny days when demand peaks and when the utilities actually face constraints and incur demand-related transmission and distribution costs, solar customers are producing significant amounts of power and place much lower demands on the system. The result is that demand charges overcharge solar customers compared to the actual costs which they cause the utility to incur, and demand charges are not cost-based rate structures for such customers. In D. 14-12-080, the Commission concluded that the record in A. 12-12-002 showed that Option R rates with reduced demand charges and higher TOU volumetric rates are the more cost-based rate

[45] NRDC September 15 Reply Comments, at pp. 4-5.

structure for commercial solar customers.[46] The same conclusion would apply to the commercial-type rate design structure that PG&E and SDG&E have proposed for residential DG customers.

B. SDG&E's Fixed Charge

Q: SDG&E has proposed a fixed charge (a "System Access Fee") of $14.34 per month to cover the customer-related costs of NEM service. Is this charge reasonable or necessary?

A: No, it is neither reasonable nor necessary. First, SDG&E notes that it is simply seeking Commission authorization for a fixed charge to recover customer-related costs; the utility makes clear that the exact number would be determined in a GRC Phase 2 case.[47] The proposed $14.34 per month is the utility's proposed residential customer costs in its current GRC Phase 2 case, A. 15-04-012. It is important to recognize that the marginal cost and revenue allocation issues in all recent IOU GRC Phase 2 cases have been resolved by settlements; these settlements often do not adopt specific marginal customer costs. Some parties to SDG&E's past GRC Phase 2 cases have argued for marginal customer costs for the residential class that are far lower than $14.34 per month and also less than the $10 minimum bill that the Commission adopted in D. 15-07-001. A sense of the range of marginal customer costs can be gained by looking at the positions of the utilities and TURN (or UCAN in SDG&E's territory) in recent GRC Phase 2 cases, as shown in **Table 6** below.

Table 6: *Marginal Customer Costs in Recent GRC Phase 2s*

Case	Docket	Marginal Customer Costs ($/customer-month)	
		Utility	TURN or UCAN
PG&E	A.13-04-012	$6.50	$5.00 (TURN)
SCE	A.14-06-014	$12.35	$4.93 (TURN)
SDG&E	A.11-10-002	$21.45	$7.43 (UCAN)

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[46] See D. 14-12-080.

[47] SDG&E Testimony of Cynthia Fang, at pp. 10-11 and footnote 11.

Generally, the range in marginal customer costs in Table 6 results from different approaches to their calculation. PG&E and TURN/UCAN have favored the New Customer Only (NCO) approach, which produces lower marginal customer costs, while SCE and SDG&E use the Rental or Real Economic Carrying Charge (RECC) method, which results in higher costs. The Commission has tended to favor the NCO method in litigated rate design cases,[48] although the choice between these two approaches remains an area of active debate. Section 739.9[e] authorizes a fixed monthly charge or minimum bill which collects "*a reasonable portion of the fixed costs of providing electric service to residential customers.*" Clearly, the Commission has the discretion to determine what a "reasonable portion" is; the use of the word "portion" indicates that a reasonable portion will be less than 100%.[49] The point here is that the $10 minimum bill which the Commission adopted in D. 15-07-001 could collect more than a reasonable estimate of the utility's marginal customer costs.

As a result of the new $10 per month minimum bill, residential NEM customers – both existing DG customers grandfathered on NEM as well as future DG customers under the successor tariff – are likely to pay all, or a substantial share, of the customer-related costs that would be included in the proposed System Access Fee. As a result, it is unclear why the System Access Fee is either reasonable or needed.

Q: SDG&E's proposal would establish a new fixed charge for a subset of residential customers. Didn't the Commission establish a timeline and process for addressing fixed costs for residential customers in D. 15-07-001?

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[48] The Commission approved the use of the NCO method in these litigated cases: PG&E GRCs D.92-12-057 and D.97-03-017; Edison GRC D.96-04-050; SoCal Gas/SDG&E BCAP D.00-04-060.

[49] For example, the utilities may argue that their full customer-related costs are several times higher than their marginal customer costs, as a result of applying the Equal Percentage of Marginal Cost (EPMC) factor to their marginal customer costs. However, the EPMC factor is based on scaling the utility's combined marginal customer and distribution costs to equal its revenue requirement, so it is unclear whether the costs covered by the EPMC scalar are customer-related. As a result, the utilities' marginal customer costs represent the "reasonable portion" of the utilities' delivery costs that are clearly not based on usage.

A: Yes, the Commission did, at pages 189-193 of the RROIR decision. Importantly, the Commission recognized that a key driver in this process will be the future extent to which customers adopt DG and other types of distributed resources, including storage and demand response:

> We believe that a fixed charge can play a role in the residential rates in the future -- especially as the electricity market evolves to accommodate more distributed technologies. We expect that in the future, there may be substantial variation in how residential customers procure and conserve electricity for their needs. The role of the utility in this changing world may include services for which volumetric pricing is not appropriate or possible. Therefore, we believe continued consideration of a fixed charge in residential rates is appropriate and we direct the IOUs and stakeholders to follow the process below.[50]

Given that the impacts of distributed resources are central to the Commission's motivation for continuing to investigate the role of fixed charges in residential rate design, it makes sense for the Commission to coordinate the consideration of fixed charges for residential DG customers with the broader process for all residential customers that the Commission adopted in D. 15-07-001. SDG&E is attempting to short-circuit that established time line and process by imposing a fixed charge on DG customers now. The Commission should not prejudge in this proceeding what fixed costs are appropriate for residential customers of any kind, and should include both non-DG and DG residential customers in the deliberative process adopted in D. 15-07-001.

Q: SDG&E also would include public purpose program (PPP) costs in its System Access Fee, with all residential DG customers paying a fixed $6.20 per month. Is this a reasonable way to recover PPP costs from DG customers?

A: No, it is not. PPP costs are collected in standard retail rates on a volumetric, $ per kWh basis. Thus, if a customer uses more electricity from the utility, that customer will pay more in PPP charges. SDG&E's fixed $6 per month PPP charge for all customers who install DG thus would be inconsistent with how PPP charges are collected from other customers. SDG&E's approach thus would benefit DG customers who install a relatively small solar system relative to their use and who continue to take a significant amount of

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[50] D. 15-07-001, at p. 190.

service from the utility; it would be unfair to DG customers whose system provides a significant amount of their on-site use and thus who make less use of the grid.

Under current NEM, DG customers pay PPP charges on their net use of grid power, i.e. on the amount of power delivered by the utility less exports back to the grid. Although the JSP do not believe that changes are needed to NEM, if the Commission were to make a change, the JSP have suggested that PPP costs could be collected based on the gross amount of power delivered to a DG customer, rather than on their usage net of exports. This is also NRDC's proposal with respect to collecting PPP costs. If such a change is made, PPP costs should be collected based on the energy (kWh) delivered to DG customers, using the same $ per kWh PPP rate that applies to standard, non-DG customers in the same rate class. SDG&E's proposal to change the PPP rate to a fixed charge should not be adopted.

V. NRDC'S CONTINUOUSLY VARIABLE DEMAND CHARGE – Witness Beach

Q: NRDC has proposed what it calls a "continuously variable demand charge" of $1 per kW-month for residential customers who install DG. Other important aspects of its NEM successor tariff proposal include a Public Purpose Program (PPP) rate applied to all deliveries from the utility to the NEM customer, and a requirement that NEM customers take service under one of the IOU's TOU rates. Please assess the NRDC proposal.

A: NRDC has revised its proposal several times, and there are a number of aspects of the proposal that remain unclear. First, NRDC has not stated clearly whether its proposed demand charge is a new rate element designed to generate new revenues, or whether the TOU rate applicable to NEM customers would be reduced to account for the revenues from the demand charge on a revenue neutral basis. I have assumed that the demand charge is a new rate element, because NRDC has not specified that there would be any changes in the TOU rate applicable to NEM customers. Second, NRDC has not specified in its proposal or comments the Public Tool modeling results that led it to propose its demand charge, and it has admitted that the $1 per kW magnitude is not supported by

Public Tool modeling of the costs and benefits of DG.[51] Third, NRDC's September 21 testimony, at page 2, states that NRDC's proposal is now "a continuously variable demand charge that is based on the highest hour of average demand coincident with the TOU on-peak period in a given monthly billing cycle."[52] This is a different proposal than the September 15 reply comments, at pages 4-5, in which the demand charge was based on "the average demand coincident with the hour of system peak" (page 4) and the customer's one-hour demand "coincident with system peak demand" (page 5). The standard definition of demand that is "coincident with the hour of system peak" or "coincident with system peak demand" is the demand in the one hour of the year when the system reaches its highest demand for the entire year. However, NRDC did not indicate in its September 21 testimony that it was making such a significant change in its proposal compared to the comments which it filed just a few days earlier.

Q: Are there any attributes of NRDC's demand charge that are different than those proposed by PG&E and SDG&E?

A: Yes. First, NRDC has revised its proposal from a charge based on maximum demand in any hour to a charge based on the customer's maximum hourly demand only during the on-peak period. As I noted above, NRDC has recognized correctly that a non-coincident demand charge which applies to a residential customer's maximum demand in any hour is not reasonable, cost-based, or understandable for the customer.[53] Second, NRDC's proposal emphasizes the "paramount" importance of customer education about how the demand charge works.[54]

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[51] NRDC September 15 reply comments, at p. 5.

[52] NRDC also does not recognize that PG&E and SCE only have on-peak TOU periods during their summer seasons, while SDG&E has both summer and winter on-peak periods. In addition, PG&E currently has a six-month summer season, while SCE has a four-month summer. Thus, the effect of NRDC's proposal would be to apply the $1 per kW demand charge in four months for SCE, six months for PG&E, and twelve months for SDG&E.

[53] NRDC September 15 Reply Comments, at pp. 4-5.

[54] NRDC Testimony, at pp. 2-3.

Q: NRDC's September 15 reply comments, at footnote 5, suggests that its $1 per kW demand charge is designed, based on a paper by the Regulatory Assistance Project, to recover "[o]nly very local components of the distribution system (service drop, line transformer) [that] are sized to the individual customer load." Is there a need for a demand charge to recover such costs?

A; No, there is not. The $10 per month minimum bill, which the Commission approved in D. 15-07-001 and which will apply to all residential NEM customers beginning in the near future, will ensure that NEM customers will pay all, or at least a significant share, of the costs that are either independent of usage (metering and billing) or sized to an individual residential customer's load (the service drop and final line transformer).

Q: Does the NRDC demand charge also have the same problems you have discussed above in conjunction with the PG&E and SDG&E demand charge proposals, in terms of the difficulties with customer acceptance, understanding, and access to demand data in time to take action?

A: Yes, it does.

JOINT SOLAR PARTIES

CHAPTER 2

SOLAR COSTS

Witness: Jose Luis Contreras [1]

[1] Witness Qualifications were provided in his September 21, 2015 Opening Testimony

Q. On whose behalf is this rebuttal testimony being offered?

A: This rebuttal testimony is submitted on behalf of the Joint Solar Parties – CALSEIA, SEIA, TASC, and Vote Solar

Q. What is the purpose of this rebuttal testimony?

A. This testimony responds to the direct testimony served on September 21, 2015 which addresses the first of issue that Administrative Law Judge Simon set for hearing in her Ruling dated September 1, 2015:

> The basis for projections of prices of rooftop solar installations that are different from those used in the Public Tool.

Q. Did any other party include information responsive to this issue in opening testimony?

A. Yes. In opening testimony, the Office of Ratepayer Advocates (ORA) includes portions of a study published by the Massachusetts Institute of Technology (MIT) to argue that the California solar market is not competitive. This argument is based on a finding that "a large difference exists between contemporary reported prices and estimated costs."[2]

Q. In your opinion, are the estimated costs used in the MIT Study reflective of the residential solar industry?

A. No. They are based on theoretical system costs that are very different from true system costs. Exhibit A-2 to this testimony contains two studies by Woodlawn Associates (Woodlawn) which were conducted on behalf of solar companies to benchmark their costs against industry averages and to give the companies information that would help them improve their business practices. The methodology utilized in the Woodlawn studies differs from the methodology of the MIT study.

Q. How do the methodologies differ?

A. In the Woodlawn study, researchers took the entire accounting ledgers of participating companies and separated costs into categories. In this way, no expenses were overlooked. This can be called the "all costs" methodology. In contrast, the MIT study

[2] ORA Opening Testimony, footnote 19 at p. 12.

was premised on interviews of industry participants about the costs of various parts of solar costs, and then those costs were added together. This can be called the "piecemeal" methodology.

Q. Is it surprising that use of the piecemeal methodology results in lower totals than an all costs methodology?

A. No. When someone is trying to think of everything to include rather than looking at everything that actually is included, real world expenses fall through the cracks. This flaw in the piecemeal methodology is aptly explained by Woodlawn in the introduction to its reports:

> "Both reports used what we call the "sculpture method" to calculate costs. The participants in each study agreed to share extremely detailed financial and operating data with us. We started with the total cost in the business and then removed everything we did not believe was customer acquisition cost or installation cost. Furthermore, because we had access to such detailed information we were able to create standardized definitions of customer acquisition or installation cost. In other words, the participants did not report customer acquisition or installation cost themselves. They essentially gave us all costs and we determined—based on consistent definitions across dealers—what to include or exclude from each category. As a result, we are confident that our figures neither under nor overstate the actual costs.
>
> "Some other organizations have published estimates of customer acquisition and installation cost based on different methodologies. One common approach is what we call the "survey method". Typically, this approach involves sending a survey to a number of dealers (or installers) that asks for participants to estimate their costs in several high-level categories. For example, such a survey might ask a dealer to report its customer acquisition cost, or the amount it spends on marketing of various sorts. This is problematic for several reasons. First, not every organization has the same understanding of terms such as "customer acquisition cost" or even "installation cost". Second, it assumes the answers are comprehensive and do not omit costs, either unintentionally or intentionally. Third, many solar dealer-installers are small companies that do not have robust cost accounting or reporting that rolls up these figures easily."

Q. The Woodlawn studies include solar providers beyond California and prices from multiple states. Given this fact, are these studies relevant to this proceeding?

A. Yes. The numbers produced by the studies are still instructive and the concepts are important for understanding the perspective of solar companies seeking to reduce costs. These studies highlight opportunities, challenges, and the complexity involved in boosting efficiency.

Q. In bottom-up cost studies, such as the Woodlawn studies, what categories of costs are generally analyzed?

A. In business accounting, costs are commonly grouped into cost of goods sold (COGS), sales, and general and administrative (G&A). In the solar industry, these categories break down as follows.

- Costs directly attributable to individual solar installations (including labor) are COGS.
- Costs related to sales are often called customer acquisition costs (CAC).
- G&A is overhead costs that are specific company expenses (not company profits or project financing), but are not attributable to individual installations.

Q. What do the results of the MIT study show with respect to these categories of costs?

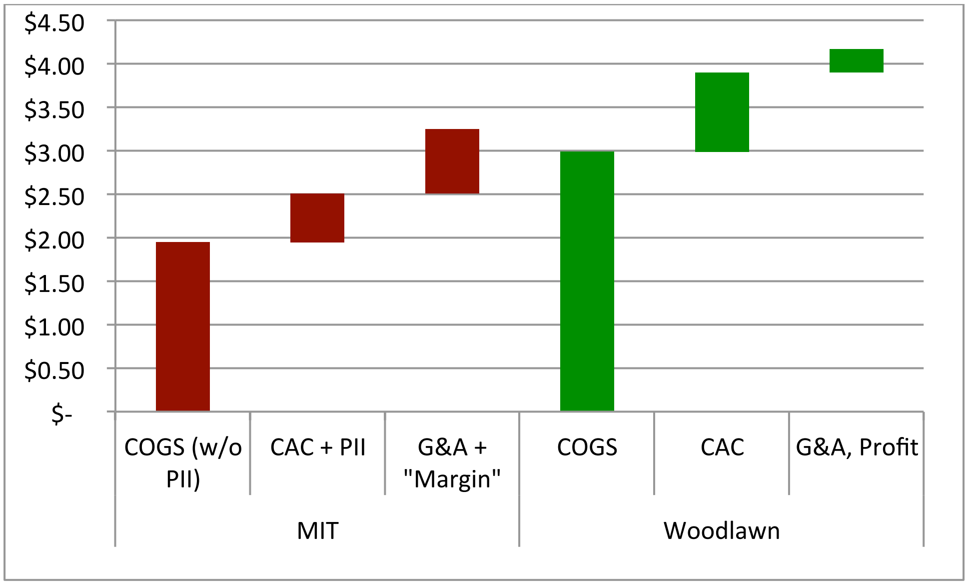
A. The results of the MIT study are consistent with the expectation of undercounting based on the use of the piecemeal methodology, as explained above. The study found that COGS for solar companies currently averages \$1.95/W-DC.[3] This is far lower than the Woodlawn COGS finding of \$2.99/W-DC in 2015.[4] The CAC cost estimated in the MIT study is \$0.56/W-DC.[5] This is far lower than the Woodlawn finding of actual CAC expenses of \$0.91/W-DC. The MIT numbers are so far from the accounting analysis of actual company expenses utilized in the Woodlawn study that they are clearly inaccurate.

[3] "The Future of Solar" at p. 85. Oddly, the study groups permitting, inspections, and interconnection (PII) with CAC, so PII is not included in this number.

[4] Woodlawn Exhibit A-2, Introduction, p. 2.

[5] Including PII.

Figure __. Cost Comparison of MIT and Woodlawn Studies



Q. Do you have any other comments on either the Woodlawn or MIT studies?

A. Yes. Neither of these studies takes into account the scheduled reduction or elimination of the ITC. If there is not sufficient margin before that change, the industry will not be able to absorb the change and offer the same value to customers.

JOINT SOLAR PARTIES

CHAPTER 3

Interconnection Charges

Witness: Mark Fulmer

Q. On whose behalf is this rebuttal testimony being offered?

A: This rebuttal testimony is submitted on behalf of the Joint Solar Parties – CALSEIA, SEIA, TASC, and Vote Solar

Q. What is the purpose of this rebuttal testimony?

A: This testimony responds to the direct testimony served on September 21, 2015 which addresses the second issue that Administrative Law Judge Simon set for hearing in her Ruling dated September 1, 2015:

> The basis for the investor-owned utilities' proposed charges in the successor tariff for interconnection of small systems.

Q. In opening testimony, what interconnection fees for small projects did each investor-owned utility (IOU) propose?

A. PG&E proposed an interconnection application fee of $100 for systems 30 kW or smaller in size.[1] For systems above this size, PG&E would charge a $1600 interconnection application fee. SCE proposed a $75 interconnection application fee for customers applying under the successor tariff.[2] SDG&E proposes a $280 interconnection application fee for systems sized 1 MW or below.[3] Systems above 1 MW would pay interconnection application fees as specified in Rule 21.

Q. On a policy level, do you have any concerns with the fees proposed by the IOUs?

A. Yes, as a general matter, the variation in the utilities' interconnection costs identified by the utilities that form the basis for the proposed fees vary widely between each utility. Even excluding the one time expenses SDG&E attempts to include for on-going recovery in future interconnection application fees, the variation between the costs SCE, PG&E and SDG&E incur to process application fees is hard to rationalize or explain. Given the wide variation in asserted costs to process applications, the JSP believe it is incumbent upon the Commission to provide incentives for higher cost utilities to drive savings in these processes.

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[1] PG&E Opening Testimony, Chapter 1, pg. 1-2
[2] SCE Opening Testimony, Chapter 3, pg. 20.
[3] SDG&E Opening Testimony, Ken Parks, pg. 2.

Q. Do you have any substantive concerns with the fees proposed by any of the IOUs?

A. Yes, in discovery, CALSEIA asked SDG&E to identify which costs identified in Witness Park's testimony were on-going, previous one-time, and future one-time expenses. SDG&E's response to CALSEIA's discovery request is attached to this testimony as Exhibit A-3. Review of SDG&E's response reveals that approximately 42% of the fees SDG&E identified for ongoing recovery from future customers seeking to interconnect distributed generation (DG) were previous one-time expenses.[4]

Q. Why is the inclusion of one-time expenses by SDG&E concerning?

A. By their very nature, one-time expenses should not be recovered on an ongoing basis from future applicants as once these fees are recovered continued inclusion of these costs in the application fee will result in over recovery by SDG&E of these costs. These costs relate to the creation of the Distributed Interconnection Information System (DIIS) and other IT improvements to streamline the application process. They benefit all customers going forward, so it is entirely appropriate to recover them from all IOU customers. This is particularly true given nearly all of SDG&E's customers have opportunities to install DG via various Commission approved programs.

Q. Do you have any other concerns about the inclusion of these one-time expenses by SDG&E in their proposed application fee?

A. Yes. The Commission pointed out in D.14-11-001 at page 7, based on remarks made by an SDG&E representative, that "SDG&E has found that having an online application process has provided immense savings that have quickly paid for the initial investment."[5] Thus it is not even clear why these costs were included in SDG&E's proposed application fee. Obviously, if the DIIS system has already resulted in "immense savings that have

[4] IT and Overheads from Capital Projects (96% is identified as previous one-time expenses) = $926,185.92; DIIS Development Phase 1 ($1,781,965) and Phase 2 ($473,000). $926,185.92+$1,781,965+$473,000=3,187,150.92. $3,187,150.92/$7,577,092=0.42

[5] D.14-11-001 at p. 7.

quickly paid for the initial investment" then these costs may have been fully recovered by SDG&E.

Q. If these costs are excluded, what is the resulting average cost for each application during SDG&E's study period?

A. Excluding previous one-time expenses, SDG&E claims to have incurred $4,389,941 in on-going expense to process 29,113 applications.[6] Thus, the resulting average cost per application is approximately $151.[7]

Q. Do you believe $151 is a reasonable application fee for SDG&E to charge its customers?

A. No. The relatively high on-going costs to process applications identified by SDG&E are far out of line with the other two major California IOUs. SCE has proposed a $75 interconnection application fee. This fee is very close to the $100 interconnection application fee proposed by PG&E. PG&E also noted in its testimony that it anticipates recently implemented automation measures will reduce administration costs. Thus it seems clear that utilization of best practices identified by SCE and PG&E are likely to result in further reduction in the cost for SDG&E to process interconnection applications.

Q. What do you believe a reasonable application fee is based on your testimony?

A. The JSP believe it is important for the Commission to take every opportunity to incentivize the utilities to share best practices and seek efficiencies in their processes. Accordingly, we believe a uniform interconnection application fee for all utilities of $75 for systems sized below 1 MW is reasonable. This fee will allow the most efficient utility, SCE, to recover the cost it has identified while providing an incentive for the remaining two IOUs to increase their efficiency.

Q. Did PG&E provide any basis for their proposed $1600 fee for large systems?

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[6] Number of applications from Testimony of Ken Parks, Attachment A.
[7] $4,389,941/29113 = $150.79

A. They did not, and this fee would have a major impact on some systems. For example, a school system that installs solar at 10 sites would pay $16,000 in application fees. The Commission should not approve a major fee when the proposing party has not even offered a basis for the fee.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT A-1

WITNESS QUALIFICATIONS

QUALIFICATIONS OF R. THOMAS BEACH

My experience and qualification ns are described in my *curriculum vitae*, which is appended to my Qualification. My CV includes a list of the testimony that I have sponsored before this Commission, and lists the testimony that I have submitted in past proceedings before the state public utility commissions in Colorado, Idaho, Minnesota, Nevada, New Mexico, North Carolina, Oregon, and Virginia. This experience includes extensive testimony on rate design issues related to solar distributed generation (DG). For example, over the last ten years, I have filed testimony on behalf of the Solar Energy Industries Association (SEIA) or its predecessor, the Solar Alliance, in the Phase 2 cases of each of the investor-owned utilities' (IOUs) general rate cases. All of this testimony has addressed rate design and cost allocation issues of concern to the solar industry. In the fall of 2006, PV Now (a predecessor of SEIA and the Solar Alliance) retained me to coordinate the solar industry's participation in an intensive, Commission-sponsored process to develop the Handbook with the program and process details for the California Solar Initiative (CSI). For the California Solar Energy Industries Association (CalSEIA), I testified before the Commission in R. 04-03-017 on the cost-effectiveness of solar incentives. Finally, I am the owner of a 2.4 kW photovoltaic (PV) system that has been installed on my family's home in Kensington, California since January 2003. We are interconnected to the PG&E system as a net metering customer under PG&E's E-7 time-of-use (TOU) tariff. Our PV system has provided most of my family's electrical requirements for the last 12 years.

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

 - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

 - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
 b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

 - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
 b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

 - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
 b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

 - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

 - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

 - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

    - *Costs and benefits of net energy metering in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

    - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

    - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

    - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

    - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

    - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

    - *Standby rates for net-metered solar customers, and the cost-effectiveness of net energy metering.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

EXHIBIT B-1

WITNESS QUALIFICATIONS

MARK E. FULMER

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1999 - Present)
Conduct economic and technical studies in support of clients involved in regulatory and legislative proceedings and power project development. Advise clients on the economic issues associated with taking electricity service from non-utility sources or self-generating power. Work includes expert testimony on rate matters; economic analysis of end-use energy-efficiency projects, retail rate and wholesale price forecasting, and pro forma analysis of cogeneration and distributed generation facilities.

Project Engineer
Daniel, Mann, Johnson & Mendenhall
(1996 - 1999)
Acted as project manager and technical advisor on energy efficiency projects. Work included management of PG&E program to promote innovative energy efficient technologies for large electricity users. Coordinated the implementation of an intranet-based energy efficiency library. Directed technical and market analyses of small commercial and residential emerging technologies.

Associate
Tellus Institute
(1990-1996)
Advised public utility commissions in five states on electric and gas industry deregulation issues. Submitted testimony on the rate design of a natural gas utility to the Pennsylvania Public Utilities Commission. Testified before the Hawaii PUC on behalf of a gas distribution utility concerning a competing electric utility's demand-side management plan. Analyzed national energy policies for a set of non-governmental agencies, including critiquing the DOE's national energy forecasting model. Developed model to track transportation energy use and emissions and used the model to evaluate state-level transportation policies. Developed model to track greenhouse gas emission reductions resulting from state-level carbon taxes.

Research Assistant
Center for Energy and Environmental Studies, Princeton University
(1988-1990)
Researched the technical and economic viability of gas turbine cogeneration using biomass in the cane sugar and alcohol industries. First researcher to apply "pinch" analysis and a mixed-integer linear programming model to minimize energy use in cane sugar refineries and alcohol distilleries.

EDUCATION

M.S.E., Mechanical and Aerospace Engineering, Princeton University, 1991
B.S., Mechanical Engineering, University of California, Irvine, 1986

SELECTED PUBLICATIONS

1. A Technical and Economic Assessment of the Co-Production of Electricity and Alcohol From Sugar Cane. Presented at the *International Engineering Conference on Energy Conversion (IECEC-90)*. American Institute of Chemical Engineers. New York, NY. August 1990. Principal author and presenter.

2. Cogeneration Applications of Biomass Gasifier/Gas Turbine Technologies in the Cane Sugar and Alcohol Industries. Proceedings, *Energy and Environment in the 21st Century*, MIT Press. Cambridge, Massachusetts. 1991. Co-author.

3. The Environmental Impacts of Demand-Side Management. Electric Power Research Institute report TR-101673. 1992. Co-author.

4. The Role of Gas Heat Pumps in Electric DSM. Presented at the 6th National Demand-Side Management Conference. Miami Beach, Florida. March 1993. Principal author and presenter.

5. Applying an Integrated Energy/Environmental Framework to the Analysis of Alternative Transportation Fuels. Invited paper at the European Council for an Energy Efficient Economy (ECEEE) 1993 Summer Study. Principal author.

6. Mistakes, Misconceptions, and Misnomers in DSM Cost-Effectiveness Analysis. Peer reviewed paper at the ACEEE 1994 Summer Study. Principal author and presenter.

7. A Social Cost Analysis of Alternative Fuels for Light Vehicles. *Energy Strategies for a Sustainable Transportation System*, ACEEE. Washington, DC. 1995.

8. Strategies for Reducing Energy Consumption in the Texas Transportation Sector. Project for the Texas Sustainable Energy Development Council. Austin, Texas. June 1995. Co-author.

9. Evaluation of Food Processing Effluent Treatment Alternatives. Paper presented at the American Chemical Society meeting, Las Vegas, Nevada. December 1997. Co-Author.

10. Market Transformation Effect Indicators for Government, Utilities, Retailers and Manufacturers. Invited panelist in a roundtable discussion at the American Council for an Energy Efficient Economy (ACEEE) 1998 Summer Study.

11. California: Crisis Over? Project Finance NewsWire, Chadbourne & Parke. October 2001. Co-author.

12. California: Back to Basics or Déjà Vu? Natural Gas & Electricity, Volume 20, Number 12. July 2004. Co-author.

13. Nuclear Fuel Reprocessing: Issues and Future Prospects. Report for the California Energy Commission. (Final Draft). March 2006. Co-author.

14. AB 1632 Assessment of California's Operating Nuclear Plants. California Energy Commission, CEC-100-2008-005-F. October 2008. Co-author.

15. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-fired Power Plants in California. California Energy Commission, CEC-700-2009-009-F. May 2009. Co-author.

PREPARED TESTIMONY

1. Rhode Island Public Utilities Commission No. 2025
   Prepared Testimony on Behalf of Rhode Island Department of Public Utilities and Carriers (Commission Staff). Testimony addressed the costs, savings, and cost-effectiveness of the proposed demand-side management programs of Providence Gas Company. April 1993.

2. Pennsylvania Public Utility Commission R-943029
   Prepared Testimony on Behalf of the Pennsylvania Office of Consumer Advocate. Testimony reviewed 1307(f) filing of Columbia Gas of Pennsylvania, particularly the impact of the proposed gas cost recovery mechanism on residential customers. May 1994.

3. Public Utilities Commission of the State of Hawaii No. 94-0206
   Prepared Testimony on Behalf of the Gas Company of Hawaii (Gasco). Testimony identification of Gasco's concerns regarding HECO's proposed DSM programs for competitive energy end-use markets. December 1994.

4. Arizona Corporation Commission No. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630. E01933A-02-0069, E-01933A-98-0471
   Rebuttal Testimony on Behalf of Constellation NewEnergy, Inc. and Strategic Energy, L.L.C. Testimony addressed the future of the Arizona Independent System Administrator. July 28, 2002.

5. FERC Docket Nos. EL00-95-075 and EL00-98-063
   Affidavit on Behalf of Duke Energy Trading and Marketing LLC. March 20, 2003.

6. CPUC Rulemaking 01-10-024
   Prepared Testimony on Behalf of the Alliance for Retail Energy Markets. Testimony addressed the utility procurement plans with respect to resource adequacy. June 23, 2003.

7. CPUC Rulemaking 01-10-024
   Rebuttal Testimony on Behalf of the Alliance for Retail Energy Markets. July 14, 2003.

8. Arizona Corporation Commission No. E-00000A-02-0051
   Reply Testimony on Behalf of Constellation NewEnergy, Inc. and Strategic Energy L.L.C. August 29, 2003.

9. Arizona Corporation Commission No. E-01345A-03-0437
   Direct Testimony on Behalf of Constellation NewEnergy and Strategic Energy, Inc. February 3, 2004.

10. Arizona Corporation Commission No. E-01345A-03-0437
Cross Rebuttal Testimony of Mark E. Fulmer on Behalf of Constellation NewEnergy and Strategic Energy, Inc. March 30, 2004.

11. CPUC Rulemaking 03-10-003
Direct Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Community Choice Aggregation Transaction Costs. April 15, 2004.

12. CPUC Rulemaking 03-10-003
Reply Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 7, 2004.

13. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 20, 2004.

14. CPUC Rulemaking 04-04-003
Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 6, 2004.

15. CPUC Rulemaking 04-04-003
Rebuttal Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 20, 2004.

16. CPUC Rulemaking 03-10-003
Opening Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. April 28, 2005.

17. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning SCE's Test Year 2006 General Rate Case Application. May 6, 2005.

18. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. May 16, 2005.

19. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning SCE's Test Year 2006 General Rate Case Application. May 25, 2005.

20. CPUC Application 06-03-005
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of the PG&E's 2007 General Rate Case Marginal Cost, Revenue Allocation and Rate Design. October 27, 2006.

21. CPUC Application 07-01-045
    Testimony of Mark E. Fulmer on Behalf of The Alliance for Retail Energy Markets and The California Manufacturers and Technology Association Concerning SCE's Application to Update is Direct Access and Other Service Fees. June 22, 2007.

22. CPUC Rulemaking 08-03-002
    Testimony of Mark Fulmer Behalf of Debenham Energy, LLC. Concerning Tariffs Supportive of Green Distributed Generation. October 31, 2008.

23. CPUC Application 09-02-022
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning PG&E's 2009 Rate Design Window Application. July 31, 2009.

24. CPUC Application 09-02-019
    Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning the Cost Recovery Proposed By PG&E in its Application to Implement a Photovoltaic Program. August 14, 2009.

25. Superior Court of San Francisco
    Deposition of Mark E. Fulmer on Behalf of the City and County of San Francisco in PG&E v. CCSF. (Verbal deposition only.) September 2, 2009.

26. California Superior Court of San Francisco Court Case No. CGC-07-470086 Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco in PG&E v. City and County of San Francisco. (Trial exhibits only in electronic file.) September 25, 2009.

27. CPUC Application 09-12-020
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase 1 of PG&E's Test Year 2011 General Rate Case. May 19, 2010.

28. CPUC Application 10-03-014
    Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of PG&E's Test Year 2011 General Rate Case Application. October 6, 2010.

29. CPUC Rulemaking 07-05-025
    Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on Behalf of the Joint Parties on a Fair and Reasonable Methodology to Determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). January 31, 2011.

30. CPUC Rulemaking 07-05-025
    Testimony of Mark E. Fulmer on Behalf of the Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements. January 31, 2011.

31. CPUC Rulemaking 07-05-025
    Rebuttal Testimony of Mark E. Fulmer on Behalf of The Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements. February 25, 2011.

32. CPUC Rulemaking 07-05-025
Rebuttal Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on Behalf of The Joint Parties on a Fair And Reasonable Methodology to Determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). February 25, 2011.

33. CPUC Application A.11-03-001, 11-03-002, 11-03-003
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition and The Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-2014 Demand Response Program Proposals. June 15, 2011.

34. CPUC Application 11-03-001, 11-03-002, 11-03-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition and The Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-2014 Demand Response Program Proposals. July 11, 2011.

35. CPUC Application 11-06-004
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets concerning PG&E's 2012 Energy Resource Recovery Account (ERRA) and 2012 Generation Non-bypassable Charges Forecast. August 26, 2011.

36. CPUC Application 11-05-023
Testimony of Mark Fulmer on Behalf of the Direct Access Customer Coalition, the Alliance for Retail Energy Markets and the Western Power Trading Forum concerning the Application of SDG&E for Authority to Enter into Purchase power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power. September 22, 2011.

37. CPUC Application 11-06-007
Testimony of Mark Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of SCE's Test Year 2012 General Rate Case Application. February 6, 2012.

38. CPUC Application 11-12-009
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition, the Alliance for Retails Energy Markets and the City and County of San Francisco Concerning PG&E's Application to Revise Direct Access and Community choice Aggregation Service Fees. May 14, 2012.

39. CPUC Rulemaking 12-03-014
Testimony on Behalf of the Alliance for Retail Markets, Direct Access Customer Coalition, and Marin Energy Authority. With Sue Mara. June 25, 2012.

40. CPUC Rulemaking 12-03-014
Reply Testimony on Behalf of the Alliance for Retail Energy Markets, Direct Access Customer Coalition, and Marin Energy Authority. With Sue Mara. July 23, 2012.

41. CPUC Application 12-03-001
    Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning PG&E Company's Application to Implement Economic Development Rates for 2013-2017. August 24, 2012.

42. CPUC Application 12-02-001
    Rebuttal Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning PG&E's Application to Implement Economic Development Rates for 2013-2017. October 19, 2012.

43. CPUC Application 12-04-020
    Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and 3 Phases Renewables Regarding PG&E's Application to Establish a Green Option Tariff. October 19, 2012.

44. CPUC Application 12-04-020
    Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and 3 Phases Renewables Regarding PG&E's Application to Establish a Green Option Tariff. November 9, 2012.

45. CPUC Application 11-11-002
    Testimony of Mark Fulmer on Behalf of the City of Long Beach. November 16, 2012.

46. CPUC Application11-11-002
    Rebuttal Testimony of Mark Fulmer on Behalf of the City of Long Beach. December 14, 2012.

47. CPUC Investigation 12-10-013
    Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding the Rate Treatment of the San Onofre Nuclear Generating Station. September 10, 2013.

48. CPUC Application 13-06-015
    Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding SDG&E's Application for Approval of an Amended Power Purchase Tolling Agreement with Pio Pico Energy Center. September 20, 2013.

49. CPUC Investigation12-10-013
    Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding the Rate Treatment of the San Onofre Nuclear Generating Station. September 23, 2013.

50. CPUC Application 13-06-015
    Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding SDG&E's Application for Approval of an Amended Power Purchase Tolling Agreement with Pio Pico Energy Center. October 4, 2013.

51. CPUC Application 13-08-004

Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding the SCE's 2014 "ERRA" Forecast. November 20, 2013.

52. CPUC Application 13-06-011
Testimony of Mark Fulmer on Behalf of the Core Transport Agent Consortium Concerning PG&E's Core Gas Capacity Planning Range. November 20, 2013.

53. CPUC Application 13-04-012
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of PG&E's Test Year 2014 General Rate Case Application. December 13, 2013.

54. CPUC Application 13-06-011
Testimony of Mark Fulmer on Behalf of the Core Transport Agent Consortium Concerning PG&E's Core Gas Capacity Planning Range. December 18, 2013.

55. CPUC Application 13-12-012/Investigation 14-06-016
Testimony of Mark Fulmer on Behalf of the Core Transport Agent Consortium Concerning Core Transport Issues in PG&E's Gas Transmission and Storage Rate Case and Consolidated Order Instituting Investigation. August 11, 2014.

56. New Mexico Public Regulation Commission Case No. 13-00390-UT
Direct Testimony of Mark E. Fulmer on Behalf of Renewable Energy Industries Association of New Mexico. August 29, 2014.

57. CPUC Application 14-05-024
Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition. September 2, 2014.

58. CPUC Application 13-12-012
Rebuttal Testimony of Mark Fulmer on Behalf of the Core Transport Agent Consortium Concerning Core Transport Issues In PG&E's Gas Transmission and Storage Rate Case. September 15, 2014.

59. CPUC Rulemaking 12-06-013
Direct Testimony of Mark Fulmer on Behalf of the Interstate Renewable Energy Council, Inc. Concerning Residential Electric Rate Design Reform. September 15, 2014.

60. CPUC Application 14-06-011
Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and the Public Agency Coalition. October 3, 2014.

61. Washington Utilities & Transportation Commission Docket UE-140762 ET AL.
Direct Testimony of Mark Fulmer on Behalf of the Alliance for Solar Choice. October 10, 2014.

62. CPUC Rulemaking 12-06-013
Rebuttal Testimony of Mark Fulmer on Behalf of the Interstate Renewable Energy Council, Inc. Concerning Residential Electric Rate Design Reform. October 17, 2014.

63. Washington Utilities & Transportation Commission Docket UE-140762 ET AL.

Cross-Answering Testimony of Mark Fulmer on Behalf of the Alliance for Solar Choice. November 14, 2014.

64. CPUC Application 14-06-014
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of SCE's Test Year 2015 General Rate Case Application. March 13, 2015.

65. CPUC Application 14-06-014
Testimony of Mark E. Fulmer on SCE's Application to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates. March 13, 2015.

66. CPUC Application 13-12-013
Testimony of Mark Fulmer on Behalf of the City of Long Beach, Gas & Oil Department. May, 8, 2015.

67. CPUC Application 14-11-003
Testimony of Briana Kobor, Laura Norin, and Mark Fulmer on Behalf of the Utility Consumers' Action Network Concerning Sempra's Revenue Requirement Proposals for SDG&E and SoCal Gas. May 15, 2015.

68. CPUC Application 13-12-013
Rebuttal Testimony of Mark Fulmer on Behalf of the City of Long Beach, Gas & Oil Department. June 12, 2015.

69. CPUC Application 14-12-017
Testimony of Mark Fulmer on Behalf of the City of Long Beach, Gas & Oil Department. June 22, 2015.

70. CPUC Application 14-12-007
Testimony of Mark Fulmer and Laura Norin on Behalf of the Utility Consumers' Action Network Concerning Risk Assignment of SONGS Decommissioning Costs. July 15, 2015.

71. Federal Energy Regulatory Commission Docket Nos. EL02-60-007, EL02-62-006 (Consolidated)
Answering Testimony of Mark Fulmer on Behalf of Shell Energy North America (US), L.P. July 21, 2015.

72. CPUC Application 14-12-007
Rebuttal Testimony of Mark Fulmer and Laura Norin on Behalf of the Utility Consumers' Action Network Concerning Risk Assignment of SONGS Decommissioning Costs. August 3, 2015.

EXHIBIT A-2

September 29, 2015

(Re-) Introduction to *Solar Marketing Effectiveness* and *Solar Installation Effectiveness*

This note provides some additional background that is not included in the reports, both on the methodology we used and on more recent developments on cost.

Definitions

First, some definitions. *Solar Marketing Effectiveness* aimed to measure the customer acquisition cost at residential solar dealers. We define customer acquisition cost as the total cost to generate or acquire leads and turn them into signed customer contracts. This is similar to, but not always the same as, the total cost of marketing and sales as shown in a company's income statement.

Solar Installation Effectiveness aimed to measure the cost of installing residential cost systems. This was defined as the total cost to the installer. In other words, the installation cost figures given in that report do not include customer acquisition cost, corporate overhead (other than for the installation function), general & administrative expenses, or any installer profit.

Methodology

Both reports used what we call the "sculpture method" to calculate costs. The participants in each study agreed to share extremely detailed financial and operating data with us. We started with the total cost in the business and then removed everything we did not believe was customer acquisition cost or installation cost. Furthermore, because we had access to such detailed information we were able to create standardized definitions of customer acquisition or installation cost. In other words, the participants did not report customer acquisition or installation cost themselves. They essentially gave us *all* costs and we determined—based on consistent definitions across dealers—what to include or exclude from each category. As a result, we are confident that our figures neither under nor overstate the actual costs.

Some other organizations have published estimates of customer acquisition and installation cost based on different methodologies. One common approach is what we call the "survey method". Typically, this approach involves sending a survey to a number of dealer (or installers) that asks for participants to estimate their costs in several high-level categories. For example, such a survey might ask a dealer to report its customer acquisition cost, or the amount it spends on marketing of various sorts. This is problematic for several reasons. First, not every organization has the same understanding of terms such as "customer acquisition cost" or even "installation cost". Second, it assumes the answers are comprehensive and do not omit costs, either unintentionally or intentionally. Third, many solar dealer-installers are small companies that do not have robust cost accounting or reporting that rolls up these figures easily.

By way of example, we worked with one company that told us about one such survey that asked for total advertising costs per customer (which our client provided). Subsequently, this plus the cost of the sales team was conflated with total customer acquisition cost. However, this totally omitted the cost the marketing team itself and the cost of producing ads in the first place.

Another way to estimate these costs is using financial statement analysis. This is more useful at organizations that have larger finance departments. Even so, it can be problematic. For example, some dealers include the cost of sales commissions in cost of goods sold. Thus, looking at the "sales & marketing" line of a P&L does not always give a complete picture of customer acquisition cost. In addition, for public companies like SolarCity, SunRun, and Vivint that also use financing, GAAP requirements may make their financials extremely difficult to interpret. Finally, many companies install both residential and commercial solar. Thus, estimates based on blended financial statements may underestimate residential installation costs since commercial costs are generally lower (on a per Watt basis).

Recent Experience

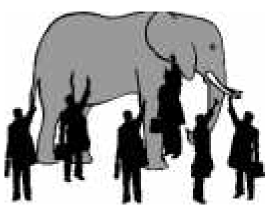
Woodlawn has completed a number of projects in customer acquisition cost and installation cost benchmarking, estimation, and optimization on a proprietary basis since the publication of the two attached reports.

In our experience, the cost of customer acquisition has not decreased significantly in the past three years, at least among "smaller" dealers (those not in the top three or so in the country). For example, we worked with two California solar dealers whose 2014 customer acquisition costs averaged $0.91 per Watt, which compares with the $0.89 per Watt from our earlier study. This range is also consistent with what third-parties charge solar companies for closed sales contracts.

Installation costs have definitely decreased, however. We worked with six dealers earlier this year on issues relating to installation costs. As part of the that project we measured their costs using the same methodology described above. Their average installation cost in the first quarter was $2.99, which is down approximately 19% in the three years since *Solar Installation Effectiveness* was published. Average revenue at those dealers was $4.17 per Watt, leaving $1.18 for customer acquisition, overhead, and profit. Average EBITDA margin was 7%.

Not all methods of benchmarking are created equal

- **"Sculpture method" involves starting with ALL costs and removing those that don't apply**
  - Ensures no costs are omitted because you didn't know to ask for them specifically *a priori*
  - Allows apples to apples comparisons – benchmarker decides which low-level costs go in each high-level category



- **"Survey method" (aka "blind men and the elephant method") asks for costs in high-level categories**
  - "Tell me what your customer acquisition cost is"
  - May miss or underestimate costs if the benchmarker did not know to ask for them
  - Firms have disparate definitions what is included in high-level categories like "customer acquisition cost" or "installation cost"

- **"Financial statement method" may be useful in some cases**
  - But, one needs to understand where costs are in the statements and possibly make some adjustments
  - Some firms include sales commissions in cost of goods sold, but this is properly considered a customer acquisition cost
  - Some firms put only materials expense in COGS, so "installation cost" includes both COGS and part of opex
  - Need to ensure expenses are appropriately allocated to residential vs. commercial solar divisions or other businesses

Woodlawn Associates

Management Consulting

Solar Installation Effectiveness

September 10, 2012

Revision e

Contents

About Woodlawn Associates

- **Management consulting firm with significant experience in solar:**
  - Go-to-market and business strategy for vendors
  - Residential solar finance
  - Residential dealer business strategy
  - Competitive analysis
- **Offices in Chicago and San Francisco**

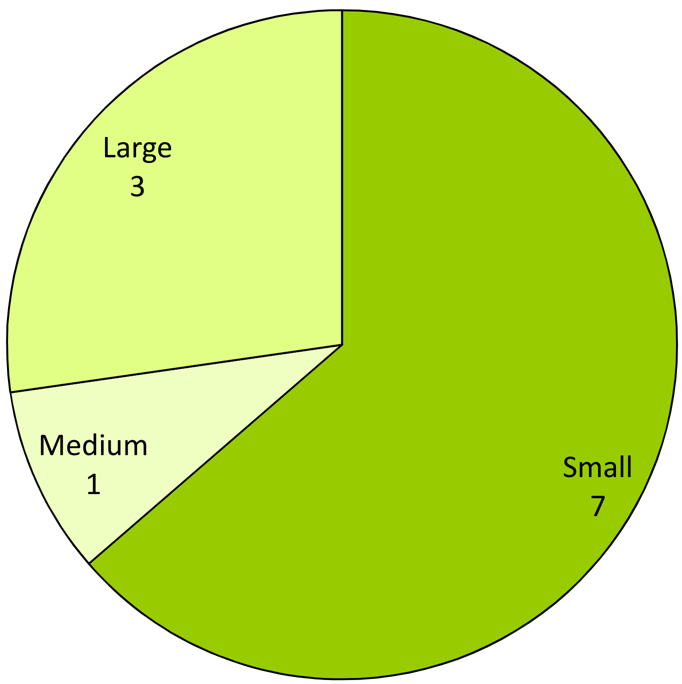
Executive summary

- **Woodlawn collected, reviewed, and analyzed financial and operational data for 11 U.S. residential solar installers for the 12 months ending June 30, 2012**
- **Dealers spent an average of $3.69 / Watt on installations**
  - They spent $3.79 / Watt adjusted for whether they purchase inverters and modules for leases
  - Excluding modules and inverters, average installation cost was $2.16 / Watt
  - The largest component of cost ex modules and inverters is labor, at $1.12 / Watt
- **By matching low cost dealers in each category, dealers could install for $2.13 to $2.59 / Watt**
- **Dealer gross margins averaged only 20% of revenue**
  - We used a standard set of costs across all dealers to ensure comparability
- **Use of microinverters appears to decrease design costs by about $0.06 / Watt**
- **Variability and uncertainty in the installation timeline drives up labor cost and inventory**
- **Dealers can reduce costs by following the 19 recommendations summarized on page 51**
- **To win loyalty and pricing power, vendors should focus on predictability**

Notes: Except where noted, all costs in this document are in $ / Watt DC at STC.

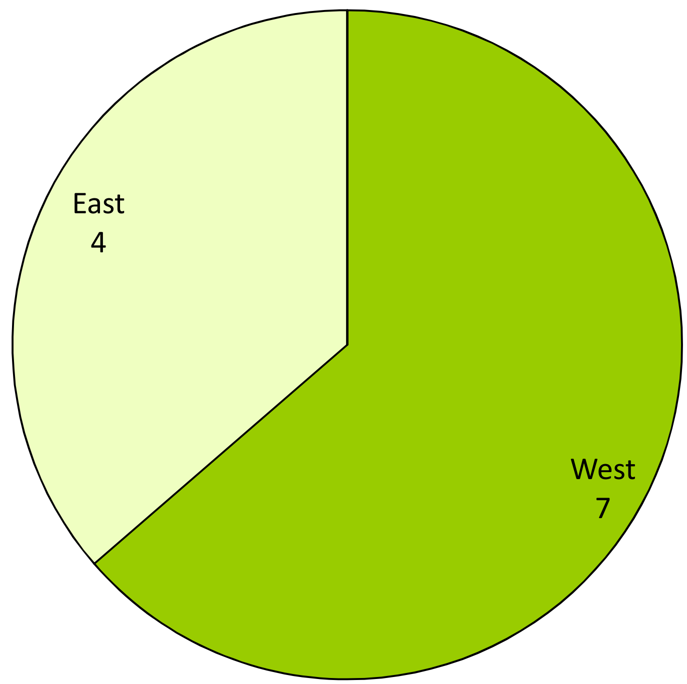
Detailed financial and operating data provided by 11 co-sponsoring solar dealers

Dealer Size

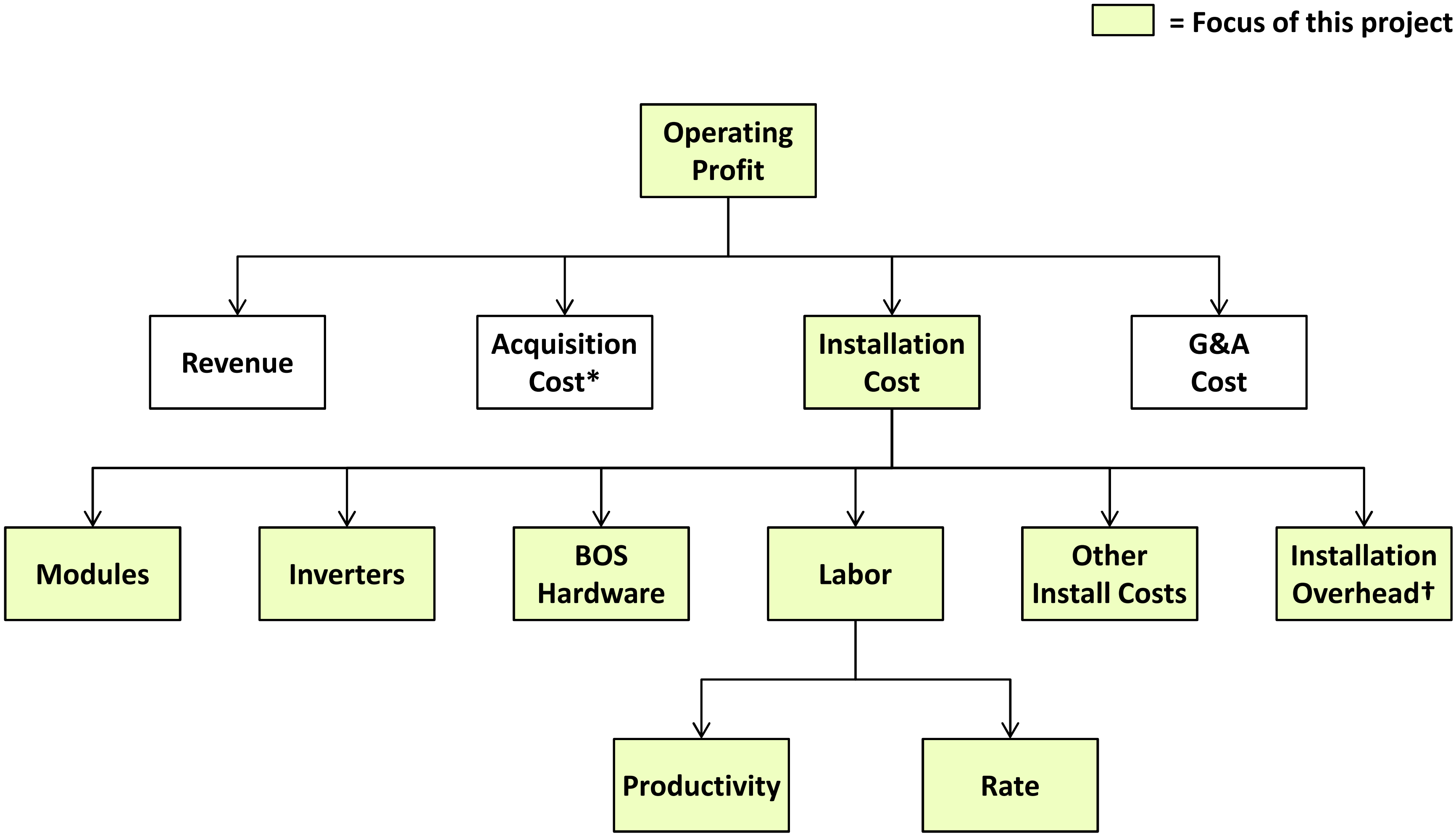


Category	Systems Sold / Month
Small	<15
Medium	15-49
Large	50+

Primary Dealer Geography



Installation cost is one of four major profit levers for solar installation businesses



Notes: * Acquisition cost was the focus on an earlier Woodlawn project, Solar Marketing Effectiveness, published in March 2012.
Some dealers also internally provide lease and PPA financing, creating a fifth lever on operating profit.
† Occupancy expenses (for example, for a warehouse), IT attributable to operations, and operations management employment costs.

Woodlawn used the following definitions for this project:

Revenue

Less: Installation Cost (a.k.a. Cost of Sales, Cost of Goods Sold)

Modules
Inverters
BOS hardware (racking, cabling, monitoring, etc.)
Sales taxes paid*
Freight
Labor
Subcontract labor/services
Workers' compensation insurance
Tools and installation-related IT
Permit and application fees
Vehicle and travel expense
Equipment rental
Warranty expense or reserve
Installation-related overhead

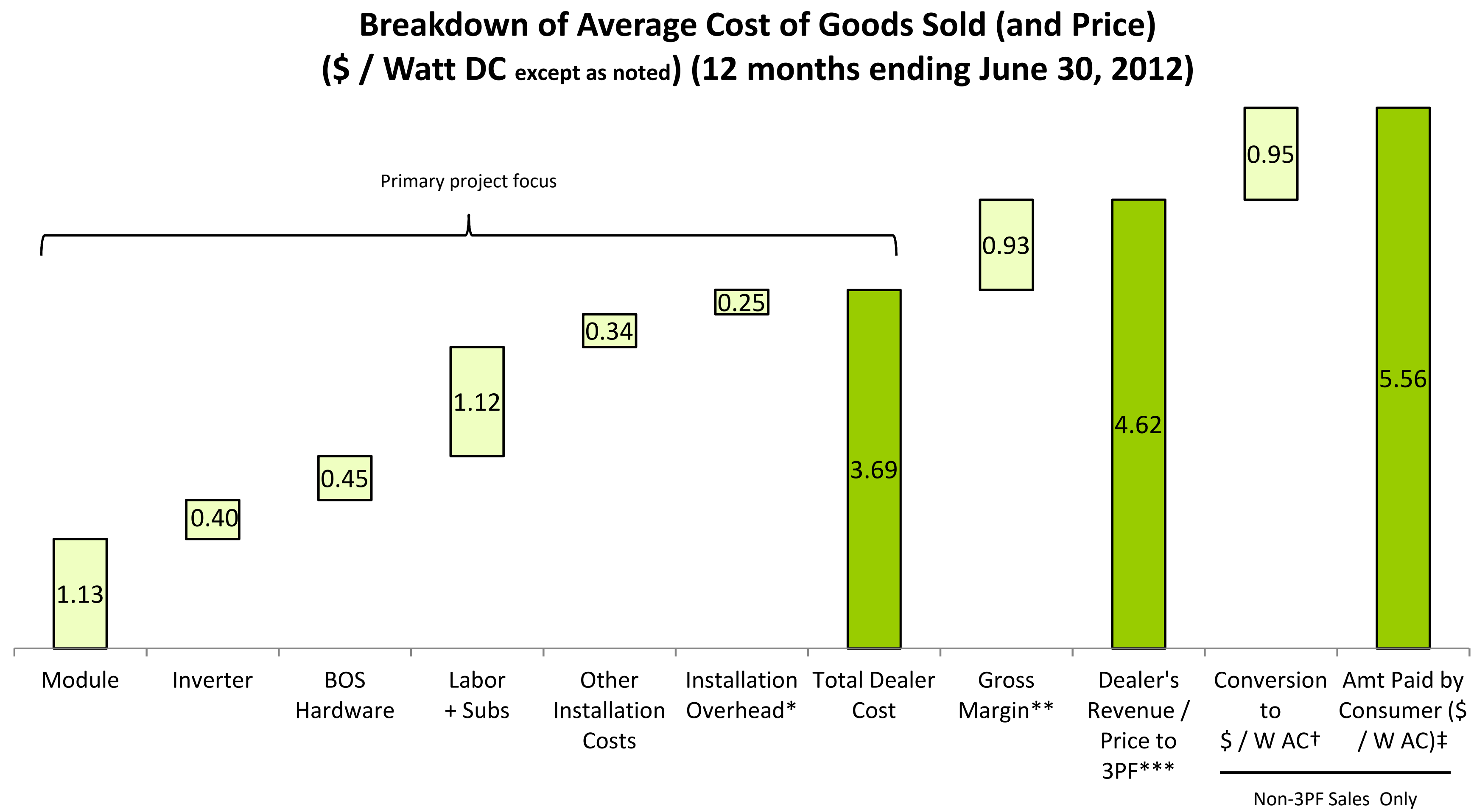
Gross Margin

Less: SG&A

Operating Profit

Notes: * Sales/use taxes paid by the dealer. Sales and use taxes payable by consumers or other downstream customers but collected by the dealer are excluded from both COGS and revenue.
Only the installation-related portion of expenses are included in installation cost.
SG&A includes sales, marketing, performance bonds, training, general liability insurance, and all other expenses.

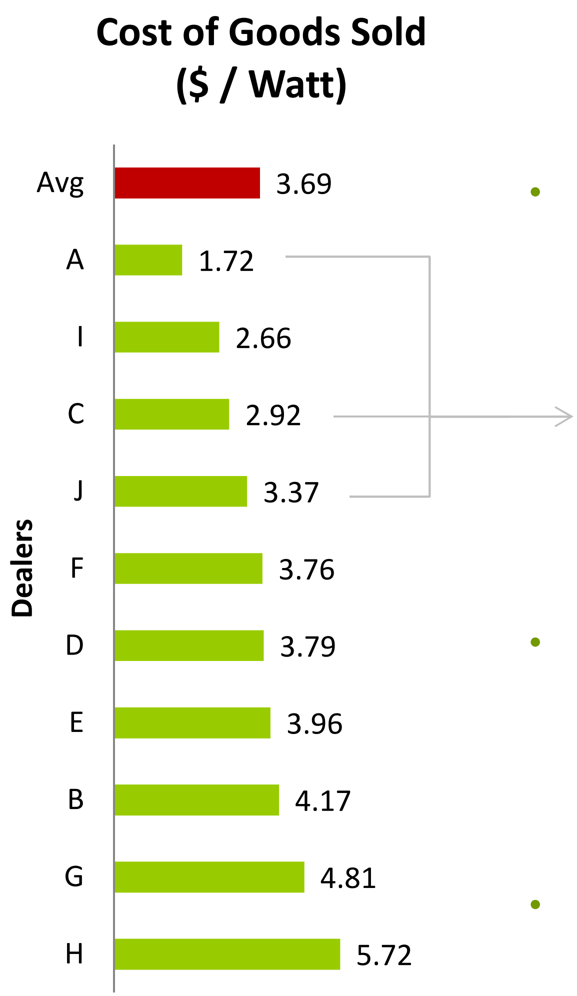
The primary focus of this project is dealers' internal installation economics



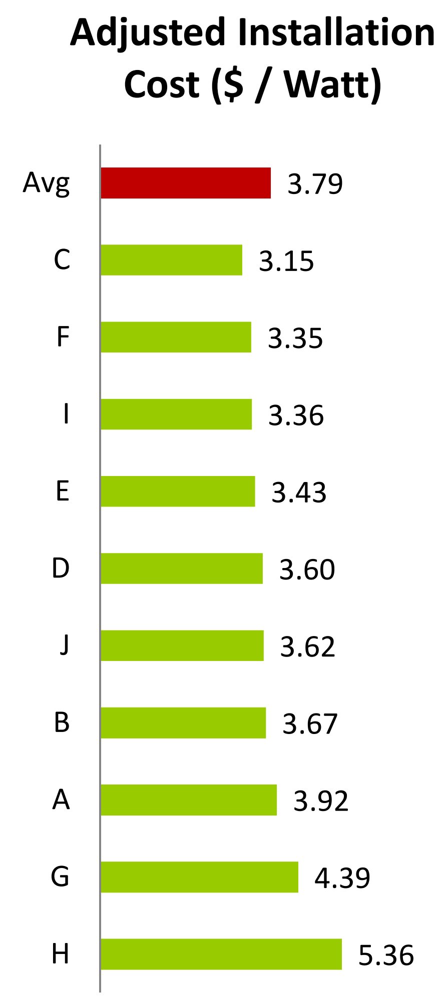
Notes: * Occupancy expenses (for example, for a warehouse), IT attributable to operations, and operations management employment costs.
** A dealer's profit is this gross margin minus sales, marketing, and G&A expenses
*** Third Party Finance company
† Assumes AC Watts = DC Watts * 0.83
‡ Excluding any sales tax payable by consumer

Contents

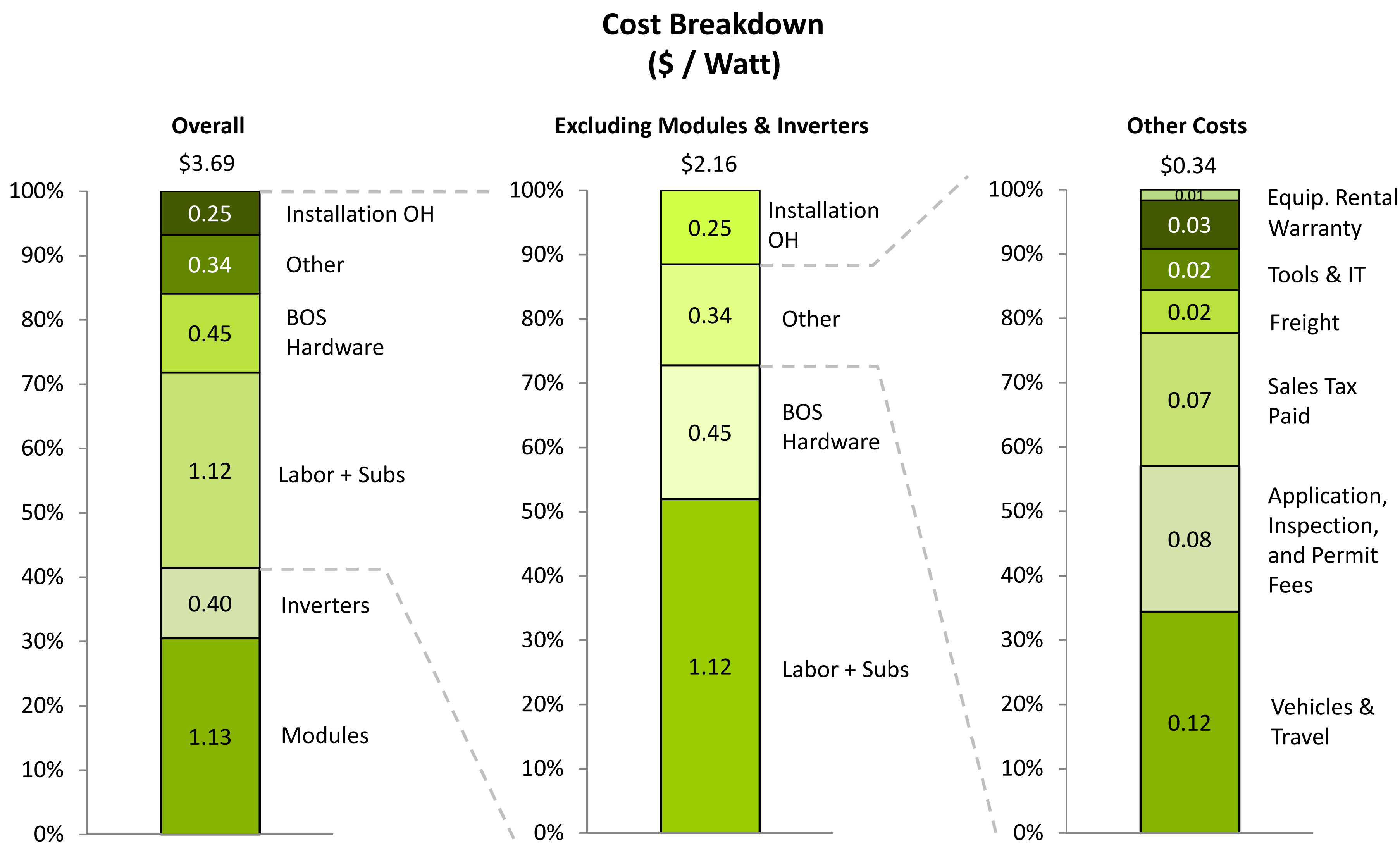
Dealers spent $3.69 per Watt on installations, or $3.79 adjusted for purchasing approach and timing



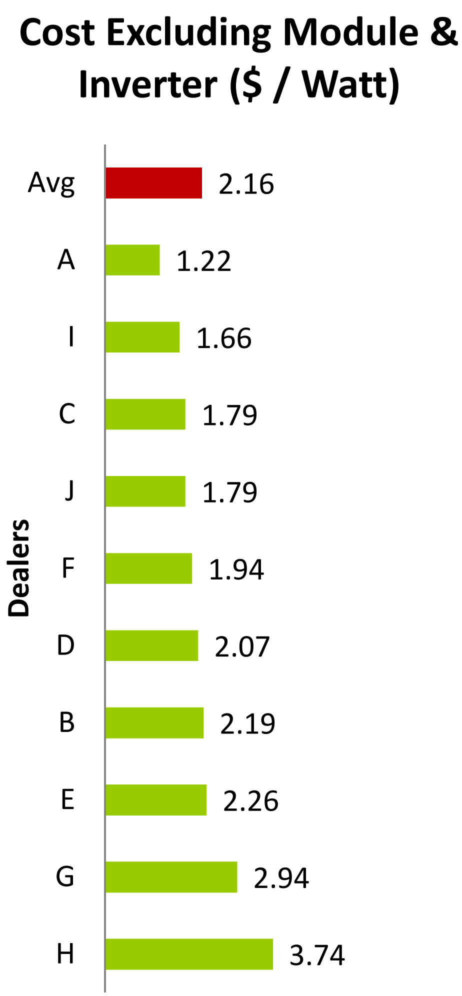
- **Cost of Goods Sold represents dealers' actual expenses to perform installations, as reflected in their financials**
  – Includes the standard set of costs defined on page 7
  – For lease sales, dealers A, C, and J did not purchase modules or inverters (their third-party finance partner did so)
  – Other dealers sometimes installed inverters that were purchased by third party finance providers
- **Adjusted Installation Cost reflects the overall cost of installations as if the dealers had bought all the modules and inverters they installed**
  – Used the prices dealers paid in the past 30 days
- **Both figures include installation-related expenses from contract to interconnect**
  – Not simply the cost incurred at the house



Modules and labor were essentially tied as the largest installation-related costs

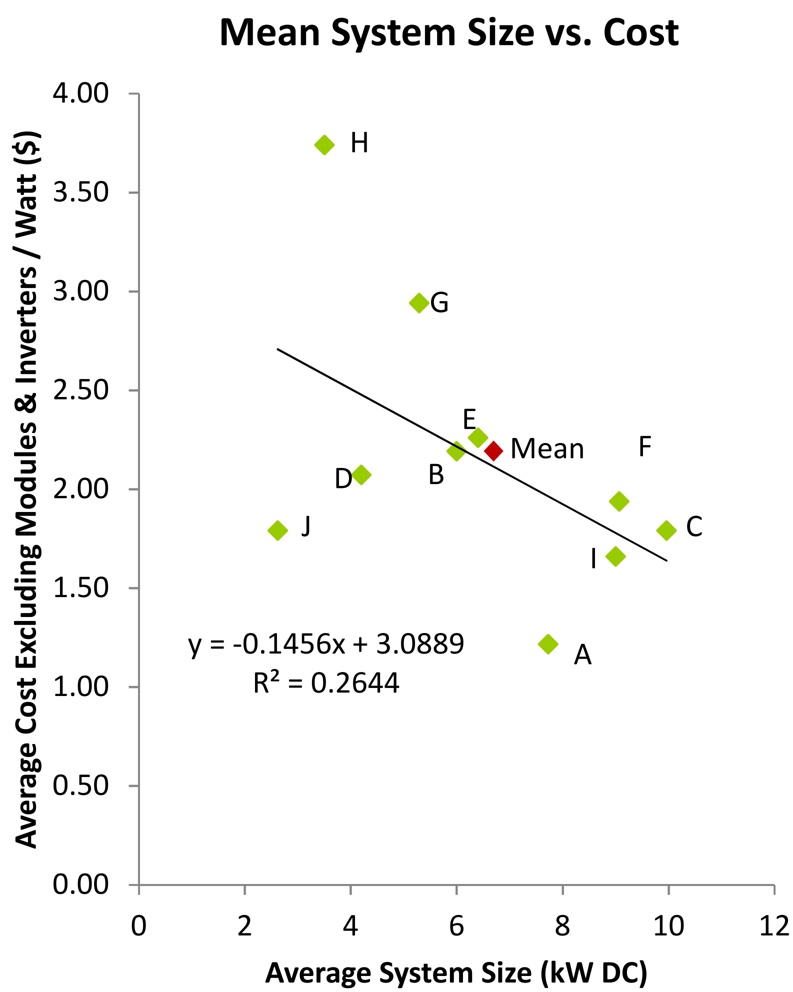


Excluding modules and inverters, dealers spent $2.16 per Watt for installation



- **On average, installation cost excluding modules and inverters totaled $12,942 per system**
- **Dealers A, C, and J installed kits that were delivered as a package. Their overhead expenses were low**
  - Dealer C did not even have a warehouse or offices until late in the study period
- **Dealers A, I, and C were among the four dealers with the largest average installed system size**
  - See relationship between system size and cost on next page
- **There is no sales tax in the states where dealers I and C do business**
  - Overall, dealers spent an average of $0.07 / Watt on sales tax
- **Dealers A and J did a substantial number of new home builds**
  - They had the lowest and third-lowest permitting labor expenses, respectively
- **Dealers I, C, and J have their installation crews work four 10-hour days**
  - They have among the lowest vehicle costs
- **Dealer A was the only dealer to use a three-man on-site crew and had a much lower wage rate than other dealers**
  - Paid only $15 / hour compared to overall average of $28/ hour

Unsurprisingly, dealers who installed larger systems achieved lower cost / Watt



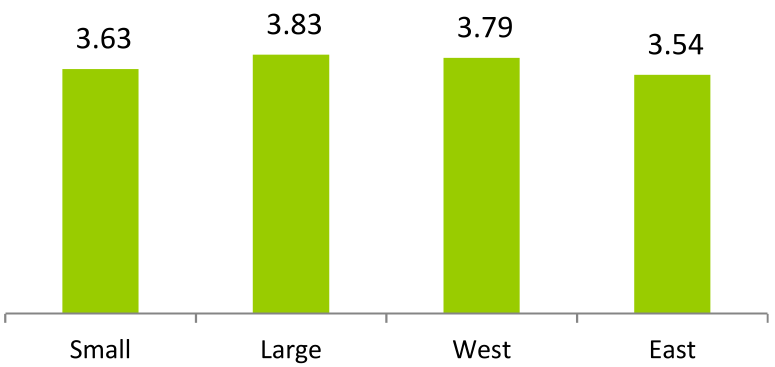
- **Installing larger systems allows dealers to spread out fixed costs (such as permit applications fees) and semi-fixed costs (such as cost of design and project management) over a larger base**
- **The data suggests increasing average system size by 1kW would decrease cost by $0.15 / Watt**
- **However, maximizing the system size for a given household may not be optimal for third-party owners**
  - If homeowner moves or reduces consumption, the lease contract may be less attractive in the future
  - Or, if PPA, system owner may see lower than expected payments
- **Therefore, ideal solution would be to sell large systems to high-consumption homeowners that nonetheless satisfy only a fraction of their total demand**
  - Even if future consumption at the building is lower, the solar system will still be a good value for the homeowner and finance company

Notes: Mean not included in regression data.

On average, small dealers had lower COGS because vendors assumed some hardware costs

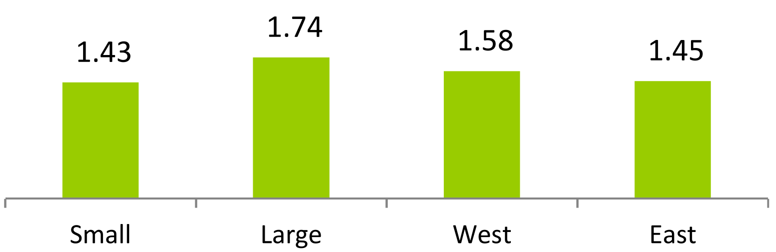
1 **Cost of Goods Sold ($ / Watt)**

It appears small dealers achieve lower costs…



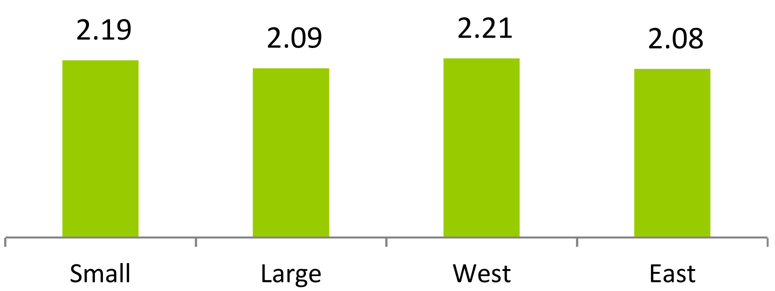
2 **Module + Inverter Cost on Books ($ / Watt)**

…driven by lower expenses for key raw materials…



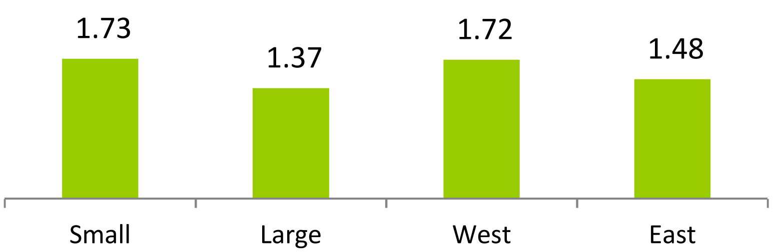
3 **Installation Cost Excluding Modules & Inverters ($ / Watt)**

…while other costs are very similar…



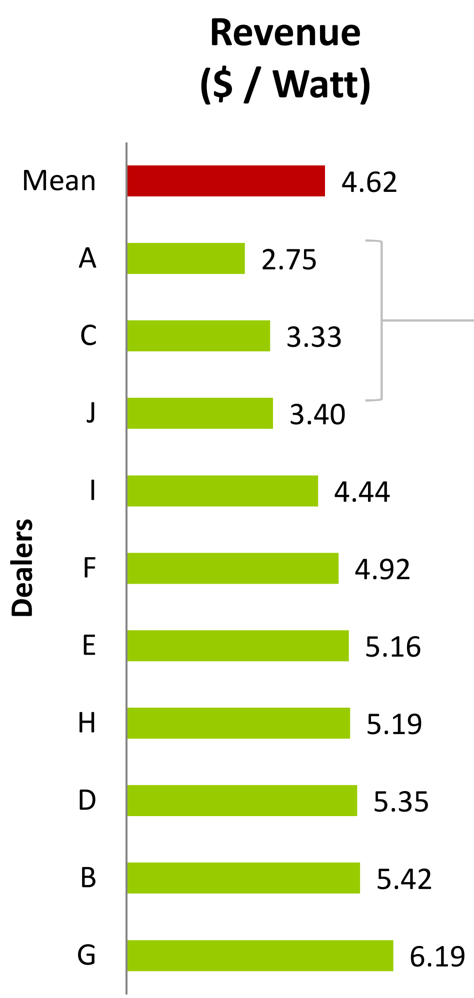
4 **Module + Inverter, Past 30 Days ($ / Watt)**

…but, when small dealers purchase all materials they actually pay $0.36 more than large dealers.*

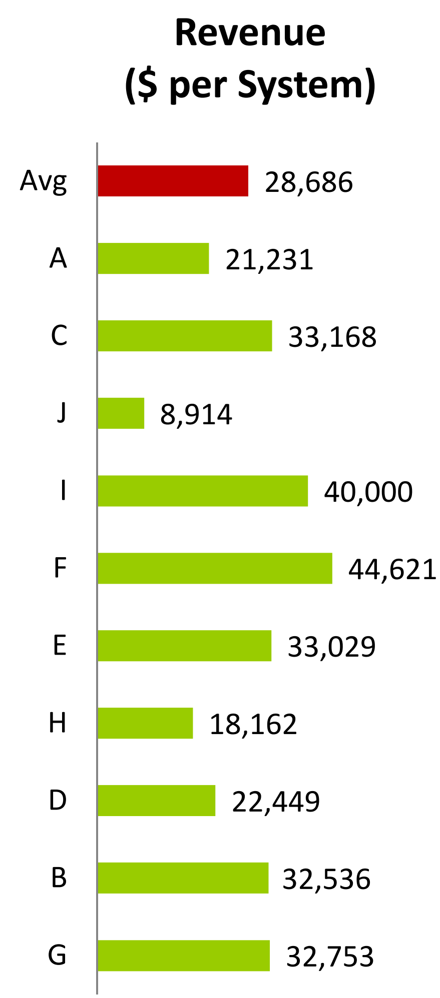


Notes: "On Books" data reflects costs on dealers books divided by number of Watts installed. This does not reflect full system costs because 3rd party financiers buy some hardware for dealers.
* $0.19 when excluding SunPower modules.

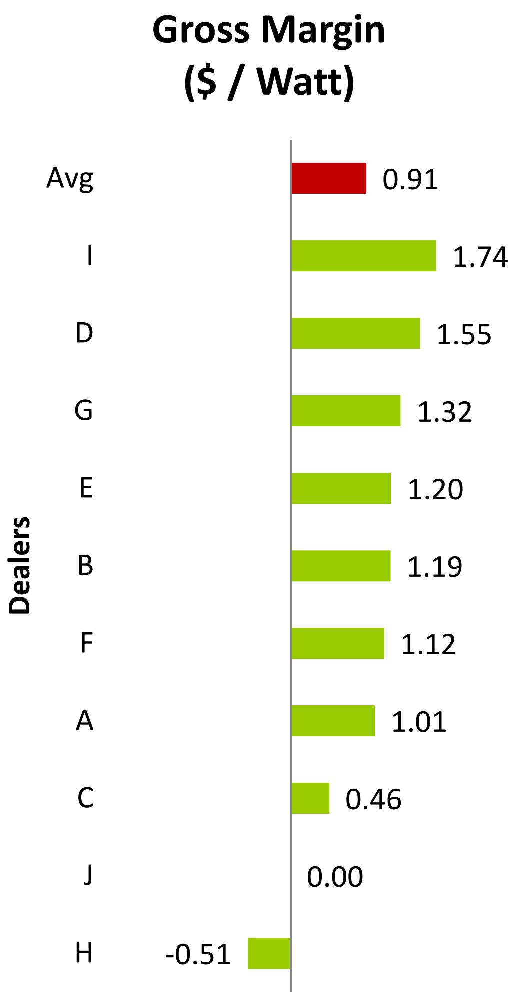
On average, dealers collected $4.62 in revenue for each Watt installed, or about $29,000 per system



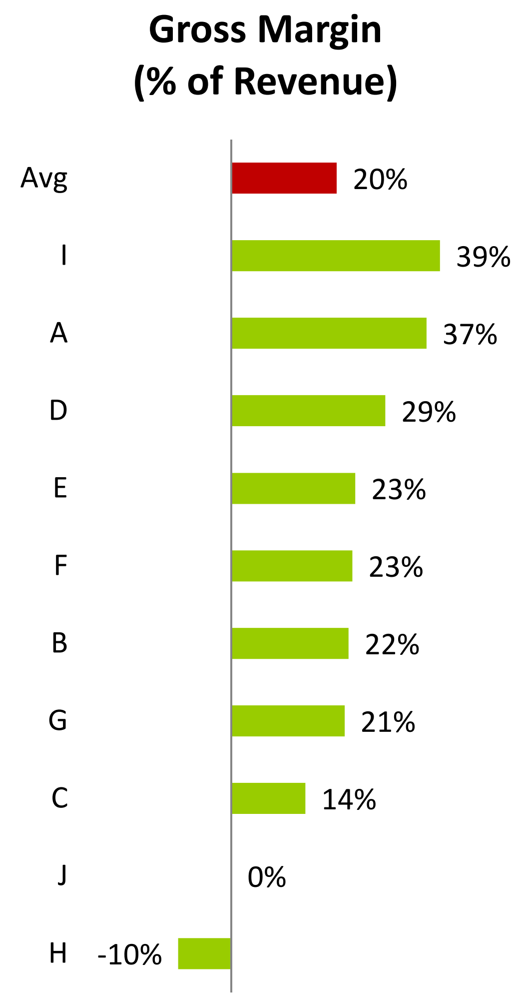
- **Dealers A, C, and J don't record revenue for modules, inverters, or racking on lease sales**
  - Some other dealers do not record revenue for inverters on leased sales they do with third parties
- **Dealer J also does a lot of very small systems on new homes**
  - Typically 1-3kW
- **Dealer G is in a relatively small market and probably has less competition than dealers in many other markets.**
  - All of its sales are cash



Dealer gross margins averaged only 20%



- **Gross margin calculated as revenue less standard set of installation-related costs**
  - Costs defined on page 7
  - Each dealer had a different approach to accounting for warranty expenses (see page 47), so we assumed 1% of revenue as a standard warranty expense reserve and applied this to all dealers
- **In *Solar Marketing Effectiveness*, we determined the average dealer spends 17% of revenue on customer acquisition, suggesting the typical dealer may not be profitable after subtracting sales, marketing, and general and administrative costs**



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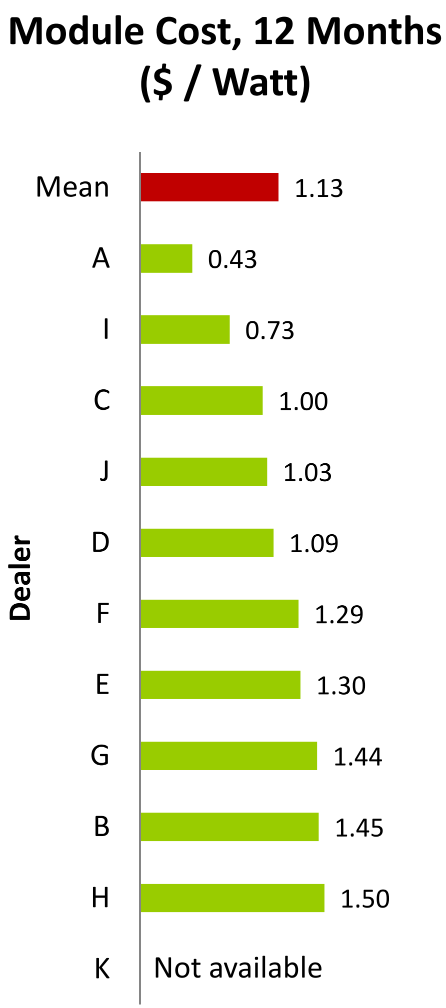
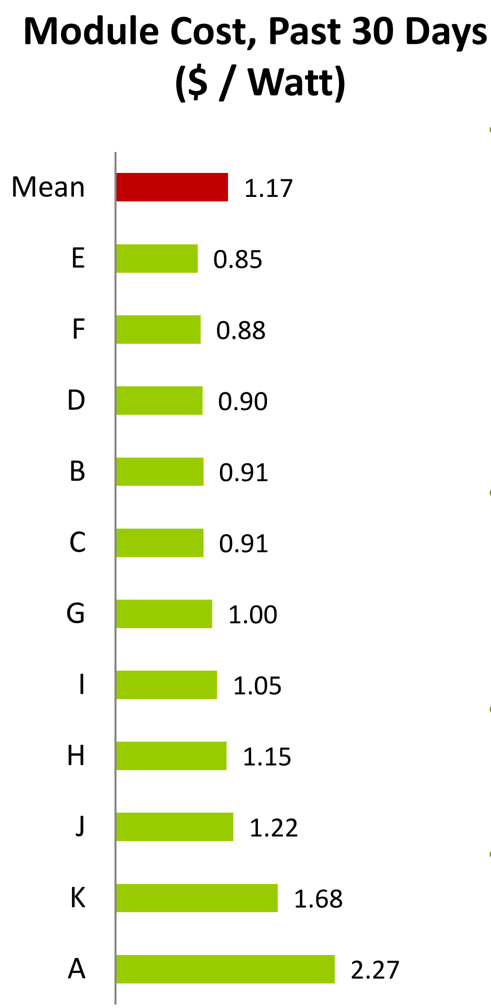
Dealers paid an average of $1.17 per Watt for modules as of August 2012

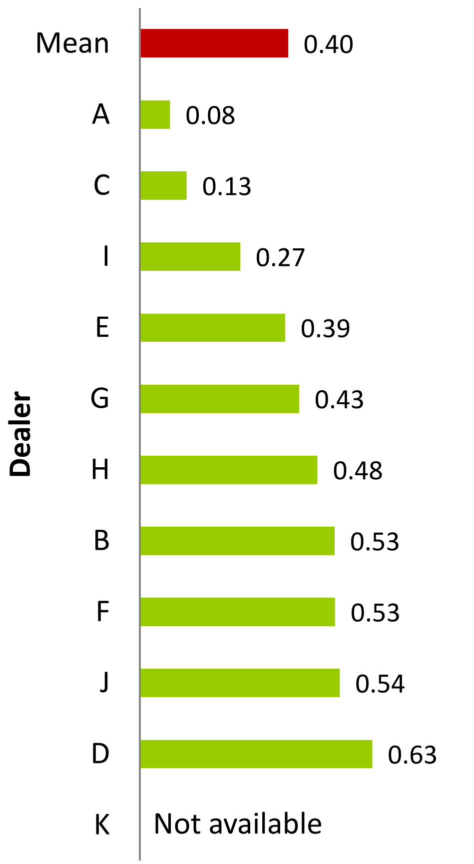




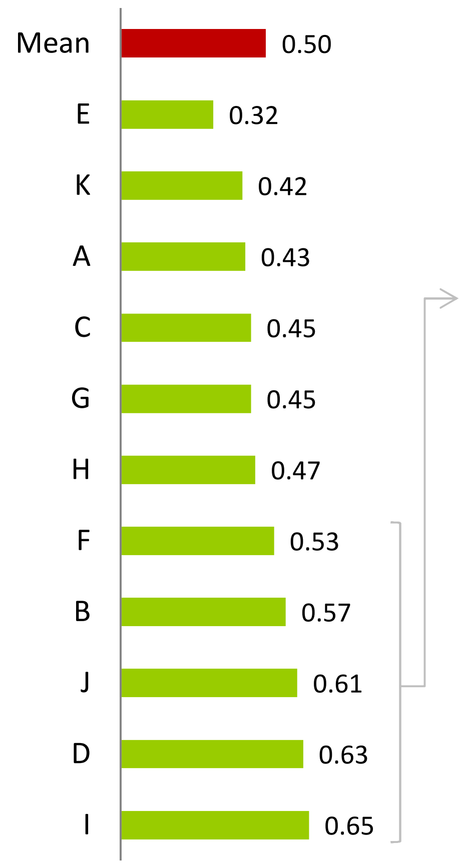
- **12 month data represents the actual module expense on dealers' books divided by number of Watts installed**
  - Does not represent comprehensive installed cost as seen by the consumer as some dealers do not purchase modules for leased systems
  - Timing of dealer purchases of module inventory (if any) may also cause cost to deviate from expected costs
- **One dealer had a significant inventory write-down, highlighting the importance of moving inventory quickly, especially when prices may change quickly**
- **30 day data represents the price dealers say they paid for modules they bought most recently**
- **Dealer size impacted the prices paid for modules**
  - Large dealers typically paid $0.34 less per Watt ($0.16 less per Watt excluding SunPower modules)

Dealers paid an average of $0.50 per Watt for inverters as of August 2012

Inverter Cost, 12 Months ($ / Watt)

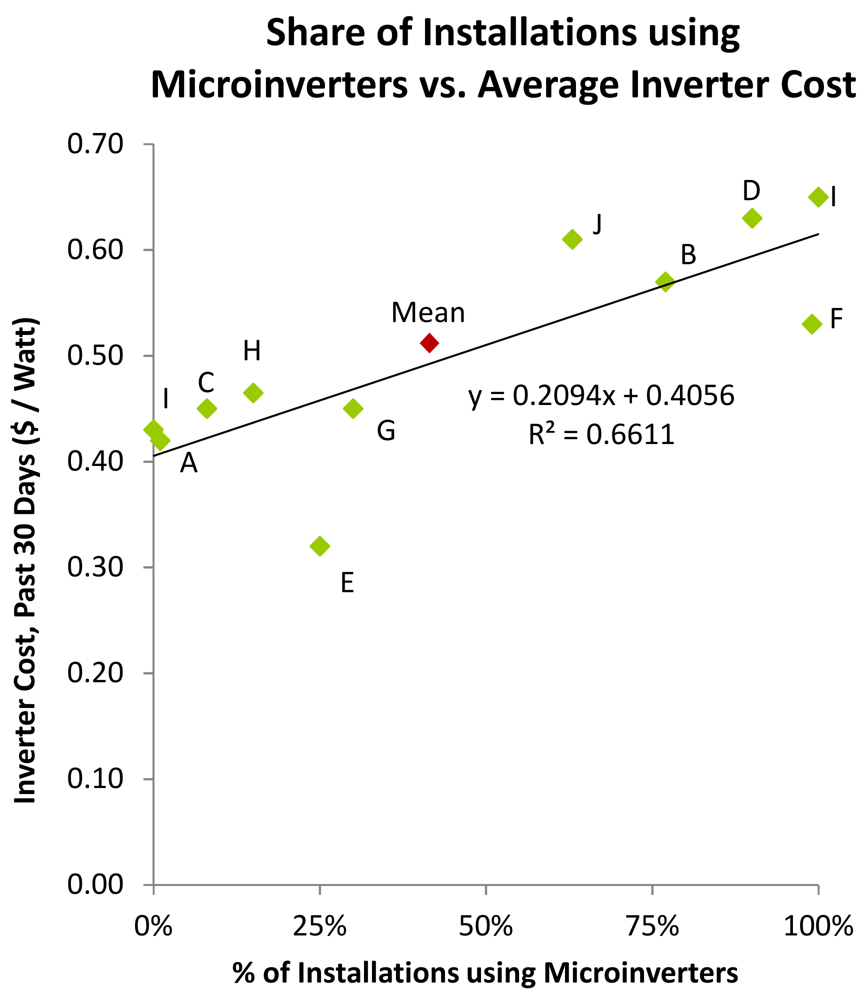


Inverter Cost, Past 30 Days ($ / Watt)



- **Same notes apply to 12-month inverter cost data as for module cost**
  - Some third-party finance companies purchased inverters in 2011 to access 30% Treasury grants
  - Certain finance providers continue to purchase inverters directly
- **Dealers at the top end of the 30-day cost scale use microinverters more than 50% of the time**
  - Dealers F, D, and I believe micros allow them to save on design costs
  - Dealer F believes micros help with inventory management as there is only one SKU stock
  - Dealer D believes micros will result in fewer maintenance calls over time, as it believes module soiling will have less of an impact
  - Dealer B says micros help it win sales against SunPower dealers
- **See impact of microinverter use on dealer labor expense on following pages**

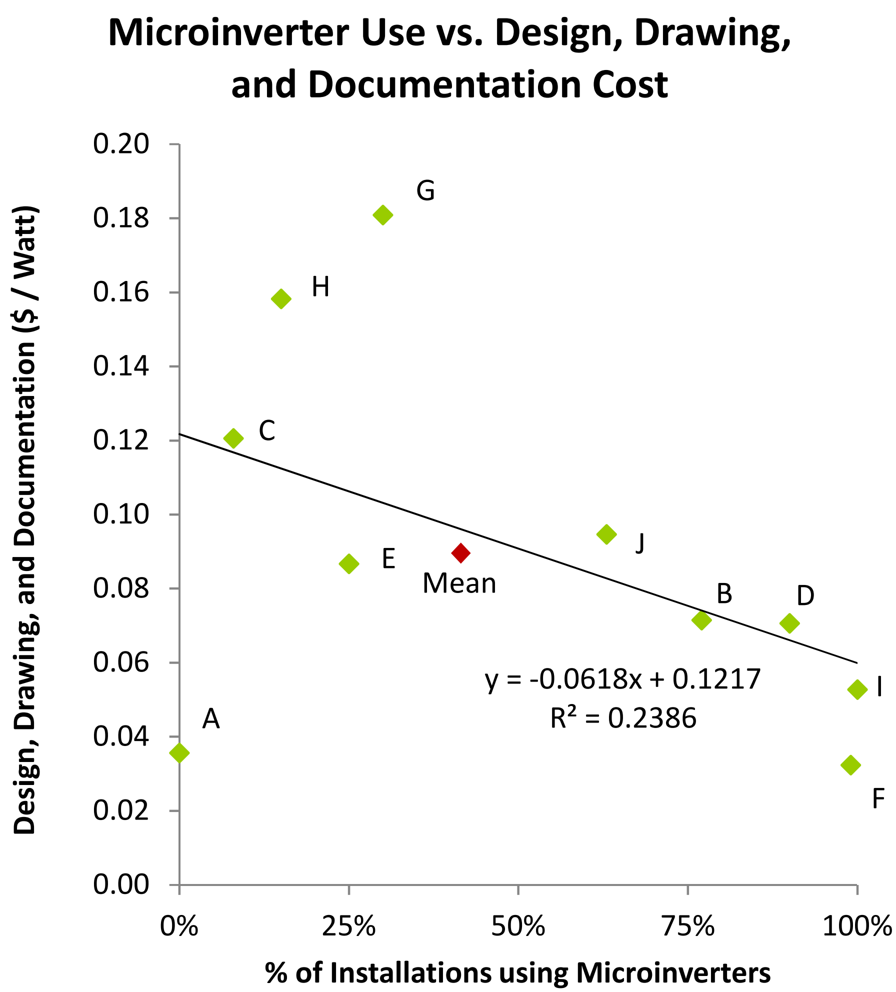
Microinverters carry a premium of about $0.21 per Watt



- **On average, dealers are using microinverters in 46% of their installations***
- **We would expect the average dealer using no microinverters to pay $0.41 / Watt, while we would expect the average dealer using all microinverters to pay $0.62 / Watt**

Notes: Mean not included in regression data.
* This is a arithmetic average of microinverter use by each dealer. It is not weighted by dealer size, although there were large dealers in both camps.

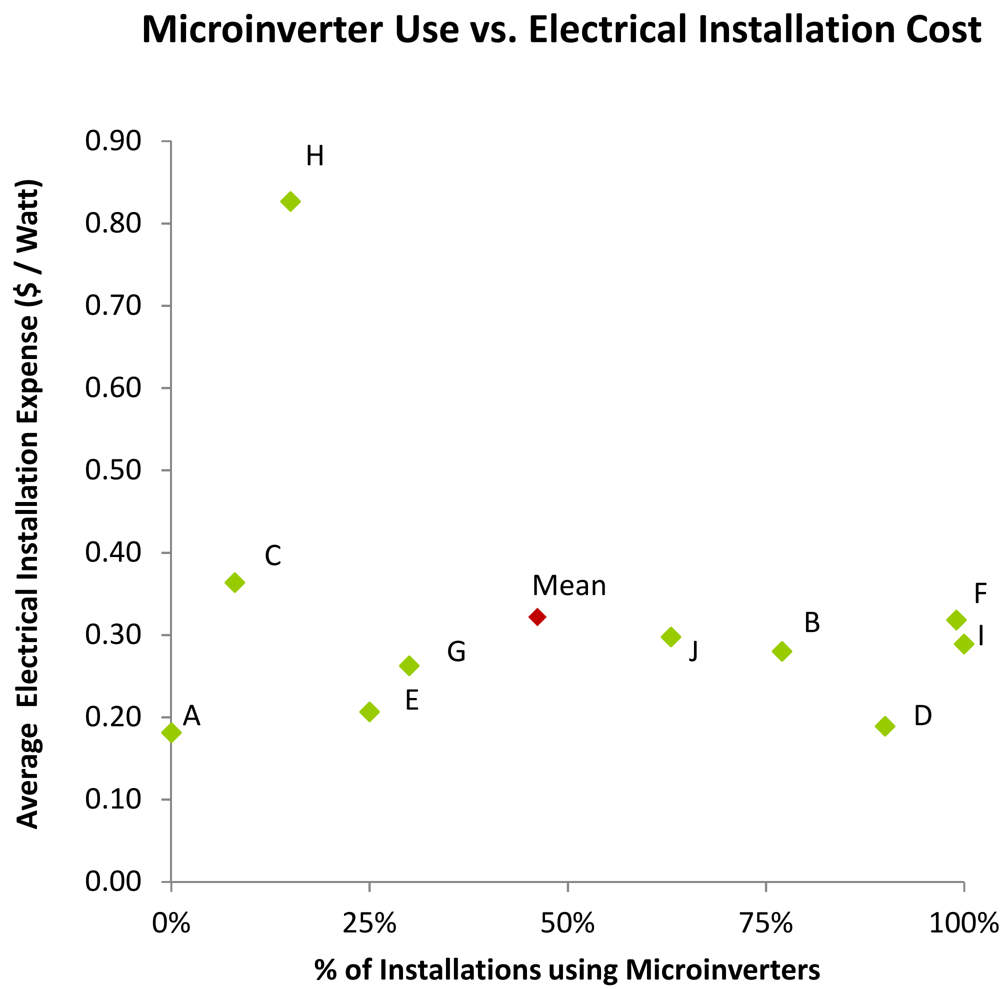
Microinverters apparently helped reduce design costs by $0.06 per Watt, partially offsetting their price premium



- **Dealers with high use of microinverters typically report lower costs for system design, drawing, and documentation**
  - "You don't have to do string calculations or iterations of how many panels you can fit."
    Dealer M
  - "We have already eliminated one person and one step in the design process by making that change."
    Dealer D
- **On average, we would expect a dealer using no microinverters to spend about $0.12 / Watt on this task, whereas we would expect one using all microinverters to spent $0.06 / Watt**
- **The fit of the data is fairly lose**
- **Net of the labor savings, microinverters are priced about $0.15 / Watt above conventional inverters**

Notes: Mean not included in regression data.

However, microinverter use seemed to have no relationship with electrical installation expense



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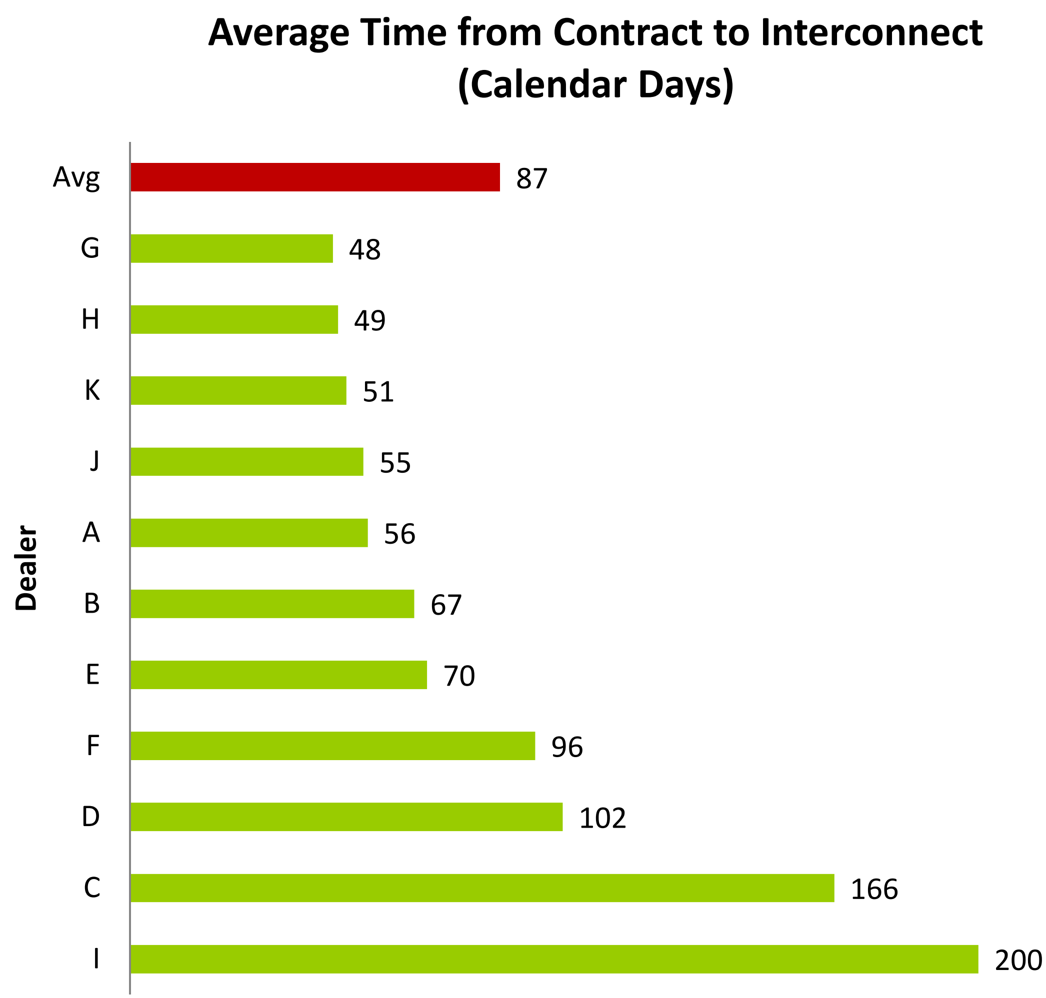
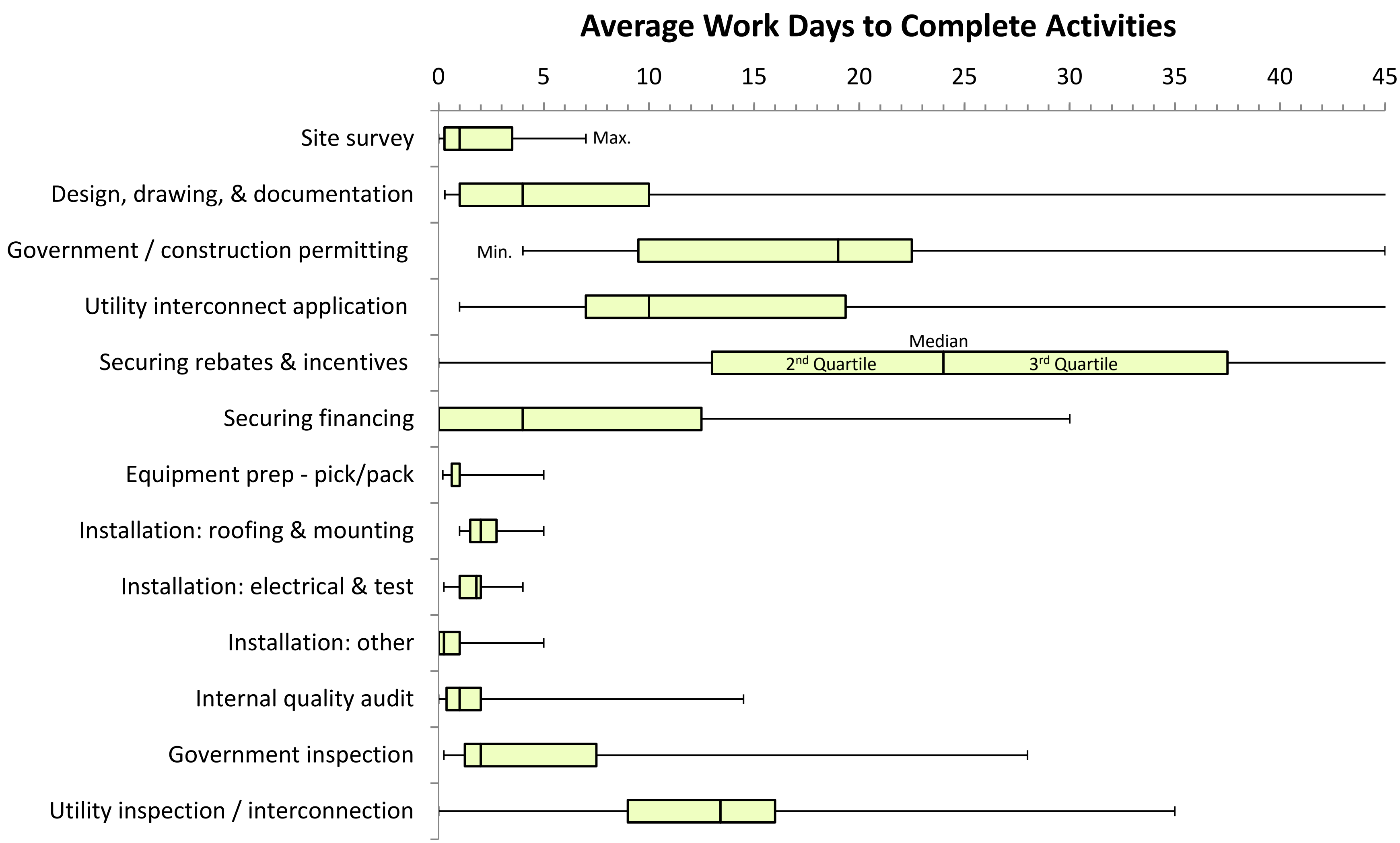
Average calendar time from sale to interconnect was 87 days

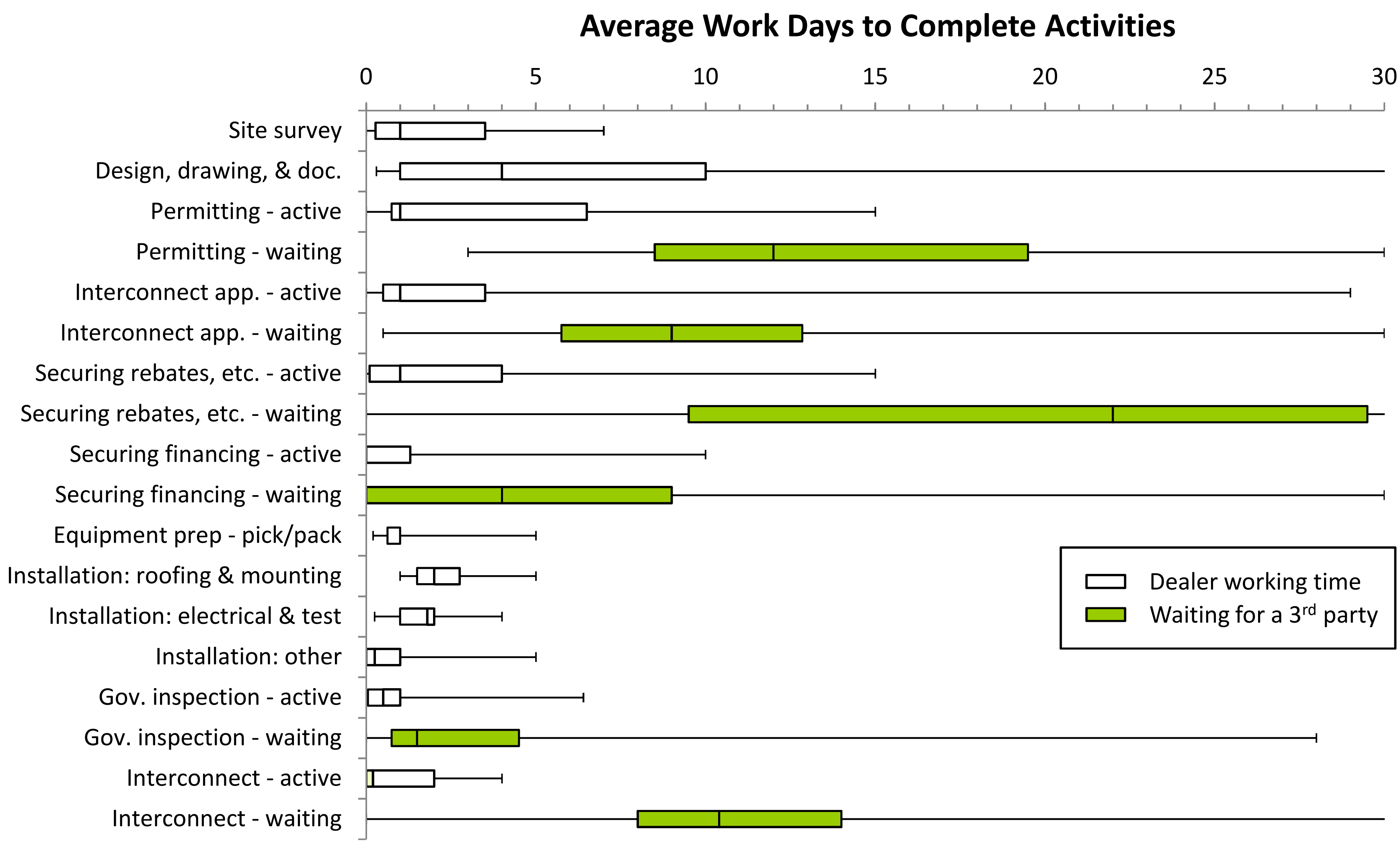


The average elapsed time to complete each activity varied significantly across installers



Notes: n=11; Work days are non-weekend, non-holidays. For most companies working days are approximately 2/3 the number of calendar days.
Chart based on each dealer's mean time to complete a task. Within a single dealer, time to complete certain tasks varied significantly from project to project.

Waiting for third parties adds up to 59 work days to the average installation timeline

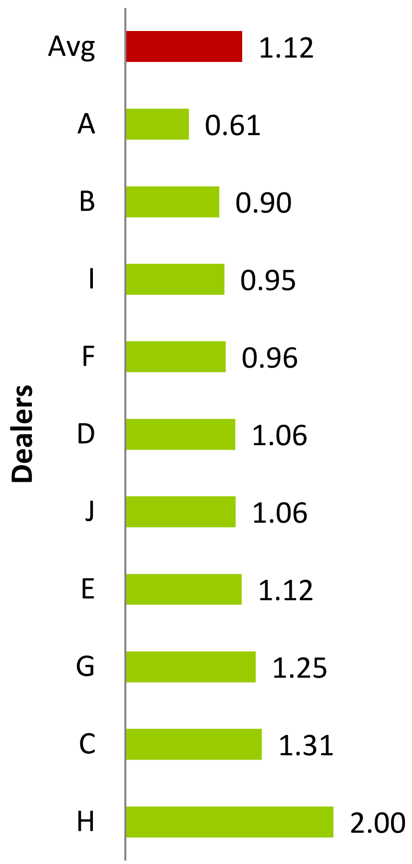


Notes: n=11; Working days are non-weekend, non-holidays. For most companies working days are approximately 2/3 the number of calendar days.
Chart based on each dealer's mean time to complete a task. Within a single dealer, time to complete certain tasks varied significantly from project to project.

Contents

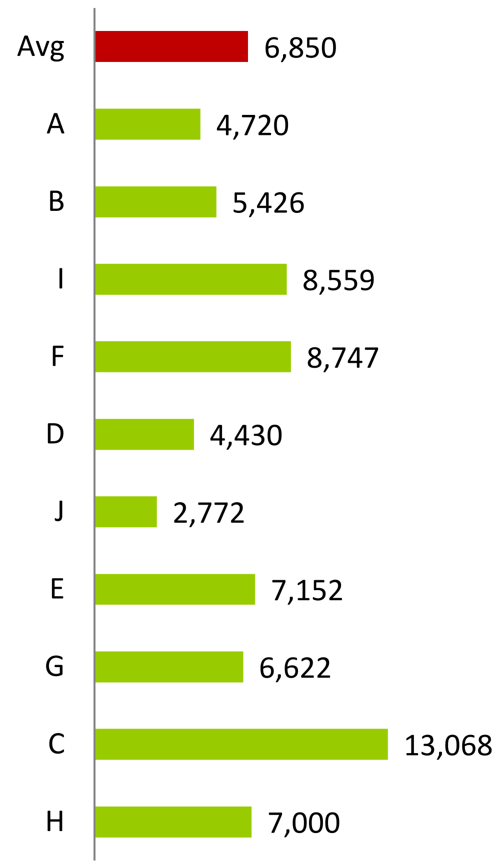
Labor was the largest single installation-related cost, at $1.12 / Watt

Labor + Subcontracting ($ / Watt)



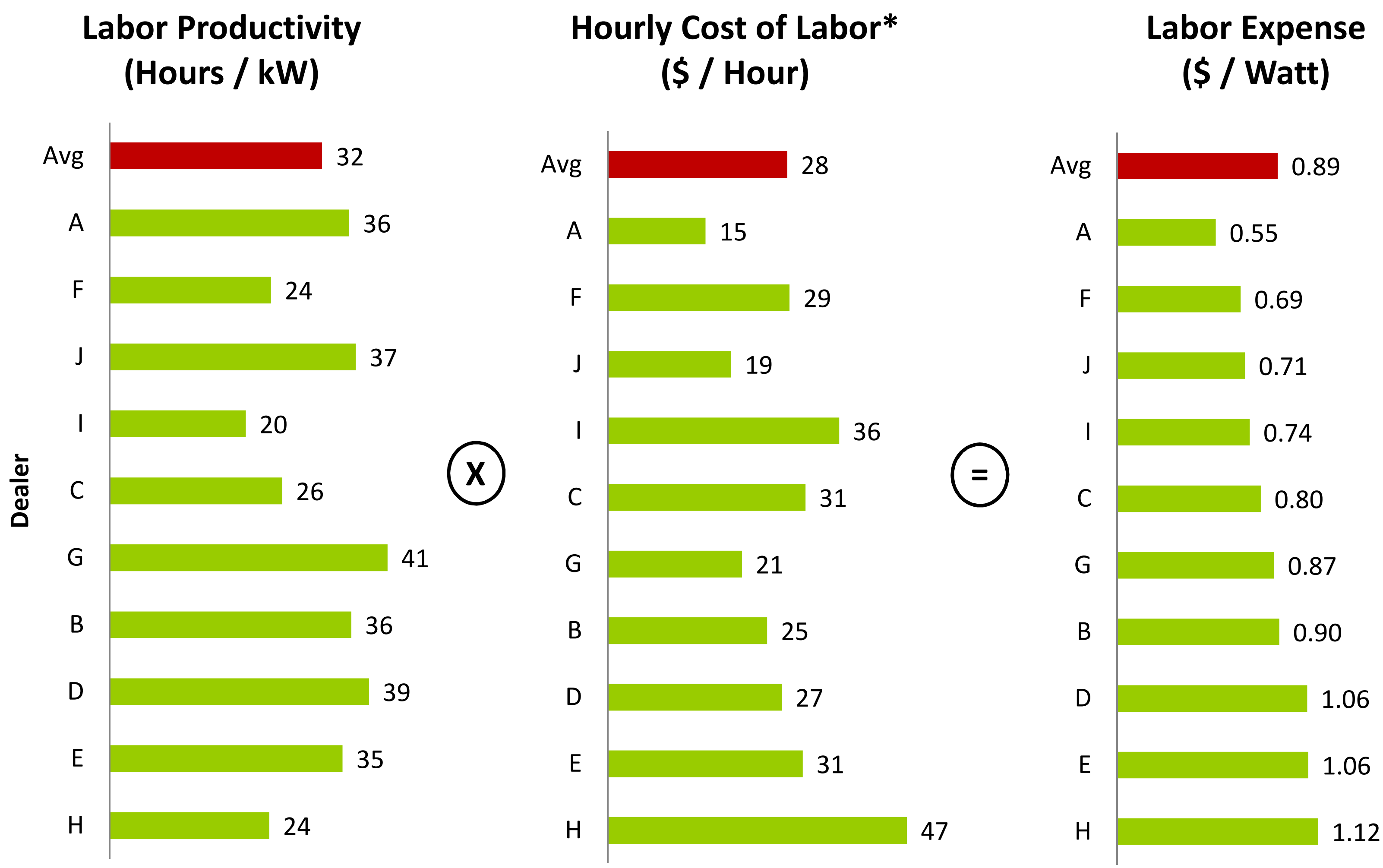
- **Labor cost comparisons remove other items in overall cost that make comparisons difficult**
  - Whether dealers purchases hardware or not (for third party leases)
  - Assumptions about allocations to overhead
  - Sales tax that varies by jurisdiction
  - Differences in warranty reserves
- **Labor is a large expense**
  - 30% of overall cost
- **High variance among dealers, suggesting significant opportunity for optimization**
  - Dealer with lowest labor costs was $1.39 / Watt below dealer with highest

Labor + Subcontracting Cost ($ / System)



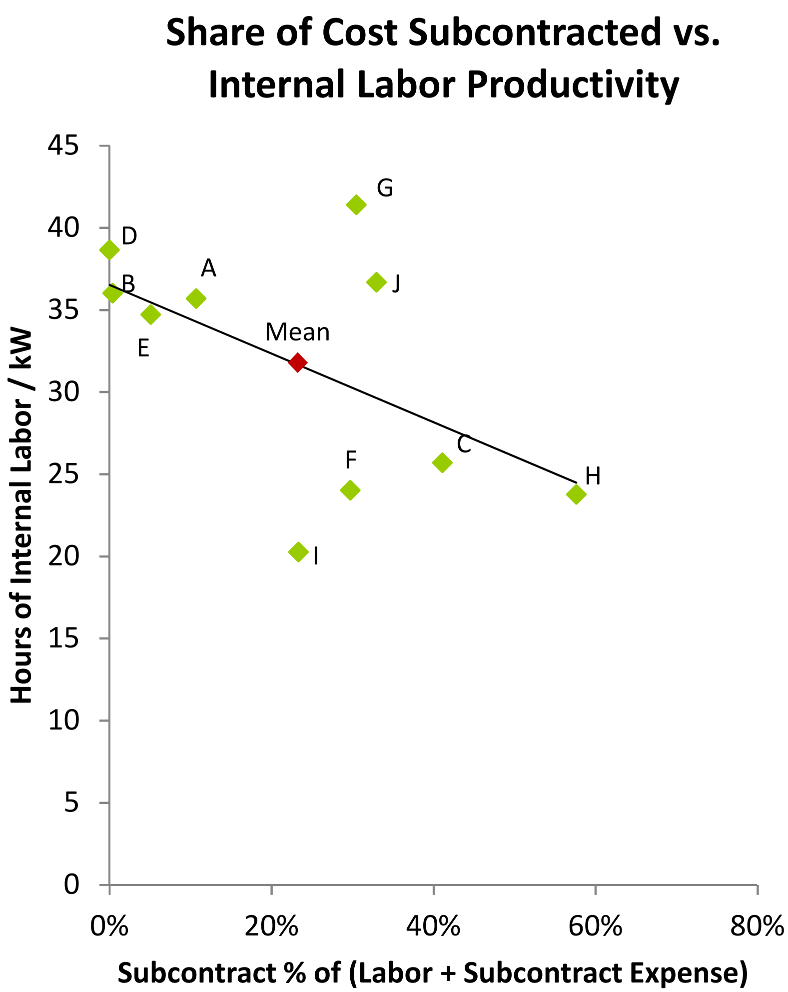
Notes: Including salaries, wages, variable compensation, employment taxes, benefits, workers' comp. insurance, and subcontractors.

Dealers can manage their own labor expense by focusing on productivity or compensation



Notes: *Salaries, wages, variable compensation, employment taxes, benefits, and workers comp. insurance.

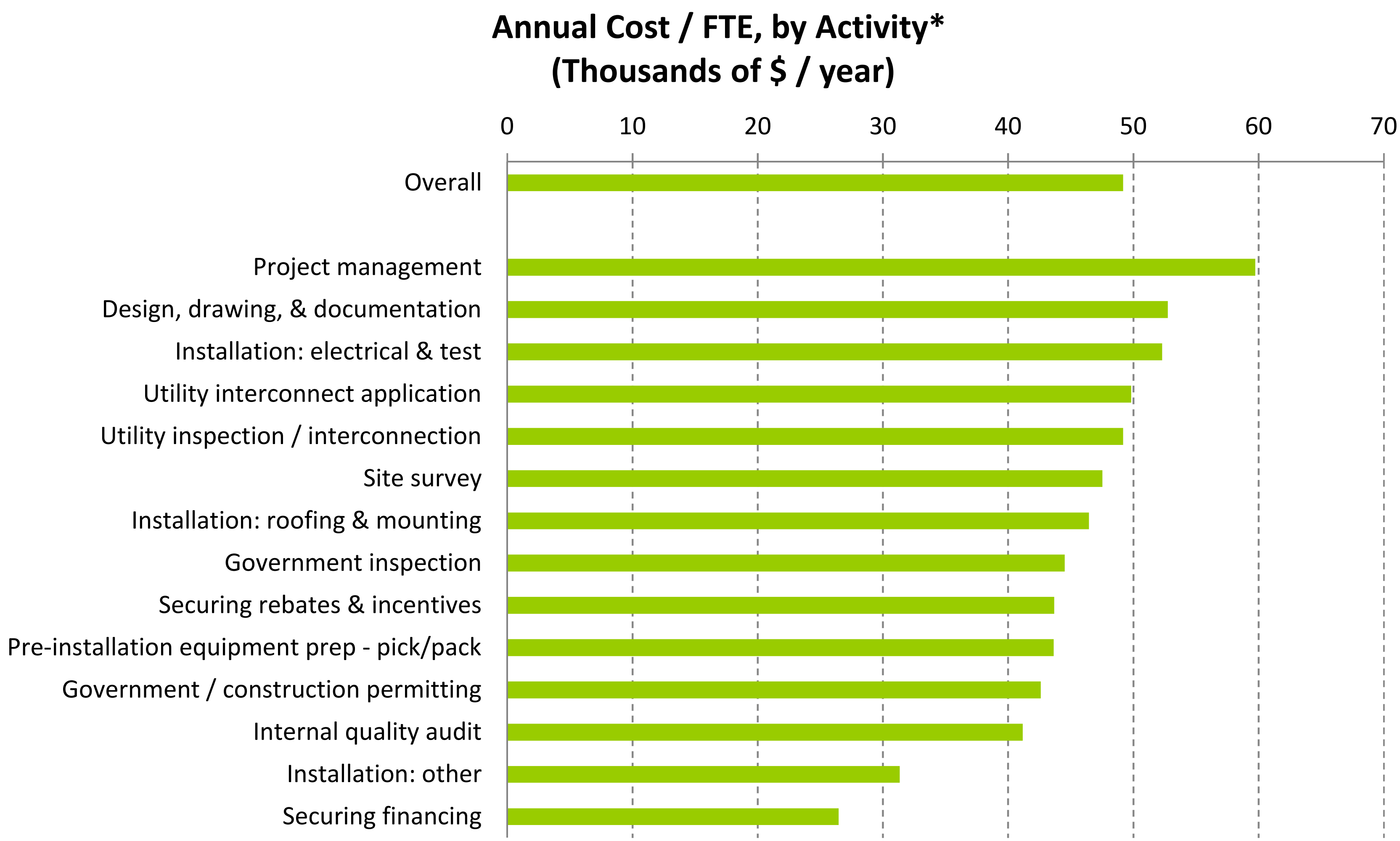
Generally, when firms subcontract more they should require less internal labor



- **We would expect firms that subcontract more to require less internal labor; broadly, this is what we see**
- **However it would appear dealers G, J, and H in particular should:**
  - Review if they can get more productivity from internal staff given the relatively high amount of outsourcing
  - Review whether the rates they pay to subcontractors are competitive

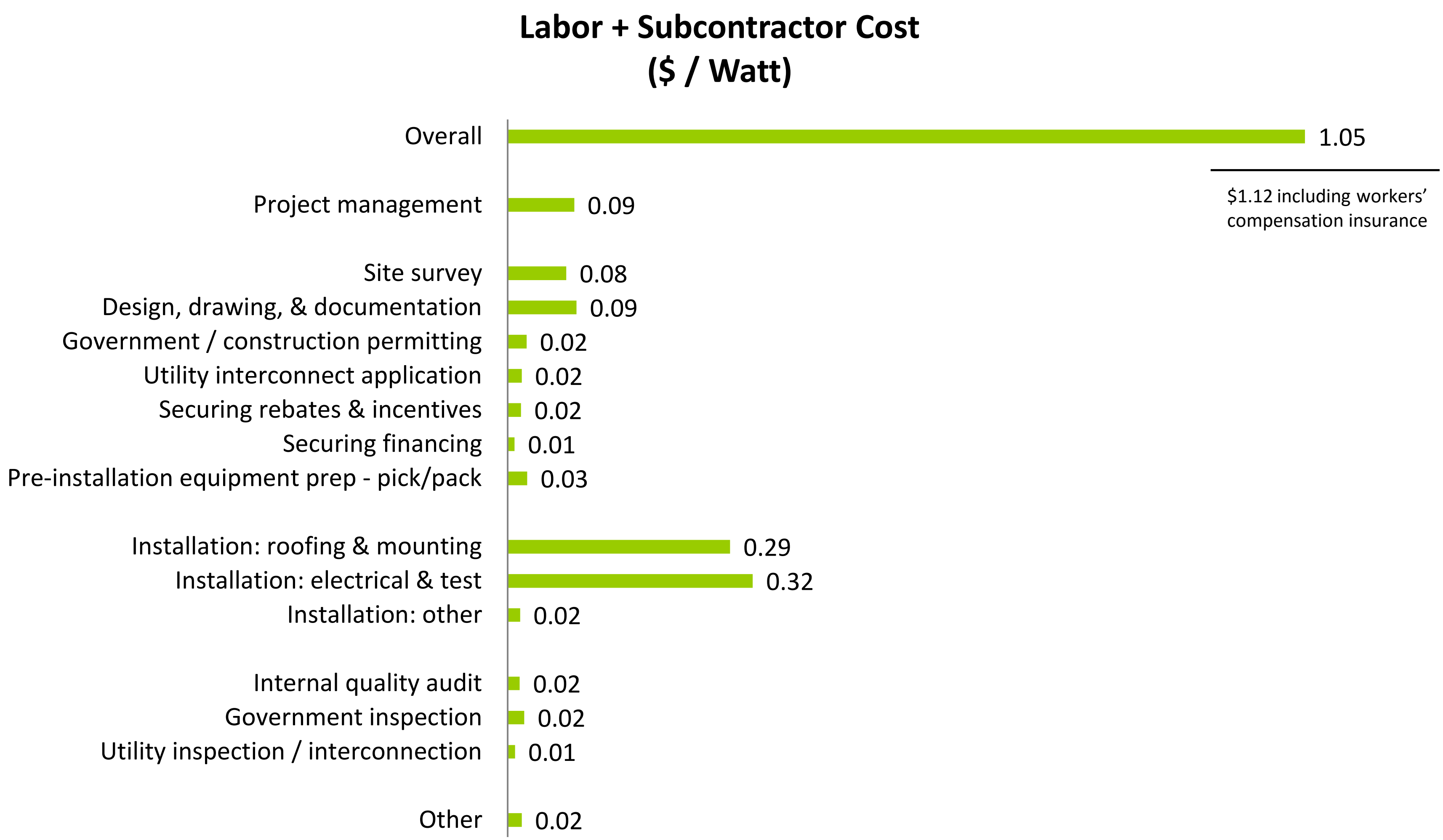
Notes: Mean not included in regression data.

Cost per installation employee averaged $49,000 / year



Notes: * Includes salaries, wages, variable compensation, employment taxes, and benefits. Excludes workers' comp. insurance.

Roofing and electrical installation were the most significant installation labor costs



Notes: Includes salaries, wages, variable compensation, employment taxes, benefits, and subcontractor fees. Excludes workers' comp. insurance.

Many dealers have experimented with on-site team size and composition; most use four man teams

- **One dealer uses two or three people on its teams**
  - "Sometimes the job is a three-person job, sometimes two-person. Sometimes two people work on that job the whole time and the project manager will spend a portion of the time out there."
    Dealer G
- **The dealer with the lowest labor cost in our study uses three-man teams**
  - "Typically it is a three man crew. One electrician, a roofer, and a laborer."
    Dealer A
- **The most commonly dealers put four people on a site**
  - "We are now at four—three mechanical, one electrical. We have tried different combinations to see if we could build them faster with more staff but we didn't find that to be the case. We even tried six or eight per team. We have used three-man teams on occasion. Right now for us the four-man team works best."
    Dealer D
  - "Typically [it's a] four-man team. We will put two guys on the roof, one guy in the attic, and the lead will do other stuff in the garage."
    Dealer C
  - "Generally, we have a have roofing truck and electrical truck…Two [people] in each."
    Dealer L
  - "We think a crew of three is most efficient for the…roof work. We think four is inefficient and two is as well. We've tried five of all things. We spent a lot more money on those installations. There is just not enough space on the roof and not enough to do for everyone to be busy. Even with three people there are usually only two on the roof. We generally use also use one electrician."
    Dealer J
- **A few use even more, though other dealers find this isn't efficient**
  - "We have four to five guys per job…I have my electrician and a helper there with the other guys."
    Dealer I
  - "We have three men that do the roof…Then we have an electrician and an electrician's helper. However, it is typically not more than three at once. Typically the roof crew gets everything done and then the electricians come on site."
    Dealer K

Dealers can use a number of strategies to reduce labor costs (1 of 2)

- **Know where you stand on spectrum of labor productivity and cost, strive to improve**
- **Use standardized systems designs**
  - "I'm trying to take the word 'engineering' out of residential. Not engineering and construction – configuration and assembly. Fundamentally I'd like to get to a 15 minute learning curve for how to design."
    Dealer E
  - "We sell 14 system sizes / configurations. Our smallest is 2.5kW with 10 panels. We never sell 11 or 12. Our next step up is 14 panels."
    Dealer D
- **Focus on city/regional market share (though consider the benefits of diversifying across incentive areas)**
  - Requires coordination with sales and marketing
  - "With the Solarize programs you really start getting into a rhythm. There is consistency in where you are working – dealing with one jurisdiction."
    Dealer H
  - "We group our installations together [geographically] to reduce drive time."
    Dealer F
- **Have sales do the site survey**
  - Easier if there are a small number of standard systems they are selling. Do not measure to create a custom design. Measure to determine "Which one of options A, B, or C would fit on this house?"
  - Admittedly, sales must be trained in the correct issues or this creates a lot of headaches later
- **Centralize where possible**
  - "We typically don't do design at the local level because it doesn't create the highest utilization and spreads out the skill sets. Also, if you centralize, you can use some drafters in the mix rather than all more skilled labor. "
    Dealer E

Dealers can use a number of strategies to reduce labor costs (2 of 2)

- **Use four 10-hour days, especially when travel times are significant**
  - Reduces time for travel (and vehicle expenses)
  - Gives flexible schedule options to accommodate weather
  - "We've gone from five 8 hour days hours days to four 10 hour days. The four 10 hour days buys us an extra hour and a half in travel time that we don't have to pay for. Also, if it rains on Wednesday we can just have them work on Friday. We also save wear and tear on trucks and gas. Plus if I get in a jam I can work them on Friday and they still have a weekend."
    Dealer C

- **Use cellular transmission for monitoring data**
  - "We spend a lot of time working on internet issues."
    Dealer B
  - "We spend quite a bit of time on monitoring and troubleshooting monitoring it. Sometimes it is the internet, sometimes login, the unit itself, configuration. It seems like we are always on the phone for a couple of hours with [our vendor] about something."
    Dealer G
  - "We don't use the home network because it adds to the installation time and causes maintenance problems because every time the teenager plays with the router we have a service call…We use cellular cards…and [pay] less than $2 / month for the cellular connection."
    Dealer D

- **Make sure installation teams know why previous installations in a jurisdiction failed inspections**

- **Schedule inspection for last day on-site**
  - "Most municipalities you call the day before you want the inspection. We generally try to request an afternoon inspection, but it is hit or miss when they show up. Most inspectors have office hours in the morning, so we try to call to see exactly when they will be there. If we are falling into the morning inspection window, we tell him we will not be ready. We'll ask to move to 12 or 1 p.m. If he does show up, at least he'll know so he won't be angry. Some we have built a rapport with so they will sign off on the basis of what we have done."
    Dealer A

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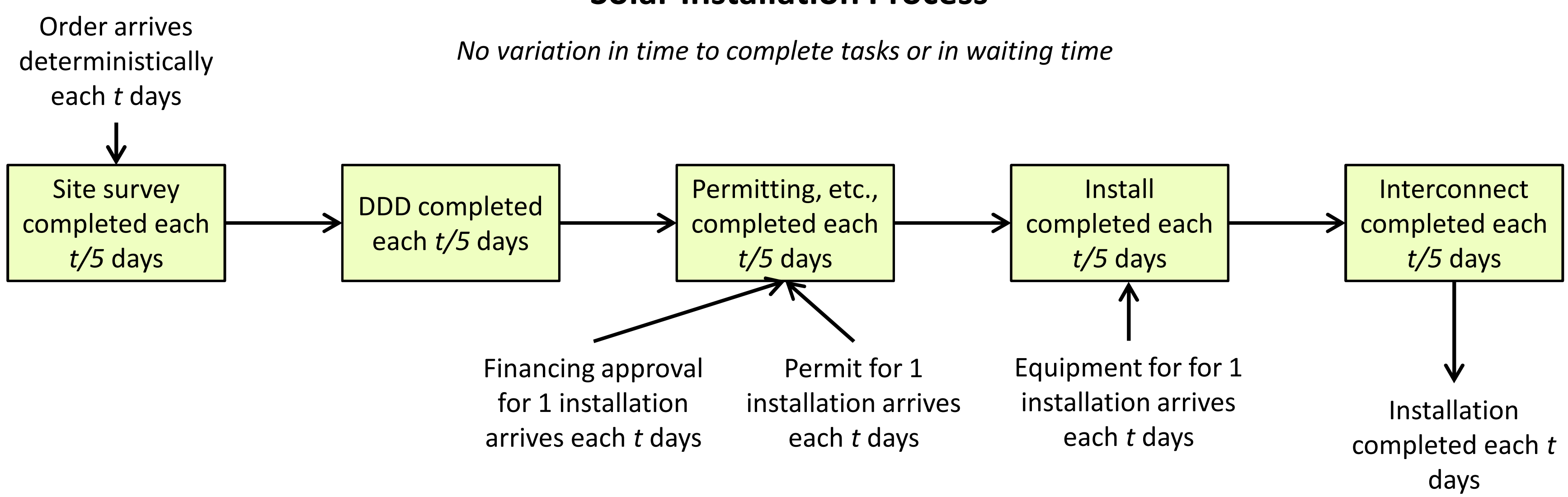
The ideal process would optimize throughput, inventory, and expense by minimizing variability

A Perfect (Though Highly Idealized)
Solar Installation Process

No variation in time to complete tasks or in waiting time



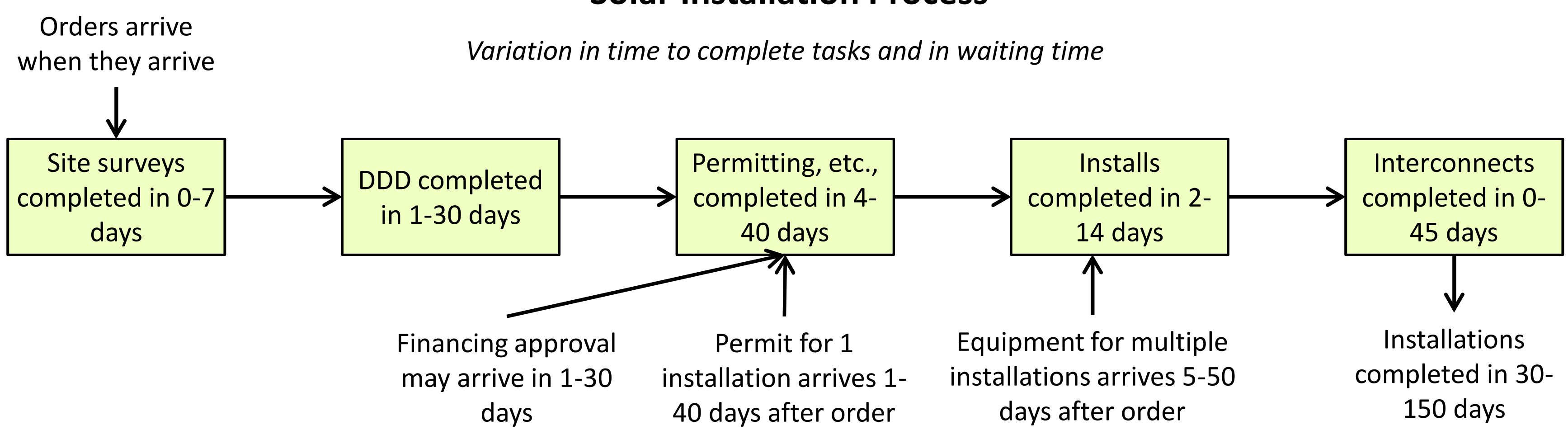
Key Process Characteristics	Results
Order-to-interconnect time is predictable and short. Dealers only manage a few in-process installs at once.	Few customers cancel orders & Expenses minimized
No workers are ever waiting for work. Each production step operates at 100% utilization.	Labor expense is minimized & Throughput is maximized
No need to keep safety stock of inventory to make sure there is something to work on.	Inventory is minimized

Notes: The optimal process also requires no fixed order delivery cost.

In the real world, variation makes timelines longer and/or increases costs

A More Realistic (Though Simplified)
Solar Installation Process

Variation in time to complete tasks and in waiting time



Key Process Characteristics	**Results**
Order-to-interconnect time is unpredictable and long. Dealers must manage many in-process installs at once.	Customers cancel orders & Expenses increase
Each step requires “extra” capacity so it is possible to make up for delays caused by previous steps. Utilization is < 100%.	Labor expense increases & Throughput decreases
Dealers keep safety stock of raw materials (such as panels or permits) to ensure enough is on-hand to keep working.	Inventory increases

The solar installation business has multiple sources of timeline uncertainty (1 of 2)

- **The sales process is a source of variability in both what dealers are selling (custom systems) and when orders arrive**
  - "A problem is that if our capacity is three per week, but we don't sell exactly three per week. We might sell none one week, then four, five, or six the next week."
    Dealer B

- **Permitting in particular is a major source of uncertainty**
  - "Installation time over the last year varied from 16 to 112 calendar days! The things that make it variable are distance, weather, and permitting. We have [City A] eating out of our hands and get that in two days, but [City B] takes 2 weeks or more."
    Dealer G
  - "The city of [City C] is very cooperative. You get a one day permit—it's a walk in. All the other communities it is three to ten days—that's inefficient."
    Dealer J
  - "I keep coming back to [City D]. We've had permits take over two months and had to threaten legal action. They've sent them back saying 'fix this,' and then when we send them back and they come back and say "now you need to fix these *other* things", and so on. And they have ten business days to review each time, so since they only work four days per week that is like 3 weeks! We are hiring someone that all they are going to do is call customers and explain what is going on with longer-than-expected timelines."
    Dealer I

- **Finance companies also drive timeline uncertainty**
  - "It is not just that [finance companies] have a lot of time and milestones, but that it is highly variable, and that kills us from an operations side. I have two employees who came from other installers because they went out of business because all their projects were stuck in the financing process."
    Dealer B
  - "Sometimes it is third party approvals – you have to bug them all the time. They change their people all the time. We send them four documents in four separate emails at four different times. There are probably eight or nine communications. Every time is an opportunity for someone to not get the email, misfile, etc."
    Dealer H

The solar installation business has multiple sources of variability (2 of 2)

- **Of course, hardware vendors can also be a source of uncertainty**
  - "The shipment delays cause a lot of rescheduling. We used to be able to order and get the equipment on the requested date. We have now started pooling [inventory] in the warehouse so we can keep the installation."
    Dealer A
  - "Last January and February I literally had guys at home I was paying with nothing to do because I could not get modules."
    Dealer G
- **Monitoring seems to be causing a lot of variation in installation time**
  - "Setting up the monitoring and internet and stuff like that can jam you up."
    Dealer G
  - "The monitoring products …all have a weakness in that they rely on a wireless or power line connection to the home networks and we find our selves troubleshooting them 25% of the time."
    Dealer J
- **It's also hard to predict when inspectors will arrive**
- **Dealers will never be able to entirely control some sources of variation**
  - Customers changing requested installation dates, weather, variation in worker speed, etc.
- **Uncertainty causes follow-on costs and requires more complex systems than would otherwise be necessary**
  - "The cost issue is not about doing a certain piece better, it is about changes to the process…Variability requires more resources to manage…"
    Dealer B

To minimize variability and minimize costs, dealers should:

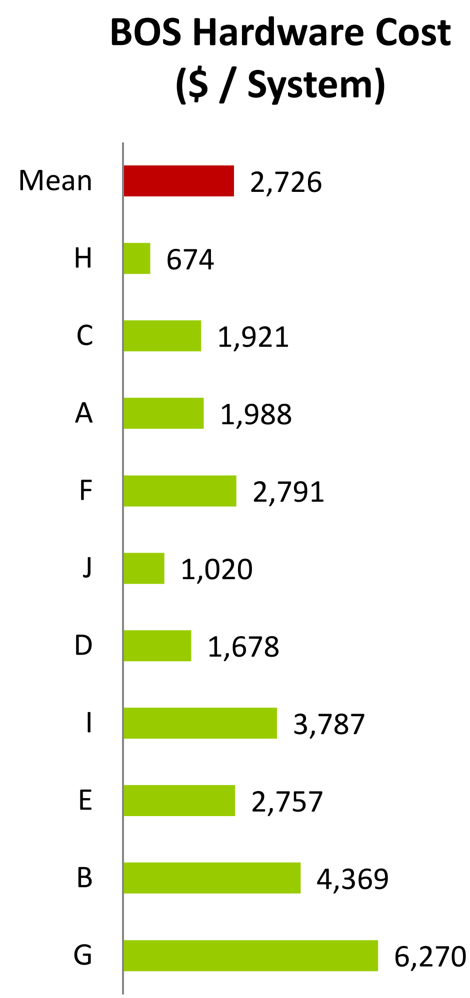
- **Synchronize sales promotions and capacity**
  - Also focus on certain cities or regions instead of aiming for broad geographic coverage
- **Emphasize to hardware suppliers the importance of delivery on promised dates**
  - Penalties for missing delivery promises
  - Switch vendors if necessary
- **Work with finance vendors to minimize variability and favor those that follow through**
- **Support industry efforts to standardize and simplify local permitting process**
- **Standardize systems to minimize variation in design, pick/pack, and installation time**
  - Sell one of *x* standard systems (i.e. 3, 5, or 7 kW)
- **Cross train workers so if they are out of work on their specialty activity they can work on another part of the process**
  - i.e. site surveyor who doesn’t have anything to survey can do system design
  - This does not reduce variability but it reduces cost of dealing with it

Vendors: To win loyalty and pricing power, focus on predictability.

Contents

Cost of balance of system hardware varies significantly by dealer

- **BOS costs varied greatly among dealers, suggesting a significant opportunity for cost advantage for dealers that focus here**
- **System standardization would also help reduce BOS costs**
  - Higher volume of smaller number of SKUs reduces both cost and inventory
  - Standard BOS could be stocked on trucks, minimizing trips to local hardware stores or supply houses for small-lot purchases



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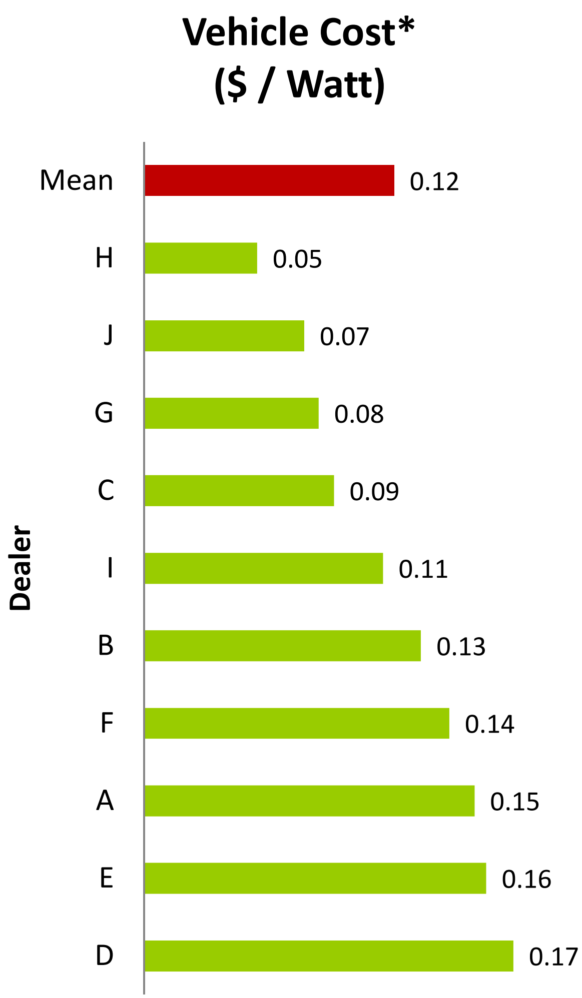
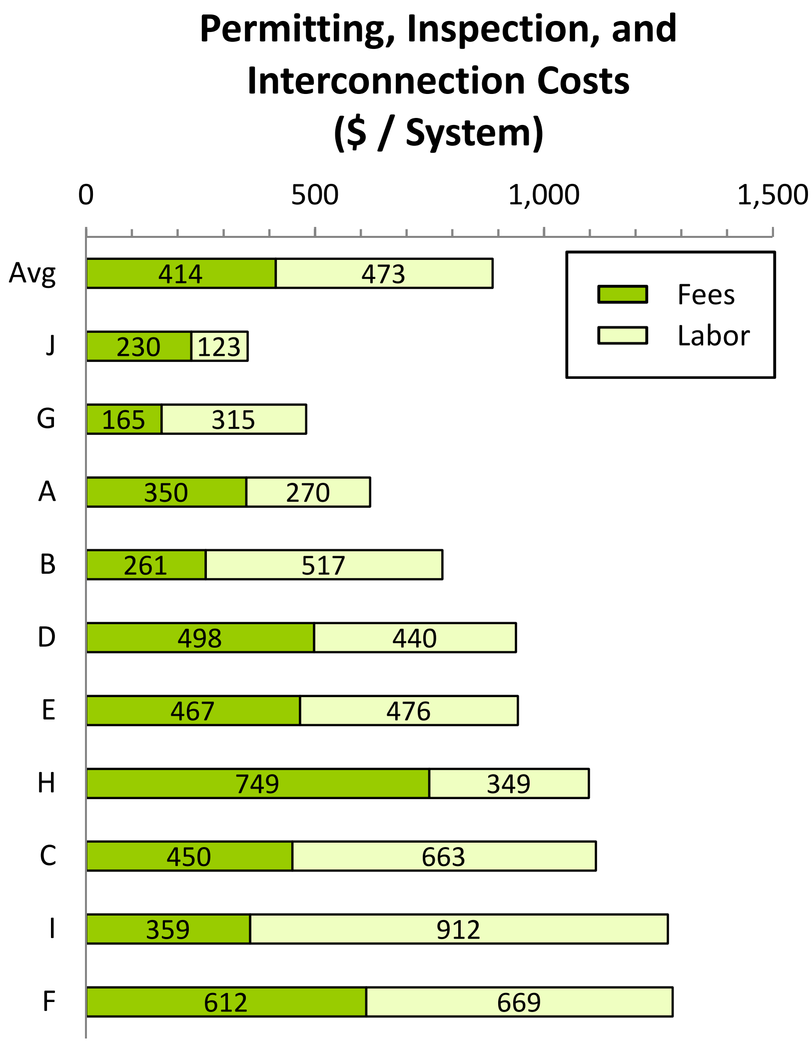
To reduce vehicle expense, reduce number and length of trips



- **Many techniques to reduce labor will also reduce vehicle expense**
  - Have sales do site surveys (Dealer H does this)
  - Work four 10-hour days (Dealers J, C, and I do this)
  - Standardize system designs or truck inventory to reduce trips to hardware stores
  - Focus on city/regional share to reduce distance and get more efficient with permitting jurisdictions
  - Schedule inspections for last day on-site
  - Make sure installation teams know why previous installations in a jurisdiction failed inspections
- **In addition, match vehicle seats to optimal team size**
  - I.e. if optimal team size is three, acquire vehicles with three seats to avoid sending two trucks

Notes: * Includes lease payments, depreciation, fuel, maintenance, and payments to employees for the use of their own vehicles.

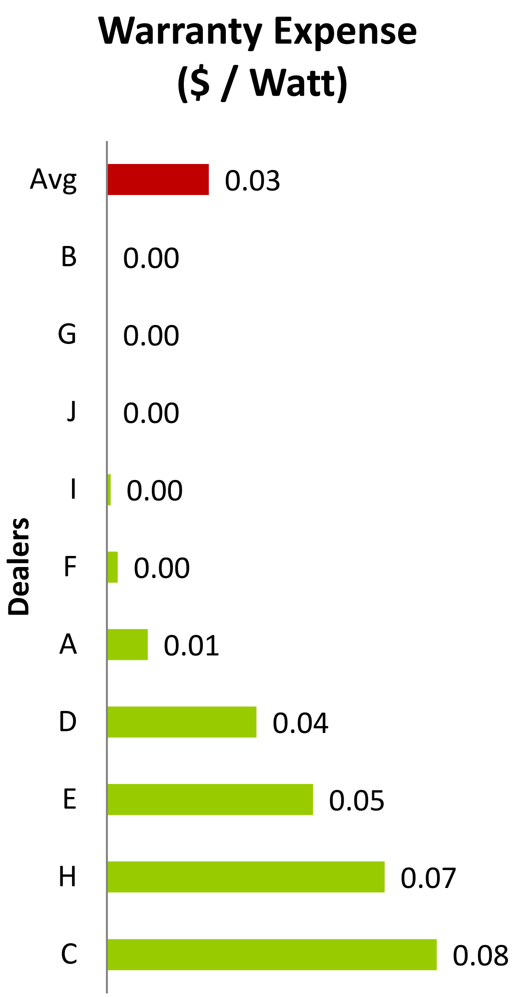
Costs permitting, inspection, and interconnection costs average at least $888 / system



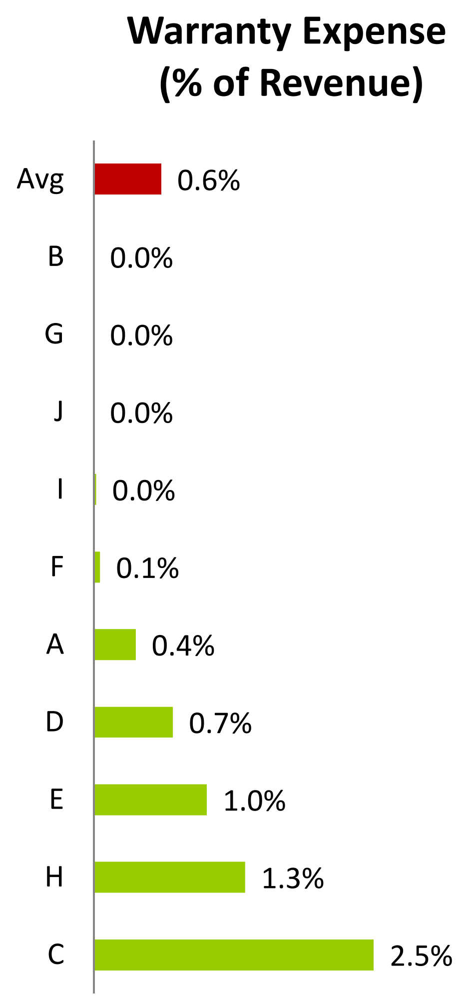
- **Equivalent to $0.15 / Watt**
- **Includes fees for construction permits and interconnect application**
  - Vast majority is fees for construction permits
- **Includes labor to make permit and interconnect applications, meet inspectors, and meet utility personnel (when necessary)**
- **In early 2011 SunRun estimated the costs of local permitting and inspection to be $2516 / system, but their figures include many costs Woodlawn Associates captured elsewhere:**
  - $581 for system costs incurred because local codes exceed state or national standards. (These costs would be in our material or installation labor costs.)
  - $520 for sales and marketing costs. (Sales and marketing costs are excluded from this study, though we have previously calculated that the cost of customer acquisition in solar is $5373 / system.)
  - SunRun's figures may include additional costs what we capture elsewhere (such as the costs of vehicles used to deliver applications, pick up permits, or meet inspectors)

Source: Woodlawn Associates, SunRun (The Impact of Local Permitting on the Cost of Solar Power)

The average warranty expense was $0.03 / Watt or 0.5% of revenue; we suggest a $0.05 or 1% reserve



- **Dealers handled warranty expenses in one of four ways:**
  - A reserve in COGS
  - Actual warranty expenses in COGS
  - Actual warranty expense in opex (not in gross margin)
  - No record of warranty expense
- **Most mature businesses include a reserve to cover future warranty expenses in COGS**
  - Seems this would be especially prudent when systems are supposed to last 20 years or more
- **Dealers D and E had the most robust explanations for their warranty reserve**
- **We would suggest other dealers use a comparable figure unless they have a reason to do otherwise**



Third party finance has opened up the market but is not without costs

- **Many dealers complain about the time for and unpredictability of various requirements of third party finance companies**
  - "The workload for a lease deal in terms of the time we spend on paperwork is triple that for a cash deal."
    Dealer I
  - "A lease always adds about 4-8 days to the front of the process…There is still some red tape… it is really mostly formality, but the leasing company wants to capture a proper signature….That gets transmitted to the leasing company...Simple things hang it up. If the electric bill is 'Jonathan' but the customer agreement is 'John' we have to go re-sign the agreement."
    Dealer J
  - "They are like another jurisdiction in that they review design work."
    Dealer M
- **This suggests that dealers with internal finance capabilities may be at a cost advantage**
  - No extra step of having a design reviewed by a third party
  - Information entered into only one computer system
- **However, third party finance companies can close this gap and distinguish themselves from one another**
  - Audit a partner's design process. If they meet requirements, don't require engineering review of each system (perhaps require occasional post mortem audits)
  - Eliminate rejections caused by "unnecessary" or "paranoid" checks (see comment from Dealer J, above)
  - Modify process to catch errors earlier, when costs to fix them are lower
- **Finally, since large dealers buy modules and inverters for about $0.36 less per Watt than small dealers, finance companies should consider using their scale to extract savings here**
  - Could be done by taking inventory and delivering kits, but also by negotiating rebates from key equipment vendors (contact us for details)

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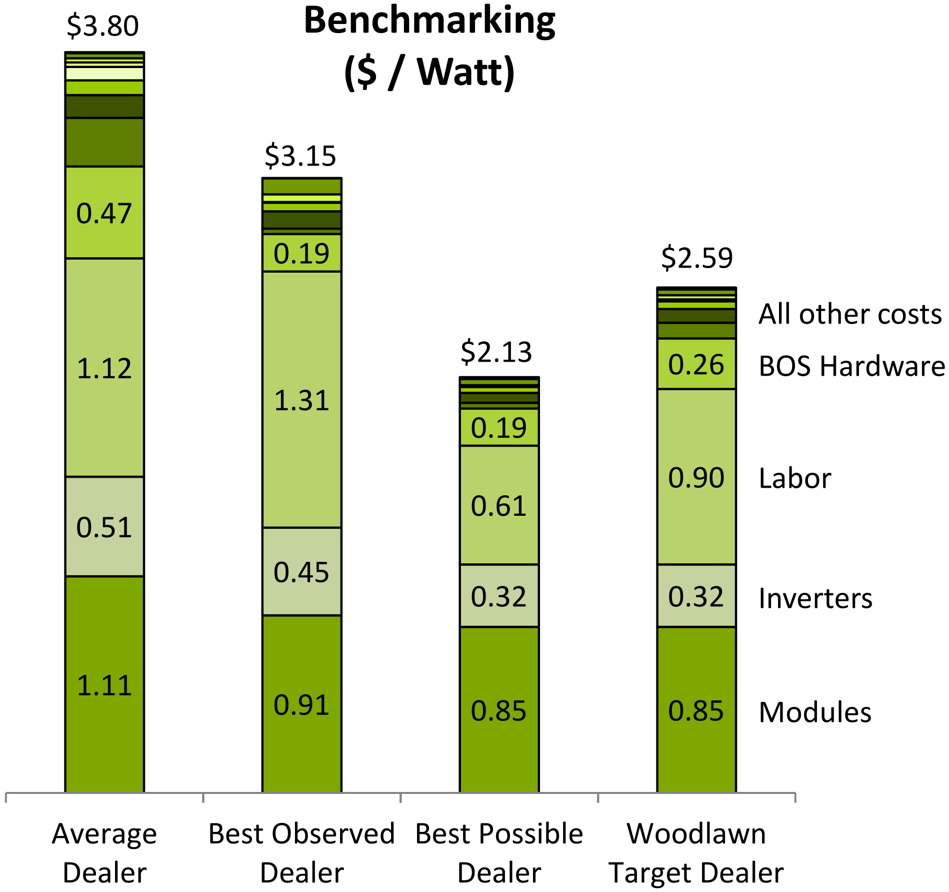
By matching low cost dealers in each category, dealers could install for $2.13 to $2.59 / Watt

Adjusted Installation Cost, Possible Improvements from Benchmarking ($ / Watt)



- **The average adjusted installation cost* in our study was $3.80 / Watt, while the dealer with the lowest observed cost was $3.15 / Watt**
- **If a single dealer could achieve the lowest cost we observed *in each cost category*, it could install at $2.13 / Watt**
- **We also built up costs for a "Target Dealer", who could install for $2.59 / Watt**
  - There may be circumstances unique to certain dealers that allow then to achieve very low cost in a single category, but not across categories
- **Key assumptions for Target Dealer:**
  - Modules and inverters have relatively transparent global prices so we assume the cost of our best dealer in each category
  - No sales tax paid on dealer purchases
  - Warranty reserve of $0.03 / Watt
  - Cost of second-lowest cost dealer in our study in most other categories

Notes: * Installation cost assuming the dealer purchases all hardware.

Summary of dealer recommendations

1. Build and maintain cost tracking system and match/meet provided benchmarks in each of the areas below
2. Make sure systems sold are large enough
3. Minimize process variation

Modules

4. Minimize inventory (avoid write-downs)

Inverters

5. Confirm micros are worth premium for production, monitoring, or sales value

BOS Hardware

6. Standardize and simplify

Labor

7. If subcontract, make sure rate is competitive with employees
8. Standardize systems
9. Have Sales do site survey
10. Focus on regional market share
11. Centralize where possible
12. Use four 10-hour days
13. Use cellular radios for transmitting monitoring data
14. Learn from inspection failures
15. Meet inspectors last day on site

Other Costs

Installation Overhead

16. Improve labor productivity to improve vehicle expense as well
17. Match vehicle size to team size
18. Favor city/regional growth over geographical growth to reduce vehicle use
19. Use a warranty reserve; 1% is recommended

Woodlawn Associates would be delighted to help you implement any of these recommendations

Woodlawn Associates

Management Consulting

Solar Marketing Effectiveness

April 2012

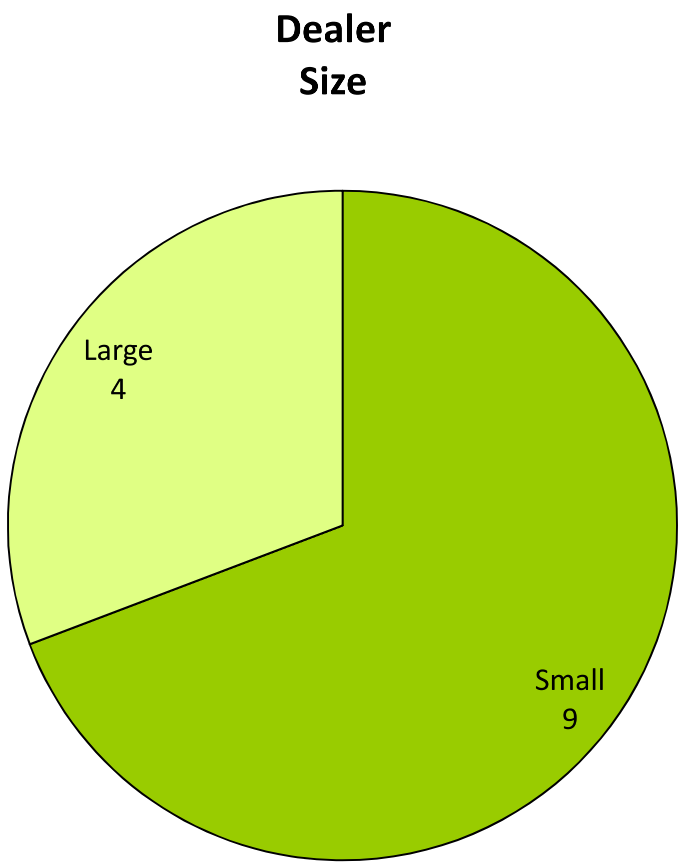
Contents

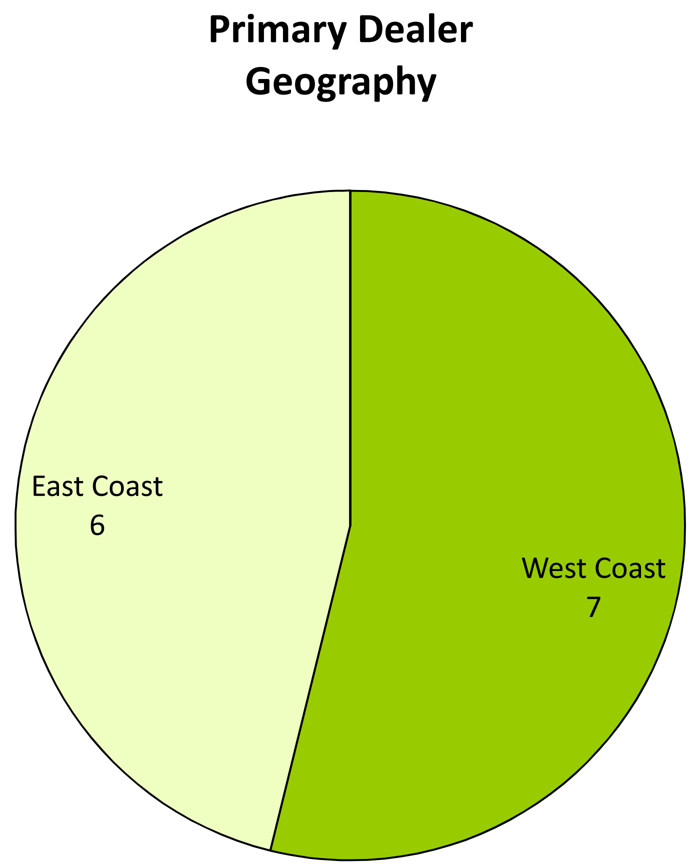
About Woodlawn Associates

- **Management consulting firm with significant experience in solar:**
  - Go-to-market strategy for module and inverter manufacturers
  - Business strategy for module manufacturers
  - Residential solar finance
  - Residential dealer business strategy
  - Competitive analysis

- **Offices in Chicago and San Francisco**

Data provided by 13 co-sponsoring solar dealers





Category	Systems Sold / Month
Small	<15
Medium	15-29
Large	30+

Executive summary

- **Study based on data from 13 U.S. residential solar dealers**
  - Representative in size and geography of broader industry
- **Dealers spend an average of 17% of revenues on acquisition, or approximately $5400 per customer**
  - Ranges from $1810 to $9605 per customer, but most are $4000-6500
- **Cost per lead is approximately $210*, but only 14% of leads convert. Most of acquisition cost is in Sales**
  - Channels generating high quality leads are inexpensive because Sales needs to spend much less time to yield a customer
  - Channels such as third-party leads, which have a low cost per lead—but also a low conversion rate—are actually among the most expensive channels
- **Dealers vary widely in the mix of channels they use**
  - They spend the most money on online advertising (SEM and otherwise)
- **Customer referrals are the largest single source of customers and also have the lowest acquisition cost, at about $2400 per customer**
  - Despite its being the lowest cost large channel, many dealers are not as systematic or creative as possible about sourcing leads from this channel
- **In general, we believe there is considerable opportunity to shift spending from expensive, inefficient channels to less expensive, more efficient channels and to optimize within channels**

Notes: * Omits one dealer counting only qualified leads, which have a higher cost.

Contents

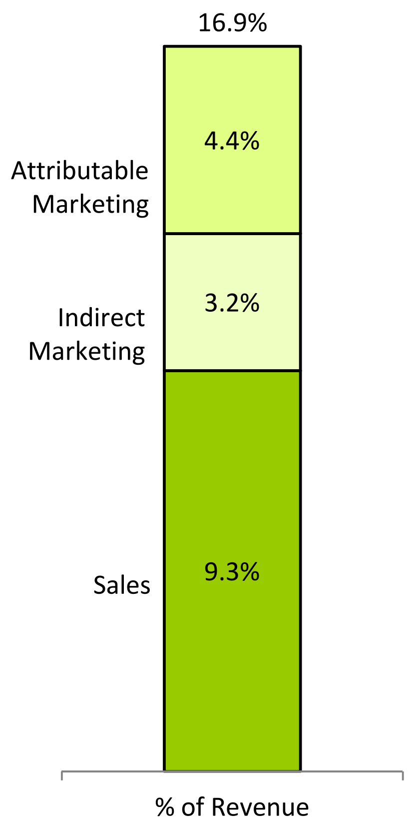
Total acquisition cost has three main components

Components of Acquisition Cost	Description	Examples
Attributable Marketing Cost	Costs to *generate* leads that increase directly with the amount of a particular type of marketing	• Media buys, internet ad fees • Per unit charges for direct mail; printing • Cost of leads from third parties, referral fees • Costs of designing particular campaigns • Staffing costs for events, retail, and door-to-door • Depreciation for items such as show booths
+		
Indirect Marketing Cost	Costs to *generate* leads that cannot be directly attributed to a particular type of marketing	• Cost of marketing staff (salary, benefits, incentive comp.)* • Brand consulting, logo design, ad agency retainers, business card printing • Other marketing overhead (rent, IT, travel, etc.)*
+		
Sales Cost	Costs to *convert* leads to customers	• Sales salaries, benefits, and commissions* • Cost associated with generating contracts, including design costs prior to contract • Depreciation for items used by / benefiting Sales, such as vehicles • CRM and design software expenses • Other sales overhead (rent, IT, travel, etc.)*

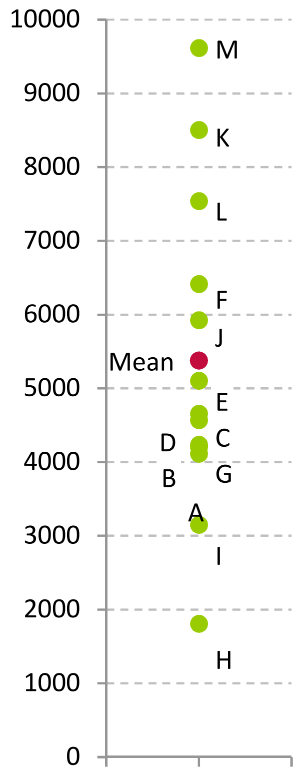
Notes: * Except as may be included in Attributable Marketing Cost for categories such as events, retail, and door-to-door.

Dealers' customer acquisition cost if $5373, or $0.89 per Watt

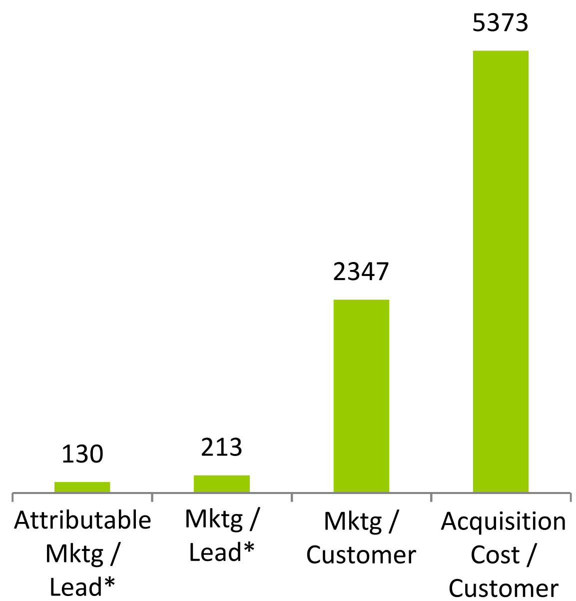
Avg. Acquisition Expense, By Type (% of Revenue)



Average Cost of Customer Acquisition, by Dealer ($)



Average Cost per Lead, per Converted Lead, and per Customer ($)

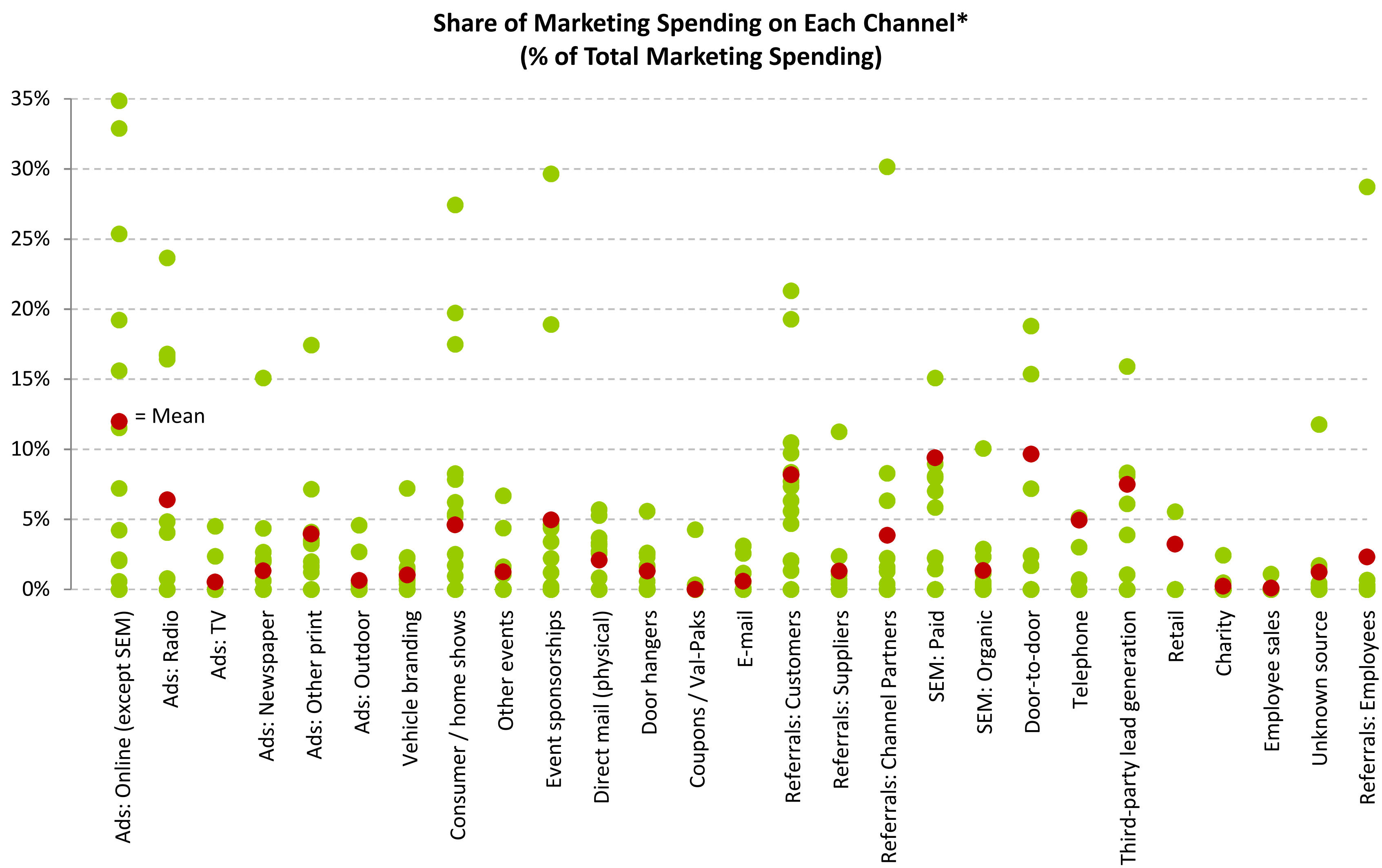


- **Average acquisition cost ranges from $1810 to $9605 among dealers in the study**
  - One often hears anecdotal figures of $1500 to $2500
- **On average, customer acquisition cost was $0.89 per Watt DC**
- **About 96% of acquisition cost is in conversion of leads to customers**
  - Sales and Marketing jointly responsible for conversion
  - On average it takes 8 leads to yield one customer (12.4% conversion rate)*
- **See Appendix for a comprehensive comparison of dealers on these and other metrics**

Source: Woodlawn Associates; n=13

Notes: * Omits one dealer whose lead definition appeared to be substantially different than other dealers. Including this dealer, average conversion rate was 13.9%.

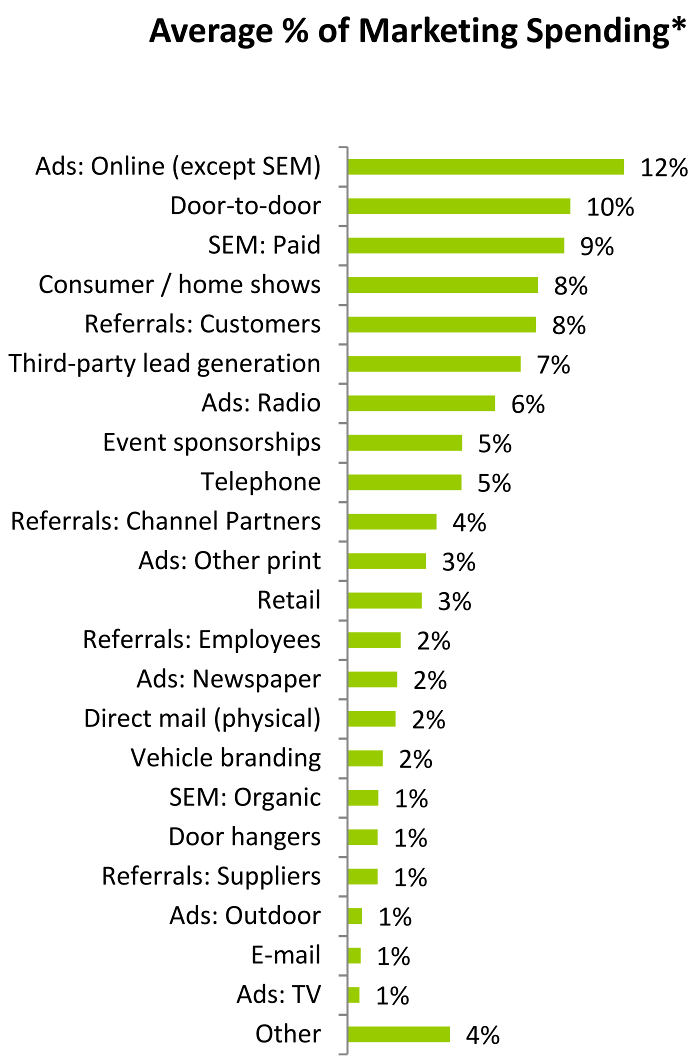
Dealers vary widely in the mix of channels they use

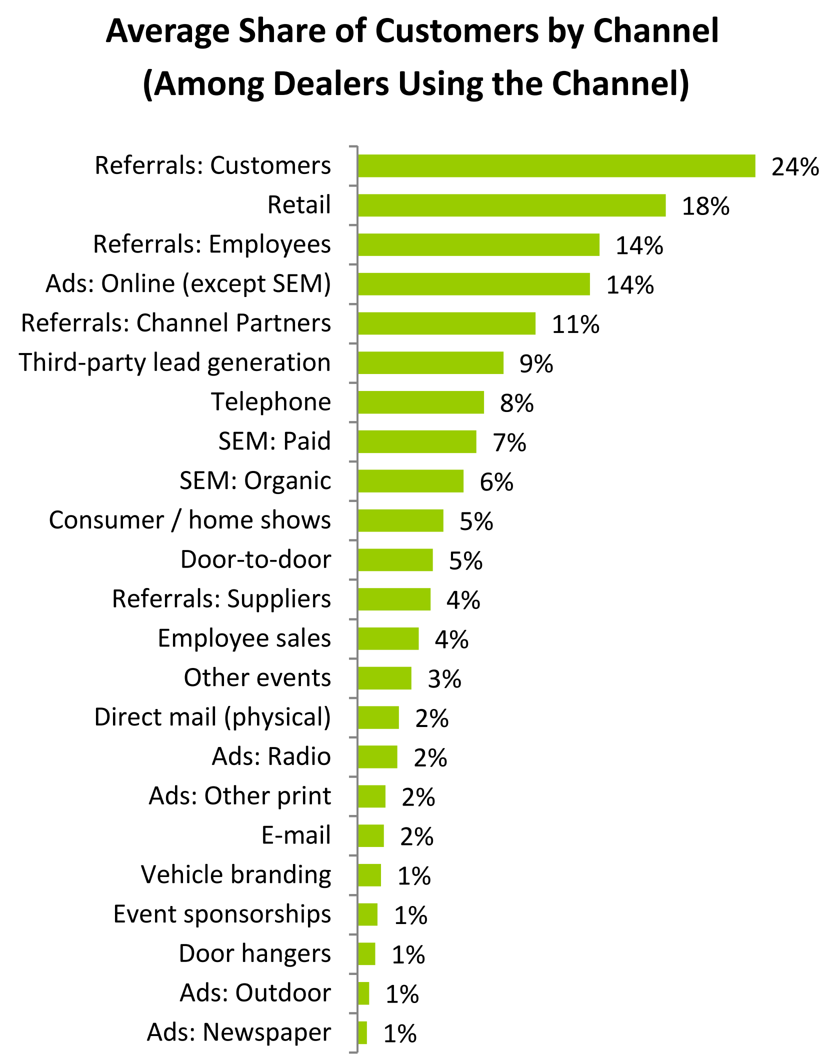


Source: Woodlawn Associates; n=13

Notes: * Includes both Attributable Marketing and Indirect Marketing.
One dealer spent 63% of its marketing expenditure on SEM: Paid (not shown).

Online ads account for the largest share of marketing spending, but referrals are largest source of customers





Source: Woodlawn Associates; n=13
Notes: * Includes both Attributable Marketing and Indirect Marketing, but excludes Sales.

Contents

Acquisition cost per customer for a given channel (or channels) is:

Acquisition Cost / Customer	=	Marketing Cost / Lead	/	Customers / Lead ("Conversion Rate")	+	Sales Cost / Customer

Where:

Marketing Cost / Lead is a function of:

(a) the cost of all directly attributable and allocated marketing activities
(b) the inherent receptivity of potential customers to the channels
(c) the quality of marketing efforts

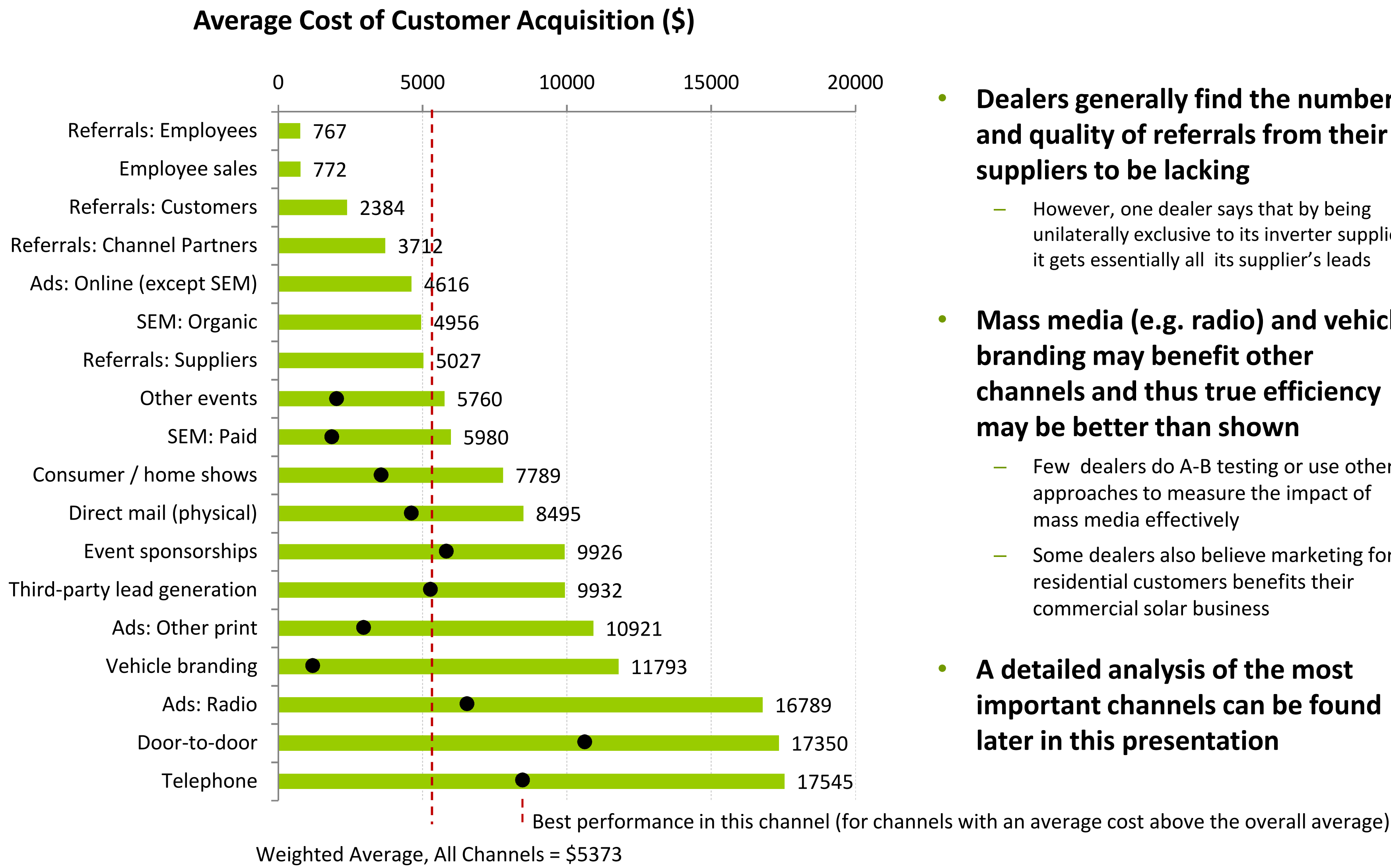
Conversion Rate is a function of:

(a) the quality of the marketing efforts (quality of leads)
(b) the inherent receptivity of potential customers in the channels
(c) the quality of the sales efforts (likelihood of conversion given a certain quality of lead)

Sales Cost / Customer is a function of:

(a) the cost of all activities to convert leads to customers
(b) the time spent to know if a lead from this channel will convert ("difficulty factor")

Referrals of all types are among the least expensive channels

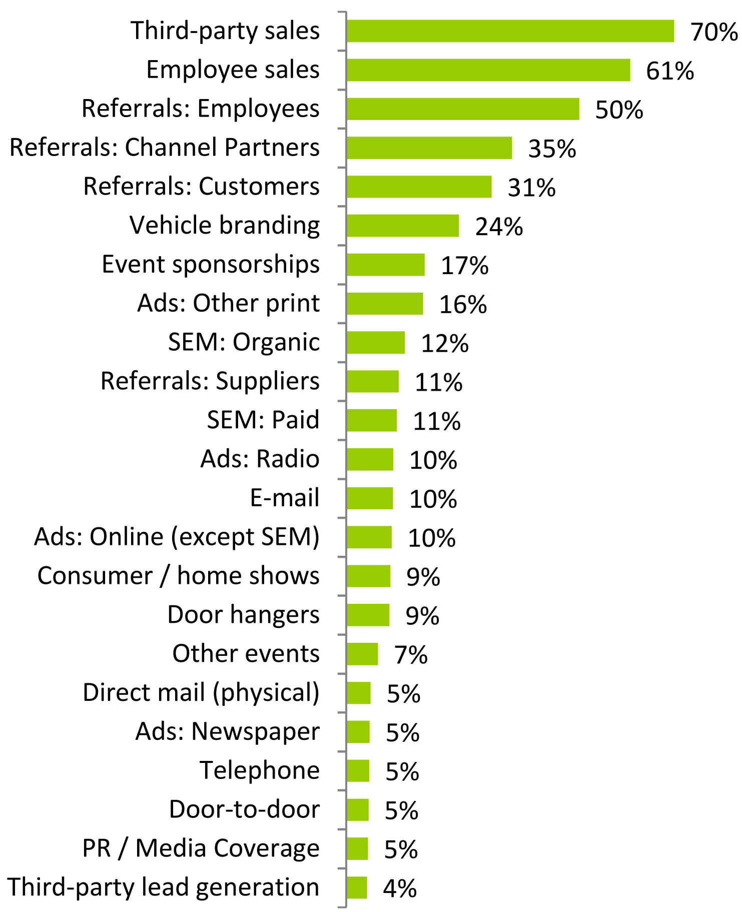


- **Dealers generally find the number and quality of referrals from their suppliers to be lacking**
  - However, one dealer says that by being unilaterally exclusive to its inverter supplier, it gets essentially all its supplier's leads
- **Mass media (e.g. radio) and vehicle branding may benefit other channels and thus true efficiency may be better than shown**
  - Few dealers do A-B testing or use other approaches to measure the impact of mass media effectively
  - Some dealers also believe marketing for residential customers benefits their commercial solar business
- **A detailed analysis of the most important channels can be found later in this presentation**

Source: Woodlawn Associates; n = 13; channels only a fraction of dealers use have been excluded.

Channels generating high quality leads are inexpensive due to high conversion rates and low difficulty factors

Average Conversion Rate



- **To get sales cost / customer in each channel, we take the total sales cost for the company and allocate it to channels in proportion to the amount of time Sales spends on each channel**

- **In addition to the number of leads it starts with, the major determinants of Sales time per channel are:**
  - How much time it takes to determine whether a lead will convert or not (which we call the "difficulty factor")
  - The share of leads that convert to customers

- **Excepting third-party sales and sales to employees, leads who are referred are the least time-consuming to evaluate and most likely to convert**
  - Dealers typically tell us it take only about 80% as long to evaluate a customer referral lead as a typical lead
  - Referrals are around 3X more likely to close than an average lead
  - For customer referrals, sales cost per customer is about *one-fourth* of the average channel

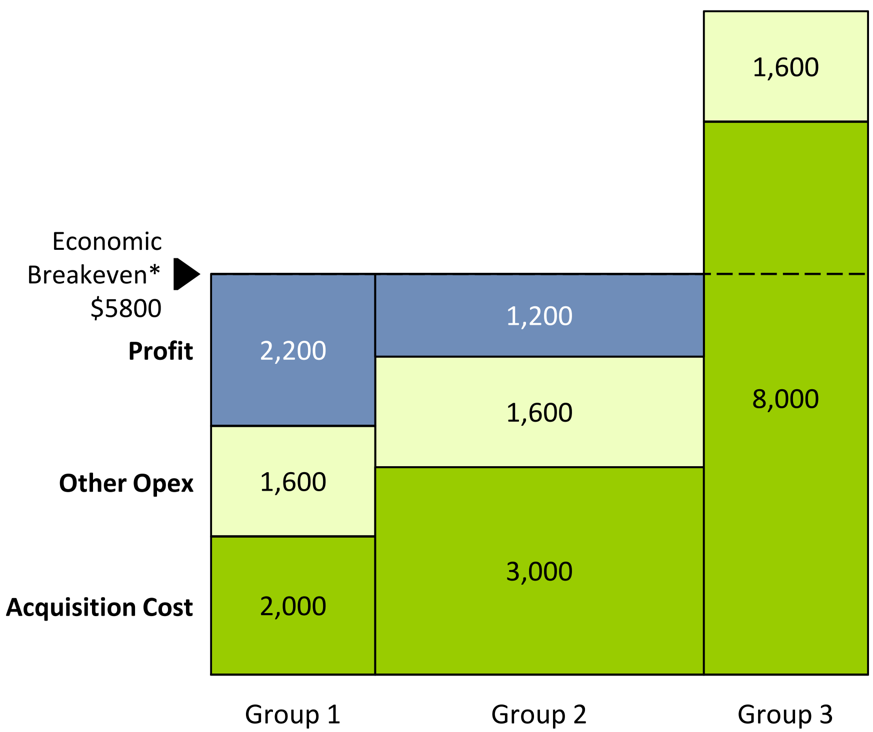
- **Almost all dealers use third-party lead generation, but very few are happy with the quality of the leads they get**
  - While this channel may have attractive cost-per-lead, relatively few customers convert; consumers are often not very good solar candidates
  - Leads often sold to several dealers, decreasing chance of conversion for each dealer

- **Telephone solicitation and door-to-door canvassing have among the lowest conversion rates and highest difficulty factors**

Source: Woodlawn Associates; n = 13; channels only a fraction of dealers use have been excluded.

Minimizing acquisition cost is not the same as maximizing profit

Operating Expense to Acquire Customers , by Group
(Illustrative Example Only)

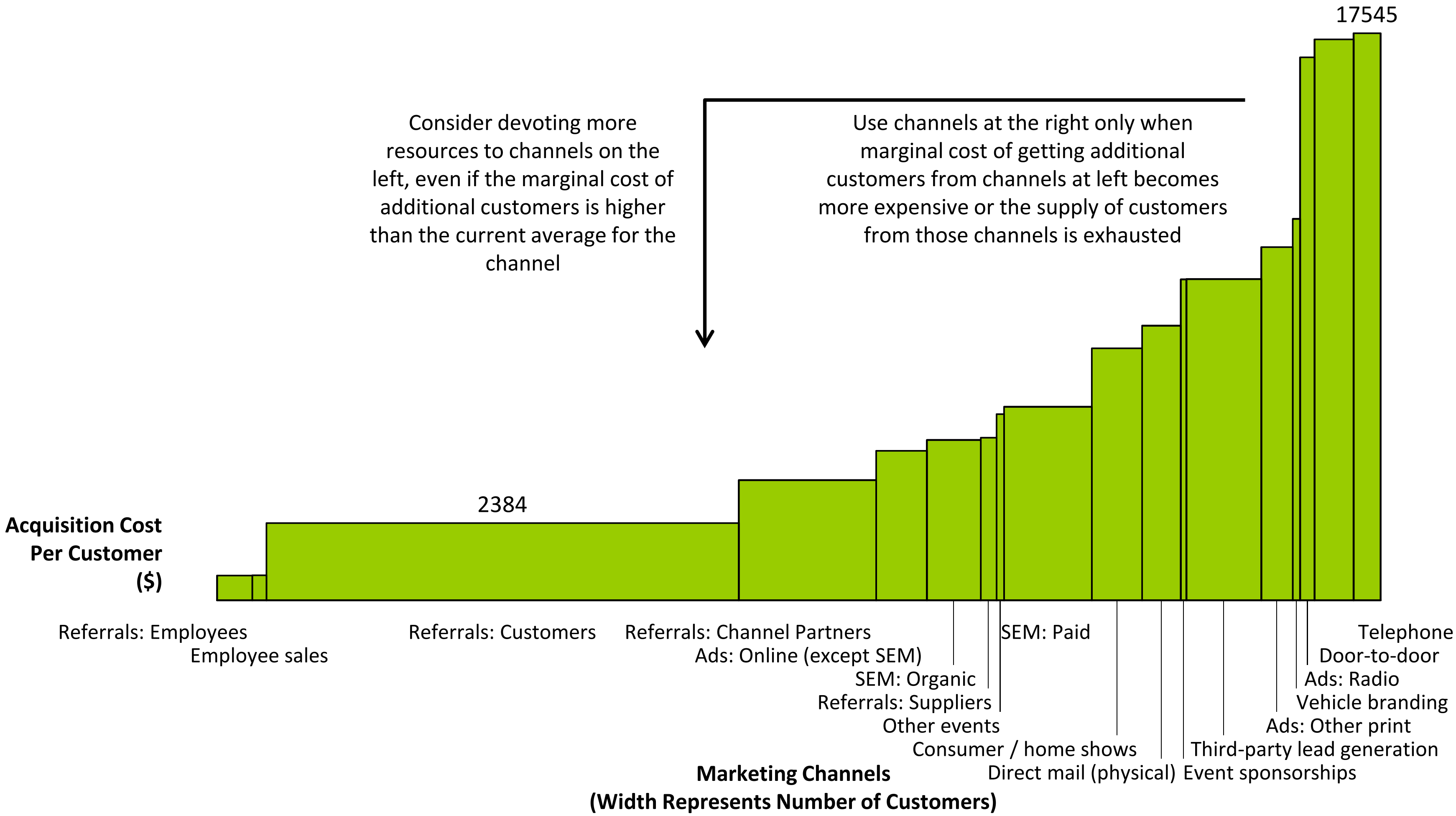


- **Firing your Marketing and Sales teams would minimize acquisition cost, but obviously would not maximize profit**
- **To maximize profit, keep expanding the use of each channel until the net margin is at the economic breakeven point* or the customers from that channel are truly exhausted**
- **In the example on the left, suppose a dealer has calculated that it must make at least $5800 in gross margin on a sale to break even, and that its non-acquisition operating expenses are $1600**
- **If the dealer sells only to Group 1, its average acquisition cost is only $2000, and its net profit / customer is $2200**
- **If the dealer spends more money per customer to acquire customers in Group 2, its average acquisition cost will increase, but so will its profit**
  - Could be a new group of customers through the same marketing channel or a different marketing channel
  - The $3000 cost to acquire customers for this group plus the $1600 in other opex is still less than the breakeven point
  - The profit margin on Group 2 customers is lower than for Group 1, but overall dealer profit still increases
- **However, this dealer should avoid marketing to Group 3. The cost of acquiring these customers is so high overall company profits will decrease**

Notes: * The point at which the economic profit on a sale is zero, after taking into account the cost of capital.

Consider doubling down on inexpensive channels

Residential Solar Customer Supply Stack



Source: Woodlawn Associates; n = 13; channels only a fraction of dealers use, other, and unknown have been excluded.

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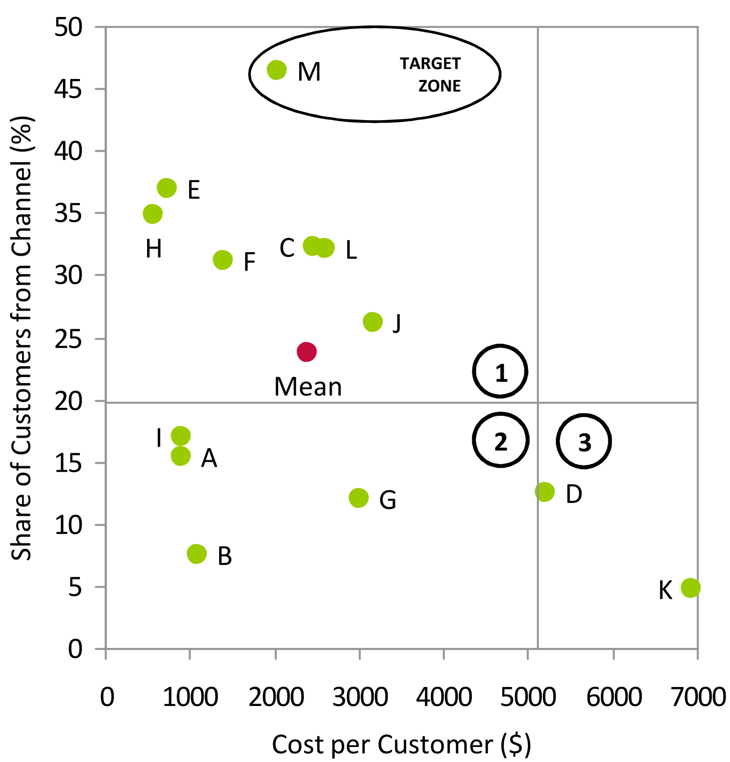
Despite it being the lowest cost large channel, many dealers have not optimized for customer referrals

Customer Referrals:
Cost per Customer vs.
Share of Customers from this Channel



- **Surprisingly, we find no relationship between the amount of spending on referrals and the share of a dealer's customers from this channel**
  - Suggests significant opportunity for optimization
- **Dealers in Sector 1 have relatively many referrals, but could afford to spend more on this channel to increase business further**
  - Cost / customer is still below industry average for all channels
  - Shift spending from other, more expensive channels
  - Aim for "TARGET ZONE" where share of customers increases but cost is still below economic breakeven
- **Dealers in Sector 2 spend as much per customer in this channel as those in Sector 1 but get few customers. They need to systematize their efforts to seek referrals**
- **Dealers in Sector 3 have both high cost / customer and low share of business from customer referrals, and should both examine why cost is so high and revamp their system for seeking referrals**

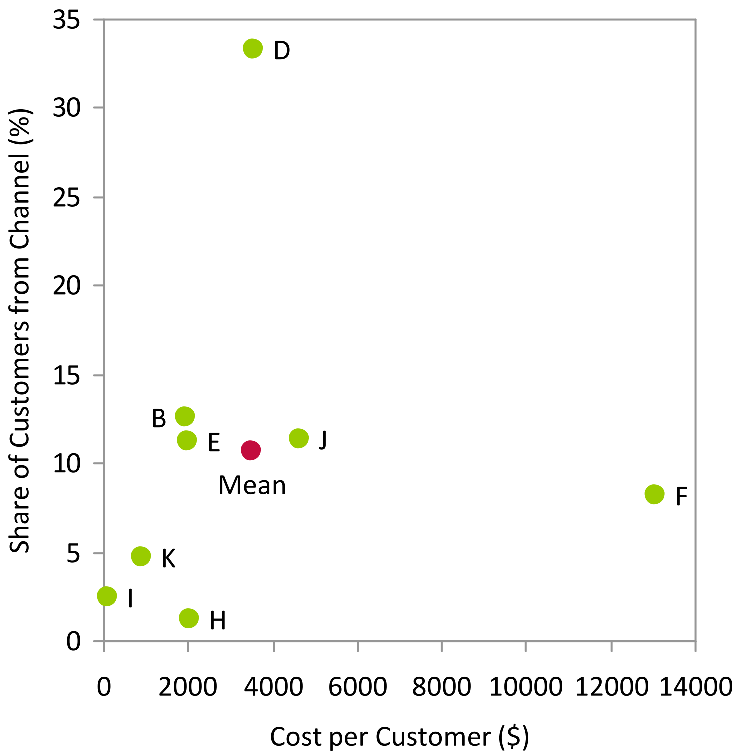
Source: Woodlawn Associates

Given the importance of this channel, dealers should be both systematic and creative about seeking referrals

- **Many dealers make the obvious point that the quality of the customer experience drives this metric**
- **However, in our experience few companies in residential solar are as systematic as they could be about referrals:**
  - Ask for referrals regularly: at contract signing, installation, system turn on, after the first 1-3 utility billing cycles, and regular intervals thereafter
  - Use lease/loan bills and customer-facing monitoring software to ask for referrals – essentially no incremental cost
  - Notify customers whose energy production is above initial predictions
  - Require all employees who are in contact with customers to ask for referrals (within reason)
  - Test which referral bonuses have best ROI: various amount of cash, free months (for financed systems), donations to charity, etc.
- **In addition, companies could:**
  - Invite happy customers to speak or attend marketing events (some are evangelists and will do this for free)
  - Fund block parties for any street with more than one customer
  - Provide postage-paid envelopes with solar background and company information for customers to send to their friends who may be interested

Make sure channel partners know how to screen potential customers effectively

Channel Partner Referrals:
Cost per Customer vs.
Share of Customers from this Channel

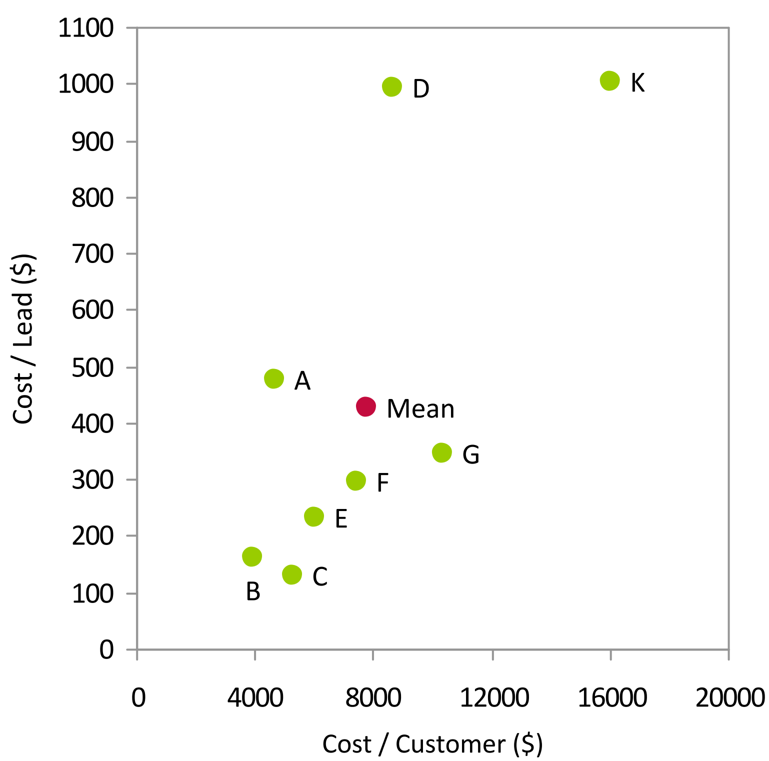


- **Dealer D got 33% of its customers from channel partner referrals at the average cost for this channel**
  - "We work closely with general contractors and leverage our good relationship to use them as a sales force."
    Dealer D
- **Dealer F converts only 4% of channel partner leads, compared with Dealer D's 23%**
  - May want to have channel partners better screen leads before passing them on to increase its conversion rate
  - At a 23% conversion rate Dealer F's cost per customer would have been $2441
- **Although some dealers get paid referrals through third parties such as One Block Off the Grid, many channel partners don't respond to money and are best approached through business development and by doing good work over time**
  - "We have not been successful in getting people to do it for money – they do it because they think we will do a good job."
    Dealer B
  - "We tend to put a lot of sales and engineering time into major remodels, working with general contractors. They are more difficult, but they get easier after a couple with the same GC and they generate recurring revenue through future referrals from the GC."
    Dealer D

Source: Woodlawn Associates

At consumer and home shows, get the lead and move on

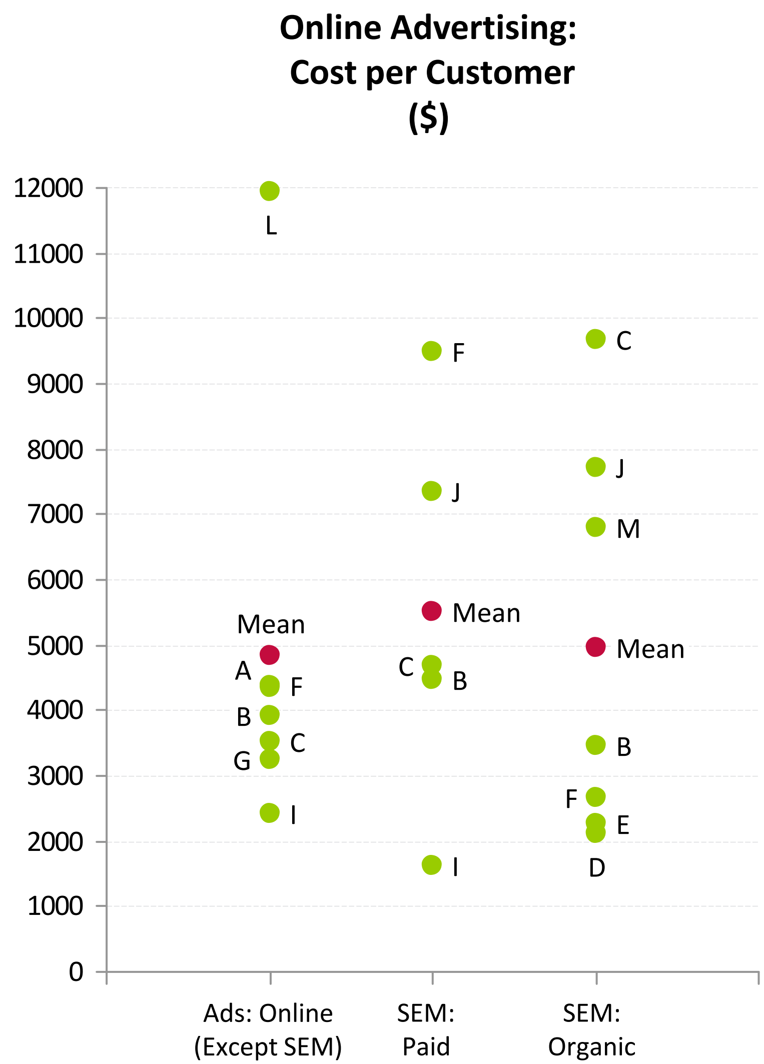
Consumer / Home Shows: Cost per Customer vs. Share of Customers from this Channel



- **Overall, this is a higher cost channel so it is less important dealers get a high share of their customers from this channel**
- **There are also limits to the growth of this channel, as there are only so many home shows to go to in each region**
- **Most dealers recognize the need for strong sales talent in the booth, being organized, and following up**
- **Focus on getting the lead and moving on**
  - "…Need to get people to understand that goal is not to educate people on solar for an hour, but to spend five minutes to…get them to sign up for a site survey."
    Dealer A
  - "Provide a compelling reason to sign up, like a discount if you give your contact information."
    Dealer B
- **Try to limit competition**
  - Dealer C likes to focus on "blue ocean" events, where there are no other solar companies. It also has a high conversion rate in this channel.
  - "We stay away from typical home shows that everyone else is at. We do a lot of community events, like farmer's markets, 5K's, Easter egg hunts, and pancake breakfasts. Any time a school calls us for something we go and usually they let us put up a banner."
    Dealer I
  - "I love it when other dealers use tote bags [at home shows]. Then I know which people to target."
    Dealer F

Source: Woodlawn Associates

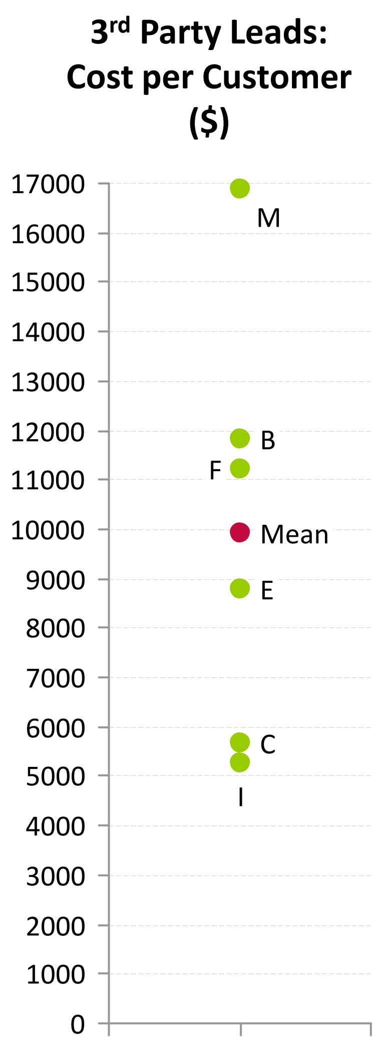
For success in online ads, make sure your own site explains solar clearly and pre-qualifies leads



- **Online ads (other than SEM) reach consumers who are *curious* about solar**
  - These ads should direct consumers to sections of web site rich in information about solar and its value proposition
  - They should also step consumers through a qualification process to avoid spending sales time with customers who will not convert
- **Dealers C, G, and I had lower-than-average cost for this channel**
  - Dealer G believes one key to success in online ads is a strong web site landing page for customers clicking on an online ad
  - Dealer C designs its web site to be rich in information on solar and provides short forms to qualify leads. Though they spend more than others for their online ads, their conversion rate is almost 4X higher than the average (38% vs. 10%).
- **SEM ads target consumers who are *interested* in solar**
  - "I put a lot of weight on SEM because it allows me to connect with people who are specifically interested in solar. I'm willing to bid $10 for certain words (for click through) because those people are specifically interested in solar. The cost of acquisition for SEM looks high, but I think that some of the customers that original come to us from search end up in our database as coming from somewhere else."
    Dealer F
- **Some dealers may need to re-examine their approach to internet advertising and lead tracking**
  - Dealers D, E, G, H, J, and M spent money in one or more of these categories but attributed no customers to that category. These are not shown on charts because cost per customer would be infinite
  - May indicate deficiency in ad placement, the ads themselves, the landing page on web site, or inbound lead tracking

Source: Woodlawn Associates

Third party lead generation is a tempting but often poor source of customers

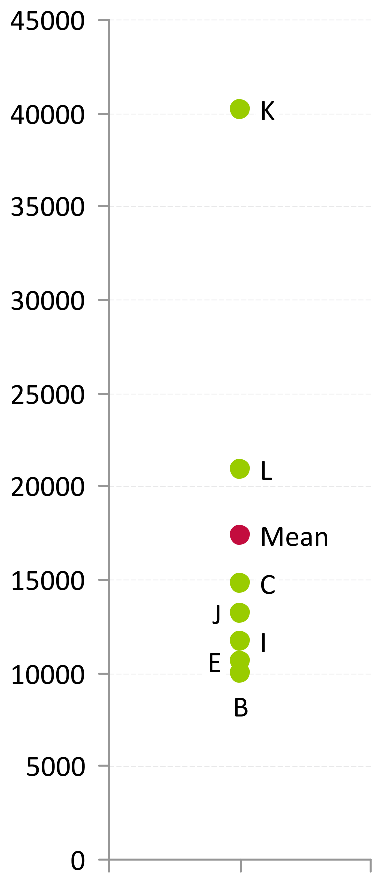


- **Almost all of our study respondents are either using third party leads or have tried them, but few are happy**
- **Averaging $125 per lead, third party leads are among the cheapest available. But, their 4% conversion rate is also among the worst**
  - "Purchased leads have been an abomination. We are not doing that again."
    Dealer D
  - "Generally they are doing things that you could do yourself but the leads you get are of lower quality, so you end up spending more on sales. Most of us pay by commission, but if the close rate is low then you have to pay more for each close."
    Dealer B
- **Optimizing this channel is about carefully choosing and managing the lead source**
  - "We would pay for leads if somebody would give us good sites and a reasonably knowledgeable customer, who has a basic understanding of solar."
    Dealer G
  - "We have a really good third party lead company. We only pay for qualified leads, and we give them the criteria to match."
    Dealer I

Source: Woodlawn Associates

Anecdotally, companies are successfully canvassing, but our respondents reveal a difficult, expensive channel

Door-to-Door:
Cost per Customer
($)



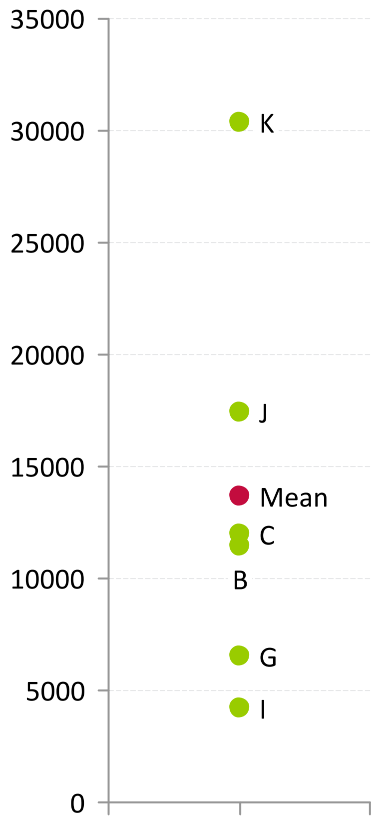
- **Despite very high costs in our survey, some dealers believe canvassing has been successful for their competitors and that is bringing others into the fray**
  - "[Dealer 1] has been a great example of success with canvassing. We've seen them take a huge part of the market."
    Dealer E
  - "Canvassing, without a doubt, will be a bigger in 2012. One, because we have seen some of our competitors be very successful with that. Two, we see potential in markets we've tested it in. It's a less competitive lead, since you've talked the customer into it instead of being one of four that they are getting quotes from. "
    Dealer J
  - "We want to do more canvassing but it seems to be very inefficient. We bought some software recently…to help us get more focused on the right neighborhoods."
    Dealer I

- **Successful canvassing seems to comes down to three factors:**
  1. Having a very strong, motivated manager for the door-to-door team
     - This is not for the marketing team to do in their spare time
     - "You need good people to supervise canvassing. We are doing some now, but it is clearly not very efficient. We have a good person in our phone room and that is what is really driving it."
       Dealer L
  2. Targeting high-potential neighborhoods
     - High density, good demographics
     - Have some existing residential solar, especially (but not only) if installed by your company
     - Use maps and satellite imagery to find streets with south-facing, suitable roofs and little shade
  3. Inducing interest and completing the sale as quickly as possible
     - "[Dealer 2] does a same day close on door-to-door. If you express interest to the canvasser, they will have a sales person there later that same day. They really try hard to prevent having to compete with another firm. "
       Dealer I

Source: Woodlawn Associates

Mass media looks expensive in our data set; few dealers are doing analysis to measure the true impact

Mass Media Average Cost per Customer ($)



- **With a very high cost per lead and low conversion rates, mass media (radio, TV, newspaper, and outdoor) looks expensive**
  - "We are unable to buy media effectively. You may get leads, but the conversion rate is low…" Dealer J
- **Radio is by far the most important mass channel for our dealers, with about two-thirds of dealers using it**
  - Many dealers also use outdoor and newspaper, but spend significantly less money on these
  - Few dealers did any TV; several reported trying it historically, with dismal results
  - "We did TV once—we spent like $30k and got maybe one job from it." Dealer A
- **Several dealers frustrated by inability to match mass media spending of very large dealers**
  - "SolarCity spends so much money! They do radio spots—I've heard them on [public radio]. They are in every Home Depot with a display at the front door…I've also seen them in the paper." Dealer H
- **Some dealers believe the leads and customers they track from mass media do not accurately reflect the overall impact of the channel**
  - "I hear from my sales team all the time that 'I made another sale because of that radio spot' but it gets booked as coming through some other channel." Dealer E
- **However, few dealers in our sample are doing the types of analysis that would allow them to measure its true impact**
  - A-B testing in markets that are otherwise similar (although difficult to do if a dealer is in a limited number of media markets
  - Outside this sample (and the solar industry), many users of mass media have unique phone numbers and web pages for mass media to enable more accurate tracking

Source: Woodlawn Associates

Focus mass media in geographies where a reasonable, sustained share of voice is possible

	Category Awareness & Perception	Brand Awareness, Recall & Perception	Purchase Intent
Key Questions	• Is the consumer aware of the residential solar category and what it can do for him or her?	• Does the consumer recognize the brand when prompted? Can he or she spontaneously recall the brand? • What attributes do consumers associate with the brand, and how strongly? • How positively is the brand viewed overall, and how does this compare with competitors?	• Is the consumer motivated to consider a purchase? • What prompts this consideration? • What factors are most important in determining which brand is selected?

Additional Considerations

- **In a highly fragmented market, it is inefficient for one or a handful of companies to drive this, as benefits are distributed**
- **Could certain manufacturers or dealers contribute to a fund that did marketing focused on category awareness and perception?**
  - "Beef – It's What's for Dinner"
  - "Got Milk?"

- **Doesn't take that much to create awareness and recall if a dealer does marketing early and if it has a relatively high share of voice**
- **Marketing and psychological literature recommend repeated exposure**
  - Favor frequency and duration over reach
- **Brands can be 'pushed aside' by competitors' marketing**
  - Advertising can resemble an arms race
  - Must meet a certain threshold to build and maintain awareness and recall
- **If using mass media, use A-B testing to determine effectiveness**
- **If a dealer can't sustain the threshold share of voice, best to favor other channels over mass media**

Source: Woodlawn Associates experience; review of marketing and psychology literature

Building consumer awareness and interest in residential solar might be done cooperatively

- **Many industry-wide marketing efforts are done under so-called "Checkoff" programs, which provide for mandatory contributions by industry; successful voluntary programs are rare**
  - Requires legislation by U.S. Congress
- **Solar dealers would like vendors to invest in developing awareness of solar benefits among consumers**
  - "The more they get solar out there, the more they promote solar, the more we will be able to jump on their back…It supports our efforts out there."
    Dealer L
  - "Vendors should do more to generate awareness of solar for the general public."
    Dealer I
  - Representative Gabriel Giffords of Arizona introduced "Got Solar?" legislation supported by the SEIA in 2007, but it failed in Congress

- **One study found that for every $1 invested in the "Beef. It's What's for Dinner" campaign, the beef industry got a $5 return**
  - Ads are funded by collecting $1 for every head of beef sold in the United States ($80M per year)
  - The Cattleman's Beef Board has a staff of 11 to manage and deploy these funds
  - Campaign received awards in 2003, 2004, 2006, and 2007; slogan now recognized by more than 88% of Americans
  - Industry failed three times to enact its program before its success in 1985

- **Eleven California milk processors agreed in 1993 to fund promotional efforts by allocating three cents per gallon sold. The resulting "Got Milk?" campaigns have been used nationally since 1995**
  - $23M per year marketing budget comparable to those for autos, beer, and finance brands
  - California milk consumption increased in the twelve months after the campaign started for the first time in a decade (though U.S per capita milk consumption is down 20% since 1990)

Source: New York Times, Advertising Education Foundation, USDA (beef and milk per capita consumption 1990-2009), CBB, SEIA
Notes: * Overall beef consumption declined 9% per capita from 1990 to 2009, but dollar volume held relatively flat

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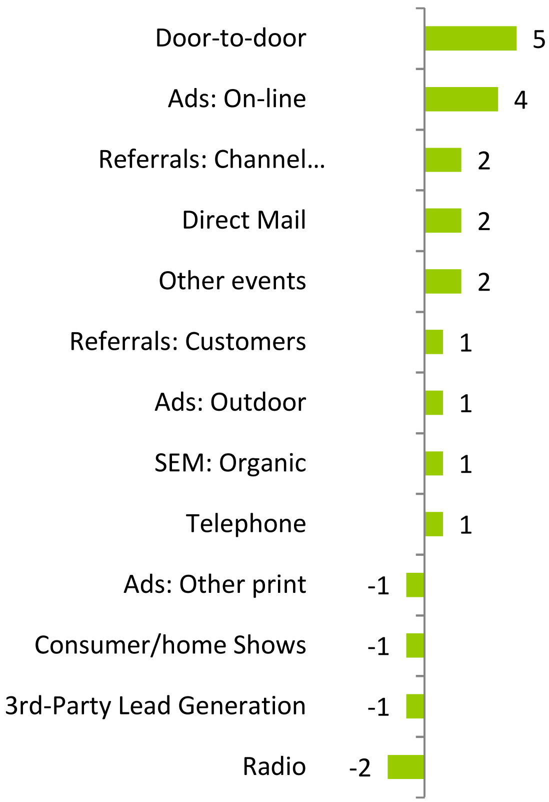
Overall, dealers said they expect to increase use of canvassing and online in 2012, but use less radio

Number of Dealers Increasing Weight of each Channel in 2012 Mix (net # of mentions)



- **Data represents dealers' view before this survey; several have mentioned intention to change strategies after seeing preliminary report**
- **Several dealers mentioned intention to increase use of door-to-door canvassing…**
  - "We are going to start doing door-to-door in neighborhoods where we have installs."
    Dealer G
  - "We will definitely do more canvassing – that seems to be our horse of choice. "
    Dealer J
- **…though some are going the other direction**
  - "We will also probably do less canvassing…The problem is if you are working down the right side of a street, there is another firm working the left side, and you will meet a third firm along the way. Good neighborhoods are saturated and we are wearing out our welcome."
    Dealer C
- **Dealers also expect to more heavily weight online advertising**
  - "This year we are going to work more web sites locally, like the site of the local newspaper."
    Dealer A
  - "Online will be a bigger share this year. We have a new web site and, with our new message, we think it will resonate."
    Dealer C
  - "We'll spend more money this year on SEO and enhancing the website…We are convinced that spending on the website will give a better return than hiring another salesperson…"
    Dealer G
- **Overall, dealers plan to do less radio**
  - "We will do less radio. We just don't have enough ammo."
    Dealer C
  - "We will decrease radio, although I am thinking about underwriting the local public radio station."
    Dealer A

Source: Woodlawn Associates; n=13

Dealers say vendors can help with marketing in three key ways: low prices, leads, and category awareness

- **Above all, dealers want competitive pricing**
  - "In the past Kyocera was probably the best [at helping with marketing] because they offered this amazing co-op program...But we are not selling them much anymore because we found we could get the same quality and performance at a lower price."
    Dealer E

- **They would also like leads**
  - "To be helpful, I would say vendors buy internet ads or keywords, or do radio advertising, and then aggregate and allocate the leads to their dealers….Canadian Solar buys keywords and gives us leads—that's really helpful."
    Dealer C
  - "If they would do mass mailing that would be good. I'd like to see them do that an put my brand on as co-branding."
    Dealer L

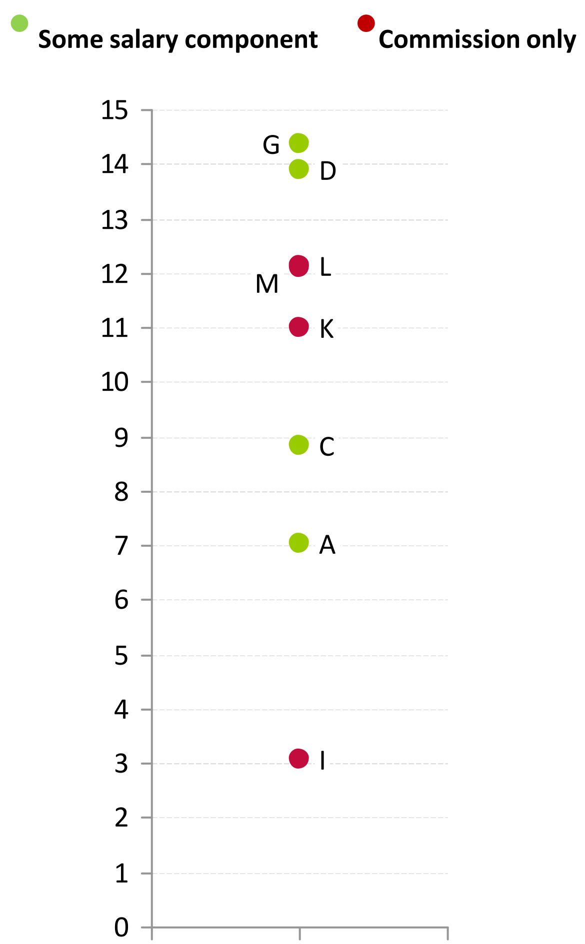
- **But, they do not necessarily feel their vendors are good at lead generation**
  - With some exceptions, vendor web sites leave a lot to be desired as consumer marketing tools
  - "They could send us leads. Actually, they all say they will but they don't."
    Dealer A
  - "They are terrible at leads and shouldn't try to collect them."
    Dealer I

- **Dealers would like greater awareness of solar, though they are not sure they not want vendors to invest in brand marketing**
  - "Vendors should PARTNER with their dealers and not push their brand so hard…[they] should…not confuse the customer by leading with their brand."
    Dealer D
  - "We are not trying to sell the 'product' much these days, so I wouldn't tell them to try to go build a brand."
    Dealer E

- **Since each vendor's starting point and assets are different, Woodlawn Associates' recommendations for vendors vary by company. Contact us for company-specific recommendations**

Sales efficiency depends more on the team and the management than on their compensation structure

Sales Expense as % of Revenue



- **Commissions range around 3-7% and are often structured as draws; however, compensation with a pure salary component is not unusual**
- **Average sales expense among commission-only dealers is barely lower than it is among dealers using some salary component, but less risky**
  - Sales costs becomes more variable, matched to revenues during business cycles
  - Underperforming salespeople will leave if commission is insufficient
- **Sales teams can be efficient either with or without salaries, depending on the management**
- **Dealers are experimenting with many different compensation methods:**
  - "We modeled ourselves on… what we heard was going on in the industry. I don't know that these are the right numbers, or the best way to do it."
    Dealer G
  - "For the vast majority of last year, it was purely commission, then non-recourse draw, then salaried"
    Dealer M
  - "I struggle to learn how to identify and motivated a really good salesperson."
    Dealer D

Source: Woodlawn Associates; n=8

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Summary

- **Study based on data from 13 U.S. residential solar dealers**
  - Representative in size and geography of broader industry
- **Dealers spend an average of 17% of revenues on acquisition, or approximately $5400 per customer**
  - Ranges from $1810 to $9605 per customer, but most are $4000-6500
- **Cost per lead is approximately $210*, but only 14% of leads convert. Most of acquisition cost is in Sales**
  - Channels generating high quality leads are inexpensive because Sales needs to spend much less time to yield a customer
  - Channels such as third-party leads, which have a low cost per lead—but also a low conversion rate—are actually among the most expensive channels
- **Dealers vary widely in the mix of channels they use**
  - They spend the most money on online advertising (SEM and otherwise)
- **Customer referrals are the largest single source of customers and also have the lowest acquisition cost, at about $2400 per customer**
  - Despite its being the lowest cost large channel, many dealers are not as systematic or creative as possible about sourcing leads from this channel
- **In general, we believe there is considerable opportunity to shift spending from expensive, inefficient channels to less expensive, more efficient channels and to optimize within channels**

Notes: * Omits one dealer counting only qualified leads, which have a higher cost.

Key Recommendations

1. **Spend significant management time on the selection, training, motivation, and tracking of the sales team**
   – 96% of acquisition cost is directly or indirectly driven by the quality of sales efforts
2. **Give the sales team high quality leads**
   – Educate and sort potential customers before they spend time with your sales people
3. **Understand your breakeven point**
   – How much is too much to spend acquiring customers?
4. **Understand your acquisition cost by channel**
   – Regularly measure and report, perhaps in quarterly operations reviews
   – Shift spending from expensive to inexpensive channels
5. **Optimize within each channel**
   – Be systematic and comprehensive in seeking referrals
   – Do not overspend on vehicle wraps
   – Do not attempt door-to-door canvassing casually; monitor performance closely
   – Reconsider use of 3rd-party lead generation
   – Consider radio and other mass media only if:
     - Can exceed effectiveness threshold
     - Can do it continuously
     - Can estimate its true impact on your business

Woodlawn Associates would be delighted to assist you—please contact us

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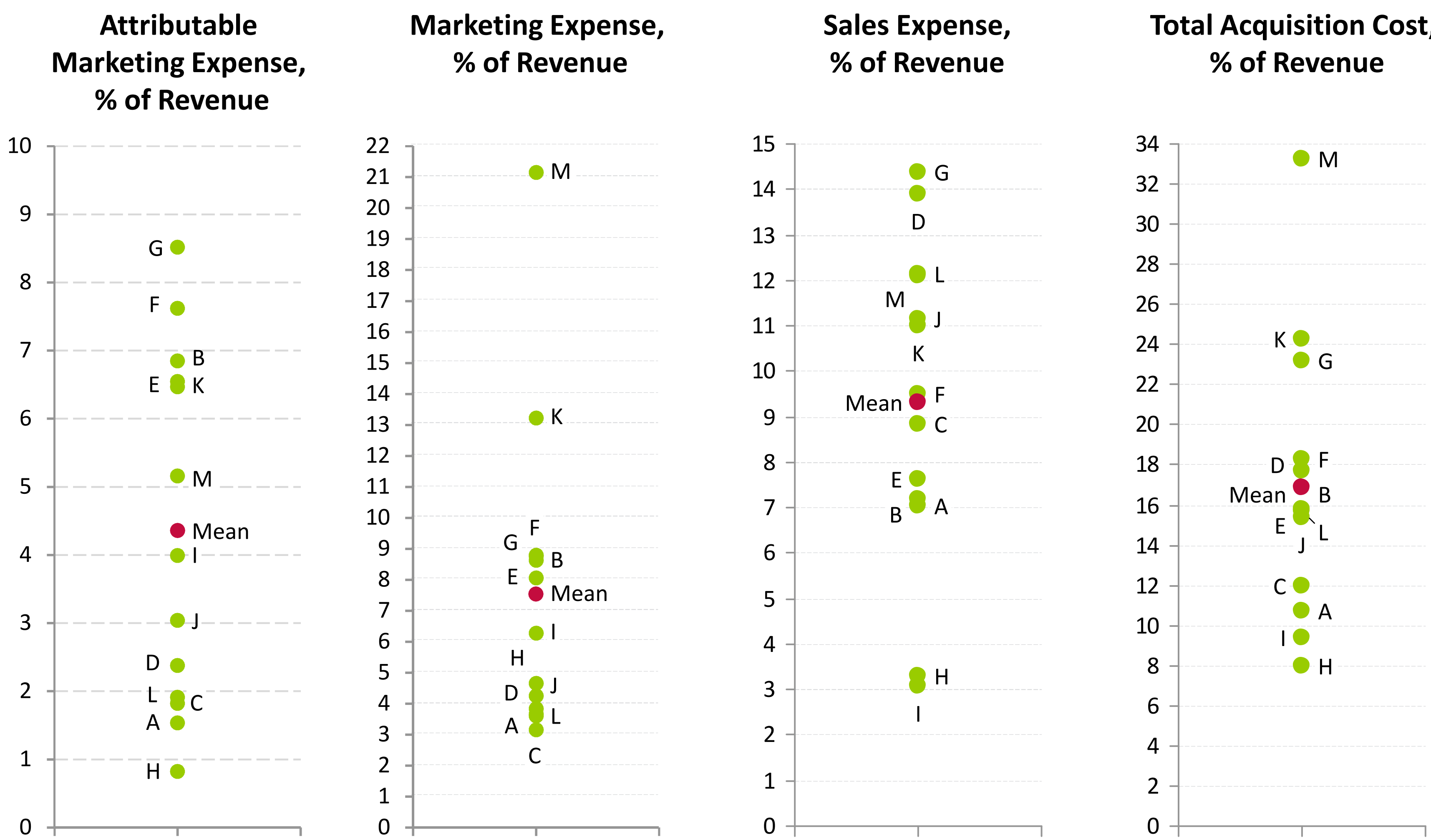
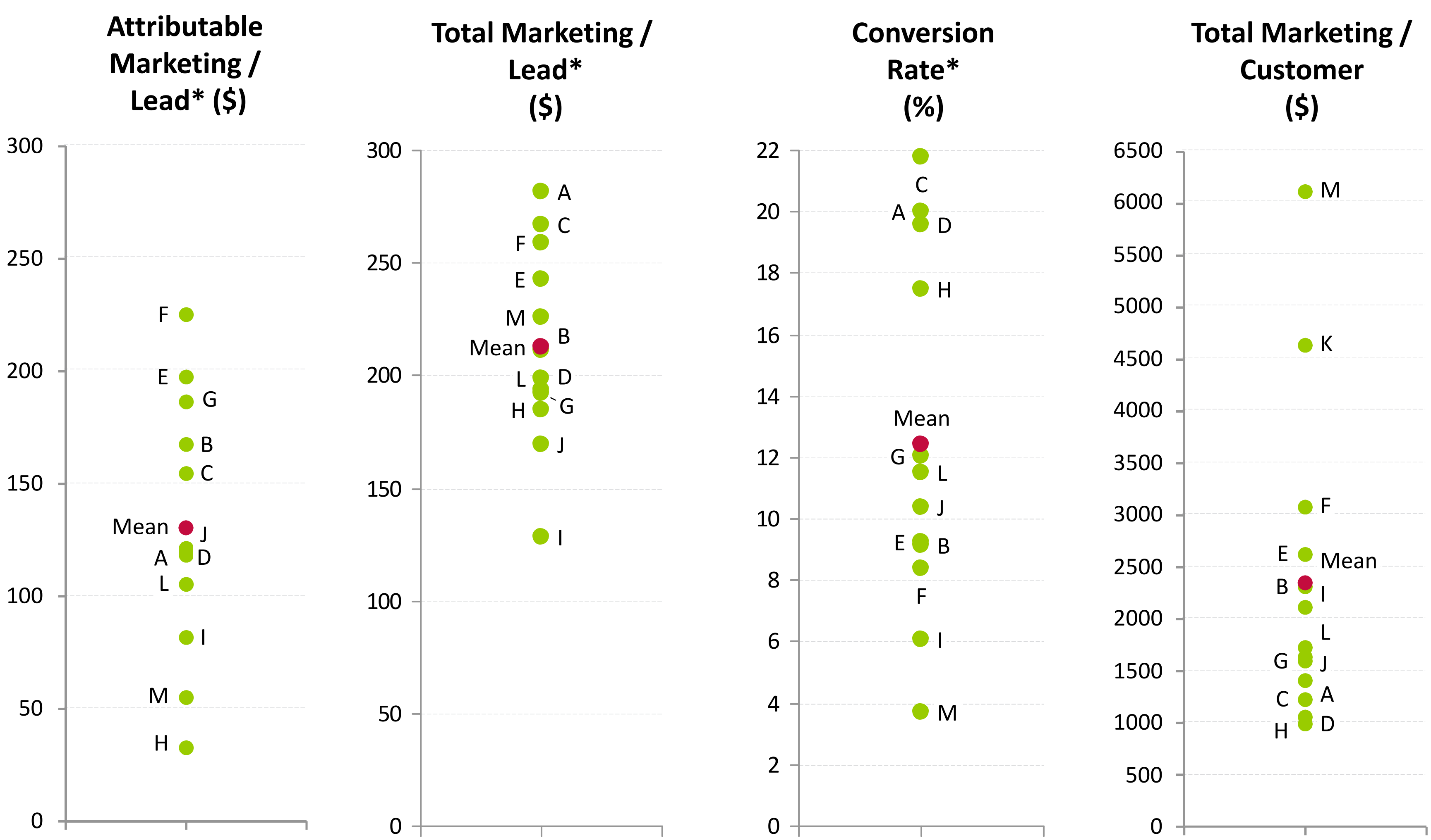
How Dealers Compare (% of Revenue)



Source: Woodlawn Associates

How Dealers Compare (Marketing and Conversion Rate)



Source: Woodlawn Associates

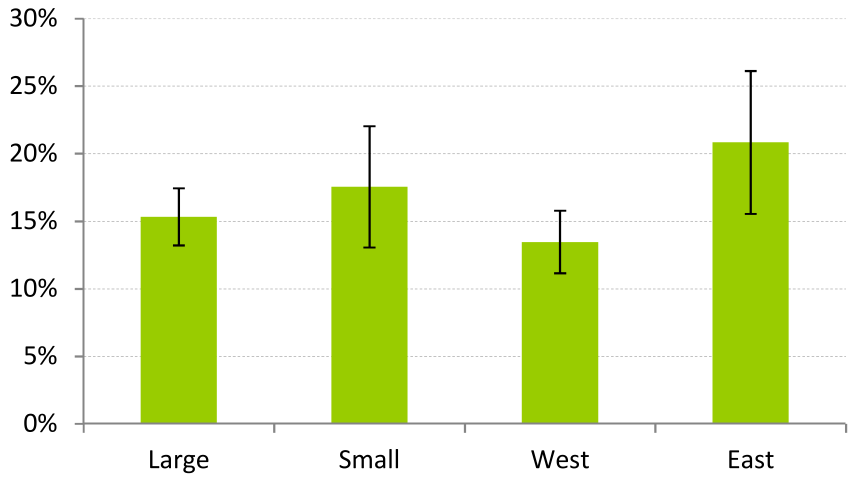
Notes: * Dealer K's cost per lead and conversion rate are not shown or included in the mean. K's leads are more qualified and thus not comparable.

How Dealers Compare (Sales and Acquisition Cost)

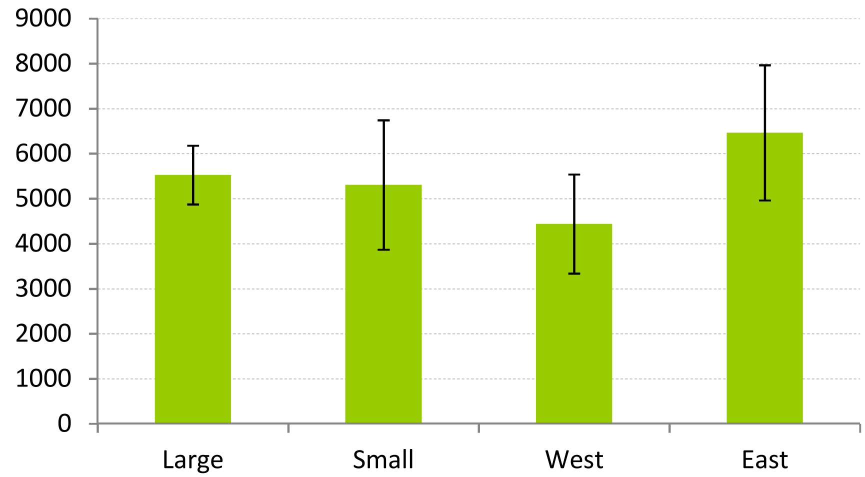
Source: Woodlawn Associates

East Coast dealers may have higher acquisition costs, although the difference is not statistically significant

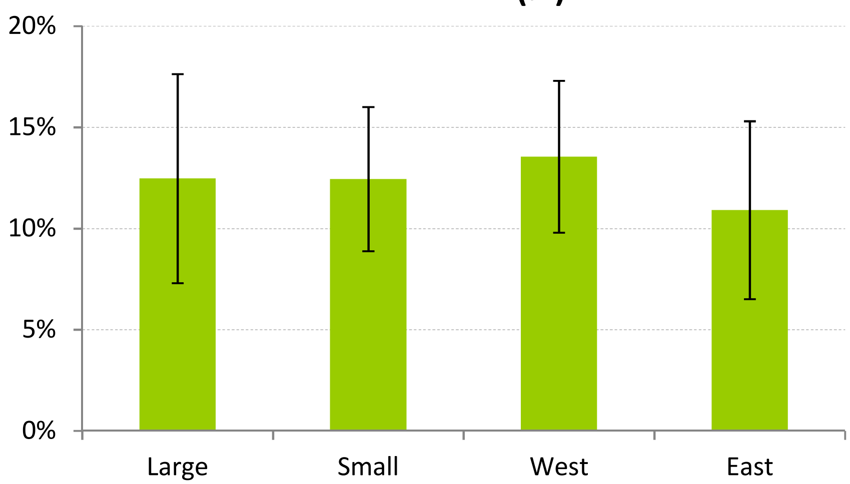
Acquisition Cost (% of Rev)



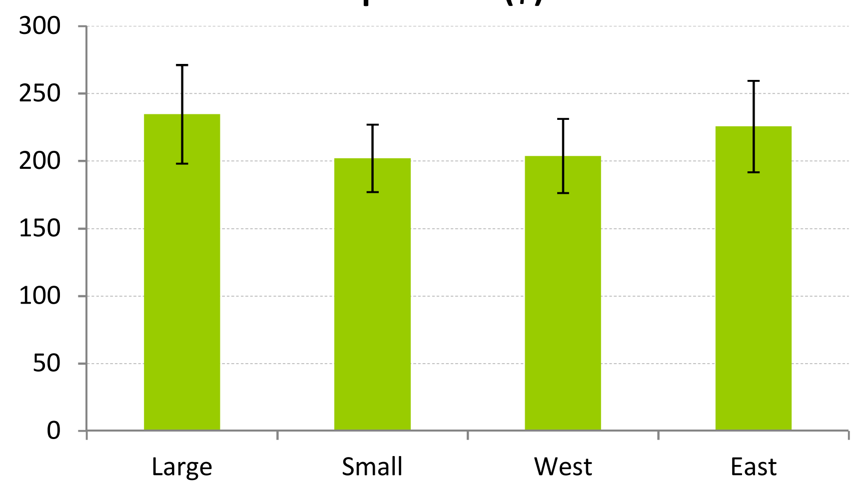
Acquisition Cost ($)



Conversion Rate (%)



Cost per Lead ($)



Notes: Error bars represent 90% confidence interval for each category; lead graphs omit one dealer counting only qualified leads, which have a higher cost.

EXHIBIT A-3

CALSEIA DATA REQUEST #7
NET ENERGY METERING SUCCESSOR TARIFF
R.14-07-002
SDG&E RESPONSE
DATE RECEIVED: SEPTEMBER 24, 2015
DATE RESPONDED: SEPTEMBER 29, 2015

A. For each line item of expenses shown in Attachment A of your testimony, list the portion of the expense that is a previous one-time expense, a future one-time expense, and an on-going expense.

		Category	Portion
Application processing costs			
CCC and Customer Service	**$ 240,243**	On-going	100%
Billing	**$ 523,529**	On-going	100%
IT and Overheads from Capital Projects	**$ 964,777**	On-going	4%
		Previous one-time	96%
Customer Generation & Overheads & Admin	**$ 629,333**	On-going	100%
In-office review costs			
Distribution Planning	**$ 9,014**	On-going	100%
System Protection Engineering	**$ 13,417**	On-going	100%
Customer site inspection and meter programming change costs			
NEM Inspections & Overheads	**$ 472,090**	On-going	100%
Vehicle Fleet Costs for inspections	**$ 1,727,124**	On-going	100%
Meter Changes, Service Orders, and Overheads	**$ 719,907**	On-going	100%
Project management costs			
Electric Project Management	**$ 11,751**	On-going	100%
Overhead for Facility Upgrade Management	**$ 10,942**	On-going	100%
DIIS Development			
DIIS Phase 1 and Phase 2 costs were incurred prior to the study dates			
Phase 1	**$ 1,781,965**	Previous one-time	100%
Phase 2	**$ 473,000**	Previous one-time	100%