Oregon Solar Energy Industries Association

Via Electronic Mail

Mar 15, 2018

Public Utility Commission
Attn: Filing Center
PUC.filingcenter@state.or.us

Re: PACIFICORP, dba PACIFIC POWER, Resource Value of Solar.
Docket No. UM 1910

Dear Filing Center:

The Direct Testimony of R. Thomas Beach on behalf of the Oregon Solar Energy Industries Association is enclosed for filing in the above-referenced docket.

Thank you for your assistance, and please do not hesitate to contact our office if you have any questions.

Sincerely,
/s/ Jon Miller
Jon Miller
Executive Director, OSEIA

PO Box 14927, Portland, OR 97293-0927
Phone: 503-853-5804 Email: admin@oseia.org
www.oseia.org

Dockets No. UM 1910 / 1911 / 1912
Exhibit OSEIA / 100
Witness: R. Thomas Beach

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Prepared Direct Testimony of
R. Thomas Beach
on behalf of
Oregon Solar Energy Industries Association

March 16, 2018

EXECUTIVE SUMMARY

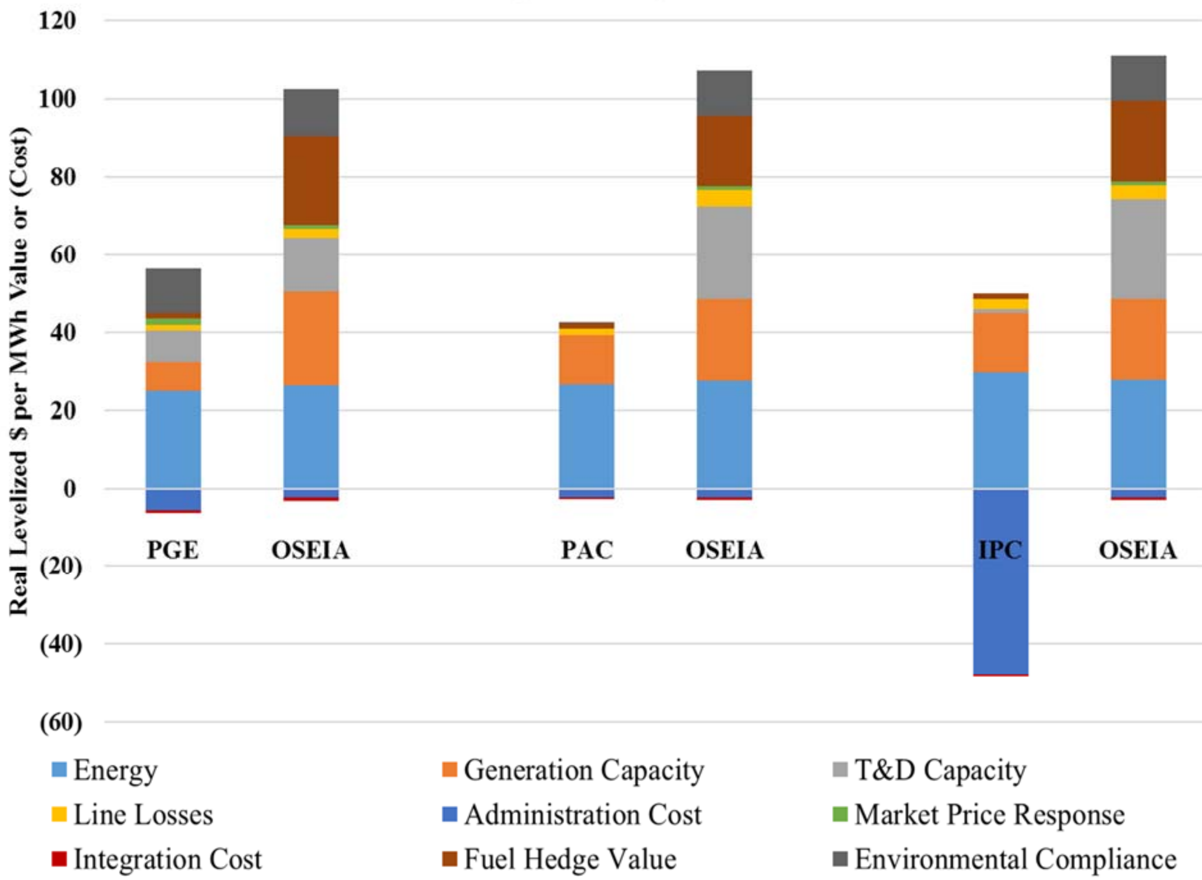
On behalf of the Oregon Solar Energy Industries Association (OSEIA), this testimony presents calculations of the Resource Value of Solar (RVOS) for the three investor-owned utilities (IOUs) in Oregon, based on the RVOS methodology set forth in the Commission's Order 17-357. The testimony recommends a number of changes to the RVOS calculations that Portland General Electric (PGE), PacifiCorp (PAC), and Idaho Power (IPC) submitted in this docket in December 2017. These modifications result in RVOS values that are more consistent with the direction that the Commission provided in Order 17-357, use more accurate methods, and are more up-to-date than what the utilities have proposed. For some of the RVOS components, the utilities themselves differ on the methods or assumptions that they have used; in these instances, where appropriate, OSEIA has used consistent methods and assumptions for all three IOUs.

OSEIA's recommendations for the RVOS values that the Commission should adopt are shown in **Table ES-1**. **Figure 1** below also shows OSEIA's RVOS recommendations, and compares them to what each of the utilities has proposed.

Table ES-1: *OSEIA Recommended RVOS Values (2018 $ per MWh, real levelized)*

RVOS Cost Component	**PGE**	**PAC**	**IPC**
Energy	26.27	27.63	27.77
Generation Capacity	24.11	20.87	20.70
T&D Capacity	13.92	23.94	25.72
Line Losses	2.33	4.18	3.55
Administration	(2.30)	(2.30)	(2.30)
Market Price Response	1.00	1.05	1.06
Integration	(0.83)	(0.63)	(0.56)
Hedge Value	22.75	18.14	20.69
Environmental Compliance	12.00	11.37	11.55
Total	**99.26**	**104.24**	**108.17**
Total (5% Hedge)	*77.81*	*87.48*	*88.87*

Figure ES-1: *Comparison of RVOS Components*



The major differences between the OSEIA and utility RVOS calculations include:

- **Avoided Energy.** For all three IOUs, OSEIA used PAC's approach to the hourly shaping of forecasted wholesale energy prices, using hourly prices from the regional Energy Imbalance Market.

- **Generation Capacity.** To recognize accurately the shorter lead times and smaller capacity increments that distributed solar resources can provide, we followed the suggestion of Order 17-357 to advance by up to four years the "resource balance year" when each of the IOUs will need capacity. We also used the Capacity Factor method adopted in Order 16-326 to calculate solar's contribution to avoiding generation capacity costs.

- **Avoided T&D Capacity.** We use consistent methods across the three IOUs to calculate the long-run transmission and distribution (T&D) capacity costs that distributed solar can avoid. For transmission capacity, we accept PGE's approach of using current FERC-approved bulk transmission rates as a reasonable proxy for marginal transmission costs, and we apply this method to the other IOUs as well. For distribution, for PGE we use the full set of capacity-related marginal distribution costs from its last marginal cost study. For PAC and IPC, we present new calculations of their marginal distribution capacity costs that use regressions of historical and forecasted distribution investments as a function of peak loads. We then use granular hourly data on the distribution substation loads of each utility to determine the ability of distributed solar to reduce the peak loads on the distribution systems of each IOU. These are the loads that drive marginal distribution investments.

- **Avoided Line Losses.** The utility RVOS calculations appear to understate the line losses avoided by solar DG, by using average line loss factors. To be more accurate, OSEIA recommends the use of marginal losses.

- **Administration.** PAC's administrative costs appear to follow the guidelines in Order 17-357 that limit administrative costs to incremental costs associated with a customer's decision to install on-site generation. PAC's administrative costs of about $2 per MWh are in line with those of other utilities in the West with active solar programs. We have used this value for all three utilities, as we see no reason why PGE and IPC cannot achieve similar efficiencies in administering their solar programs.

- **Market Price Response.** We accept PGE's calculations using the Aurora model of the market price response to increased solar deployment, and we apply PGE's results (about 4% of avoided energy costs) to all three IOUs. This MPR value is in line with other calculations of this benefit that have been made in the New England Independent System Operator's market.

- **Hedge Value.** Distributed solar displaces the marginal use of natural gas to generate power, and thus reduces ratepayers' exposure to volatile fossil fuel prices. This hedging benefit can be quantified using a method that Clean Power Research developed for the Maine Public Utilities Commission. This approach recognizes that the value of the hedge that a renewable resource provides is equal to the cost that the utility would have to incur to fix the costs for its avoided natural gas burn for the life of the renewable resource. We have applied this method to each of the IOUs, and we recommend the use of the resulting values. Alternatively, we also present the placeholder referenced in Order 17-357 – 5% of avoided energy costs.

- **Environmental Compliance.** It is reasonable to assume that any compliance regime for carbon emissions will apply to all utilities in Oregon. Accordingly, OSEIA has used the avoided carbon compliance costs in PGE's RVOS for all three utilities. These avoided costs are based on an assumption for a future regulatory regime that places a price on carbon emissions. Neighboring states and provinces already are subject to such a regime (California and British Columbia), or have one under active discussion (Washington).

The testimony also comments on the alternative RVOS approach that uses the cost of utility-scale solar as a proxy for all of the RVOS elements except T&D capacity, administration, and line losses. This alternative RVOS is misleading and fails to capture important additional, quantifiable benefits of distributed solar. These include environmental benefits from reduced land use impacts, additional benefits when paired with storage (including enhanced reliability and resiliency), and the important benefit of increasing customers' ability to choose their source of electric energy. Both distributed and utility-scale solar should have central roles in the transition to a clean, sustainable, resilient electric industry.

Finally, the testimony shows how the resource value of solar may increase significantly when solar is paired with on-site storage. This is due principally to the ability of storage to shift a portion of solar output to the hours when it is most valuable to the system, thus increasing substantially the contribution of distributed solar to avoiding generation and T&D capacity costs. Storage also may enhance the ability of solar resources to provide a range of grid services, benefits which the Commission may explore in a subsequent phase of these dockets.

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I. INTRODUCTION

Q1: Please state for the record your name, position, and business address.

A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q2: Please describe your experience and qualifications.

A2: I have 35 years of experience in utility analysis, resource planning, and rate design. I began my career on the staff at the California Public Utilities Commission ("CPUC"), working from 1981-1984 on the initial implementation in California of the Public Utilities Regulatory Policies Act ("PURPA") of 1978. I also served for five years (1984-1989) as a policy advisor to three CPUC commissioners. Since entering private practice as a consultant in 1989, I have served as an expert witness in a wide range of utility proceedings before many state utility commissions. This includes sponsoring testimony on PURPA-related issues, including the calculation of avoided cost prices, in state regulatory proceedings in Oregon, California, Idaho, Montana, Nevada, North Carolina, Utah, and Vermont. I also have extensive experience on public policy issues related to the development and deployment of solar generation, both photovoltaic ("PV") and solar thermal. This includes assessing the costs and benefits of both small, distributed solar and large, utility-scale systems. Prior to this professional experience, I earned degrees in English and Physics from Dartmouth College and a Masters in Mechanical Engineering from the University of California at Berkeley. My full CV is included as Exhibit OSEIA 101.

Q3: Have you previously testified before this commission?

A3: Yes, I have. In 2004 and 2006, I presented several pieces of testimony on avoided cost and power purchase agreement issues concerning qualifying facilities (QFs) in Oregon, on behalf of Weyerhaeuser Corporation and the Industrial Customers of Northwest Utilities, in Docket UM 1129.

Q4: On whose behalf are you testifying in this proceeding?

A4: I am appearing on behalf of the Oregon Solar Energy Industries Association (OSEIA). OSEIA is a trade association founded in 1981 to promote clean, renewable, solar technologies. OSEIA members include businesses, non-profit groups, government agencies, and other solar industry stakeholders. OSEIA's mission is to make solar energy a significant energy source and to expand markets by strengthening the industry and developing a skilled and stable workforce.

Q5: Please briefly describe the background and goal for this case?

A5: The purpose of the Resource Value of Solar (RVOS) methodology is to produce a 25-year levelized value for a generic, small-scale solar resource installed in 2017. The RVOS will inform the Commission's future decisions on net metering and community solar programs in Oregon. In Order 17-085 in Docket UM 1716, the Commission set forth a straw proposal for the RVOS, using a methodology developed by the Commission's consultant, Energy & Environmental Economics (E3). Following comments from interested parties, Order 17-357 adopted a modified version of E3's proposal, leading to the initial utility RVOS calculations of the three investor-owned utilities (IOUs) – Portland General Electric (PGE), PacifiCorp (PAC), and Idaho Power (IPC) – which the utilities filed in these dockets on December 4, 2017.

Q6: What is the purpose of your testimony?

A6: This testimony responds to the RVOS calculations of PGE, PAC, and IPC filed last December. On many of the RVOS elements, I present alternative RVOS calculations that are more consistent with the direction that the Commission provided in Order 17-357, use more accurate and appropriate methods, or are more up-to-date, than what the IOUs have proposed. On behalf of OSEIA, this testimony supports these recommendations for the RVOS that the Commission should adopt for each of the three IOUs.

II. RVOS ELEMENTS

Q7: Order 17-357 adopted an RVOS methodology that includes eleven elements. Which of these elements is the Commission considering at this time?

A7: The Commission directed the utilities to present RVOS calculations on the first nine of the adopted RVOS elements, which are:

1. Avoided energy;
2. Avoided generation capacity;
3. Avoided transmission and distribution capacity;
4. Avoided line losses;
5. Administration;
6. Integration;
7. Market price response;
8. Avoided fuel hedge value; and
9. Avoided environmental compliance.

The final two elements will be addressed in subsequent phases of these dockets:

10. Avoided renewable portfolio standard (RPS) compliance; and
11. Grid services.

I will comment below on each of the nine RVOS elements that are the subject of this phase, indicating where I agree or disagree with the specific calculations that each of the utilities has presented.

Q8: Are there threshold issues that impact many of the RVOS elements?

A8: Yes. The focus of the RVOS is the value of small-scale, distributed solar located behind customers' meters or in close proximity to load centers. As a result, in my RVOS calculations I have used hourly solar output profiles for fixed arrays located in the major load centers for each of the IOUs, as summarized in **Table 1**, using the National Renewable Energy Lab's PVWATTS solar simulation tool.[1] I used three locations for PAC, given the more widespread and varied geographic area that it serves.

Table 1: Solar Output Profiles Used

Utility	Location(s)	Orientation	Type of Array	Tilt (degrees)	Inverter Loading Ratio
PGE	Portland	South	Fixed	20	1.2
PAC	Redmond	South	Fixed	20	1.2
	Medford	South	Fixed	20	1.2
	Corvallis[2]	South	Fixed	20	1.2
IPC	Boise	South	Fixed	20	1.2

Some of the utility calculations for their proposed RVOS are based on the output of utility-scale solar arrays located in locations remote from load centers and using single-axis tracking. These profiles might be appropriate for the Commission's alternative RVOS method that uses the value of a utility-scale solar facility as "a reference point to

[1] See http://pvwatts.nrel.gov/.

[2] I use PVWATTS data for Corvallis in the Willamette Valley, which PAC serves. PAC used solar output data from Portland, which it does not serve.

advance understanding of evaluation methods," but they should not be used in the base RVOS method set forth in Order 17-357.[3]

A. Avoided Energy

Q9: Please comment on the utilities' calculations of avoided energy costs.

A9: The utilities generally use the avoided energy costs from their most recent filing of QF avoided costs.

The one modification that I recommend is the use of a consistent approach to shaping forecasted wholesale on-peak and off-peak market prices to capture the hourly energy costs avoided by solar DG output. I recommend that all three utilities should use PAC's approach to this shaping, which is based on a recent hourly profile of prices in the regional Energy Imbalance Market (EIM). This is the most granular market data available for the Pacific Northwest wholesale energy market. The RVOS models that I have developed for all of the utilities, including PGE and IPC, use this approach to develop an hourly (i.e. 8760 hours in a year) shaping of avoided energy costs. I use the profile of uncapped EIM prices that PAC has developed; I see no reason to cap artificially the actual EIM prices paid by willing buyers and sellers in this broad regional market.

B. Avoided Generation Capacity

Q10: What direction did Order 17-357 provide for calculating avoided generation capacity costs related to solar DG?

[3] See Order 17-357, at p. 18.

A10: Generally, Order 17-357 directed the utilities to use avoided generation capacity values that are based on their approved, standard QF avoided costs for generating capacity. However, the order also encouraged parties to explore certain modifications to the standard avoided capacity cost calculations that may better reflect the attributes of solar DG. These potential changes include:

- allowing the full capacity value up to a reasonable number of years before the deficiency year {e.g., three or four years) in recognition of the "lumpy" nature of utility-owned central station resource additions;

- using the short run marginal costs for operations and maintenance (O&M) at existing marginal fossil plants as a proxy for the value of capacity during the sufficiency period (as suggested by the Commission's consultant, E3); and

- other ideas arising from related Commission dockets or as raised by the parties.[4]

Q11: Based on these ideas, do you propose any adjustments to the utilities' calculations of avoided generation capacity costs?

A11: Yes. Consistent with the first idea that the Commission suggested in Order 17-357, I propose to advance, by 3 years for PGE (to 2018) and 4 years for PAC and IPC (to 2025 and 2020, respectively), the "resource balance year" in which the capacity costs of the avoided resource begin.[5] This modification is rooted in the Federal Energy Regulatory Commission's (FERC) PURPA regulations, which explicitly state that avoided cost rates for purchases from QFs must take into account "the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities."[6] All solar DG facilities have *per se* status as QFs under PURPA,[7] and this technology clearly

[4] Order 17-357, at p. 7.
[5] In other words, the resource balance year is the first year of the deficiency period in which capacity is needed and the avoided resource is assumed to begin operations.
[6] 18 CFR § 292.304(e)(2)(vii).
[7] Utility customers who install renewable DG systems (solar or wind) are, by definition, QFs under PURPA. For a customer installing a system with a net power production of 1 MW of less, the designation

can be installed with shorter lead times and construction periods than traditional utility-owned central station capacity, with construction requiring as little as two months once permitting is complete. In addition, solar DG capacity obviously is available in smaller increments, given that behind-the-meter solar DG units can be installed at any scale from 1 kW up to the current net metering capacity limits in Oregon.[8] In contrast, typical utility additions of capacity are made in increments of at least 50 to 100 MW, and often more, as shown by the utilities' historical resource additions and resource plans.[9] These large central station units require significantly longer times to develop, permit, and build. As a result of the long lead times and the large, "lumpy" nature of utility capacity additions, new utility plants must be sized to provide much more than the amount of capacity which the utility needs in the year in which the new plant enters service. The result is that ratepayers may have to pay for years of excess capacity until demand "catches up" to the last major addition. Because QF capacity can be built in smaller increments and with shorter lead times, QF development can match more closely the utility's future load growth and future capacity needs, with less excess capacity. The result of this benefit is that small, distributed QFs can be paid the full value of the avoided capacity resource for

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as a qualifying small power production facility (and therefore a QF) is automatic with no filing at the FERC required.

[8] For public utility customers, these limits are 2 MW for non-residential systems and 25 kW for residential units. See Or.Admin.R.860-039-0010, available at https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=223368.

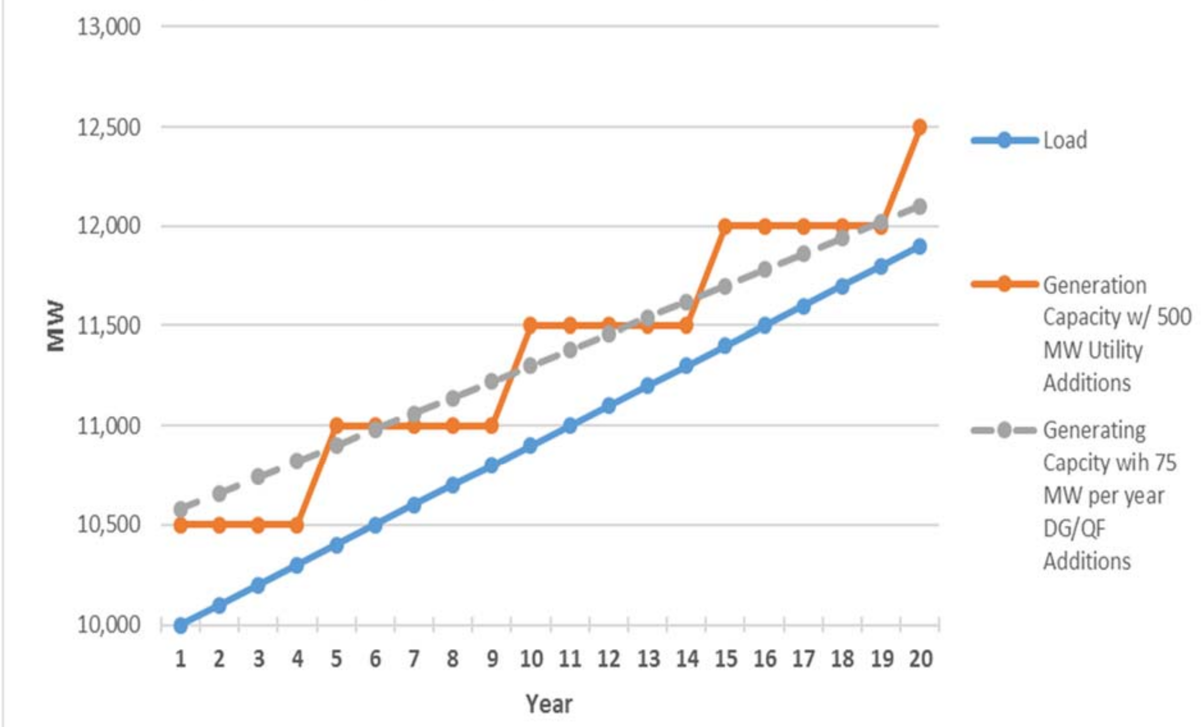
[9] See, for example, page 376 of PGE's 2016 IRP, at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en. Resources that PGE has added in the recent past include the 395 MW Port Westward 1 CT that started operation in 2007, the 222 MW Port Westward 2 CT added in 2014, and the 434 MW Carty CC/CT that was added in July 2016. All of these projects are well over 100 MW in size. PAC's 2017 IRP (Table 5.4 at page 77 of http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf) shows that the average size of PAC's 11 gas-fired plants is about 250 MW (= 2,734 MW / 11 plants), with a minimum size of 40 MW. IPC's 2017 IRP, https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf, describes its existing resources, including (at page 29) a description of the natural gas facilities it has added in recent years. These include Langley Gulch (318 MW), Danskin (271 MW), and Bennet Mountain (173 MW).

a number of years before the utility has a need, at a cost to the ratepayer that is no higher than what the utility would have incurred "but for" QFs. As a result, solar DG QFs will be under-valued, contrary to the FERC requirements, if a small-scale solar DG resource is assumed to have zero capacity value until the year when the next major utility unit would be operational.

Q12: Can you provide a simple example to illustrate this point?

A12: Yes. Assume that a simplified utility system with 10,000 MW of demand (including the reserve margin) in Year 1 has existing installed capacity of 10,500 MW and load growth of 100 MW per year. The utility plans to add capacity in 500 MW increments, while solar DG capacity can be developed in small increments at a rate of 80 MW per year. The new utility capacity costs $100 per kW-year, and the same rate is used to value the solar DG capacity. **Figure 1** compares meeting load growth over a 20-year period with the addition of four "lumpy" 500 MW utility plants (red line) and with the much more granular DG additions (gray line). The utility would add the first 500 MW unit in Year 5 and then add another unit every five years, while the distributed QFs are added starting in Year 1 at a steady pace of 80 MW per year. Over the 20 years, both the utility and DG scenarios have the same average amount of excess capacity at the end of each year (about 300 MW, with a minimum of 100 MW of excess capacity in any year) and have similar cumulative costs ($1.7 billion). This is the result even though the DG that is installed in Years 1 to 4, when it could be argued that no capacity is needed, is valued at the full avoided capacity rate of $100 per kW-year. In essence, because the DG/QF capacity can be added more quickly and in smaller increments, the DG/QF additions result in less excess capacity in many years, and the compensation for this benefit is to value DG at the full avoided cost for capacity in all years, including in Years 1-4 that traditionally would be considered "sufficiency" years when there is no need for capacity.

Figure 1: Lumpy Utility vs. Granular DG/QF Capacity Additions



Q13: Have other state commissions recognized this attribute of small renewable QFs?

A13: Yes. In 2014 the North Carolina commission rejected a utility proposal to reduce to zero the capacity payments to small QFs (under 5 MW) in the years prior to when the utility next planned to add central station capacity. The North Carolina order recognized that the assumption of zero capacity value for an initial period of years may undervalue the costs avoided by a QF over the full 15-year term of QF power purchase contracts in that state.[10]

[10] State of North Carolina Utilities Commission, *Order Setting Avoided Cost Input Parameters* (issued December 31, 2014) in Docket No. E-100, Sub 140, at pp. 35-36.

Q14: Please comment on the E3 proposal to use short run marginal costs for operations and maintenance (O&M) at existing marginal fossil plants as a proxy for the value of capacity during the sufficiency period.

A14: I believe that E3's proposal has significant merit. The value of capacity is never zero, even if a utility has excess capacity. If a utility is "long" on capacity in a particular year, it has an opportunity to sell that excess capacity in the market to earn additional revenues for the benefit of its ratepayers. The value of short-term capacity is most apparent in control areas such as the PJM Interconnection, the New York ISO, and the New England ISO, all of which have organized and visible capacity markets. California's short-term market for resource adequacy capacity has produced values that are similar to the ongoing O&M costs for existing combined-cycle plants. Even in the Pacific Northwest, there is a market for short-term capacity in which the utilities participate, although transactions are bilateral and prices are not transparent.[11] At a minimum, I recommend that the Commission should recognize that the short-term, non-zero value of DG capacity during the sufficiency period provides another reason why the resource balance year (i.e. the first year if the assumed deficiency period) should be advanced by up to four years in the utilities' RVOS calculations, as I have done.

Q15: Please summarize the adjustments that you propose to the avoided generation capacity element of the utilities' RVOS calculations.

A15: The avoided generation capacity element for PAC and IPC should be determined using resource balance years that are advanced by four years, i.e. to 2025 for PAC and to 2020 for IPC. Since PGE's resource balance year is only three years into the future, solar DG capacity should be assumed to have value equal to a combustion turbine immediately, in

[11] For example, PAC's 2017 IRP notes, at page 148, that it conducts front office transactions (FOT), in which a broker, such as the Intercontinental Exchange (ICE), is used to obtain forward firm market purchases. PAC assumes that FOTs will contribute capacity toward meeting the 2017 IRP's capacity need and 13% reserve margin.

2018. I have calculated avoided generation capacity costs for the utilities using these revised resource balance years.

Q16: What approach do you use to determine the contribution of solar DG to avoiding generation capacity costs in each of the utilities' service territories?

A16: I have used the Capacity Factor (CF) method that the Commission adopted as reasonable in Order 16-326. That order adopted a stipulation in which the parties agreed that two approaches would produce reasonably accurate values for wind and solar resources' contribution to capacity for Integrated Resource Planning (IRP) purposes – an Effective Load Carrying Capacity approach (the ELCC Method) and a method that uses the product of hourly solar capacity factors and loss-of-load probabilities (the CF Method). I have used the CF Method because it is a consistent, transparent approach that can be readily applied to each of the utilities.

C. Avoided Transmission and Distribution (T&D) Capacity

Q17: Please summarize the avoided T&D capacity costs that you have included in your RVOS.

A17: **Table 2** summarizes the key components of the avoided T&D capacity costs for each of the utilities. These include the capacity contribution that solar DG makes to reducing the peak loads on the transmission and distribution system that drive the utilities to incur T&D capacity costs; this contribution is expressed as a percentage of solar's AC nameplate capacity. The table also shows the marginal T&D capacity costs (in $ per kW-year) that I have used. Solar's avoided capacity costs for T and D are the product of the capacity contribution times the marginal capacity cost. The remainder of this section discusses in detail the derivation of each of these key elements.

Table 2: *Key Elements of Avoided T&D Capacity Costs*

Utility	Transmission			Distribution		
	A	*B*	*A x B*	*C*	*D*	*C x D*
	Solar Capacity Contribution *(%)*	Marginal Transmission Costs *($/kW-year)*	Solar Avoided T Costs *($/kW-year)*	Solar Capacity Contribution *(%)*	Marginal Distribution Costs *($/kW-year)*	Solar Avoided D Costs *($/kW-year)*
PGE	26.1%	21.52	5.62	19.2%	65.73	12.62
PAC	43.9%	32.03	14.04	35.5%	61.78	21.93
IPC	32.8%	34.90	11.45	22.0%	126.85	27.91

Q18: Please explain generally why distributed solar resources will allow the utilities to avoid costs for transmission and distribution (T&D) capacity.

A18: Distributed solar resources that interconnect behind the meter or directly to the distribution system produce power that typically is consumed on that distribution system. For solar DG installed behind the meter, a significant share of the solar output will serve the on-site load. This share typically ranges from 40% to 60% and depends on the size of the solar system and the load profile of the customer. The DG output used onsite never touches the grid, and thus clearly reduces loads on the utility's T&D system. Even for the remaining power that a solar DG unit exports to the grid, these exports are likely to be entirely consumed on the local distribution system by the solar customer's neighbors, reducing loads on the upstream portions of the distribution system and the higher voltage transmission system. Thus, much like energy-efficiency and demand response resources, solar DG displaces traditional generation sources which must use the utility T&D system to be delivered to customers. This makes available T&D capacity that can serve load growth and provide transmission capacity for future wholesale generation, avoiding the need over time to expand the T&D system.

I agree with the utility witnesses that solar DG avoids transmission and distribution capacity costs only to the extent that solar production occurs at times of peak demand on the T&D system.[12] Solar DG helps the utility to manage and to reduce today's loads and future load growth, thus avoiding and deferring the need for load-related T&D investments. Solar DG also can defer the need for new transmission to access utility-scale renewables, if DG provides an alternative to larger-scale renewable projects to supply needed capacity or to meet renewable energy goals. Lower loads on the high-voltage, bulk transmission system also make capacity available for sale to other transmission customers. These T&D benefits can be quantified based on the utility's marginal costs for transmission and distribution capacity. Order 17-357 indicated that existing marginal cost of service studies could be used as a source for system-wide avoided costs for T&D capacity.[13]

Q19: Do you agree with the general proposition that the extent to which solar DG can avoid T&D costs depends on the ability of distributed solar output to reduce the location-specific loads that drive T&D investments?

A19: Yes, particularly with respect to avoiding distribution costs. Ultimately, the T&D capacity costs avoided by solar should be determined on a locational basis, because load profiles on the T&D system and the need for capacity will differ based on location. These locational differences are most apparent on the distribution system. However, for the purposes of this case, I concur with Order 17-357 that it makes the most sense to determine avoided T&D costs on a system basis, while continuing to develop a more locational valuation.[14]

Q20: PAC and IPC limit their avoided T&D costs only to the costs of deferring T&D upgrades that are being planned today that solar resources might avoid. For

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[12] See, for example PGE / Murtaugh, at p. 9, lines 15-18 and p. 10, lines 7-9.
[13] See Order 17-357, at p. 9.
[14] *Ibid*., at pp. 8-9.

example, IPC asserts that any distribution benefits are limited to growth-related projects included in its approved three-year distribution budget for 2016.[15] Do you agree with this limited time horizon for determining avoided T&D capacity costs?

A20: No, I do not. Solar DG has a useful life of 20-30 years, and other types of distributed energy resources (including energy efficiency measures and today's commercial storage units) are expected to operate for 10 years or more. As a result, solar DG and other distributed resources can avoid future T&D upgrade or expansion costs that are not within the shorter time horizons that utilities use for transmission and distribution planning.[16]

Even within the shorter-term planning processes for distribution, utilities in several areas of the U.S. increasingly are incorporating solar and other types of distributed energy resources (DERs) as "non-wires alternatives" that can be less expensive than distribution upgrades. This represents a natural extension of the well-accepted use of energy efficiency and demand response resources to "manage" the growth of the demands for electric energy and capacity, thus avoiding the need to build more generation and transmission infrastructure.

Q21: How do you recommend determining the contribution of distributed solar to reducing the need for transmission capacity on a system-wide basis?

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[15] IPC / Haener, at p. 9.

[16] This is similar to the generation side, where new independent wholesale generation (e.g. QFs) or customer-sited resources (e.g. solar DG or storage) that are built today will impact the utility's future load and resource projections for the full planning period in its next Integrated Resource Plan (IRP), and thus can defer or displace generation resources that are not planned to be operational for many years. In recent rebuttal testimony in Idaho PUC Case No. IPC-E-17-13, Mr. David M. Angell of IPC clarified IPC's view that five years is the period IPC is able to forecast distribution requirements with some certainty, but five years is not a limit to the period that avoided distribution benefits may exist. See http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1713/company/20180126ANGELL%20REBUTTAL.PDF, at page 35.

A21: Generally, the utilities' transmission systems reach their peaks at or close to the same time as system loads.[17] Thus, it is reasonable to assume that solar DG makes the same contribution to avoiding transmission capacity that it does to avoiding generation capacity. As a result, I have used the solar capacity contribution based on the Capacity Factor method to value solar's contribution to avoiding transmission capacity.[18] Column A of Table 2 summarizes distributed solar's capacity contribution to reducing transmission costs, as a percentage of the solar AC nameplate capacity.

Q22: Have you conducted, or are you aware of, studies that have examined the range of load profiles across a utility's distribution system and then have used that locational data to calculate solar DG's contribution to avoiding long-term distribution capacity costs?

A22: Yes. The "Public Tool" benefit/cost model of renewable DG developed by E3 for the CPUC's "NEM 2.0" docket in California includes a calculation of the benefits of DG in avoiding sub-transmission and distribution capacity costs for the California utilities.[19]

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[17] FERC Form 1 data on the hour of the annual system (p. 401b) and transmission (p. 400) peaks:

Year	PGE		IPC		PAC	
	System Peak	Transmission Peak	System Peak	Transmission Peak	System Peak	Transmission Peak
2012	8/16 1700	1/16 1800	7/12 1600	1/12 1600	7/12 1500	7/12 1500
2013	12/9 1900	12/9 1800	7/2 1600	7/1 1500	7/1 1600	7/1 1600
2014	2/6 1900	7/28 1800	7/8 1800	7/14 1400	7/14 1600	7/14 1600
2015	7/30 1800	6/29 1800	6/30 1600	7/1 1800	6/30 1700	7/2 1600
2016	8/18 1800	8/12 1800	6/28 1900	6/27 1900	7/28 1700	7/28 1700

[18] This results in the same solar capacity contribution to avoided generation and transmission capacity, except for PGE, which apparently calculates LOLPs for transmission that are distinct from its LOLPs for generation. I have used PGE's two distinct sets of LOLPs in applying the Capacity Factor Method to PGE, which results in different solar capacity contributions for generation and transmission.

[19] The CPUC's Public Tool model and the association documentation are available at http://www.cpuc.ca.gov/general.aspx?id=3934. The marginal subtransmission and distribution costs are shown in Lines 323-350 of the "Avoided Cost Calcs" tab; the PCAF allocation factors by TOU period are listed in Lines 352-371 of the same tab.

This model begins with the utilities' long-run marginal sub-transmission and distribution capacity costs, from the marginal cost studies used in rate cases. These marginal sub-transmission and distribution capacity costs then are allocated to each hour of the year using a set of "peak capacity allocation factors" ("PCAFs") based on hourly data on each utility's substation loads. The PCAFs are hourly allocation factors that give a non-zero weight only to those substation loads that are within 10% of the annual peak load at each substation, using this formula:

$$PCAF_s(h) = \frac{Max\ [0, (Load_s(h) - Threshold_s)]}{\sum_{k=1}^{8760}\ Max[0, (Load_s(k) - Threshold_s)]}$$

where:

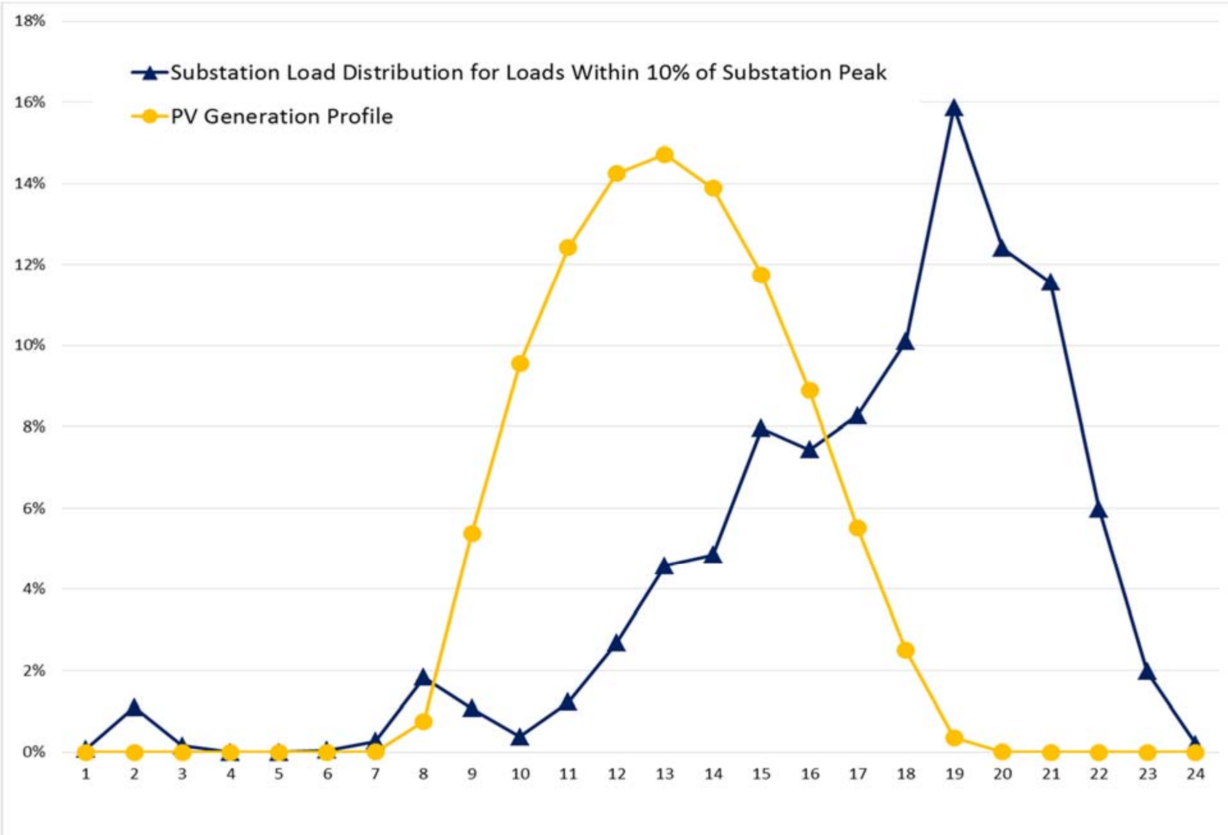
$PCAF_s(h)$ = peak capacity allocation factor for substation *s* in hour *h*,
$Load_s(h)$ = the load for substation *s* in hour *h*, and
$Threshold_s$ = 90% of the substation *s* annual peak load.

All hours where the substation load is below 90% of the annual peak have a PCAF of zero. The resulting hourly distributions of marginal sub-transmission and distribution capacity costs are applied to the hourly output profile of solar DG resources to calculate avoided sub-transmission and distribution costs. For the three major California investor-owned electric utilities, the resulting avoided sub-transmission and distribution capacity costs are about $0.03 per kWh (not including avoided line losses).

As another example from Colorado, we applied the same PCAF method to hourly substation load data that we obtained from Public Service of Colorado (PSCo) for the 58 distribution substations at which a majority (55%) of the solar DG on the PSCo system was installed. For each substation we developed the hourly PCAF allocation that measures, in each hour, how close that substation is to its annual peak, for all hours with loads within 10% of the annual peak hour load. **Figure 2** shows the resulting average PCAF allocation for each hour of the day across all 58 substations, weighted by the amount of solar DG installed at each substation. The figure also shows a typical south-facing PV output profile for Boulder, Colorado. As the figure shows, the substation peaks tend to occur later in the day, with the peak in the allocation around 7 p.m., due to substations that largely serve residential load. We applied this allocation to the typical hourly PV output profile for Boulder to determine the portion of PSCo's marginal distribution capacity costs that DG can avoid. The result is that one kW of DG nameplate capacity (south-facing) can avoid 0.23 kW of PSCo's marginal distribution capacity costs. This can be considered a measure of the "effective load carrying capacity" (ELCC) of solar DG with respect to PSCo's distribution capacity costs.[20]

[20] Crossborder Energy, *Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado: A Critique of PSCo's Distributed Solar Generation Study* at 9-11 (December 2, 2013). This study was filed in Colorado Public Utilities Commission Docket No. 13A-0836E on behalf of The Alliance for Solar Choice.

Figure 2: *PSCo Substation PCAF Distribution of Loads within 10% of Substation Peak*



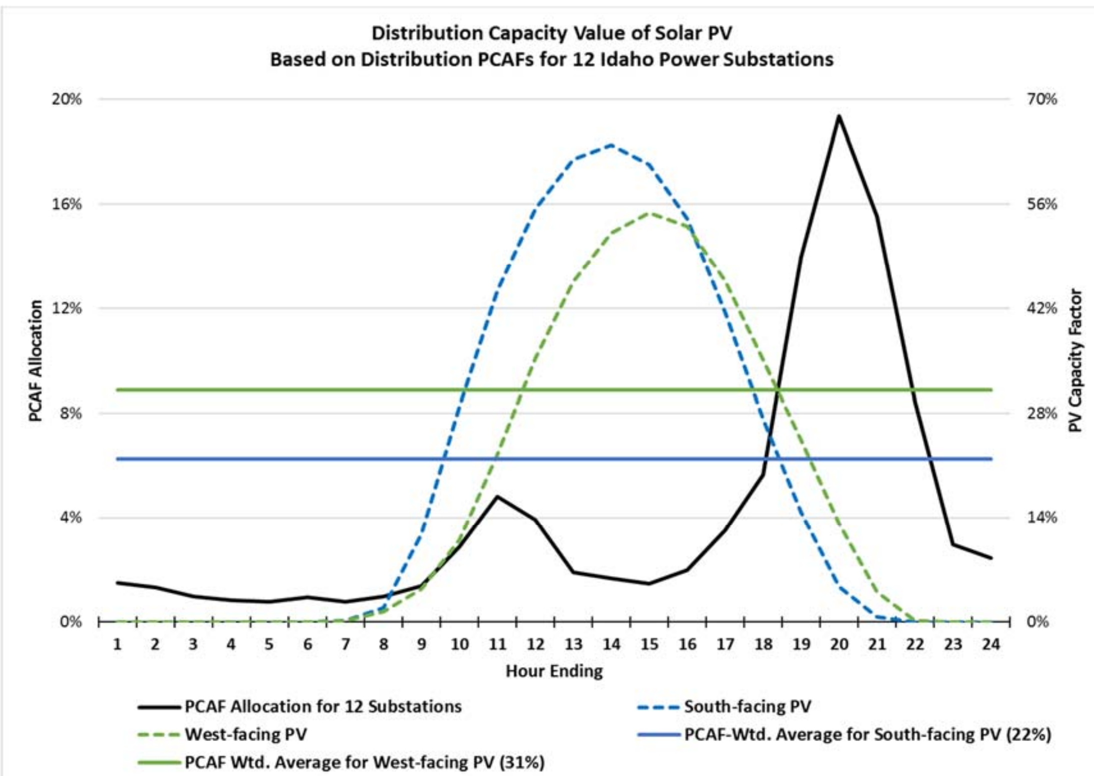
Q23: Do you have comparable data for substations on the PAC, PGE and IPC systems?

A23: Yes, in discovery I obtained hourly loading data for the utility substations that currently are planned for upgrade, i.e. those that presumably are closest to needing capacity. For example, for IPC I obtained hourly loading data for 2016 for 12 substations on its system for which it is undertaking upgrade projects.[21] I derived an hourly PCAF allocation

[21] For IPC, I obtained this data in the ongoing net metering docket in Idaho involving IPC (Idaho PUC Case No. IPC-E-17-13), and I presented this data (including Figure 3) in testimony in that docket on behalf of the Sierra Club. See *Direct Testimony of R. Thomas Beach of behalf of the Sierra Club*, submitted December 22, 2017 in Idaho PUC Case No. IPC-E-17-13, at pp. 30-31, available at http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1713/intervenor//SIERRA%20CLUB/20171222BEACH%20DIRECT.PDF.

based on the loads at these substations that are within 10% of the annual peak hour load. This result is shown in the solid black line in **Figure 3**, which also shows the hourly output profiles for south- and west-facing PV arrays in Boise. This is a similar analysis to the one that we performed on the PSCo substations, and we obtained similar results. For these Idaho Power substations, one kW of DG nameplate capacity (south-facing) can avoid 0.22 kW of marginal distribution capacity costs; one kW of west-facing DG capacity avoids 0.31 kW of marginal distribution capacity costs.

Figure 3



Q24: Did you perform similar analyses for PGE and PAC?

A24: Yes. The results for solar DG's contribution to avoiding distribution capacity, as a percent of the solar nameplate, are shown in Column C of Table 2.

Q25: Does this process suggest how one could develop more locational values for avoided distribution capacity costs?

A25: Yes. The substation data shows that some distribution substations are closer to capacity than others, and solar DG (as well as other types of DERs) installed on those constrained parts of the distribution system will provide greater benefits than in other locations. In other words, there is significant variation in marginal distribution costs by location, and constrained parts of the distribution system will have marginal costs that are far higher than the system average. As an example, **Figure 4** shows the marginal distribution costs of the three large California electric utilities disaggregated by distribution planning area (DPA).[22] Some DPAs have marginal distribution costs that are significantly greater than other DPAs and larger than the overall system average. Studies of other utilities in the U.S. also have demonstrated a wide range of marginal distribution costs.[23] **Table 3** shows similar disaggregated data for Pacific Gas & Electric (PG&E).[24] PG&E's system average marginal primary distribution cost is $39.43 per kW-year (see the bottom line of the table), but some of its divisions have much higher marginal distribution costs. Thus, if DERs – including solar DG, storage, or energy efficiency programs – can be targeted to the parts of the system where they are most needed, i.e. where marginal distribution costs are the highest, they can produce significantly greater benefits than what are estimated using system-wide marginal distribution costs.

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[22] E3, *Workshop Discussion: California Locational Net Benefits Analysis Update* (September 20, 2017 presentation in the New York REV process), at Slide 21.

[23] *Ibid*., at Slide 14.

[24] PG&E Testimony in CPUC Docket A. 16-06-013, Exhibit PG&E-9, Chapter 6, at p. 6-2 (Table 6-1), served December 2, 2016.

Figure 4

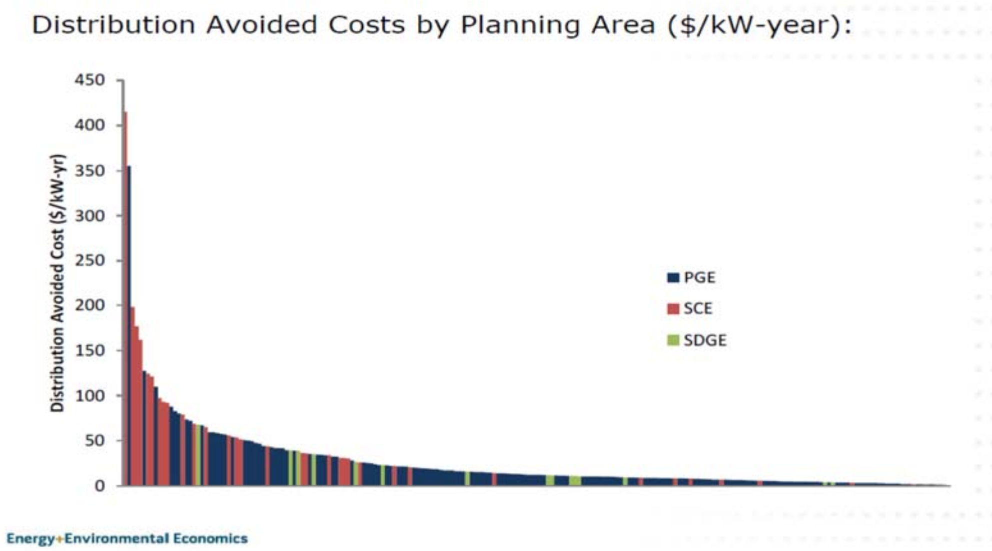

Table 3: *PG&E Marginal Distribution Costs by Division*

TABLE 6-1
MARGINAL DEMAND-RELATED PRIMARY AND SECONDARY DISTRIBUTION CAPACITY COSTS BY DIVISION AND SYSTEM AVERAGE

Line No.	Division	Primary Distribution $/PCAF kW	New Business on Primary Distribution $/FLT kW	Secondary Distribution $/FLT kW
1	Central Coast	$69.09	$14.53	$1.04
2	De Anza	$35.65	$19.66	$1.01
3	Diablo	$17.78	$23.20	$1.56
4	East Bay	$19.99	$18.07	$0.88
5	Fresno	$39.52	$15.81	$1.36
6	Humboldt	$73.97	$14.20	$1.12
7	Kern	$34.07	$16.08	$1.23
8	Los Padres	$56.49	$14.41	$1.06
9	Mission	$13.63	$16.37	$0.97
10	North Bay	$29.42	$14.62	$1.75
11	North Valley	$53.40	$19.23	$1.26
12	Peninsula	$31.79	$14.02	$1.06
13	Sacramento	$40.91	$16.49	$1.22
14	San Francisco	$40.41	$19.69	$1.52
15	San Jose	$40.12	$17.45	$1.16
16	Sierra	$30.65	$20.07	$1.25
17	Sonoma	$121.98	$16.65	$1.28
18	Stockton	$33.36	$15.13	$1.34
19	Yosemite	$60.18	$15.63	$1.56
20	System	$39.43	$16.42	$1.25

Q26: Please comment on the avoided transmission capacity costs used by the utilities.

A26: PGE uses an existing Bonneville Power Administration transmission rate of $21.52 per kW-year as a proxy for its avoided transmission costs. This is one reasonable approach – to use the utilities' existing FERC-approved rates for firm transmission service, or a regional value applicable to all of the Oregon utilities, such as the BPA firm rate. This approach recognizes that a utility's existing firm transmission rate is the utility's opportunity cost to market additional firm transmission made available to the extent that distributed generation reduces peak loads on the transmission system, making existing capacity available to serve other customers. I have used the utilities' current firm transmission rates as their avoided transmission costs for the purposes of this testimony. However, it is important to recognize that firm transmission rates are based on average costs, not marginal costs, and thus this approach may undervalue the transmission costs avoided by solar DG, to the extent that a utility's marginal transmission cost is higher than its average cost.[25]

For marginal distribution capacity costs, PGE uses its marginal costs for subtransmission and substation capacity, from the utility's most recent marginal cost of service study.[26] However, that study also calculated marginal costs for other capacity-related components of the distribution system whose costs can be avoided by solar DG, including marginal distribution feeder costs of $40 to $54 per kW-year.[27] PGE has not justified why these additional capacity-related distribution costs should be excluded. Including the low end of the range of marginal distribution feeder costs, plus subtransmission and substation marginal costs, PGE's full marginal distribution capacity costs are $65.73 per kW-year, as shown in Table 2 above.

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[25] PGE / Murtaugh, at p. 7.
[26] *Ibid*.
[27] See PGE / Exhibit 101, at p. 3.

PAC's and IPC's avoided T&D capacity costs both are based on T&D deferral calculations prepared for the analysis of demand-side management resources in these utilities' 2017 IRPs.[28] These deferral values use the average $ per kW cost of currently-planned projects, with the denominator being the sum of the maximum capacities of the individual projects, not the increase in system peak demand. As a result, the PAC and IPC values do not represent a systemwide calculation of marginal T&D costs as a function of system peak demand. Moreover, these analyses appear to look at relatively short time horizons: for example, IPC's analysis looked at the ability of energy efficiency projects to defer T&D projects over just a three-year period.[29]

Q27: What approach do you recommend to calculating long-run marginal distribution capacity costs for PAC and IPC?

A27: I recommend using the well-accepted National Economic Research Associates (NERA) regression method. This approach is used by many utilities to determine their long-run marginal distribution capacity costs that vary with changes in load.[30] The NERA regression model fits incremental distribution investment costs to peak load growth, using at least 15 years of data to capture the utility's long-term marginal costs for capacity. The slope of the resulting regression line provides an estimate of the marginal cost of distribution investments associated with changes in peak demand. The NERA methodology typically uses ten or fifteen years of historical expenditures on distribution investments and system peak loads, as reported in FERC Form 1, and, if available, a five-year forecast of future expenditures and expected load growth.

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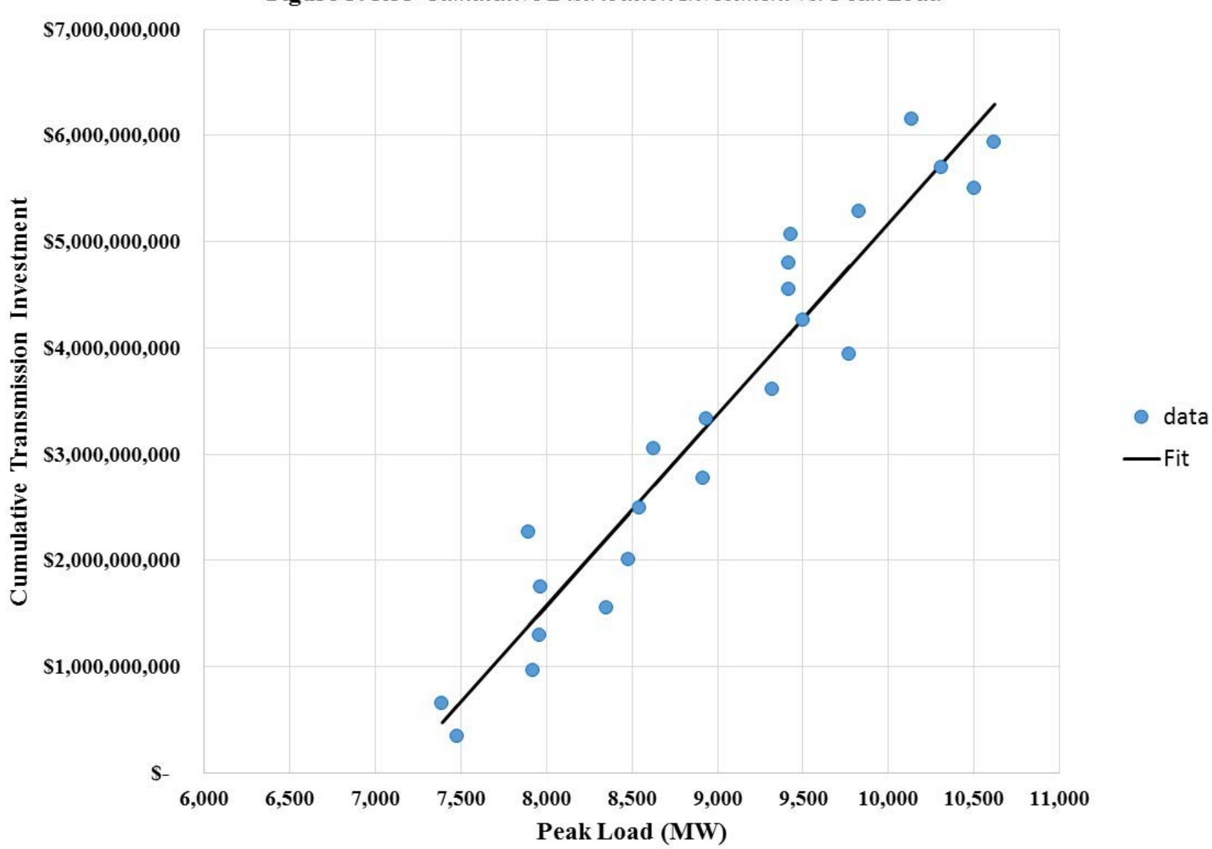
[28] PAC / Putnam, at p. 2; IPC / Haener, at p. 9.
[29] IPC / Haener, at p. 9.
[30] For a detailed explanation of this approach, see Southern California Edison's recent testimony in CPUC Docket A. 17-06-001, Exhibit SCE-02, at pp. 36-38, available at http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/F40D6AEFD8622526882581CB007FC097/$FILE/A1706030-%20SCE-02A-2018%20GRC%20Ph2-Various-Errata%20Marginal%20Cost%20and%20Sales%20Forecast.pdf.

I have used the NERA regression method to calculate the marginal investment-related distribution costs for PAC and IPC. Our analysis uses ten years of historical data on cumulative net distribution investments, plus five years of forecast data. For example, **Figure 5** shows the regression fit of cumulative distribution capital additions as a function of incremental demand growth for PAC.

Figure 5: *PAC Cumulative Distribution Investment vs. Peak Load*



The regression slope resulting from this analysis is $549 per kW. We add 7.9% to this amount as a general plant loader, convert the total to an annualized marginal distribution cost using a real economic carrying charge (RECC) of 6.7%,[31] and include $22.13 per kW-year for distribution O&M costs. Our estimate of general plant and distribution O&M costs are also from PAC's FERC Form 1 data. The resulting avoided cost for distribution capacity for PAC is $61.78 per kW-year.

The comparable calculation of IPC's marginal distribution capacity costs is $128.65 per kW-year, using the same methodology and data from IPC's FERC Form 1.

D. Avoided Line Losses

Q28: Have the utilities presented accurate estimates of avoided line losses?

A28: No. Generally, the utilities' estimates of avoided line losses are based on the average loss factors that they use to set retail rates (PAC), or on studies of system average losses under various load conditions (PGE), with some consideration of the hourly and seasonal profile of solar generation. However, the use of average losses fails to capture the fact that the reductions in line losses on the margin, from small changes in load on the system, are significantly greater than average losses. In simple terms, average resistive line losses on a circuit are proportional to the square of the current (load), so marginal resistive losses for a small change in load are roughly double the average losses. In practice on utility grids, marginal losses are less than double average losses, due to factors such as no-load losses that do not increase with loads. For the purposes of the calculations presented in this testimony, I have increased the average loss factors used by the utilities by 50% to capture the higher marginal losses avoided by solar DG resources, based on a study from the Regulatory Assistance Project on the relationship between

[31] Based on PAC's currently-authorized capital structure and cost of capital.

average and marginal line losses avoided by distributed energy resources such as energy efficiency and solar DG.[32]

E. Administration

Q29: Please critique the IOUs calculations of the incremental administrative costs from distributed solar DG.

A29: In Order 17-357, at page 10, the Commission asked utilities to propose and to justify an estimate of "direct, increased utility costs of administering solar PV programs" (not including interconnection costs). The order includes a reference to E3's explanation that such costs should be incremental to costs that the utility incurs for any other customer account and incremental to any costs paid by an interconnecting solar generator.

Generally, PAC's administrative costs appear to follow these guidelines. The only adjustment we have made to PAC's stated administrative costs is to express them as a real, levelized value instead of the real, nominal value that PAC presents. PAC's administrative costs of about $2 per MWh are consistent with those of other utilities in the West that have significant net metering programs, such as the California IOUs.[33] PGE and, in particular, IPC propose significantly higher administration costs. We would not expect such substantial differences between the administrative costs for these large utilities. The higher costs for PGE result, in part, from PGE treating customer

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[32] Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), at p. 5. See http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

[33] The Public Tool model used to evaluate net metering in California included program administration and interconnection costs provided by the California IOUs, which averaged about $3 per MWh (including interconnection costs). The Public Tool is referenced in footnote 18 above. California has implemented application fees for net metering of about $75 per customer to defray interconnection costs. See CPUC Decision No. 16-01-044, at pp. 87-88.

interconnection costs as an annual expense instead of a one-time cost amortized over the life of the DG solar units installed in that year (as PAC does).[34] IPC's absurdly high administrative costs of $48 per MWh are based on the costs to administer a very small solar pilot program with 0.41 MW of capacity and 808 MWh of annual output.[35] Distributed solar would not be the rapidly growing resource that it is nationally if the costs to administer a solar program were almost 5 cents per kWh. Experience nationally, as well as the administrative costs from the other two Oregon utilities, shows that there are significant economies of scale in administering these programs and that IPC's administrative costs are clearly unreasonable for a well-established solar program that has moved beyond the pilot stage. In our RVOS estimates, we have used PAC's $2.30 per MWh administration costs for all three utilities, as a reasonable estimate that follows the Commission's direction in Order 17-357 and is validated by the experience of other large utilities with established distributed solar programs. I assume that all of these large utilities can achieve a similar level of cost efficiency in administering their solar programs that PAC has achieved.

F. Integration

Q30: Do you accept the utilities' proposed integration costs, which generally are based on solar integration studies that each utility has conducted for its system?

A30: Yes, I do.

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[34] The workpapers for PGE's Administrative costs show $202,000 in one-time interconnection costs (RC 576 - Customer Interconnection Group), which PGE allocates over 95,428 MWh of annual solar DG output. PGE's administrative costs would be reduced to $4 per MWh if this cost is amortized over the 25-year production of solar DG.

[35] See IPC / Haener, at pp. 15-16.

G. Market Price Response

Q31: Do you agree with the concept behind the market price response benefit, namely, that the increasing penetration of new renewable generation in Oregon and the West will provide the benefit of reducing energy market prices?

A31: Yes. This new solar generation will increase the electricity supplies available to the utilities. Because this generation largely serves on-site loads, is must-take, and has zero variable costs, it will displace the most expensive fossil-fired or market resources that the serving utility would otherwise have generated or purchased. The addition of this local generation will reduce the demand which the utility places on the regional markets for electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the price in these markets, which benefits the utility when it does buy power or natural gas in these markets.[36] This "market price response" benefit of renewable generation is widely acknowledged and has become highly visible in markets that now have high penetrations of wind and solar resources. The magnitude of these benefits will depend on the overall amount of renewables on the western grid.

Q32: Are you aware of any modeling of this benefit in the West?

A32: Yes. Beginning in 2010, the National Renewable Energy Laboratory (NREL) and GE Consulting undertook the Western Wind and Solar Integration Study (WWSIS), a major, multi-phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[37] This modeling included analysis of the impact of

[36] This same effect is visible in the Company's indicative prices for QF generation. As more such generation is added to the system, the marginal or avoided cost for the utility declines, as a more efficient unit becomes the marginal supply source.

[37] The high penetration solar results from the WWSIS are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), at p. 8 and Figure 19. This report, as well as all reports from the WWSIS, are available on the NREL website at https://www.nrel.gov/grid/wwsis.html.

increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in **Figure 6.** The high penetration solar cases (15% to 25% penetration) in the WECC result in 10% to 20% reductions in spot market prices.

Figure 6: *Impact of Solar Penetration on AZ Spot Prices, from WWSIS*

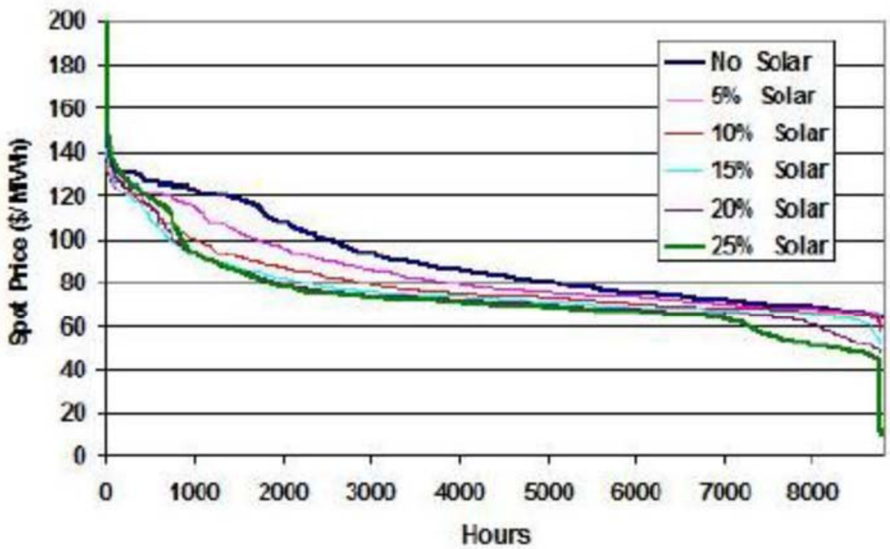


Figure 19 – Arizona Spot Price Duration Curves.

Q33: Please comment on the utilities' calculations of the market price response (MPR).

A33: PGE computes a non-zero MPR based on using the Aurora model to determine the market price impacts of 100 MW of solar PV, and finds a similar MPR with a much larger amount of solar, 1000 MW. The other two utilities, on the other hand, recommend a zero MPR. For example, IPC asserts that 0.41 MW of solar from its Oregon Solar PV Pilot Program is not significant enough to impact the market. In my view, PGE's Aurora results show a modest MPR over a broad range of solar deployment, and is a reasonable basis for the MPR for all three utilities.

PGE's MPR calculations show a levelized market price effect over the 2020-2045 period that is 3.8% of the comparable levelized avoided energy cost over the same period. I have used 3.8% of avoided energy costs over 2018-2042 as a reasonable estimate of the MPR that should be applied to PAC and IPC as well as PGE. The MPR has been analyzed most extensively in the New England ISO market, where it is regularly included as part of the regional avoided costs used to evaluate the cost-effectiveness of DERs.[38] An MPR of 3.8% of avoided energy costs is similar to the values of about 4% of avoided energy costs that have been used for solar DG in New England.[39]

H. Avoided Fuel Hedge Value

Q34: Why does renewable DG provide value as a fuel price hedge?

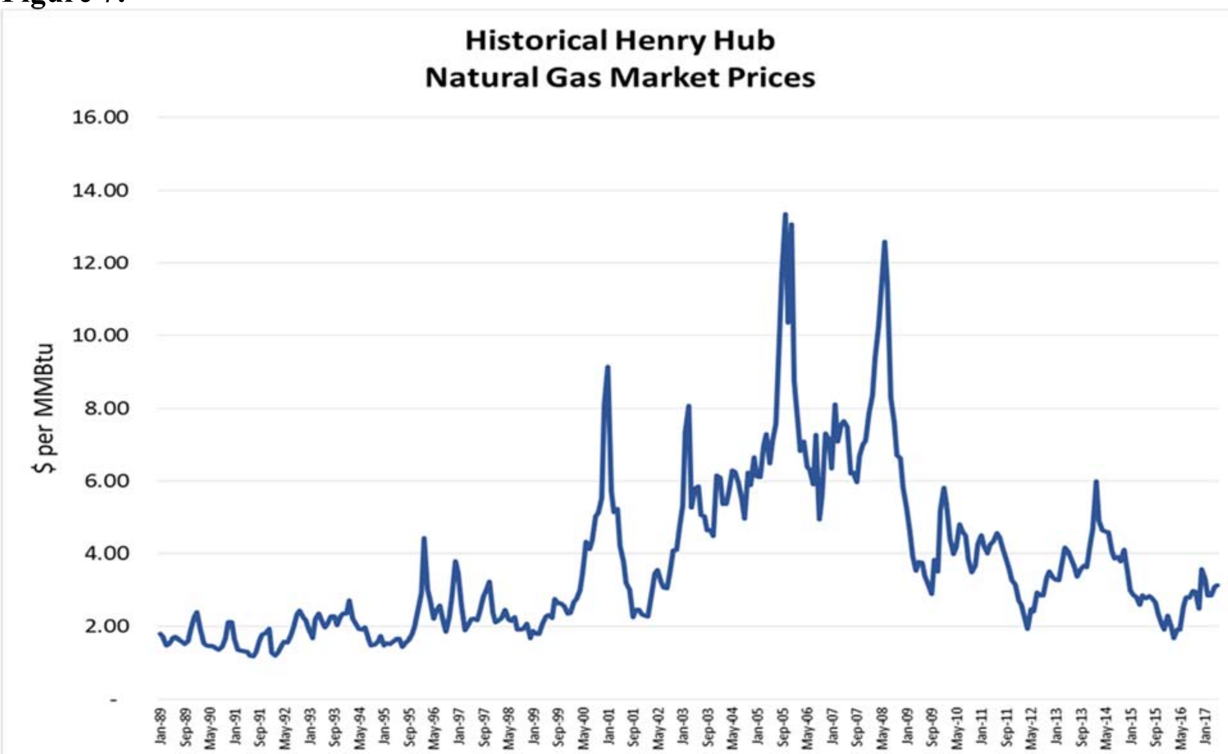
A34: Renewable generation, including solar DG, reduces a utility's use of natural gas, and thus decreases the exposure of ratepayers to the volatility in natural gas prices, as exemplified by the periodic spikes in natural gas prices. Such spikes have occurred regularly over the

[38] See Chapter 7 of the report on *Avoided Energy Supply Costs in New England*, March 27, 2015, at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf. Hereafter, "*AESC*" reports. MPR calculations are easier in regions with competitive energy markets based on transparent hourly locational marginal prices, such as New England.

[39] The New England states have done the most extensive work to calculate the MPR benefit, which they have labelled the Demand Reduction Induced Price Effect (DRIPE). DRIPE is included in the region's biennial *AESC* forecasts of avoided costs used for demand-side programs. I have reviewed the DRIPE calculations in the 2013 and 2015 AESC reports. See *2015 AESC*, at Appendix B, Tables One and Two, https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf. There is a significant difference in the DRIPE impacts between the *2013* and *2015 AESC* reports, as a result of changes in the methodology for the DRIPE calculations in the *2015 AESC*. See *2015 AESC*, at pages 1-5 and 1-16 to 1-17. For example, the *2015 AESC* assumes a much shorter duration for energy DRIPE impacts (three years). The average of the energy DRIPE impacts between the two studies is a 4.1% to 4.5% reduction in 25-year levelized avoided energy costs. See *Direct Testimony of R. Thomas Beach on behalf of The Alliance for Solar Choice* in New Hampshire PUC Docket No. DE 16-576 (October 24, 2016), at Appendix D, p. D-5 (Table D-5).

last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 7** below.[40]

Figure 7:



Renewable generation also hedges against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as has occurred periodically during drought conditions in the U.S. that reduce hydroelectric output and curtail generation due to the lack of water for cooling. For example, in 2014, the rapidly increasing output of solar projects in California made up for 83% of the reduction in hydroelectric output due to the multi-year drought in that state.[41]

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[40] Source for Figure 7: Chicago Mercantile Exchange data.

[41] This is based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-*

Q35: Many utilities, including those in Oregon, conduct risk management programs that include hedging their exposure to gas and electric market price fluctuations using a variety of forward market instruments. Please explain how the hedge provided by renewable DG resources is different than these existing hedging programs.

A35: Existing utility hedging programs are designed primarily to reduce the near-term volatility of their short-term fuel and purchased power expenses. Generally, these programs focus on reducing volatility only in the next one to three years, as the forward markets are most liquid in the near-term and there are substantial transaction costs associated with long-term hedges in financial markets. However, utilities regularly engage in long-term hedging through their resource portfolios, and companies such as PacifiCorp are careful to evaluate their overall risk position as including both their short- and long-term positions in both natural gas and power. Significantly, PacifiCorp's discussion of its hedging program in its 2015 IRP emphasized how its long position in the power market can function as a hedge against its short position in natural gas, and concludes that "[t]his has the effect of reducing the amount of natural gas hedging that the Company would otherwise pursue."[42] This is exactly the hedge represented by renewable DG resources whose output decreases the utility's exposure to price volatility in gas and electric markets. In addition, other observers have noted that long-term, fixed-price contracts for renewable generation provide utilities with a means not available in the financial markets to hedge their long-term exposure to gas and power markets, and thus could replace a portion of their current budgets for risk management.[43]

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fifths of California's lost hydro production in 2014 (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

[42] 2015 PAC IRP, at pp. 246-247.

[43] Lisa Huber, *Utility-scale Wind and Natural Gas Volatility: Unlocking the Hedge Value of Wind for Utilities and Their Customers* (Rocky Mountain Institute [RMI], July 2012), at pg. 15, available at http://www.rmi.org/Knowledge-Center/Library/2012-07_WindNaturalGasVolatility.

Q36: Order 17-357 directed the utilities to use 5% of avoided energy costs as a placeholder for the value of renewable DG in avoiding the uncertainty and volatility in natural gas prices. Did you use this placeholder?

A36: Yes, I did.

In addition, I would like to bring to the Commission's attention several studies that have quantified the long-term hedge value of renewable generation. In 2013, Public Service of Colorado estimated that the long-term (20-year) hedging benefits of distributed solar resources on its system to be $6.60 per MWh.[44] This study used the cost of options contracts in the gas futures market to calculate the hedging benefit.

More recently, the consultant Clean Power Research developed another approach to calculating the hedge value of renewables, as part of the Maine Public Utilities Commission's *Maine Distributed Solar Valuation Study*, released in 2015.[45] This method assumes that natural gas prices are the primary driver of marginal energy costs, and calculates the additional costs to fix the fuel costs of a marginal gas-fired generator for a 25-year period, compared to purchasing gas on an "as you go" basis. To fix fuel costs for a long-term period, the money to purchase fuel in the future must be set aside today in risk-free investments. This results in higher costs because this money could otherwise be deployed to earn a higher return (assumed to be the utility's weighted average cost of capital) if it was available to be used for alternative investments. These incremental costs are what the utility who owns marginal gas generation (or who purchases such power)

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[44] Xcel Energy Services, *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System: Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223* (May 2013), at pp. 6 and 43, and Table 1.

[45] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015); hereafter, "Maine Solar DG Valuation Study." Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

would have to spend to obtain the same hedging benefit that it can obtain from an identical renewable resource whose fuel costs are zero, thus eliminating the uncertainty and volatility in future fuel costs for the 25-year life of the renewable generation. These additional costs are substantial when one considers the alternative uses to which one can put the money that must be set aside upfront to fix the cost of natural gas for 25 years.

Q37: Have you applied either of these methods to PAC, PGE, and IPC?

A37: Yes. I applied the approach developed in the Maine Solar DG Valuation Study to the Oregon IOUs, using their gas commodity cost forecasts, U.S. Treasuries (at current yields) as the risk-free investments, the IOU's weighted average cost of capital, and a marginal heat rate of 7,500 Btu per kWh. The result is hedge values that range from $18 to $23 per MWh as the 25-year real levelized benefit of hedging fuel price uncertainty.

I. Avoided Environmental Compliance

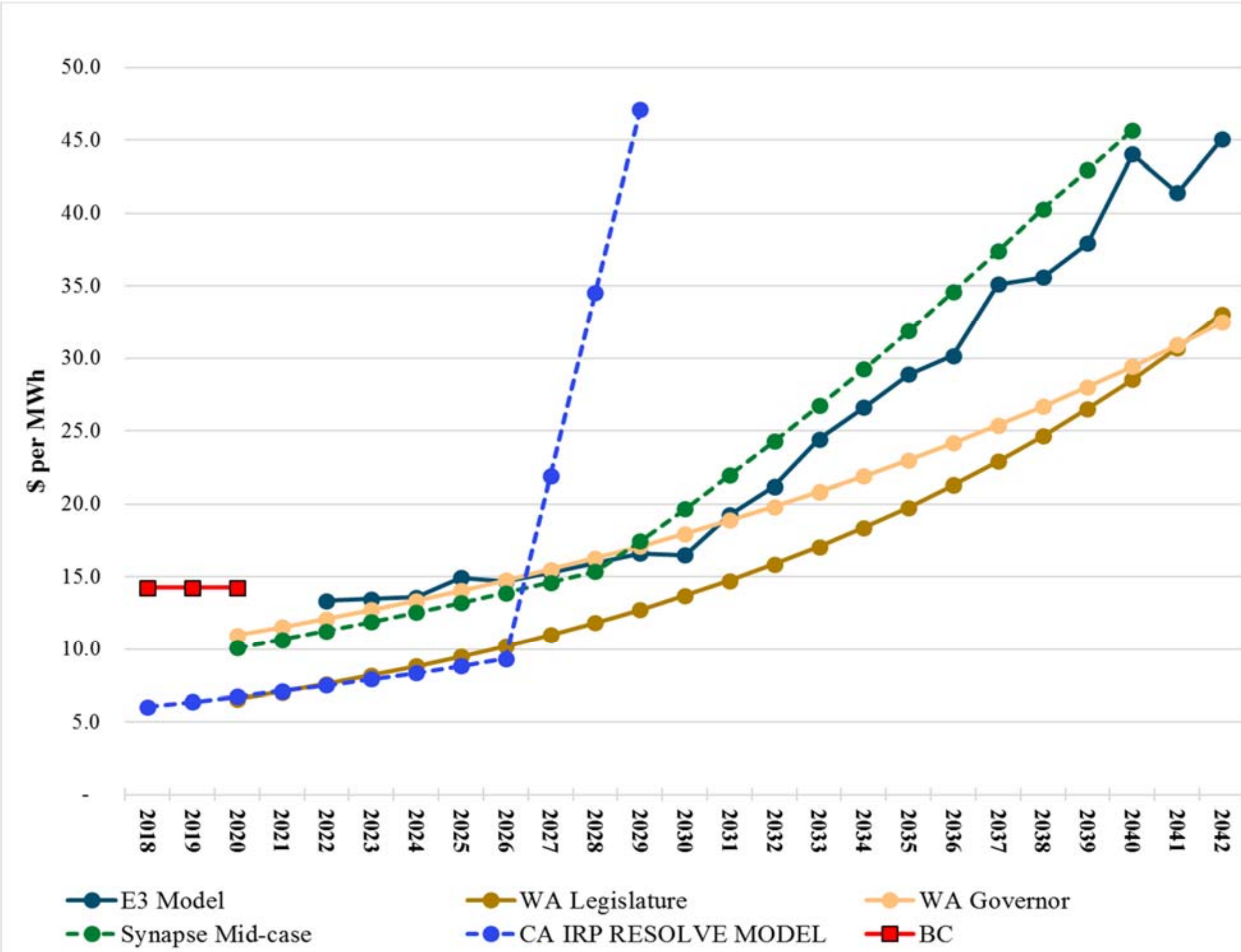
Q38: Does it make sense to use different carbon compliance costs for each utility?

A38: No – the most reasonable assumption is that a carbon compliance regime will apply to all utilities in Oregon. Accordingly, I use the avoided carbon emission costs in PGE's RVOS for all of the utilities. These costs are based on an assumption for a future regulatory regime that places a price on carbon emissions. One of Oregon's neighbors, California, already has a cap & trade program that places a carbon price on all electricity used in the state. California carbon emission allowances in its cap & trade market have generally traded in the range of $10 to $20 per metric tonne. Recent modeling of the effective carbon compliance prices in California, as part of the state's new integrated planning process, show a continuation of the same relatively modest carbon prices until the latter part of the 2020s, when the price will spike higher in order to meet the state's

2030 carbon reduction goals.[46] The nearby province of British Columbia has had a successful carbon tax, now $30 (Canadian) per metric tonne, since 2008.[47] Another of Oregon's neighbors, the state of Washington, is considering legislation or a ballot initiative to adopt a carbon tax that initially would be in the same range as California's cap & trade prices.[48] All of these carbon price scenarios are relatively similar, and are reasonably approximated by the Synapse mid-case used by PGE in its RVOS, as shown in **Figure 8**. This figure converts all of the carbon prices referenced above, in dollars per metric ton, to $ per MWh assuming 117 lbs of carbon emission per MMBtu of natural gas, a heat rate of 7,500 Btu per kWh, and a 2022 start date. These carbon pricing regimes apply to all burning of fossil fuels to produce electricity; as a result, it is reasonable to assume that any similar regulatory regime in Oregon would apply to all utilities. On this basis, PGE's avoided carbon emission costs should be used in the RVOS for all three utilities.

[46] See CPUC Decision No. 18-02-018 (issued February 8, 2018), at pp. 114-116, especially Table 5.
[47] See, for example, https://publicpolicy.wharton.upenn.edu/live/news/1520-analyzing-british-columbias-carbon-tax.
[48] The proposed carbon tax in Washington would start at $10 per tonne in 2020 and escalate by $2 per year to $30 per tonne in 2030.

Figure 8: *Carbon Prices*



J. Results

Q39: Please present the RVOS that you recommend for each utility, incorporating all of the changes you have discussed above.

A39: **Tables 4, 5, and 6** presents our results for PGE, PAC, and IPC, respectively. We also report our results using the placeholder hedge value of 5% of avoided energy costs, as the Commission requested in Order 17-357 (see the last line of each table, in italics).

Table 4: *RVOS Results for PGE (2018 $ per MWh, real levelized)*

RVOS Cost Component	**PGE**		**Summary of Major Changes**
	Utility	**OSEIA**	
Energy	24.98	26.27	Uncapped EIM shape.
Generation Capacity	7.30	24.11	Reduce RBY by 4 years, use Capacity Factor method.
T&D Capacity	8.08	13.92	BPA Rate; PGE Marginal Cost Study with feeder costs
Line Losses	1.48	2.33	Marginal losses = 1.5 x Average losses
Administration	(5.58)	(2.30)	Based on real levelized costs for PAC
Market Price Response	1.81	1.00	3.8% of avoided energy costs
Integration	(0.83)	(0.83)	No change
Hedge Value	1.25	22.75 *1.31 at 5%*	Uses Maine PUC method. *Placeholder of 5% of avoided energy costs*
Environmental Compliance	11.41	12.00	Use Synapse mid-case carbon prices.
Total	**49.88**	**99.26**	
Total (5% Hedge)		*77.81*	*Assumes placeholder for hedge value of 5% of avoided energy costs.*

Table 5: *RVOS Results for PAC (2017 IRP & PDDR – 2018 $ per MWh, real levelized)*

RVOS Cost Component	PAC		Summary of Major Changes
	Utility	OSEIA	
Energy	26.49	27.54	Uncapped EIM shape.
Generation Capacity	12.72	20.87	Reduce RBY by 4 years, use Capacity Factor method
T&D Capacity	0.05	23.94	NERA Distribution MC, PAC Pt-to-Pt Transmission
Line Losses	1.69	4.18	Marginal losses = 1.5 x Average losses
Administration	(2.22)	(2.30)	Based on real levelized costs for PAC
Market Price Response	0.00	1.05	3.8% of avoided energy costs
Integration	(0.63)	(0.63)	No change.
Hedge Value	1.32	18.14 *1.38 at 5%*	Uses Maine PUC method. *Placeholder of 5% of avoided energy costs*
Environmental Compliance	0.15	11.37	Use Synapse mid-case carbon prices.
Total	**39.58**	**104.24**	
Total (5% Hedge)		*87.48*	*Assumes placeholder for hedge value of 5% of avoided energy costs.*

Table 6: *RVOS Results for IPC (2018 $ per MWh, real levelized)*

RVOS Cost Component	**IPC**		**Summary of Major Changes**
	Utility	**OSEIA**	
Energy	29.74	27.77	Changed flat price shape, but not annual prices.
Generation Capacity	15.31	20.70	Reduce RBY by 4 years, use Capacity Factor method
T&D Capacity	0.87	25.72	NERA Distribution MC, IPC Pt-to-Pt Transmission
Line Losses	2.54	3.55	Marginal losses = 1.5 x Average losses
Administration	(47.77)	(2.30)	Based on real levelized costs for PAC
Market Price Response	0.00	1.06	5.8% of avoided energy costs
Integration	(0.56)	(0.56)	No change.
Hedge Value	1.49	20.69 *1.39 at 5%*	Uses Maine PUC method. *Placeholder of 5% of avoided energy costs*
Environmental Compliance	0.00	11.55	Use Synapse mid-case carbon prices.
Total	**1.61**	**108.17**	
Total (5% Hedge)		*88.87*	*Assumes placeholder for hedge value of 5% of avoided energy costs.*

III. UTILITY-SCALE ALTERNATIVE

Q40: Order 17-357, at page 18, asked the utilities to provide separate RVOS calculations "assuming a utility scale solar proxy to replace all elements but T&D capacity, administration, and line losses." Please comment on what the IOUs provided.

A40: The utilities appear to have interpreted this direction differently. PAC and IPC appear simply to have applied their RVOS models to a profile of the output from a utility-scale solar plant, without the T&D capacity, administration, and line loss components. I do not believe that this is what the Commission intended in Order 17-357. PGE appears to have followed the Commission's intent correctly, which is to use the costs of a utility-scale solar plant (which PGE cites as $62 per MWh) as a proxy to replace all of the elements of RVOS <u>except</u> for T&D capacity, administration, and line losses. The concept is based on a straw proposal from E3, and the idea is that a utility-scale solar plant can provide all of the value elements included in RVOS except for these three. Thus, an alternative formulation of RVOS for distributed solar could be the costs of a utility-scale solar plant plus T&D capacity, administration, and line losses.

Q41: Do you think that this alternative formulation of RVOS is reasonable?

A41: No, it is overly simplistic. The E3 straw proposal recognizes correctly that distributed solar provides additional benefits by avoiding the line losses and T&D infrastructure that is necessary to deliver utility-scale solar power to customers. However, this formulation fails to capture important additional benefits of distributed solar. Distributed solar facilities can be sited in the built environment (e.g. on rooftops and parking lots), thus providing additional environmental benefits from reduced land use impacts. Distributed solar that is located behind the meter also provides greater benefits when it is paired with on-site storage, for example, by increasing avoided T&D infrastructure costs and by enhancing the reliability and resiliency of electric service. Finally, distributed solar development is driven by the choices of individual customers who wish to be served by a higher penetration of renewable energy. This customer choice has significant value, and will be lost if only utility-scale solar resources are developed.

I have included in this testimony, as Exhibit OSEIA 102, a white paper that Crossborder Energy prepared for Sunrun, Inc. in February 2017 that discusses in detail the cost and resource value comparisons between utility-scale and rooftop (i.e. distributed) solar. This study reached several important conclusions: (1) while utility-scale solar remains less expensive than rooftop solar, the cost difference is narrowing, and (2) the additional benefits of rooftop solar are sufficient to make up for this cost difference. Our conclusion is that both distributed and utility-scale solar should have central roles in the transition to a clean, sustainable, and resilient electric industry.

IV. THE VALUE OF STORAGE IN THE RVOS METHODOLOGY

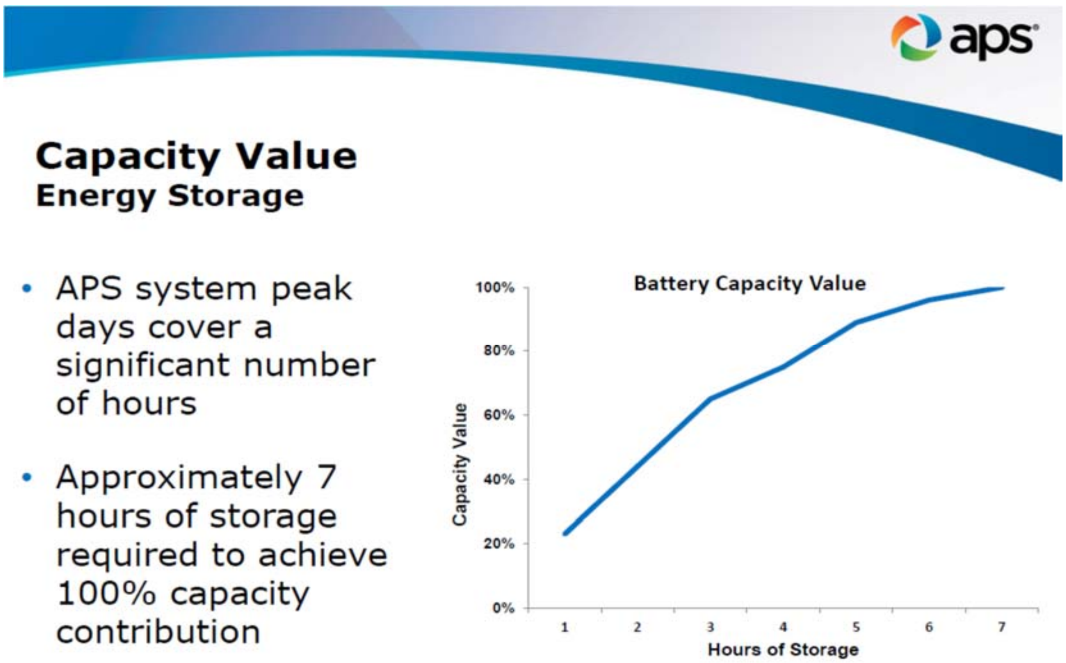
Q42: Order 17-357 provides that parties may submit proposals for valuing solar paired with storage and expresses interest in "understanding the value of storage."[49] Have you investigated this issue as part of the development of your RVOS recommendations?

A42: Yes, I have. Storage paired with solar offers the potential to shift a significant portion of solar output to the time periods when it is most valuable to the system, and to increase the certainty that solar resources will be available exactly when needed. With storage, solar becomes a dispatchable resource whose output can be targeted to the times when the power has the greatest value to the grid. Utilities in the West are recognizing this value:

[49] Order 17-357, at p. 15 and Ordering Paragraph 2.

the following figure was prepared by Arizona Public Service for its 2017 IRP, and shows the utility's recognition that adding adequate storage will firm the capacity value of solar.

Figure 9



With respect to the RVOS calculations presented in this testimony, the principal impact of storage is to increase substantially the contribution of distributed solar to avoiding generation and T&D capacity costs. For example, the following **Table 7** shows the increase in avoided generation capacity costs when solar is paired with a storage unit capable of storing the daily average amount of solar output, and discharging it during the four hours each day with the highest LOLPs.

Table 7: *Added Generation Capacity Value – Solar plus Storage*

Utility	Generation Capacity *($/MWh)*	Solar Capacity Contribution		% Increase in Value with Storage	Added Generation Capacity *($/MWh)*
		No Storage	With Storage		
	A	*B*	*C*	*D = C/B-1*	*E = AxD*
PGE	24.11	26.1%	41.9%	61%	14.60
PAC	20.87	43.9%	73.2%	67%	13.97
IPC	20.70	25.3%	61.4%	142%	29.48

These incremental increases in solar value are conservative in that they assume the same hourly profile of storage output each day; additional value could be realized, for example, if the storage unit is dispatched by the utility. Comparable percentage increases in T&D capacity value also are possible for with storage paired with distributed solar. Finally, additional savings in energy costs can be achieved with daily cycling of storage, as the addition of storage shifts solar output to hours with higher avoided energy costs.

Q43: Order 17-357, at pages 15-16, recognizes that solar can provide certain grid services that offer security, reliability, and resiliency benefits. Will adding storage enhance the ability to provide these benefits?

A43: Yes. Storage paired with solar also has the potential to provide many grid services (such as voltage support, regulation, and load following) as well as to enhance the resiliency of electric service as a source of backup, on-site electric service. I also do not necessarily agree with E3 that there are no public benefits from a more secure, resilient and reliable grid,[50] as there are significant public benefits if public safety facilities and communications infrastructure can retain electric service when the broader grid is down.

[50] See Order 17-357, at p. 15.

Q44: Do the added RVOS benefits of solar-plus-storage that you have calculated, for example in Table 7 above, include any of these potential benefits?

A44: No. Such benefits are promising and are likely to be significant in magnitude, but it is my understanding that they are beyond the scope of this phase of these dockets.[51]

Q45: Does this complete your direct testimony?

A45: Yes, it does.

[51] *Ibid*., at p. 16.

Exhibit OSEIA 101

CV of R. Thomas Beach

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 U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. 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 the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many 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, standby rates, greenhouse gas emission regulations, 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 CALIFORNIA PUBLIC UTILITIES COMMISSION

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 thermal 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 thermal 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; marginal costs.*

78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

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

79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

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

83. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

    - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony of R. Thomas Beach on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

    - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

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). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

    - *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.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, of R. Thomas Beach on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

    - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

    - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

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.*

2. a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony of R. Thomas Beach on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

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 MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony of R. Thomas Beach on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

   - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES 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)

   - *QF pricing issues in Nevada.*

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.*

4. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony of R. Thomas Beach on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).
   c. Prepared Rebuttal Testimony of R. Thomas Beach on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

   - *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

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)
   http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *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.*

April 25, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

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 PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014) https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

   - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

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) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

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 OSEIA 102

Power to the Customer:
Differentiating Rooftop and Utility-scale Solar

Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

Power to the Customer: Differentiating Rooftop and Utility-scale Solar

Prepared for:

Sunrun, Inc.

Prepared by:

Crossborder Energy

Authors:

R. Thomas Beach
Patrick G. McGuire
Andrew B. Peterson

February 6, 2017

*2560 Ninth Street * Suite 213A * Berkeley, California 94708 * tomb@crossborderenergy.com*

Power to the Customer: Differentiating Rooftop and Utility-scale Solar

R. Thomas Beach, Patrick G. McGuire, and Andrew B. Peterson
Crossborder Energy

Executive Summary

This white paper presents an updated consideration of the benefits and costs of distributed, behind-the-meter, "rooftop" solar facilities in comparison to large, central station, "utility-scale" solar projects. In several states, utilities and ratepayer advocates have argued that utility-scale solar can provide the same benefits as rooftop systems, but at a lower cost due to the economies of scale of utility-scale projects. This paper argues that this simple comparison fails to consider important differences between these two types of solar resources, differences based on where these resources are located and how customers are able to choose them. We update the benefit/cost comparison between these two types of solar (including the costs of financing), provide new perspectives on the value of customers' freedom to choose to adopt rooftop solar, and discuss how rooftop solar combined with on-site storage will leverage additional benefits for the electric system that cannot be supplied by utility-scale solar plus storage.

We have previously examined this argument quantitatively, in a white paper prepared in 2014 that compared both the benefits and costs of rooftop and utility-scale solar using data from Colorado.[1] That paper found that utility-scale solar offers higher capacity factors and lower capital costs due to economies of scale, compared to rooftop systems. However, this advantage is offset by rooftop solar's more valuable location at the point of end-use, by its ability to meet the demand for 100% renewable power at a lower cost to the customer than the typical utility "green pricing" program, by the reliability benefits of rooftop solar when paired with storage, and by the greater societal and customer choice benefits of rooftop. To the extent that these added benefits of rooftop could be quantified, they essentially offset the cost advantage of utility-scale systems.

A report prepared by the Brattle Group for a utility-scale solar developer, with support from the Edison Electric Institute and Xcel Energy, has also addressed this issue in Colorado, concluding that the per kWh costs of utility-scale solar are significantly lower than for rooftop.[2] However, the Brattle Study appears to calculate utility-scale costs using an overestimation of the proportion of utility-scale projects that use tracking. Moreover, it did not examine quantitatively certain key differences, including:

- the general body of ratepayers pays directly for only a portion of rooftop costs, i.e. just for the portion of rooftop output that is exported to the grid;

1 "Relative Benefits and Costs of Rooftop and Utility-scale Solar" (Crossborder Energy, July 28, 2014).

2 "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area" (Brattle Group for First Solar, July 2015). Hereafter, "Brattle Study.."

- the location of rooftop facilities allows them to avoid line losses and reduce infrastructure costs for transmission and distribution (T&D);

- rooftop solar can be deployed more quickly;

- customer-sited and customer-driven rooftop solar responds directly to customers' desire to use a higher penetration of renewable generation;

- there are incremental benefits from the pairing of rooftop solar and on-site storage; and

- there are important differences between these resources in their societal and customer choice benefits.

This updated white paper focuses on this comparison using benefits and costs specific to Arizona, where regulators have decided to use the costs of utility-scale solar as a factor in pricing the exported power from rooftop solar facilities.[3] We caution that the benefits and costs will vary from state to state and utility to utility; nonetheless, our analyses for Colorado and now for Arizona are designed to provide a fuller perspective on how to compare different types of solar resources. Accordingly, this paper not only updates our prior analysis using Arizona data, but also extends our earlier work to include new perspectives on this important comparison.

Table ES-1 summarizes the findings of our updated analysis, and lists the additional quantifiable benefits of rooftop solar beyond those provided by utility-scale facilities.

Table ES-1: *Summary of Location and Choice Benefits of Rooftop Solar*

Benefit	**Value** *(cents per kWh)*
Locational Benefits	
Avoided line losses	+0.6
Avoided transmission capacity	+1.2
Avoided distribution capacity	+1.5 to +4.0
Subtotal – direct locational benefits	+3.3 to +5.8
Added benefits when paired with storage	+5.0
Land use benefits	varies widely
Choice Benefits	
Accelerate renewable deployment • Increase electrification • Exceed RPS requirements • Avoid Green Pricing premiums • Includes local economic benefits vs. utility-scale	+7.4
Lower cost third-party financing vs. rate base for utility-owned solar	Lower LCOE by 15% to 20%

3 See the Arizona Corporation Commission's (ACC) order approved December 20, 2016 in its "Value of Solar" Docket E00000J-14-023.

The table shows that rooftop solar provides additional benefits by avoiding the transmission and distribution (T&D) infrastructure that is necessary to deliver utility-scale solar power to customers. Both types of solar generation provide substantial environmental benefits to the public, but rooftop solar offers additional benefits from the reduced land use impacts. Rooftop solar also provides greater benefits when it is paired with on-site storage. Finally, rooftop solar development is driven by the choices of individual customers who wish to be served by a higher penetration of renewable energy. The value of customer choice should not be minimized; in Arizona, it has resulted in Arizona Public Service (APS) exceeding its renewable energy standard (RES) goals. The value of this additional renewable energy would be lost if only utility-scale solar resources are developed to meet RES requirements.

Utility-scale solar remains less expensive than rooftop solar, although this difference is narrowing, as we discuss in the next section. The additional benefits of rooftop solar shown in Table ES-1 are sufficient to make up for this difference, such that we continue to conclude that both rooftop and utility-scale solar should have central roles in the transition to a clean, sustainable, and resilient electric industry.

1. Rooftop and Utility-scale Costs

a. The difference between these costs continues to narrow.

Economies of scale in installation, plus the greater use of tracking systems, result in lower costs per unit of solar output for large, utility-scale solar facilities. However, data on solar costs shows that the difference in costs between rooftop and utility-scale facilities is steadily decreasing.

Lawrence Berkeley National Lab's (LBNL) annual reports on rooftop and utility-scale solar installation costs show that the difference between residential rooftop and utility-scale solar costs has decreased by 50% over the last five years, and the difference between small commercial rooftop (under 500 kW) and utility-scale solar costs has dropped by 67%. Further, in 2015 there was essentially no difference in cost between large (over 500 kW) distributed solar facilities and utility-scale projects. These trends are illustrated in **Figure 1** below.[4] Data from 2016 reported by the Solar Energy Industries Association (SEIA) through the third quarter of 2016 shows that the difference between residential and utility-scale costs remains in the range of $1.50 to $2.00 per watt DC, with residential costs now falling to $3 per watt DC and utility-scale costs below $1.50 per watt DC.[5]

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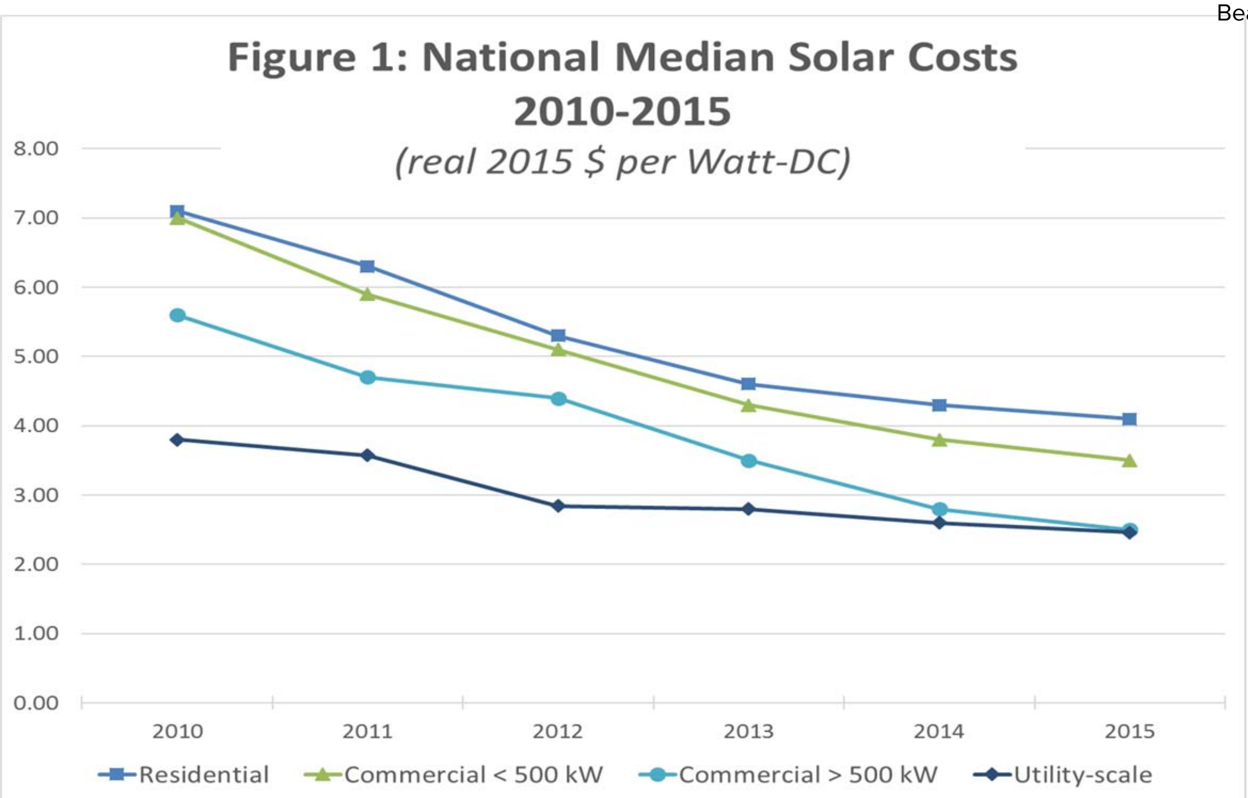
[4] See LBNL, *Tracking the Sun IX* (August 2016), Figures 6 and 7, available at https://emp.lbl.gov/publications/tracking-sun-ix-installed-price.

[5] See SEIA, *Solar Market Insight Report 2016 Q4*, at Figure 2.3, available at http://www.seia.org/research-resources/solar-market-insight-report-2016-q4.



The primary drivers for the decreasing differential in installed costs over the last five years are the significant reductions in the installation and "soft" costs for rooftop systems. In the U.S., there remains room for further narrowing of these costs, as shown by the much lower costs for residential solar in other developed markets such as Germany and Australia, where residential prices in 2015 were just $1.70 and $1.80 per watt-DC, respectively, which was below utility-scale costs in the U.S.[6]

b. The Brattle study exaggerates the cost difference.

Brattle used costs for utility-scale solar that include a mix of both fixed and tracking systems.[7] However, Brattle also assumed that the output from utility-scale projects in Colorado is 100% from tracking systems.[8] Thus, for a portion of its sample, Brattle used costs for fixed arrays but assumed the production of trackers. This inconsistency underestimates the cost of utility-scale solar, as the most recent LBNL data shows that tracking systems are about 11% more expensive, on a $ per watt basis.[9]

[6] See LBNL, *Tracking the Sun IX*, at pp. 1-2 and 22-24.
[7] For example, Brattle relied on LBNL data on utility-scale solar costs from Figure 29 of LBNL's *Tracking the Sun VII* report. See Figure 6 of the Brattle report. As shown in the data for Figure 30 of the LBNL *Tracking the Sun VII* report, the data that Brattle used is for a mix of fixed and tracking systems (roughly two-thirds fixed and one-third tracking for 2011-2013 systems), with the costs for the tracking systems 5% to 17% higher than the fixed systems.
[8] Brattle Report, at p. 26, footnote 24.
[9] LBNL, *Utility-scale Solar 2015* (August 2016), at data table for Figure 10, comparing tracking and fixed-tilt costs for 2013-2015.

Further, Brattle's projection of utility-scale capacity factors of 24% in Colorado are 50% above Brattle's assumed 16% capacity factor for rooftop solar. These projections are based on simulated output, not on actual production data.[10] Actual solar generation data from California, which has over 9 GW of utility-scale solar and almost 5 GW of rooftop solar, shows capacity factors of 27% for utility-scale solar (based on CAISO generation data from 2015-2016) and 21% for rooftop systems (from the five years of output data on CSI systems with performance-based incentives).[11] This actual solar output data indicates a significantly smaller difference in output between utility-scale and rooftop systems than modeled by Brattle. Similarly, based on actual generation, APS is reporting capacity factors of 33% for its utility-scale solar and 26% and 28% for residential and commercial rooftop solar, respectively.[12] This smaller difference in capacity factors is due, in part, to a significant portion of utility-scale solar projects being fixed arrays, and not 100% trackers as assumed by Brattle.

2. Utility-scale and Rooftop Solar Provide Different Products, at Different Locations

Rooftop and utility-scale solar do not provide the same energy product. The majority of the output of a rooftop solar facility provides power directly to end-use loads, behind the meter, where it displaces retail power from the utility. The rest of the power is exported to the distribution grid, where as a matter of physics it immediately serves neighboring loads, also displacing retail power from the utility.[13] The rooftop solar customer using distributed generation (DG) is compensated for this power at the retail rate, through net energy metering (NEM). In contrast, utility-scale solar supplies wholesale power to the utility, delivering power to the transmission system.

The most significant difference between these products is that the retail, rooftop product has been delivered to end use loads, whereas the wholesale, utility-scale product has not. Thus, for an apples-to-apples comparison with rooftop solar, the cost of utility-scale power to the ultimate consumer needs to include the marginal cost of delivery. The correct delivery cost to use in this comparison is not necessarily the utility's delivery rate, that is, what it charges to provide transmission and distribution (T&D) service. Instead, the correct rate to use in this comparison is the utility's marginal costs for T&D service. These are the line losses and T&D infrastructure costs which the utility avoids if rooftop solar supplies a customer and his neighbors, thus avoiding the

[10] See Brattle Report, at pp. 24-26.
[11] CAISO generation data is from the CAISO's "Renewables Watch" data (at http://www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx). CAISO system solar capacity is based on the CAISO's "Master CAISO Control Area Generating Capability List" for November 2, 2016. Rooftop solar output data for PBI systems can be found at https://www.californiasolarstatistics.ca.gov/data_downloads/, see the CSI Measured Production Data Set.
[12] Based on 2017-2021 forecasted generation data in APS's 2017 Renewable Energy Standard Plan, filed with the ACC on July 1, 2016 (Docket No. E-01345A-16-0238).
[13] It is only at relatively high penetrations of rooftop solar, as have been experienced in some locations in Hawaii, that significant amounts of rooftop solar are at times backfed upstream through the distribution substation.

need for the utility to provide delivery service from a more remote utility-scale solar producer or other wholesale generator.[14]

a. The significant cost of transmission to deliver utility-scale solar

Utility-scale solar projects require transmission to deliver this power to the utility's load centers. New transmission can be expensive, and can require many years to site, permit, and build. It is well known that the availability of adequate transmission is a critical issue for the development of utility-scale solar and wind resources in the western U.S. Transmission bottlenecks can constrain a utility's ability to access utility-scale solar. As an example, APS has been building, in phases, a new 500 kV line from the Yuma area to the Palo Verde hub and then to the Phoenix load center, with a stated purpose of accessing solar and natural gas resources in the Yuma and Palo Verde areas.[15] Adequate transmission also has been a central issue in California's ambitious Renewable Portfolio Standard program, whose goals are now 33% renewable generation by 2020, and 50% by 2030.[16]

The table below shows representative transmission capacity costs for new utility-scale solar that is located at a distance from utility load centers, using data from the recent APS transmission plans, as well as comparable transmission costs from other states.

Table 1: *Utility-scale Solar Transmission Costs (cents per kWh)*

Resource	Transmission Cost (c/kWh)
Arizona[17]	
New 500 kV lines to access gas and solar	1.2
California 50% RPS data[18]	
In-state renewables	3.4
Small-scale solar	2.1
Colorado SB 100 data[19]	
San Luis-Comanche line (access 1,400 MW of solar)	1.0

[14] The Brattle Report, at pp. 38-39, acknowledges that rooftop solar may avoid transmission costs, and cites the avoided transmission costs for Public Service of Colorado (PSCo) that we calculated in our 2014 critique of Xcel Energy's *Distributed Solar Study*, both filed in Colorado PUC Docket No. 11M-426E. Brattle argues that these avoided costs are not large enough to bridge the cost divide between utility-scale and rooftop solar.

[15] See APS Renewable Transmission Plan and its recent 10-year Transmission Plans.

[16] Some utility-scale solar projects in California have been developed on an "energy-only" basis as a result of their inability to secure firm transmission capacity to deliver their power on a firm basis.

[17] Based on the costs per kW of the North Gila to Palo Verde 500 kV line and the segments of the Palo Verde to Morgan 500 kV line, which APS has justified as accessing new solar and gas resources. We use a 11.05% fixed charge rate and an assumed 32% capacity factor for utility-scale solar. The fixed charge rate is from an SAIC Energy, Environmental and Infrastructure LLC study for APS, *2013 Updated Solar PV Value Report* (May 2013), at Table 3-2.

[18] See Energy and Environmental Economics (E3), *A 50% Renewable Portfolio Standard in California* (E3, February 2014), at p. 58 and Tables 10 and 29, hereafter "E3 50% RPS Study."

[19] The capital costs for the San Luis line were converted to cents per kWh assuming a 7.4% levelized carrying charge for transmission and that utility-scale solar resources operate at a 25% capacity factor.

Clearly, transmission costs are significant, although they are also location-specific. In addition, line losses on the T&D system are significant, and are avoided by rooftop solar. APS has estimated that its marginal line losses avoided by solar DG are 12%, or 0.6 cents per kWh assuming utility-scale solar costs of 5 cents per kWh.[20]

Rooftop solar is sited in the built environment in the load center and therefore avoids transmission costs and line losses. For residential customers, about one-half of the output of rooftop systems is consumed on-site by the solar host. The other half of the power is exported and, at today's relatively low penetrations of solar, is consumed by the host customer's neighbors on the distribution system, thereby avoiding line losses and displacing power that would have to be imported from more remote generators. As a result, rooftop solar makes capacity available on the upstream transmission and distribution systems that can be used to serve other customers, to import other power supplies, and to meet load growth.

b. DG can accelerate distribution and grid modernization at a lower cost for consumers.

Today, the primary impact of the development of rooftop solar DG is to reduce the overall level of the utilities' loads. In this way it is similar to other demand-side resources. Over the long-run, these lower loads will reduce the utility's need to invest in distribution infrastructure. Customer-sited DG thus combines with other customer investments in energy efficiency (EE) and demand response (DR) to allow the utility to avoid investments in distribution capacity.[21] As a result, the avoided distribution capacity costs from rooftop solar are not zero.

These distribution benefits can be measured, at the utility-wide level, by the utility's long-run marginal cost of distribution capacity, which can be calculated using a regression of distribution investments as a function of load growth. This effectively separates that portion of overall distribution investments that are driven by load growth from those that are pursued for other reasons, such as reliability, replacement, or grid modernization.[22] Solar PV's share of the

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[20] See R.W. Beck, *Distributed Renewable Energy Operating Impacts and Valuation Study* (January 2009), hereafter, the "*R.W. Beck Study*," at Table 4-3. Other studies use system average line losses, but this does not reflect the fact that solar DG output is produced when system loads, and losses, are higher. It also does not consider that marginal line losses are higher than average losses. The Beck Study includes a full discussion and analysis of the loss issue, at pages 4-4 to 4-8.

[21] These benefits are largely counterfactual; in other words, they result from the long-term demand trajectory of the utility being significantly lower as a result of demand-side EE, DR, and DG resources than a "business as usual" trajectory that will not actually be experienced. Such "avoided cost" benefits will rarely show up publicly, or even in utility rate cases, as DG (or DR or EE) replacing or deferring a specific distribution investment. Instead, the utility planning process will respond over time to a lower level of demand and will need to build less infrastructure, as a result of the development of demand-side resources.

[22] It is important to recognize that distribution investments can have a variety of benefits, and it is often inaccurate to say that a particular distribution project is only being pursued for reliability, for example. A new substation can provide benefits from added load-serving capacity even if its principal justification

load reduction benefits can be determined by calculating a "load match factor" that captures the ability of solar DG to reduce the peak distribution system loads that drive load-related distribution investments.[23]

Recent studies of avoided distribution capacity costs resulting from rooftop solar have used the correlation between solar output and distribution substation peak loads (or class loads as a proxy) to calculate load match factors for distribution capacity. These factors are then applied to an estimate of marginal distribution capacity costs derived from data on utility distribution investments. This approach has resulted in significantly higher estimates of avoided distribution capacity costs than prior studies, because it captures the ability of widespread DG deployment to reduce the distribution-level loads that drive the overall level of long-term distribution additions.[24] **Table 2** summarizes the results of several recent studies using this approach.

Table 2: *Studies of Avoided Distribution Capacity Costs*

State	Study	Date	Avoided Distribution Capacity Costs *(cents/kWh)*
AZ	Crossborder-TASC[25]	2016	1.5 (residential) 4.0 (commercial)
NH	Crossborder-TASC[26]	2016	2.3 (average for three NH utilities)
CA	CPUC-E3 / Public Tool Model[27]	2015	2.9 (average for three CA utilities)

The distribution benefits of solar DG and other demand-side resources are location-specific, but this is not a reason to assign them an overall value of zero until they can be

is reliability or replacement of aging equipment.

23 In addition, recent work has highlighted how the impacts of DG and storage on distribution capacity also can be evaluated by looking at their impact on the thermal loads in distribution transformers, rather than on peak power flows. The focus on thermal demand can increase avoided T&D capacity by one-third, in comparison to evaluations based on peak power flows. See the Solar City white paper, *Enhancing Methodologies for Valuing Transmission and Distribution Capacity*, available as Exhibit RH-4 to the Direct Testimony of Ryan Hanley of Solar City, presented in Public Utilities Commission of Nevada Docket No. 16-06-006, dated October 7, 2016.

24 The older studies of the distribution benefits of rooftop solar are referenced and discussed in the Rocky Mountain Institute's meta-analysis of these benefit-cost studies.
See Rocky Mountain Institute, *A Review of Solar PV Benefit and Cost Studies* (July 2013), at page 31, available at http://www.rmi.org/Knowledge-Center/Library/2013-13_eLabDERCostValue. Generally, the distribution capacity benefits in these studies were in the range of 0 to 1 cents per kWh.

25 See Crossborder Energy, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (Updated APS DG Study)*, at Table 6, filed on behalf of The Alliance for Solar Choice in the ACC Value of Solar case (Docket No. E-00000J-14-0023).

26 See Crossborder Energy, *The Benefits and Costs of Distributed Solar Generation in New Hampshire*, at Appendix D, Table D-7 of Exhibit RTB-1, filed on behalf of The Alliance for Solar Choice in the New Hampshire Public Utilities Commission Docket No. DE 16-576.

27 Based on the marginal sub-transmission and distribution costs of the California electric utilities and the CPUC-E3's Public Tool model of the benefits and cost of net metering in California. The Public Tool is described and is available at http://www.cpuc.ca.gov/General.aspx?id=11285.

assessed on a location-specific basis. Instead, the more accurate and equitable approach is to assess these benefits now on an overall "system" basis, and then to proceed in the future, as DG penetration grows, to develop a more location-specific assessment of avoided distribution costs. States such as California and New York are taking steps in this direction, with California's Distribution Resource Plans and New York's Reforming the Energy Vision (REV) initiative.

Renewable DG is now being installed on the distribution system in the context of many initiatives underway across the U.S. to modernize the electric grid. Grid modernization will expand the electric system's capabilities to handle not only renewable DG but also a wide variety of other new distributed energy loads & resources – new DR programs such as programmable thermostats, electric vehicle (EV) charging, and distributed storage, for example. Solar DG is the customer's central, "gateway" investment that can unlock the customer's interest and investment in these customer-focused clean energy technologies that will be integral to a modern grid infrastructure.[28]

From the perspective of the utilities and customers who do not invest in DG, there are other significant benefits of grid modernization, including the following:[29]

1. Reducing the frequency and effects of outages, by allowing greater visibility for system operators into local grid conditions and reducing response times to customer outages;

2. Optimizing demand to reduce system and customer costs;

3. Improving utility workforce and asset management, such as reduced costs for distribution maintenance;

4. Developing a charging infrastructure for EVs - a major new market for electricity;[30]

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[28] Studies have shown that solar customers adopt more energy efficiency measures than other utility customers. For example, see:

- The *2009 Impact Evaluation Final Report* on the California Solar Initiative, prepared by Itron and KEMA and submitted in June 2010 to Southern California Edison and the Energy Division of the California Public Utilities Commission. See pages ES-22 to ES-32 and Chapter 10. Also available at the following link: http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=7677.
- Center for Sustainable Energy, *Energy Efficiency Motivations and Actions of California Solar Homeowners* (August 2014), at p. 6, finding that more than 87% of solar customers responding to a survey had installed or upgraded one or more energy efficiency technologies in their homes. Also available at https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf.

[29] *See*, for example, *Investigation by the Department of Public Utilities Upon its Own Motion into Modernization of the Electric Grid*, Massachusetts Department of Public Utilities ("DPU") order D.P.U. 12-76-B, at pp. 7-15 (Jun. 12, 2014).

[30] There is a strong correlation between EV ownership and solar DG installation – a 2014 survey of California EV owners found that 32% of EV owners have installed solar and an additional 16% plan to do so. See https://cleanvehiclerebate.org/eng/vehicle-owner-survey/feb-2014-survey.

5. Opportunities to reduce stationary source air emissions through further electrification of buildings and industrial processes; and

6. Allowing deployment of distributed storage, which in turn has numerous potential benefit streams – energy arbitrage, capacity deferral, ancillary services, enhanced reliability and resiliency, and power quality.

7. Providing voltage support and enhancing conservation voltage reduction (CVR) programs through the use of smart inverters.[31]

As a result, states have recognized that there are many reasons to modernize the grid, and many benefits from doing so beyond the traditional need to meet load growth. Moreover, there is significant potential for the intelligent deployment of DG to reduce the costs associated with grid modernization. Solar City recently released a white paper, *A Pathway to a Distributed Grid*, which quantifies the net benefits of distributed energy resources ("DER") – including both DG and other distributed resources such as smart inverters, storage, energy efficiency, and controllable loads – and shows that they are a cost-effective, least-cost approach to grid modernization.[32] This report shows that distributed energy resources (DERs), including rooftop solar, have the potential to replace a portion of the real-world grid modernization projects that Pacific Gas and Electric has proposed in its 2017 General Rate Case, at a lower net cost to the utility's ratepayers. Thus, rooftop solar can be an integral part of a cost-effective grid modernization program, even if the key drivers and benefits of such a program for ratepayers go well beyond simply serving load growth.

3. Rooftop solar customers can expand their system for a low incremental cost close to that of utility-scale solar.

Most studies of how to achieve deep reductions in carbon emissions by mid-century recognize that the most likely path will involve increasing the use of clean electricity as the source of primary energy for buildings and transportation. For example, the California Air Resources Board's 2014 update to its *AB 32 Scoping Plan* observes that meeting California's ambitious goal to reduce GHG emissions to 80% below 1990 levels by 2050 will require the widespread electrification of the state's transportation, building, and industrial sectors.[33] This is also the conclusion of academic researchers who have modeled how the state can reach its 2050 goal.[34]

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[31] Based on an analysis from Solar City using the results of its smart inverter field demonstration projects, smart inverters used for CVR can produce an incremental 0.4% energy consumption savings, with the associated greenhouse gas emissions reductions, as reported in a white paper from Solar City Grid Engineering and the Natural Resources Defense Council, *Distributed Energy Resources in Nevada: Quantifying the net benefits of distributed energy resources* (May 2016), available at. http://www.solarcity.com/sites/default/files/SolarCity-Distributed_Energy_Resources_in_Nevada.pdf.

[32] This Solar City white paper is available at http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf.

[33] CARB, *First Update to the Climate Change Scoping Plan: Building on the Framework* (May 2014), at 36-37, available at https://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

[34] Academic publications on this topic include the following:

With electricity's share of primary energy use growing, there is the potential for customers to install larger rooftop solar arrays, at an incremental cost that is closer to utility-scale costs, to allow them to charge electric vehicles at home and to replace natural gas-fired water and space heaters with efficient electric heating. The cost-effectiveness of these incremental rooftop resources are further enhanced by the fact that this power would be already delivered at or very close to these new loads, thus avoiding significant T&D costs.

For example, we examined the potential for an incremental expansion of a residential rooftop system to be used to charge an electric vehicle (EV), displacing gasoline. We assume that a residential customer in Phoenix adds enough incremental solar capacity to fuel a typical EV travelling 10,000 miles per year. **Table 3** shows the key assumptions and results of our analysis.

Table 3: *Using Incremental Solar for EV Charging*

Key Assumptions	**Input**
Incremental solar cost	$2.50 per W-DC
Incremental solar capacity	1.8 kW-DC
Phoenix solar output	1,470 kWh/kW-DC
EV efficiency	3.3 miles/kWh
Mileage of equivalent gasoline car	35 miles/gallon
Current gasoline price in Phoenix	$2.05 per gallon
Results	**Value**
Incremental solar cost – first year	7.8 cents/kWh
Equivalent gasoline cost for EV charging	$0.83/gallon
First year gasoline savings (10,000 miles/year)	$300
Annual GHG emission reductions	2.3 tonnes

The incremental solar cost we use is above today's utility-scale solar costs,[35] but results in a charging cost that is competitive with off-peak charging at APS's off-peak time-of-use rate, which is what an EV customer would pay if the power were supplied by either incremental utility-scale solar or marginal power production using predominantly natural gas. This example shows that a vibrant rooftop market can provide an economical means to expand electrification that is cost-competitive with the use of utility-scale solar for the same purpose.

• Williams, J. H., et al. 2011. "The Technology Path to Deep Greenhouse Gas Emissions cuts by 2050: The pivotal role of electricity." Science Express 335 (6064): 53–59. http://www.sciencemag.org/content/335/6064/53.
• Wei, M., et al. 2013. "Deep carbon reductions in California require electrification and integration across economic sectors." Environmental Research Letters 7: 1–9. http://iopscience.iop.org/1748-9326/8/1/014038/.

[35] We use an incremental cost of $2.50 per kW-DC, assuming a current cost of $3.00 per kW-DC and an incremental cost for a 2 kW addition that is $0.50 per kW-DC lower. This incremental cost is based on LBNL 2015 data for residential solar costs for systems of various sizes. See LBNL, *Tracking the Sun IX*, at the data table for Figure 16, for systems from 2 kW to 12 kW in size.

4. Rooftop solar is driven by customer demand, not RPS mandates. Customer choice of rooftop solar accelerates renewable energy adoption.

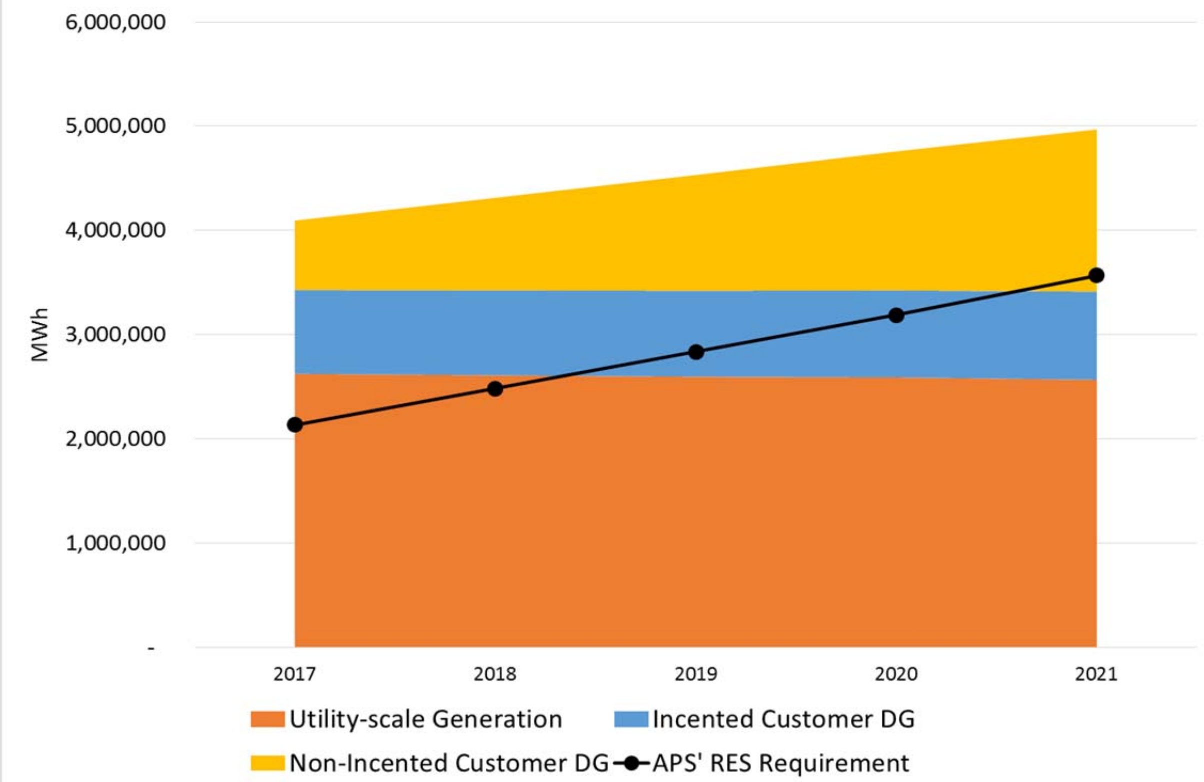
The Brattle Study joins many utilities in arguing that both rooftop and utility-scale solar provide similar societal benefits per kilowatt-hour of output. For example, both produce similar reductions in carbon emissions and criteria air pollutants, lower water use, and provide benefits from fuel hedging and market price mitigation.[36] However, even if utility-scale and rooftop solar provide similar societal benefits, there is now significant evidence that rooftop solar can provide these benefits more rapidly, compared to limiting solar development just to wholesale utility-scale projects developed in response to a state's RPS program. Driven by customer choice, this acceleration has a significant value.

Another way to look at this benefit is to recognize that utility-scale solar is not a substitute for rooftop solar if additional utility-scale solar is not going to be built because RPS goals have been reached. APS provides a good example of a utility where rooftop solar has driven an acceleration of renewable development well beyond the state's RPS requirements:

- Arizona's current Renewable Energy Standard (RES, i.e. RPS) goal is 7% of sales in 2017, with the RES percentage increasing by 1% per year to 10% in 2020 and 15% in 2025. APS expects to use renewable generation to serve 12% of sales in 2017 and 15% in 2021. This over-achievement will be driven largely by continued strong growth in rooftop solar installed without RES-linked incentives, as shown by the yellow area in the **Figure 2**. Arizona has a separate requirement for distributed energy (DE, i.e. DG) deployment, which is 30% of the overall RES requirement in each year. Figure 2 also shows that DG development in APS's territory is expected to be far greater than the state's RES requirement for DG.

[36] See Brattle Study, at pp. 40-44.

Figure 2: APS Renewable Procurement



- There is nothing in APS's 2014 Integrated Resource Plan (IRP) or draft 2017 IRP which indicates that rooftop and utility-scale solar are substitutes for each other. So, if APS installs less rooftop solar, it is not committed to installing more utility-scale solar, or vice versa. APS's own testimony in the Value of Solar docket assumes that the output from DG solar avoids the cost of APS's marginal fuel, which is natural gas.[37] There is no RES requirement in Arizona to mandate the substitution of utility-scale for rooftop solar if the latter is not developed, and APS is in compliance with the existing RES goals.

- Rooftop solar is driven by customer choice and customers' investment, and can occur more quickly than utility-scale development, because the development and permitting time from sale to commercial operation is so much shorter than for utility-scale projects. Large scale solar projects also face constraints from the need to provide additional bulk transmission capacity, which can take years to site and build.

The conclusion from the strong growth in rooftop solar is that APS's customers want to be served with more renewable energy than the RES requirements, which were established in legislation enacted a decade ago in 2007. Rooftop solar has been available to meet this strong customer demand for a higher penetration of renewables, without an RPS cost premium and indeed with the potential for long-term customer savings.

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[37] Direct testimony of Leland Snook for APS, at p. 17 ("The method described above uses the filed avoided fuel costs for all kWh produced by the rooftop solar system.").

The problem which utilities face is that, even if utility-scale solar is less expensive than the utility's overall portfolio of generation, they are unlikely to offer to serve customers with 100% utility-scale renewable energy unless they can charge a premium to their existing rates. If the utilities were to offer customers 100% utility-scale renewable energy at a discount to their existing rates, the utilities would be overwhelmed by the demand from customers who, as polling data shows, express strong support for renewable energy across the political spectrum.[38] As a result, utility "green pricing" programs all charge a premium even though the cost of renewables in many states is now at or below the all-in costs of fossil generation.[39] For example, the three largest investor-owned utilities in Arizona charge an average premium of 1.7 cents per kWh for additional renewable generation. Such premium pricing has limited the success of green pricing programs. In 2017, APS's Green Choice program (which charges the lowest premium in the state of 1.0 cent per kWh above the retail rate) will supply less than 10% of the renewable generation provided by the customer-sited DG installations in APS's service territory.

All Arizona citizens realize the substantial environmental and societal benefits of this accelerated renewable development driven by DG, even though the capital is provided by either customers or third parties, who also bear the installation and operational risks of this generation. This contrasts with utility-scale solar, whose installation costs and risks are assumed by all ratepayers. In 2017, the additional 1,960 GWh of renewable generation above the RES requirement on the APS system will have societal benefits of $145 million, based on the 20-year levelized societal benefits of 7.4 cents per kWh calculated in our 2016 *Updated APS DG Study*.[40] Essentially, this quantifies the value of choice – of customers choosing to make their own investments to accelerate the deployment of renewable generation in Arizona.

Finally, APS ratepayers only pay directly for the portion of the DG generation that is exported to the grid, typically about 50% to 60% of the output, depending on the system size.[41] In contrast, APS ratepayers must pay directly for 100% of the costs of wholesale utility-scale solar in order to obtain the same environmental benefits per kWh.

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[38] See, for example, this Pew Research Center survey, http://www.pewinternet.org/2016/10/04/public-opinion-on-renewables-and-other-energy-sources/.

[39] See Department of Energy's survey of the premiums for utility green pricing programs, at http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml.

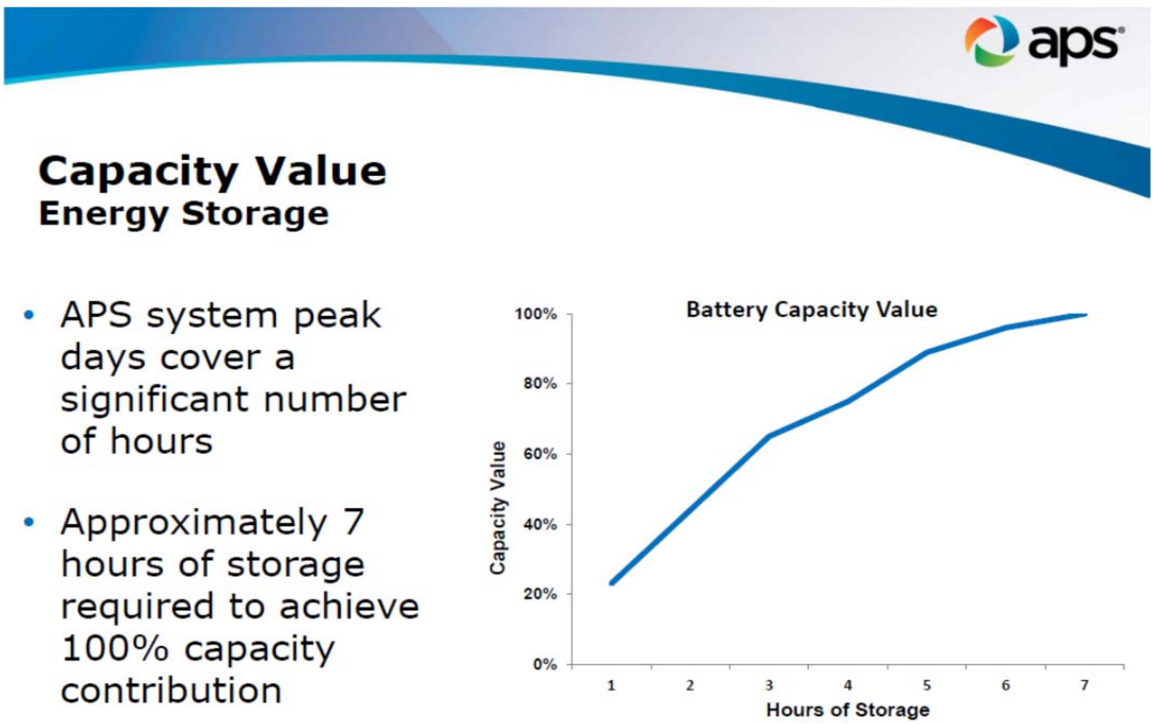
[40] See *Updated APS DG Study*, pp. 17-20, adjusted to reduce local economic benefits for the difference between residential/small commercial and utility-scale solar, as discussed below in Section 8.

[41] Billing data produced in discovery in the ongoing APS general rate case (Arizona Corporation Commission Docket No. E-01345A-16-0036) for the 26,000 residential solar DG customers on the APS system in the 2015 test year show that 44% of the average solar customer's production in 2015 served their on-site load, with 56% exported to the grid. The percentage of exports for APS is larger than for other utilities because APS uses two-channel meters that instantaneously measure exports and imports. See *Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association* (Docket No. E-01345A-16-0036), filed February 3, 2017, at page 8.

5. DG solar plus storage leverages greater benefits than utility-scale plus storage.

Utilities often highlight the anticipated decline in solar's value as more solar capacity is added, due to the shift in the hours of highest "net loads"[42] into the late afternoon and evening when solar output is declining. However, this picture will change fundamentally with the pairing of solar plus storage. Importantly, the benefits of pairing solar plus storage are significantly greater for rooftop solar than for utility-scale projects, for the following reasons:

- DG solar plus storage can increase the ability of distributed generation to defer investments in T&D capacity, in addition to avoiding a higher level of generation capacity costs. In contrast, storage sited with utility-scale solar only provides generation-related benefits. With storage, solar becomes a dispatchable resource whose output can be targeted to the times when the power has the greatest value to the grid, and can avoid capacity-related costs for T&D as well as generation. The following figure is from a recent APS presentation on its draft 2017 IRP, and shows the utility's recognition that adding adequate storage will firm the capacity value of solar.



- Based on the avoided generation and T&D capacity costs calculated in our *Updated APS DG Study*, and assuming that the addition of four hours of storage will increase south-facing residential solar's capacity value to 75% of nameplate (as shown in the APS figure above), rooftop solar paired with storage will provide benefits that are 10.3 cents per kWh higher than solar alone, while utility-scale solar plus on-site storage will increase in value by just 5.3 cents per kWh. These calculations are shown in **Table 4**.

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[42] Net load is defined as the end use load less variable wind and solar generation.

Table 4: *Increased Benefits of Solar plus Storage for APS*

Capacity Component	Marginal Cost w/losses *($/kW-yr)*	Solar Capacity Value as % of Nameplate	Solar Output *(kWh/kW-AC)*	Avoided Cost *($/MWh)*
	A	**B**	**C**	**1000 x A x B / C**
Generation – applies to both utility-scale and DG				
No storage	237.3	36.2%	1,730	50
With storage	237.3	75%	1,730	103
Increase due to storage				53
Transmission – applies to DG				
No storage	43.3	36.2%	1,730	9
With storage	43.3	75%	1,730	19
Increase due to storage				10
Distribution – applies to DG				
No storage	127.0	20.1%	1,730	15
With storage	127.0	75%	1,730	55
Increase due to storage				40
Added benefits of solar plus storage				
For Utility-scale solar – generation alone				53
For DG solar – generation plus T&D				103

- Finally, DG solar plus storage enhances reliability and resiliency at the end-use level. Storage plus solar can maintain service to critical loads during grid outages. Most electric system interruptions do not result from high demand on the system, but from weather- or disaster-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with a short-term back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

6. DG solar has access to lower cost financing than rate-based solar.

Utility-scale solar can be owned and operated either by merchant generation companies who sell the power to a utility under a power purchase agreement (PPA) or by the utilities themselves. The costs of utility-owned generation are recovered through the utility's rate base, earning the utility's regulated return on that rate base. The rate base for a generation asset depreciates over the life of the asset, resulting in cost recovery that is front-loaded into the early years of the asset's life. In comparison, the pricing in typical PPAs for renewable resources are levelized over the contract life.

There also can be differences in the cost of capital and the tax benefits available to merchant generators and utilities. Generally, utility cost recovery through rate base is more expensive than merchant PPAs, for several reasons. The first is the front-loaded nature of cost recovery through rate base. The second reason is the higher Weighted Average Cost of Capital (WACC) that regulators have approved for regulated utilities, compared to competitively-sourced capital from the efficient capital markets that fund merchant assets and rooftop solar. **Table 5** below highlights this difference, estimating that the lower cost of capital of independently-owned assets, compared to regulated assets with higher-than-market allowed ROEs, reduces the levelized cost of energy (LCOE) of solar by 12%. Said another way, energy procured through independently owned solar assets costs 12% less than if a utility were to rate-base the asset.

Table 5: *Exemplary WACCs for Independently-owned and Regulated Utility Assets43*

Owner	Capital Cost	Capital Structure
Regulated Utility Solar Assets		
Approved Return on Equity	10.0%	57%
Cost of Debt	4.0%	43%
WACC	6.8%	
Solar Assets owned by Independent Parties		
Cost of Equity	10.0%	35%
Cost of Debt	5.0%	65%
WACC	5.6%	
Difference in Cost of Capital	1.2%	
Resulting difference in LCOE	**-12.0%**	

Similarly, the LCOE model developed by Energy and Environmental Economics (E3) for the Western Electricity Coordinating Council calculates LCOEs for either utility or merchant cost recovery.[44] Based on the E3 models, utility-owned LCOEs with rate base cost recovery are typically 15% - 20% more expensive than merchant plant LCOEs over comparable 25- or 30-year periods.

Utilities can access the lower cost of third-party financing by purchasing utility-scale solar from third-party developers, instead of building such plants themselves. However, rooftop solar still provides an advantage by avoiding investments in utility-owned T&D whose costs clearly must be financed at a higher cost through rate base. Moreover, there are lower cost financing options available to rooftop customers, such as when homeowners are willing to pay cash for a DG system or to use home equity loans whose interest is often tax-deductible. In these ways, DG solar brings new, lower-cost capital to the utility system than the combination of utility-scale solar plus a utility-owned, rate-based T&D system to deliver that power.

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[43] The capital structure for utilities is derived using the S&P 500 Utility index, weighted by market capitalization, as of December 31, 2016. The capital structure for merchant solar assets is based on typical project finance structures. The cost of utility debt is estimated to be 4%, slightly higher than the current market capitalization weighted statistic of 3.5% for the S&P 500 Utility index as of December 31, 2016, owing to a shorter-term debt profile than comparable project-level debt for solar assets arranged in typical transactions by comparable parties.

[44] This *WECC Generation Costing Tool* model is available on the E3 website at https://ethree.com/public_projects/renewable_energy_costing_tool.php.

7. DG utilizes the built environment, reducing the amount of land used for energy production.

Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station renewable plants require larger single parcels of land, and are more remotely located where the land has other uses for agriculture, grazing, recreation, or wildlife habitat. The land must be removed from this prior use when it becomes a solar farm. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year.[45]

The lost value of the land depends on the alternative use to which it could be put. There is obviously a wide range of land values. The U.S. Department of Agriculture has reported the average rental value of pastureland and irrigated farmland in Arizona in 2016 to be $2 and $222 per acre, respectively.[46] These values can be much higher in other states – for example, these values are $16 and $440 per acre in California. Land is much more expensive in metropolitan areas, with one source reporting an average metropolitan land value of $100,000 per acre in Arizona.[47] If the 1,470 GWh of rooftop solar production that APS expects on its system in 2017 were instead ground-mounted in the metro Phoenix area, the value of the land required would approach $600 million.

8. Communities enjoy unique local economic benefits from rooftop solar.

While distributed generation has higher costs per kW than central station renewable or gas-fired generation, the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. Utility-scale solar plants have significantly lower soft costs, per kW installed, and often are not located in the same local area where the power is consumed.

There have been a number of recent studies by the national labs on the soft costs of solar DG, as the industry has focused on reducing such costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following **Table 6** presents recent data, from detailed surveys of solar installers conducted by the National Renewable Energy Lab (NREL), on residential and large commercial soft costs that are likely to be spent in

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45 S. Ong *et al.*, "Land-Use Requirements for Solar Power Plants in the United States" (NREL, June 2013), at Table ES-1.

46 United States Department of Agriculture, National Agricultural Statistics Service, Quick Stats, at https://quickstats.nass.usda.gov/results/58B27A06-F574-315B-A854-9BF568F17652#7878272B-A9F3-3BC2-960D-5F03B7DF4826. Given the significant environmental opposition to utility-scale solar development on unoccupied federal lands, this is a reasonable, even conservative proxy for the value of the open land used for utility-scale solar development.

47 See http://datatoolkits.lincolninst.edu/subcenters/land-values/land-prices-by-state.asp.

the local area where the DG customer resides.[48] Conservatively, if we take the large commercial soft costs to be representative of utility-scale costs, then the 17% difference between residential and large commercial soft costs, as a percentage of overall system costs, represents the added local economic benefit of rooftop systems in comparison to utility-scale solar.

Table 6: *Residential vs. Large Commercial Local Soft Costs*

Local Costs	Residential		Large Commercial	
	$/watt	%	$/watt	%
Total System Cost	5.22	100%	4.05	100%
Local Soft Costs				
Customer acquisition	0.48	9%	0.03	1%
Installation labor	0.55	11%	0.17	5%
Permitting & interconnection	0.10	2%	0.00	0%
Permit fees	0.09	2%	0.04	1%
Total local soft costs	**1.22**	**23%**	**0.24**	**6%**

These economic benefits occur in the year when the DG capacity is initially built. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same NPV in 2016 dollars. We also use more current DG capital costs than the system costs used in the LBNL and NREL studies. The result is an economic benefit of 2.9 cents per kWh of DG output. Finally, as discussed in Section 4, the growth in DG in Arizona above the RES requirements means that the state has benefitted from this local economic activity to a greater extent than if Arizona had limited DG development only to enough solar to meet the RES DG set-aside requirements.

9. Summary & Conclusion

The location of rooftop solar on the customer's premises and its deployment at the customer's choosing are the key factors that differentiate rooftop from utility-scale solar. Although utility-scale solar has lower installed costs as a result of economies of scale and higher capacity factors, this advantage is decreasing as the soft costs of rooftop solar have declined. There is significant potential to further reduce this difference, as shown by the experience in other countries and by the fact that large solar DG systems now have comparable costs to utility-scale solar.

The following table summarizes the additional benefits that rooftop solar offers as a result of its location and its deployment through customer choice, using the values that we have calculated for Arizona.

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48 B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2. See also J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37.

Table 7: *Summary of Location and Choice Benefits of Rooftop Solar*

Benefit	**Value** *(cents per kWh)*
Locational Benefits	
Avoided line losses	+0.6
Avoided transmission capacity	+1.2
Avoided distribution capacity	+1.5 to +4.0
Subtotal – direct locational benefits	+3.3 to +5.8
Added benefits when paired with storage	+5.0
Land use benefits	varies widely
Choice Benefits	
Accelerate renewable deployment • Increase electrification • Exceed RPS requirements • Avoid Green Pricing premiums • Includes local economic benefits vs. utility-scale	+7.4
Lower cost third-party financing vs. rate base for utility-owned solar	Lower LCOE by 15% to 20%

The table shows that the direct locational benefits of rooftop solar account for much of the cost difference between rooftop and utility-scale solar. While both types of solar generation provide substantial environmental benefits to the public, there are significant additional, quantifiable locational benefits from the reduced land use impacts of rooftop solar and the greater benefits from pairing rooftop solar with on-site storage. Finally, rooftop solar is developed through the choices of customers, allowing electric consumers to exercise fully their freedom to choose to be served from a higher penetration of clean energy resources for an expanding share of their primary energy needs. The value of this choice can be substantial, as illustrated by the choices to adopt rooftop solar that have resulted in APS far exceeding its RES goals. These additional benefits would be foregone if only utility-scale solar resources are developed. Distributed solar should not be undervalued by equating it to utility-scale solar when there are substantial differences between the two sources of electricity. Our conclusion remains that both types of solar should have central roles in the transition to a clean, sustainable, and resilient electricity infrastructure.

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