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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE, CHAIRMAN
BOB STUMP, COMMISSIONER
BOB BURNS, COMMISSIONER
TOM FORESE, COMMISSIONER
ANDY TOBIN, COMMISSIONER

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	**DOCKET NO. E-04204A-15-0142** **THE ALLIANCE OF SOLAR CHOICE'S NOTICE OF FILING SURREBUTTAL TESTIMONY OF MARK FULMER**

The Alliance for Solar Choice hereby provides notice of filing the Surrebuttal Testimony of Mark Fulmer in the above-referenced matter.

Respectfully submitted this 23rd day of February, 2016.

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Rose Law Group pc
Attorney for TASC

Original and 13 copies filed on this 3rd day of February, 2016 with:

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By: ______________________

Before the

Arizona Corporation Commission

In the Matter of the Application of	**)**	
UNS Electric, Inc. for the	**)**	
Establishment of Just and Reasonable	**)**	
Rates and Charges Designed to	**)**	
Realize a Reasonable Rate of Return	**)**	**Docket No. E-04204A-15-0142**
On the Fair Value of the Properties	**)**	
Of UNS Electric, Inc. Devoted to It's	**)**	
Operations Throughout the State of	**)**	
Arizona and for Related Approvals	**)**	

Testimony of

Mark Fulmer
For The Alliance for Solar Choice

February 23, 2016

Table of Contents

I. Introduction and Summary

Q: Please state your name.

A: I am Mark Fulmer.

Q: Did you provide direct testimonies in this proceeding on November 6, 2015 and December 9, 2016 on behalf of The Alliance for Solar Choice (TASC)?

A: Yes.

Q: What is the purpose of this surrebuttal testimony?

A: I respond to a number of issues raised by witnesses for Staff, Arizona Public Service (APS) and RUCO in their December 9 testimonies, as well as UNSE witnesses Tilghman, Dukes, and Overcast. My silence on any particular issue should not be construed as agreement or assent.

Q: Did UNSE make a major change in its proposal with respect to residential rates?

A: Yes. It is now proposing that a three-part rate with time-of-use (TOU) periods be applied to all residential and small commercial customers.[1] This differs from its initial proposal of requiring three-part rates only for residential and small commercial customers with new distributed generation (DG) systems, and no mandatory TOU.

Q: Please summarize your conclusions.

A: My main conclusion is that the UNSE proposed rates and policies would not provide an

[1] Rebuttal Testimony of David G. Hutchens at 2.

opportunity for residential customers to make cost-effective investments in solar DG. For purchased systems, the payback periods would be measured in decades rather than years, and for systems that are leased, positive cash flow would not occur.

My other conclusions are:

1. There is no foundation for UNSE to impose a mandatory three-part TOU rate on residential customers. There has been only a smattering of opt-in pilot programs testing residential customer understanding of and response to demand charges and to my knowledge no utility has yet implemented mandatory residential TOU. More first-hand knowledge is needed.
2. UNSE and Staff greatly understate the difficulty customers will have understanding and responding to demand charges. Even the educational materials of the only utility with a mandatory residential demand charge identified in the proceeding offered suggestions on how to respond to the demand charges that were so generic so as to be equally applicable to any time-of-use tariff.
3. A number of parties rely heavily on the ratemaking principles of James Bonbright. As aptly stated by APS witness Dr. Faruqui, "each of Professor Bonbright's principles should be read in conjunction with the others." However, UNSE and Staff have not heeded this advice, and as such, the Commission must be cautious when considering these arguments in the context of setting a residential rate.
4. The recent examples of utility regulators' rulings on DG in other states raised by UNSE are not applicable here, and in the case of Nevada, actually provide

a cautionary tale of how not to reform net energy metering.

5. I calculate that the impact of UNSE's and RUCO's proposals will be as detrimental to existing and new solar DG customers as the final rates approved in Nevada.
6. Using data from UNSE's 2014 Integrated Resource Plan (IRP), I calculate the levelized value of solar DG to UNSE to be on the order of 10¢-14¢/kWh. This is relatively close to UNSE's average residential rate, indicating that in the long run, full-service customers would be held neutral and, in fact, could even receive a net benefit by continuing current net metering policies.

II. A Three-Part TOU Rate Is Not Ready for Prime Time

Q: What does this portion of your testimony address?

A: In this section I discuss the reasons why it inappropriate to for UNSE to introduce a mandatory three-part rate, particularly one with TOU energy charges. In doing so, I rebut other parties' witnesses who argue otherwise.

Q: Throughout your testimonies in this proceeding you have been very skeptical of demand charges for residential customers, be they full-service or those using DG. Are you alone in this skepticism?

A: No. I note that the Regulatory Assistance Project recently issued a paper urging "great caution" in designing residential demand charges.[2] The paper confirms many of the concerns that I raise, as well as others such as impact on apartment dwellers, disregard of

[2] Lazar, Jim, November 2015. "Use Great Caution in Design of Residential Demand Charges," Montpelier: Regulatory Assistance Project. Included as Attachment A. The Regulatory Assistance Project is a nonprofit that "advises public officials on regulatory and competitive utility policies."

diversity patterns and mis-allocation of costs into demand charges.[3]

A. There Is Little To No Experience With Residential Demand Charges On This Scale, Let Alone With Mandatory TOU

Q: All the examples of utilities with residential three-part rates provided in Mr. Tilghman's opening testimony were voluntary: the customer had to choose to be on the rate. Have any witnesses addressed the prevalence—or even presence—of residential tariffs with mandatory demand charges?

A: UNSE witness Dr. Overcast was able to provide one single example of a utility with mandatory residential demand charges: Butler Rural Electric Cooperative (Butler REC) in El Dorado, Kansas.[4]

Q: Do any other witnesses provide examples of mandatory or default three-part residential rates?

A: No. Arizona Public Service (APS) witness Dr. Faruqui provides testimony suggesting that residential customers could respond to demand charges. He states:

> More than 40 pilot studies and full-scale rate deployments involving over 200 rate offerings over roughly the past dozen years have found that customers respond to new price signals by changing their energy consumption pattern.[5]

However, <u>none</u> of the over 40 pilot studies or 200 rate offerings included rates with demand charges. They were solely time of use rates, peak time rebates, and critical peak pricing rates.

[3] *Ibid.*
[4] Overcast at 35.
[5] Faruqui at 14.

Q: Did Dr. Faruqui cite any academic studies explicitly exploring residential demand charges?

A: Yes. However, with the exception of one study from 2009, all of the studies were at least 30 years old.[6] The one more recent study is for an opt-in program in a town in Norway. Given that the participants in the Norwegian study were self-selected, coupled with the cultural and climatic differences between Norway and Arizona, I cannot recommend the Arizona Corporation Commission (ACC) rely upon this study as a justification for a three-part rate for UNSE.

Q: Do any other witnesses provide examples of mandatory TOU residential rates?

A. No. To my knowledge there are no utilities in the U.S. that currently employ mandatory TOU rates for all residential customers. California is set to move all residential customers to *default* TOU rates starting in 2019, but *default* TOU is very different than *mandatory* TOU. Default TOU rates allow all residential customers to maintain the flexibility to choose a rate design that is right for them, while mandatory TOU rates leave customers with no options if they find that they are unable to adapt. While the California Public Utilities Commission did recently vote to move only all new DG customers onto mandatory TOU rates starting likely in 2017, this decision was in response to a much higher penetration of DG customers than exists in UNSE's territory. Mandatory TOU for DG customers remains an uncommon rate design that is typically only explored in areas with very high DG penetration.

[6] Faruqui at 15.

Q: What considerations are being made by California utilities in the transition to default residential TOU?

A. The transition to residential default TOU is not being taken lightly. The California PUC has ordered the utilities to implement extensive piloting to determine how ratepayers will respond to TOU rates and to ensure that such a transition is not unduly harmful, particularly to vulnerable rate classes such as elderly or low-income. To ensure successful implementation, these pilots will collect data on several differ rate TOU rate designs over the course of 15 months from more than 50,000 participants.[7]

Q: Has UNSE proposed any pilot programs to explore the impact of mandatory TOU rates or demand charges?

A. No. UNSE has not proposed to do any piloting for these extreme rate designs either before or after implementation. In my opinion, adoption of these rates without thorough testing is simply experimenting on ratepayers unnecessarily. With such untested rate design, the outcomes could be severe. Furthermore, both Staff and UNSE suggest that demand charges be implemented after providing the customer with only three months of historical usage data.[8] Given the highly varied seasonal climates in Arizona, this is clearly insufficient. Usage data from March, April, and May are not sufficient for a customer to understand or manage their demand and TOU energy consumption during the following summer and winter months. If UNSE is authorized to implement such drastically different rate design, it should provide customers with at least a full year of usage data prior to implementation.

[7] Statewide TOU Pilot Design Final Report, p. 99.
[8] Solganick at 31; Dukes at 9.

B. A Three-Part Rate Cannot Currently Encourage Innovation

Q: A number of witnesses suggest that a three-part residential rate would encourage innovation, prompting customers to react to the demand charge.[9] In his rebuttal testimony, Mr. Tilghman provides the examples of battery storage and fuel cells.[10] Are these innovations costly?

A: Yes. While demand charges would in theory create a market for demand-reducing technologies, these technologies are not nearly as simple as installing a new thermostat, light bulb, or windows. For example, the TESLA Powerwall battery with 7 kWh of storage costs $3,000, plus the cost of installation by a qualified electrician, and if used without solar PV, the cost of an inverter.[11] With respect to the other technology mentioned by Mr. Tilghlman, fuel cells, the non-profit Upgrade Energy California says a residential fuel cell can cost over $50,000 in addition to installation costs.[12]

These are serious investments for households at virtually any income level. Given that the average income in Mohave and Santa Cruz Counties are 26% and 29% lower, respectively, than the national average; that over 26% of the population of Santa Cruz County is below the federal poverty line; and that over ¼ of Mohave County residents are senior citizens, investments of this magnitude should not be expected to be widespread.[13] And while innovative entrepreneurs may develop business models to deliver these technologies (and others) in a way that lower-income citizens can afford, they currently

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[9] E.g., Faruqui at 14, Tilghman at 5, Broderick at 8.
[10] Tilghman at 5. All citations to Tilghman refer to his January 19, 2016 Rebuttal Testimony.
[11] https://www.teslamotors.com/powerwall Accessed 2/13/16.
[12] http://www.energyupgradeca.org/en/save-energy/home/make-your-power/make-your-power-with-fuel-cells Accessed 2/13/15
[13] Statistics from U.S. Census Bureau: State and County QuickFacts. http://quickfacts.census.gov/qfd/states/04000.html. Accessed 2/13/16

do not exist.

C. It Has Not Been Demonstrated That Residential Customers Will Understand and be Able to Respond to Demand Charges

Q: Staff witnesses Broderick testifies, "residential customers can be quickly educated" on how to respond to a demand charge;[14] that "Staff believes that new meter technology, internet communications portals, and smart phone applications have made it feasible and much easier for residential customers to understand and accept a three-part tariff than ever before;"[15] and "Staff does not presume that any group is so vulnerable as to be unable to understand and tolerate a demand kW charge."[16] Has Mr. Broderick provided any evidence to support these opinions?

A: No. They are simply assertions with no discussion or evidence to support them. Furthermore, educating the customers in Santa Cruz County will present an extra challenge, as over ¾ of the population speaks a language other than English at home.[17] Given that the only pilot programs for residential demand charges cited so far in this proceeding were opt-in,[18] I believe that data from a pilot program with randomly assigned participants is needed in order to conclude that "customers can be quickly educated" and meaningfully respond to demand charges.

Mr. Broderick also testifies that "Solar DG customers will, therefore, need to carefully consider their lifestyle decisions and additional related technology choices for those hours, for example, in the summer from when the sun starts to set and until 8

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[14] Broderick at 8.
[15] Broderick at 7.
[16] Broderick at 9.
[17] Statistics from U.S. Census Bureau: State and County QuickFacts. http://quickfacts.census.gov/qfd/states/04000.html. Accessed 2/13/16
[18] Butler REC was not a pilot and is discussed later.

p.m."[19] Since Staff and UNSE also propose having full service customers on demand charges, they too will have to "carefully consider their lifestyle decisions." I am skeptical that a rate design, which requires customers to carefully consider their lifestyles in order to adjust their electric bill, is rational or fair.

Q: UNSE witness Dr. Overcast points out that one rural electric cooperative in Kansas, Butler REC, has residential demand charges, and included as an attachment to his testimony the educational material that Butler REC provides for its customers. Did you review this attachment?

A: Yes. The Butler REC educational material emphasizes "FREE demand" (emphasis original), in that customers don't pay demand charges a majority of the time. The "tips" for how to reduce demand include only one that is specific to reducing demand charges: running large appliances outside of the peak demand periods.[20] The other nine suggestions are equally applicable to general energy efficiency. The Butler REC message to its demand-charge customers is no different than what a utility would provide concerning a time-of-use rate, except that the ramifications of using power in the peak hours are much greater. Nowhere does the Butler REC educational material state that the customer has to reduce demand <u>every</u> weekday evening between 5:00 and 8:00—with no exceptions—in order to reduce the demand charge portion of their bill. If a Butler REC customer has to run one load of laundry in the evening, or cook one meal using an electric range, they're paying a hefty the demand charge for that month. I cannot conclude from either Dr. Overcast's testimony or the Butler REC education materials that

[19] Broderick at 8.
[20] HEO-5, page 4.

he provided that the Butler REC customers in general fully understand demand charges and are reacting in a knowledgeable way.

Q: Witnesses for UNSE have pointed to the mandatory three-part rate instituted by Salt River Project (SRP) for customers with solar DG. Has SRP management been consistently positive about residential demand charges?

A: No. At a SRP Special Board Meeting on February 12, 2015, SRP General Manager Mark Bonsall was perhaps a bit more candid than he intended, when he flatly stated that it would be difficult for him to put his grandmother on a three-part rate, and that she'd likely be paying more than she needs to:

> MR. BONSALL:I guess the bottom line on that is I think it would be very difficult, were she still with us, to put my grandma ma on a demand charge. I mean, we're gonna have people that just don't want to do that or it's too complicated for them to understand and/or they don't care about it. I think we need to be sensitive to some of those issues as well.
>
> MR. HOOPES: I hope you're not suggesting that I want your grandmother to pay more than she needs to, but --
>
> MR. BONSALL: Actually, President Hoopes, I was assuming that.[21]

Q: Have there been societal repercussions from SRP's rate design?

A: According to the Solar Jobs Census, Arizona lost 2,282 of its 9,204 solar jobs last year.[22] While solar employment in Arizona is expected to grow 8.4% in 2016, this figure will be much lower and possibly negative if UNSE's mandatory 3-part TOU rate design is approved, particularly if other Arizona utilities follow suit.

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[21] Salt River Project Special Board Meeting Continuation Special Board Meeting On Proposed Changes To Standard Electric Price Plans And Terms And Conditions Of Competition. February 12, 2015. Transcript at 46. Attachment B

[22] The Solar Foundation, 2015. *State Solar Jobs Census Compendium* at 119.

Q: Please summarize your testimony concerning customer understanding and reaction to demand charges.

A: Neither UNSE or any other party has provided studies or evidence that residential customers generally understand demand charges and will be able be able to react to the "price signals" they send. Additionally, movement of residential customers to mandatory TOU rates, especially in the absence of extensive piloting, would be unprecedented and inappropriate. As such, it would be putting the cart way in front of the horse to institute a three-part TOU residential rate throughout the service area. Additional controlled studies are needed to ascertain how much customers would actually understand about demand charges and TOU. Furthermore, additional affordable tools need to be in place for customers to meaningfully react to demand charges and TOU before the ACC contemplates implementing such a rate.

III. Rate Design Principals

Q: A number of witnesses in the proceeding have referred to fundamental ratemaking principals as formulated by James C. Bonbright and presented in *Principles of Public Utility Rates.*[23] Can you summarize who has referred to Bonbright in testimony, and what they have said?

A: Yes. First, in his December 9th testimony APS witness Dr. Faruqui summarizes Bonbright's ten "attributers of a sound rate structure," grouping them into five general categories: economic efficiency, equity, revenue adequacy and stability, bill stability, and

[23] Bonbright, James C., Albert L. Danielsen and David R. Kamerschen, 1988. *Principles of Public Utility Rates (Second Addition).* Arlington VA: Public Utility Reports, Inc.

customer satisfaction.[24] He then focuses on "cost causation," arguing that while not explicitly listed in Bonbright's list, is clearly implied by it (particularly on economic efficiency and equity). [25] To his credit, he also testifies, "cost causation may need to be balanced against the other core principles," and "Each of Professor Bonbright's principles should be read in conjunction with the others."[26]

UNSE rebuttal witness Dr. Overcast frames his testimony around three principles: fairness, efficiency, and gradualism, stating that, "These principles are consistent with rate principles developed by Bonbright and discussed widely by others."[27] He further includes quotes attributed to Bonbright throughout his testimony, however specific citations are not provided.

Other witnesses also refer to Bonbright, although not in the detail that Drs. Faruqui and Overcast do. RUCO witness Huber testifies that his recommendations are based on Bonbright's principals, as summarized in a NARUC document.[28] SWEEP witness Schlegel and VoteSolar Witness Kobor both cite to Bonbright when discussing very specific cost and rate issues.[29] Lastly, I responded in my December 9th testimony to how UNSE witness Dukes used Bonbright's text, pointing out that he focused on only two of the foundational principals, revenue stability and rates that yield total revenue requirements, at the expense of others, such as simplicity, understandability, public acceptability, avoidance of undue discrimination, and wastefulness.[30]

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[24] Faruqui at 5-8.
[25] Faruqui at 8.
[26] Faruqi at 9.
[27] Overcast at 40.
[28] Huber at 5.
[29] Schegel at 7; Kobor at 57.
[30] Fulmer at 10.

Q: Can these rate making principles sometimes conflict?

A: Yes, and as such, regulators must strike a balance: too much emphasis on any one principle can lead to undermining the others.

Q: Please provide an example of how some of these ratemaking principles are in conflict.

A. A prime example of this is the tension between revenue adequacy and economic efficiency. Revenue adequacy requires that the utility can recover all of its costs. Utility revenues are typically determined using embedded or marginal short-term costs. Economic efficiency requires that customers be provided with price signals that will allow them to make economically efficient decisions with regard to their electricity consumption levels. In other words, customers must be given the proper price signals to invest in energy efficiency measures, invest in distributed generation resources, or simply consume less energy in order to save on electric bills.

As I have noted in my prior testimonies in this docket, there can be significant differences between short-term costs used for determining revenue adequacy and long-term costs used for sending economically efficient price signals. In the short-term, fixed costs can include capacity costs associated with generation, transmission and distribution; while over the long-term, none of these costs are truly fixed. Setting rates based on short-run price signals will not be efficient in the long run.

Q: Do you have any concerns with the way other witnesses are using Bonbright's principles?

A: Yes. First, I note that near the beginning of his chapter on Cost of Service, Bonbright states, "In the first place, the principle [the cost standard of ratemaking] is followed far more closely as a measure of general rate levels than a measure of individual rate schedules."[31] However, much, if not all, of the cost-of-service discussions raised by Drs. Faruqui and Overcast focus solely on "individual rate schedules." As such, the Commission must be cautious when considering these arguments in the context of setting a residential rate.

IV. Mischaracterizations of TASC Testimony

Q: What do you address in this section of your testimony?

A: I will point out some of the mischaracterizations of, and misleading statements about, my testimony made by UNSE witnesses.

Q: Mr. Tilghman testifies, "The Company will credit every kWh of energy produced from the DG system that the customer uses at the full retail rate."[32] Is this correct?

A: First, characterizing the savings of reduced customer use at the electric meter, for whatever reason, as a "credit" bestowed by the utility is disingenuous. It isn't a credit; it is simply the value of not paying for power that is not purchased. This is true whether the customer is not a home, has installed energy efficient equipment or self-provides a portion of their electricity usage. Second, federal law requires that utilities allow customers to self-provide power behind the meter.[33] UNSE is not crediting the customer;

[31] Bonbright at 110.
[32] Tilghman at 6.
[33] *See* 18 C.F.R. 292.303(c)(e)

it is following the law.

Q: In response to your testimony on the differing environmental impacts between solar DG and central solar, Mr. Tilghman states, "Even without the Company's site selection criteria to minimize these impacts, it is irrational to argue that any minimal environmental impact associated with utility scale facilities justifies a solar DG credit equal to twice the cost of energy from utility scale facilities."[34] How do you respond?

A: In this sentence from his rebuttal, Mr. Tilghman is responding to an argument that I did not make. Nowhere in my Direct Testimony do I say that the differences in the environmental impact between central solar and DG solar <u>alone</u> justify any purported cost difference between the two technologies. I would not make such a statement. Instead, I point out that there are differences in the environmental impacts of DG and central solar, and that those differences should be noted and accounted for. Never do I argue that "any minimal environmental impact associated with utility scale facilities justifies a solar DG credit equal to twice the cost of energy from utility scale facilities."

Q: How do the UNSE witnesses mischaracterize solar DG's contribution to peak hours?

A: First, Mr. Tilghman states: "[Mr. Fulmer testifies that] 'solar provides power during times of high system load when power is more valuable,' once again highlighting his lack of actual operational experience in grid management and relying on an often repeated, yet incorrect, statement that applies to only a few months during the year."[35] While I have

[34] Tilghman at 13.
[35] Tilghman at 13.

not participated in grid management, I have prepared and critiqued integrated resource plans (IRPs) and testified in state utility commission proceedings on electric resource planning. As I will discuss below, utilities plan their supply capacity portfolio based on the anticipated demand occurring on a few highest days—if not hours—of the year.

Second, Mr. Tilghman says,

> "The Company has previously shown that at no time during the year does the system peak when solar peaks. In fact, during the winter months when the system peaks before the sun rises and after the sun sets, solar has absolutely zero value during the times of greatest need and when prices are the highest."[36]

Dr. Overcast also makes analogous statements.[37]

Q: How do you respond?

A: First, nowhere do I state that solar PV's output coincides with UNSE's system peak. Simply because the PV panels' maximum output does not occur at the exact same time as the utility's maximum load does not mean that it does not contribute to reducing system peak. In fact, in the value of solar analysis presented later in this testimony, I explicitly take this fact into account using UNSE's own solar "coincidence factor." The coincidence factor is a number that reflects what fraction of power solar PV's capacity contributes to system peak demand.

Second, I do not understand why Mr. Tilghman and Dr. Overcast suggest that the fact that the UNSE system peaks during winter months is applicable to the capacity value of solar. As noted in UNSE's 2014 Integrated Resource Plan, UNSE is a summer-peaking utility.[38] As shown in the Charts 12 and 13 from its IRP (repeated below), UNSE's

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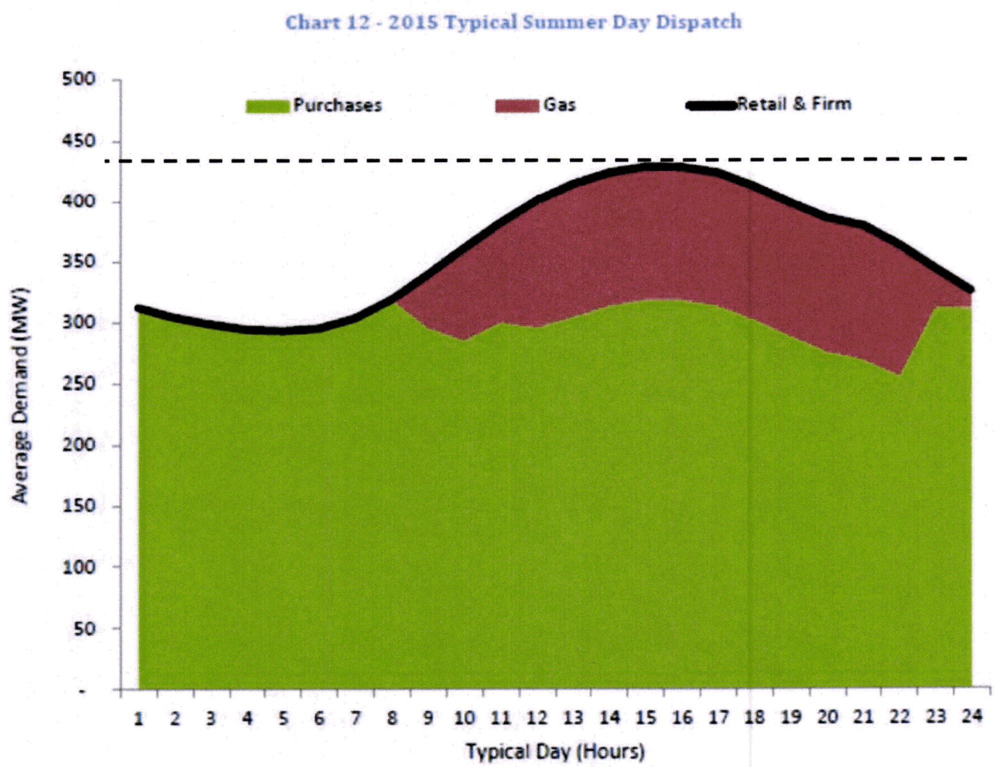
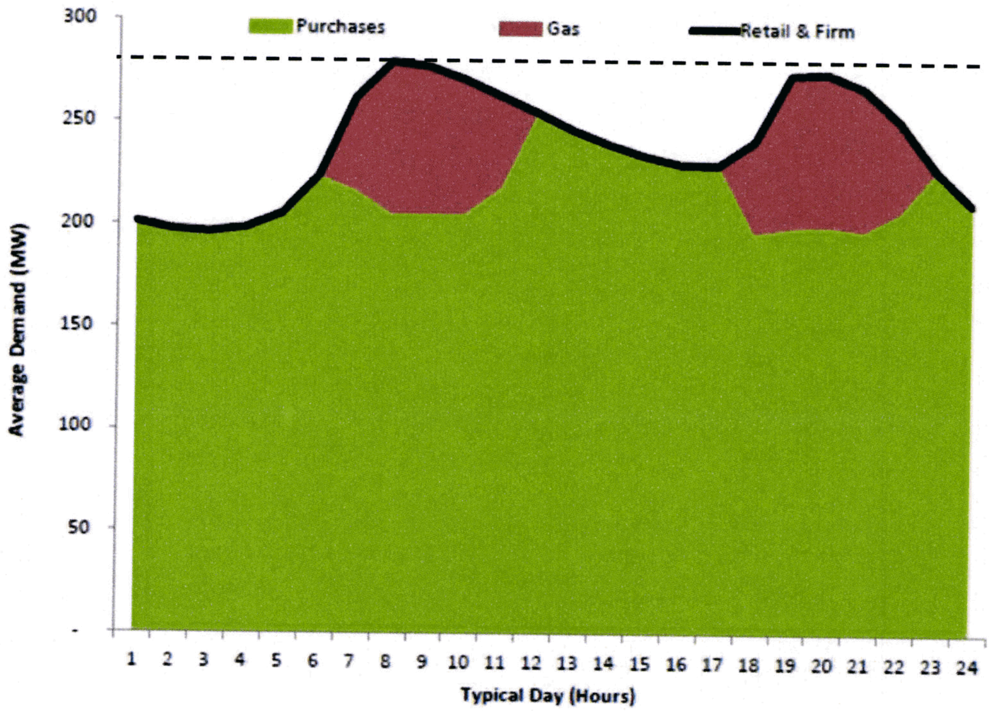
[36] Tilghman at 13.
[37] Overcast at 12-13.
[38] UDR 1.006: Unisource Energy 2014 Integrated Resource Plan (IRP), April 1, 2014 at 44. This is also shown in

typical peak summer load is ~160 MW more than its typical winter peak load. Furthermore, the two figures show that the typical <u>peak</u> winter load is less than the <u>average</u> summer load.. Given that generation capacity is planned around the system's peak load, the fact that solar PV does not generate power during early winter mornings is not relevant when considering PV contribution to a utility's generating capacity.



RUCO witness Huber's testimony at 20.

Chart 13 - 2015 Typical Winter Day Dispatch



Q: What does Dr. Overcast testify concerning rate options to address DG?

A: Dr. Overcast states,

> All of this evidence suggests that with a two part rate and net metering with banking can never result in just and reasonable rates for partial requirement customers. The only possible alternative to treat partial requirements, DG customers equitably is a separate rate class with a three- part rate."[39]

This statement is a classic example of a false dichotomy. Setting aside whether or not net metering with banking is just and reasonable or not, he simply asserts that the "only possible alternative" is the one he supports: DG as a separate rate class with a three-part rate. Obviously, this isn't the only possible alternative. RUCO has proffered alternatives. Staff has suggested alternatives. Even UNSE's own recommendation to move all

[39] Overcast at 19.

residential customers onto the three-part TOU rate, and not just DG uses, contradicts Dr. Ovcercast's statement. There are many ways to address solar DG besides the two stated by Dr. Overcast. To assert that his is the only answer is disingenuous and misleading.

In fact, I recommend that Staff and UNSE work together to examine alternatives to both the simple two-part rate and a three-part rate with TOU. Some options that I believe should be considered include default time of use, minimum bill provisions, and critical peak pricing (i.e., very high rates a few hours a year during system peaks).

V. Miscellaneous Issues

A. RUCO Rate Proposals

Q: Please Summarize RUCO witness Huber's proposals concerning residential customers with DG.

A: Mr. Huber suggests three alternatives to UNSE's proposal.

1. A "non-export" policy, whereby customers with DG system are not allowed to export power to the grid, or if the Commission is not agreeable, to allow exports to be valued at wholesale rates.[40]
2. A "DG TOU rate," with "energy and TOU demand intended to recover fixed costs from customers with DG.[41]
3. A "simple fixed credit mechanism," whereby the customer with DG simply pays the tariffed rate for all if his or her actual consumption while being credited for all of the output of the customer's DG system. I would classify

[40] Huber at 13.
[41] Huber at 14.

this as a "buy-all-sell-all" or a feed-in tariff.

Q: Do you find Mr. Huber's first suggestion—non-export policy—to be reasonable?

A: No. Although Huber would grandfather existing DG customer into their current DG compensation mechanism, forbidding grid export or crediting exports is poor policy. First, it would remove much of the economic value of solar DG, which I believe would reduce new solar DG adoptions to a trickle. This violates the Commission's REST goals (as later discussed by Huber).[42] In addition, the non-compensation or minimal compensation (short-run wholesale power market prices) would grossly understate the value that DG systems are providing to UNSE and its customers. This is discussed in depth later in Section VII of my testimony.

Q: Do you find Mr. Huber's second suggestion—the three-part TOU DG rate—to be reasonable?

A: No. As discussed in Section VI and shown in Table 1 of my testimony, Mr. Huber's proposed flat energy rate with a seasonal TOU demand charge would not offer a viable economic opportunity for customers desiring solar DG.

Q: What about his feed-in-tariff proposal?

A: While a feed-it-tariff can be a piece of the solar DG puzzle, it isn't a replacement for net metering. First, it is equally as difficult to set an appropriate FIT rate as it is to determine how or if costs shifting with net energy metering. Second, there are significant tax implications, such as loss of certain tax benefits that accrue to residential solar that serves

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[42] Huber at 21.

onsite load as well as the sales to the utility of power being seen as income.

B. Intermittency And Geographic Diversity

Q: Mr.Tighlman also states "Mr. Fulmer's and Ms. Kobor's claims that there is a benefit of intermittency smoothing that lacks any credible, real-world evidence."[43] Is this accurate?

A. No. Pages 13 through 15 of my November 6 Direct Testimony list many credible studies based on real-world evidence that geographically dispersed DG provides a "smoother" more reliable solar power source than a central solar station. For example:

- A study that analyzed the power fluctuations of seven PV plants scattered throughout Spain concluded "[t]he geographical dispersion of the PV plants is a highly effective way of smoothing the power fluctuations, even for ten minute sampling intervals. It is sufficient to locate two PV plants at a distance of 6 km, one from the other, to ensure that the fluctuations over 10 minute intervals are independent of each other and are smoothed out when combined."[44]
- A similar study conducted in Colorado arrived at the same conclusions: "[o]verall, a significant smoothing effect was observed when the averaged solar irradiance at four solar sites across Colorado is compared to the individual sites."[45]
- Lave et al. concluded in their study that "[w]hile the variability of PV powerplants can be a concern, geographic diversity within the plant will lead to a reduction in

[43] Tilghman at p 12
[44] Marcos, J., L. Marroyo, E. Lorenzo, and M. García. "Power Output Fluctuations in Large PV Plants." In *International Conf. on Renewable Energies and Power Quality*, 2012. http://www.icrepq.com/icrepq'12/676-marcos.pdf.
[45] Lave, Matthew, and Jan Kleissl. "Solar Variability of Four Sites across the State of Colorado." *Renewable Energy* 35, no. 12 (December 2010): 2867–73. doi:10.1016/j.renene.2010.05.013.

variability versus a single point. By examining a 2.1MW residential rooftop PV plant in Ota City, Japan and a 19MW central PV plant in Alamosa, Colorado, the relative variability as a function of capacity was found to decay exponentially for both plants."[46]

- A Lawrence Berkeley National Laboratory study "conclude[d] that the costs of managing the short-term variability of PV are dramatically reduced by geographic diversity and are not substantially different from the costs for managing the short-term variability of similarly sited wind in [the Southern Great Plains]."[47]
- Finally, a report by the National Renewable Energy Laboratory, citing studies in Japan,[48,49] and Germany,[50] concluded "[i]t is well studied that aggregation of sites produces a smoother output of power on a per capacity basis. These studies primarily address smoothing through geographic dispersion, and attempts have been made to mathematically model this phenomenon."[51]

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[46] Lave, Matthew, Joshua S. Stein, and Abraham Ellis. "Analyzing and Simulating the Reduction in PV Powerplant Variability due to Geographic Smoothing in Ota City, Japan and Alamosa, CO." In *Photovoltaic Specialists Conference (PVSC), Volume 2, 2012 IEEE 38th*, 1–6. IEEE, 2012. http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=6656719.

[47] Mills, Andrew. "Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power." *Lawrence Berkeley National Laboratory*, 2010. http://escholarship.org/uc/item/9mz3w055.pdf.

[48] Murata, Akinobu, and Kenji Otani. "An Analysis of Time-Dependent Spatial Distribution of Output Power from Very Many PV Power Systems Installed on a Nation-Wide Scale in Japan." *Solar Energy Materials and Solar Cells* 47, no. 1 (1997): 197–202.

[49] Otani, Kenji, Jyunya Minowa, and Kosuke Kurokawa. "Study on Areal Solar Irradiance for Analyzing Areally-Totalized PV Systems." *Solar Energy Materials and Solar Cells* 47, no. 1 (1997): 281–88.

[50] Wiemken, E., H. G. Beyer, W. Heydenreich, and K. Kiefer. "Power Characteristics of PV Ensembles: Experiences from the Combined Power Production of 100 Grid Connected PV Systems Distributed over the Area of Germany." *Solar Energy* 70, no. 6 (2001): 513–18.

[51] Urquhart, Bryan, Manajit Sengupta, and Jamie Keller. "Optimizing Geographic Allotment of Photovoltaic Capacity in a Distributed Generation Setting." *Progress in Photovoltaics: Research and Applications* 21, no. 6 (2013): 1276–85.

C. Recent Development Examples

Q: Mr. Tilghman also provides examples of states where actions have recently been taken to change their met metering policies. What examples did he provide?

A: He pointed to three states: Hawaii, Utah and Nevada. However, he did not include a major one—California, where the commission chose to continue net energy metering with compensation based on retail rates and month-to-month banking.[52] Furthermore, I found none of the policy recommendations in the three states to be compelling or applicable to Arizona.

- Hawaii: First and foremost, Hawaii Electric is at a much higher DG penetration level that UNSE, making the technical and economic issues associated with net metered solar ripe for discussion. Also, retail rates in Hawaii are significantly higher that UNSE's rates, with residential and small commercial rates ranging from a low of 22¢/kWh up to 35¢/KWh.[53] Additionally, the current buyback rate offered by Hawaiian utilities is no less than 15.07¢/kWh and ranges as high as 27.88¢/kWh.[54] Even their new pricing, which is many times higher than that proposed by UNSE, is higher than UNSE's retail rates.
- Utah: Mr. Tilghman provides a number of "fallacies" from a recent Utah Public Service Commission order addressing solar DG issues. However, none of the issues enumerated in the Utah decision cited by Mr. Tilghman are new, and in fact most are addressed organically by the dispersed nature of small solar DG. In fact, all six issues

[52] California Public Utilities Commission Decision 16-01-044.
[53] Hawaiian Electric Effective Rate Summaries, January 29, 2016. https://www.hawaiianelectric.com/Documents/my_account/rates/effective_rate_summary/efs_2016_02.pdf
[54] Customer Grid Supply prices. https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-grid-supply-and-self-supply-programs. accessed 2/18/16.

listed by Mr. Tilghman focus on the fact that the utility does not have control over customer-side solar DG systems. This is true, but reflects the utility's (and frankly, the Utah Commission's) discomfort with elements outside of its control, while not considering the actual impacts. Yes, customers decide if and how much solar to install (Issues 1, 2, 4 and 6); how to maintain it (Issues 3 and 5). But this does not account for the fact that these decisions are made by thousands of independent actors (customers) as well as the fact that actors' best interests are generally aligned with the utility's. It is in the best interest of both the utility and the solar PV user (or if different, the PV owner) to keep the system well-maintained and operational. Furthermore, a diversity of actors (i.e., decisions concerning each system are made independently) mitigates most of the remaining concerns. People will not abandon their solar PV at the same time, creating the system problems implied by the six listed issues. Electric utilities need to be able to predict the load that they must serve; not control it.

- Nevada: The Nevada decision cited by Mr. Tilghman has caused widespread economic and political reverberations throughout the state. Major solar PV providers have pulled out of Nevada, laying off thousands of workers.[55] Solar customers have filed a class-action lawsuit.[56] If Arizona wants to avoid these problems, looking to Nevada for guidance would be poor advice.

[55] http://www.pv-magazine.com/news/details/beitrag/solarcity-pulls-out-of-nevada_100022579/#axzz40IJTiCx5 Accessed 2/15/16

[56] http://lasvegassun.com/news/2016/jan/15/lawsuit-filed-over-new-rooftop-solar-utility-rates/ accessed 2/15/16.

VI. Impact of Proposed Rates on Prospective Solar DG Customers

Q: Have you reviewed the impact that UNSE's proposed rates would have on solar customers' electric bills and how that would likely impact the business of solar?

A: Yes I have.

Q: Please explain the economics of solar to the utility customer and what you found in your analysis.

A: It appears most electric customers implement solar because it is a sound investment and a good use of their money. Before going solar, a utility customer has one bill for all his power. This bill comes from the utility, in this case, UNSE. In order to acquire solar, the customer either purchases or leases solar equipment to generate solar power for his use. After the customer purchases his solar equipment, and it is up and running, the customer pays the utility a reduced amount on a monthly basis, reflecting his reduced reliance on the utility for much of his electricity. The reduced monthly payments to the utility act as the return on the solar investment, ultimately paying the customer back for his sizable investment over a period of time. This period of time is also called the "payback period" in the solar business. The old adage, "the shorter the payback period, the better the investment," clearly applies here. If the payback period gets too long, then a customer could make wiser investments elsewhere, potentially eliminating the financial incentive to purchase a solar system entirely.

In the lease situation, the customer ends up with two bills related to his consumption of energy. The customer continues to receive a bill from the utility, reflecting his reduced reliance on the utility for his power needs; but also receives a monthly bill from the solar leasing company for the lease payments on the solar equipment. When these two monthly bills are added together, they should be less than what the customer would otherwise pay to the utility if the customer was still relying on the utility for 100% of his electric needs. If the two bills added together are more than the customer would otherwise pay a utility for 100% of his power needs, then the customer's investment in solar will not be a profitable one and, like other poor investments, will be avoided.

I examined UNSE's proposed tariffs using the spreadsheet tool first circulated by Staff (per Staff data request to TASC, SFT-BG 2.1), as modified to accurately account for appropriate assumptions and to model specific rate plans at issue in this case as described below, to determine what impact they would have on the payback period for a purchased solar system and the impact they would have on a solar leasing customer's ability to save money by leasing solar panels. As I summarize below in Table 1, the proposed UNSE tariffs leave the payback period much too long to justify the purchase of solar equipment and eliminates the opportunity for a customer to save money with a solar lease.

I examined each proposed UNSE tariff, under both status quo net metering and proposed net billing scenarios, using public load and generation profiles appropriate for the geographic territories that UNSE serves. I focused primarily on northern Arizona, using NREL Las Vegas billing determinants and load shape.

Under the proposed UNSE transition rates and final rates and a net billing mechanism, solar customers would pay significantly more per year than full-service customers (Table 1). Using the NREL billing determinants,[57] solar lease customers under the proposed 2-part non-TOU net billing transition rate would pay roughly $188 more per year for solar, or $16 per month. With the same rates, but under the current net metering billing mechanism, solar customers would save roughly $207 per year, or $17 per month. For customers that purchased their system outright, under the 2-part net billing transition rates it will take roughly 46 years to recoup the investment of their system, far exceeding the expected system life of roughly 35 years, and compared with roughly 23 years under the two-part transitional rate with net metering. Under the proposed final TOU demand charge rates, solar customers would lose under both net metering and net billing. Under net metering, customers would pay $347 more per year for solar ($29 per month), and $409 per year ($34/month) under net billing. With the proposed demand charges, solar customers who buy their systems outright would likely never be able to recoup the upfront cost of their investment, with the payback under both net metering at 58 years, and the payback under net billing exceeding 100 years.

[57] Assumes NREL Las Vegas high load estimate, most indicative as solar customers typically have higher than average load. Further assumes average monthly consumption at roughly ~1,500 kWh per year, with a system sized at 8.5kW offsetting 80% of load.

Table 1. Economics of Solar DG Under Proposed Rates

	Proposed 2-part transition non-TOU rate (net metering)	Proposed 2-part transition non-TOU rate (net billing)	Proposed final 3-part TOU rate (net metering)	Proposed final 3-part TOU rate (net billing)	Nevada Final Rates (net billing)	RUCO Advanced DG TOU rate (net billing)
Pre-Solar Utility Bill	$2,030	$2,030	$1,816	$1,816	$2,220	$1,985
Post-Solar Utility Bill	$513	$907	$853	$914	$1,533	$1,009
Utility Bill Savings	$1,517	$1,123	$963	$901	$687	$976
Total Lease Cost*	$1,311	$1,311	$1,311	$1,311	$1,311	$1,311
Total Solar Bill	$1,823	$2,217	$2,163	$2,225	$2,844	$2,319
Annual Bill Savings	$207	($188)	($347)	($409)	($623)	($334)
Breakeven Lease Rate	$0.10	$0.08	$0.07	$0.06	$0.05	$0.07
Discounted payback**	22.8 Years	45.5 Years	57.6 Years	100+ Years	100+ Years	100+ Years

*As reported in Greentech Media, the LCOE for solar leases in Arizona is 11.1 cents per kWh. Year 1 lease rate of $0.08946/kWh converted from LCOE by assuming 2.9% escalation, 7.2% discount rate, and 0.5% annual degradation.

**Assumes system cost of $3.60/watt (DC),[58] 2.9% escalation, 7.2% discount rate, and 0.5% annual degradation.

Q: How does this compare to the tariff's recently implemented in Nevada?

A: The impact of the rates that will be implemented over a transition of several years in Nevada, which have led to the near shutdown of the solar DG industry in the entire state, is similar to the impact of UNSE's proposed final 3-part rate. To determine the Nevada results, I simply input into my UNSE impact model the final approved Nevada fixed charge, energy, and export rates under a net billing scenario, consistent with Nevada's new rates. As shown in the table above, the Nevada rates result in customers paying roughly $623 more per year for solar, which, from a customer's perspective is not significantly different than the anticipated $347 per year increase under UNSE's proposed 3-part net metering rate, or the $409 per year increase resulting from UNSE's

[58] Lawrence Berkeley National Laboratory, Tracking the Sun VIII, August 2016, p. 32.

proposed 3-part net billing rate. Under UNSE's proposed 3-part net billing rate, customers would need to obtain a solar lease rate of no more than $0.06 per kWh in order to not lose any money going solar. Under a 3-part net metering rate this breakeven is slightly higher at $0.07 per kWh. Compare these rates to the breakeven rate at $0.05 per kWh under the Nevada scenario. Any rate design resulting in a breakeven rate well below the estimated $0.08946/kWh currently available to Arizona customers is unreasonable.

Q: Have you evaluated the rate proposals of other parties in this proceeding?

A: Yes. I also calculated the impact of RUCO's "Advanced DG TOU Option," which is a 3-part DG-only net billing rate design with three components: 1) a minimum bill of $12.25 per month; 2) a base energy rate equal to $0.085/kWh; and 3) and a summer only demand charge of $19.50/kW, assessed over peak hours (2-8 p.m.).[59] The proposed export rate under RUCO's Advanced DG TOU Option is $0.085/kWh. I compared the solar bill savings under this DG-only rate to pre-solar costs assuming that a customer would otherwise take service on the Residential Service rate schedule. Revenue neutral rates for this rate schedule were provided by RUCO in Exhibit 2 of Huber's testimony.

Q: Please explain your findings from your RUCO analysis.

A: The impact of RUCO's proposed 3-part rate is included in Table 1. RUCO's Advanced DG TOU Option would be extremely detrimental to solar customers, with impacts very similar to UNSE's proposed rates and the Nevada rates. Under RUCO's proposed rate, customers would spend roughly $334 more per year ($28 per month) for solar, requiring

[59] Huber Direct Testimony, p. 14.

a solar lease rate of $0.07/kWh to bring this loss to $0.

Q: So what does this suggest about what would happen to the solar industry in UNSE service territory if the proposed rates are implemented?

A: It is clear that UNSE's and RUCO's proposed tariffs would render investing in rooftop solar through purchase or lease a poor economic choice for consumers. In other words, the economics of the solar investment would make adopting solar actually more expensive than simply continuing to purchase all power from the utility. In other instances where this has occurred, like SRP territory and Nevada, the market for rooftop solar has essentially grounded to a halt. Given my analysis, that is what I would expect to happen in UNSE territory if these tariffs are adopted. I expect UNSE's proposed tariffs to essentially stop the implementation of DG solar in UNSE's service territory.

VII. Value of Solar Analysis

Q: What is the purpose of this section of your testimony?

A: UNSE witness Dallas Dukes noted that TASC and Vote Solar simply opposed all rate design changes without proposing any substantive alternatives.[60] This is because TASC believes that net metering continues to be an appropriate policy for residential and small commercial solar DG. To support this assertion, I present a value of solar analysis, which shows that the long-term value of solar DG is comparable to the forgone rates that the solar offsets.

[60] Dukes at 3.

A. Method and Assumptions

Q: How did you conduct this value of solar analysis?

A: In general, I followed the structure outlined in the report "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service" (Crossborder Report).[61] The report was prepared on behalf of solar interests in response to a January 23, 2013 ACC order for APS to conduct a multi-session technical conference to evaluate the costs and benefits of renewable DG and net energy metering (NEM). This report identified a number of key utility areas where solar DG can, in the long run, avoid costs to the utility costs, thus providing value to the utility.

Q: Please describe your analysis.

A: To calculate the value of DG solar, I estimated values for seven areas where DG solar can avoid or cause utility costs. I looked at each of these elements over the long run, projecting the levelized value of each element over the 20 year life of a typical solar DG system. I used the UNSE weighted average cost of capital from its 2014 Integrated Resource Plan (IRP)[62] for the discount rate.

The seven elements considered are:

1. Avoided energy: Avoided energy is the variable cost of power plants that is avoided due to the effective load reductions provided by solar DG. They can be calculated assuming a specific proxy power plant (e.g., a combustion turbine) or using wholesale market prices.

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[61] Beach, R. Thomas and Patrick G. McGuire, "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service," Crossborder Energy, May 8, 2013.

[62] IRP Table 27 at 214

2. Avoided generation capacity: Avoided generation capacity cost is value of the forgone or deferred power plants caused by the load reduction provided by solar DG.

3. Avoided transmission costs: Avoided transmission cost is value of the forgone, deferred or downsized transmission investments caused by the load reduction provided by solar DG.

4. Avoided distribution costs: Avoided distribution cost is value of the forgone, deferred or downsized distribution investments caused by the load reduction provided by solar DG.

5. Avoided greenhouse gas (GHG) emissions costs: Avoided GHG emissions costs are the emissions associated with the reduced output of the marginal power plants which set the avoided energy cost. These emissions are multiplied by an assumed carbon dioxide (CO_2) cost ($/metric ton) to arrive at the avoided greenhouse gas cost. Separately, in the avoided environmental externality component, I account for the full social cost of greenhouse gas emissions.

6. Incremental integration costs: Even with geographic diversity, there is a cost to integrate solar DG into the UNSE system. Based the UNSE IRP, these integration costs cover the incremental ancillary services to support the added solar generation.

7. Avoided environmental externalities. Like with avoided greenhouse gas emissions costs, solar DG can reduce criteria air pollutant (NO_x, SO_x and fine particulate matter) emissions associated with the reduced output of the marginal power plants which set the avoided energy cost. These emissions are multiplied by an assumed

emissions cost to arrive at the criteria air pollutant cost. Because there is currently no market value for these pollutants in Arizona, and one is not anticipated, these costs are best described as externalities.

I also included the estimated marginal cost of water. Given the arid climate of Arizona and the increasing demand for water in the Southwest, including the marginal cost of water (i.e., the cost of water reclamation or desalinization) is appropriate.

Q: What data do you use?

A: I consider two cases. In one, I rely upon data from UNSE's 2014 IRP to the fullest extent possible. This is labeled throughout as "IRP Case." I also show a case using some alternative data, which differs from the IRP Case in that it assumes a west-facing PV array (so as to maximize on-peak production) and uses data from the Crossborder Report for distribution avoided costs and integration costs. In each section below, where I explain my calculations, I note what data I use and their source.

I must be clear that simply because I choose to label the second case "Alternative" does not mean that the results in the IRP are truer or more reliable. Rather, the purpose of the IRP case is to show that using UNSE's own data, solar DG can have much greater value than has been asserted in this proceeding

B. Results

Q: What did you find?

A: Overall, I found that the levelized benefits of solar DG are on the order of 10¢-14¢/kWh ($100-$140/MWh). This analysis is detailed in Table 2. The value of each component listed above for each of my cases is shown, along with subtotals at key intervals: only the avoided costs; the avoided costs net the integration costs; and the avoided and integration costs plus a value for air emission externalities. When avoided costs alone are considered, the value of solar is ~$100/MWh (using IRP data and $142/MWh with a west-facing array and alternative assumptions). Accounting for integration costs reduces these amounts by about $4.50/MWh. Including air emissions externalities brings the totals back to $136/MWh and $180/MWh for the IRP and Alternate cases, respectively.

Table 2. Value of Solar (Levelized $/MWh)

	IRP Case	Alternate
Energy	$50.44	$50.44
Gen. Capacity	$40.16	$77.62
Transmission	$2.78	$5.15
Distribution	$0.00	$2.00
GHG	$6.76	$6.76
Avoided Costs	$100.13	$141.97
Integration costs	($4.55)	($2.00)
With Integration costs	**$95.58**	**$139.97**
Eniv. Externalities	$40.28	$40.28
With Emissions costs	$135.86	$180.25

Q: What do these values mean for this proceeding?

A: Other solar advocates and I have been arguing in this proceeding that net metering can provide value to UNSE in ways that are not captured in the narrow, short-term cost of service perspective that UNSE and others have taken. Because the avoided cost value of solar DG is approximately equal to UNSE's residential rate, net metered solar DG should not impact and may even benefit full-service customers in the long run. Solar DG should be held to similar cost-benefit standards as other behind-the-meter activities such as energy efficiency; a high bar singling out solar DG is inappropriate.

C. Avoided Energy

Q: How did you calculate avoided energy costs?

A: I calculated avoided energy costs as the price of natural gas multiplied by a market heat rate and added in a loss factor (Table 3). A market heat rate is the implied relationship between the market price of natural gas and the market price of power. Inherent in this, is the assumption that natural gas generation is predominantly on the margin in power markets, which indeed is the case throughout the Western US. The natural gas price used here is calculated from the current Henry Hub futures prices, a basis swap to the Permian Basin, and transportation to a gas plant in UNSE territory (UNSE schedule T-1). The Henry Hub futures prices and basis swap values are from *Platt's Gas Daily*, while the market heat rate is taken from the 2014 IRP.[63] I then included a factor of 10% to account for the transmission and distribution losses from a transmission-connected power plant to the customer meter.[64] This calculation results in a levelized cost of energy of $50.44/MWh.

[63] IRP at 219, Chart 42, rounded mean value.
[64] Tilghman at 11.

Table 3. Derivation of Avoided Energy Cost

year	Gas Price $/mmbtu	Market Heat Rate mmbtu/MWh	Power Price $/MWh	loss factor	Price $/MWh
2017	$3.92	8	$31.37	10%	$34.51
2018	$4.06	8	$32.51	10%	$35.76
2019	$4.20	8	$33.58	10%	$36.93
2020	$4.35	8	$34.77	10%	$38.25
2021	$4.49	8	$35.95	10%	$39.55
2022	$4.65	8	$37.18	10%	$40.90
2023	$4.80	9.5	$45.63	10%	$50.19
2024	$4.96	9.5	$47.08	10%	$51.79
2025	$5.11	9.5	$48.58	10%	$53.43
2026	$5.27	10	$52.70	10%	$57.98
2027	$5.43	10	$54.30	10%	$59.73
2028	$5.58	10	$55.83	10%	$61.41
2029	$5.71	10	$57.12	10%	$62.83
2030	$5.80	10	$57.97	10%	$63.77
2031	$6.08	10	$60.81	10%	$66.89
2032	$6.34	10	$63.40	10%	$69.74
2033	$6.60	10	$66.05	10%	$72.65
2034	$6.88	10	$68.76	10%	$75.64
2035	$7.13	10	$71.29	10%	$78.42
2036	$7.40	10	$73.99	10%	$81.39
				Levelized	**$50.44**

D. Avoided Capacity

Q: Why is it reasonable to include an avoided generation capacity cost in your calculation?

A: Including avoided generation capacity in my calculation is consistent with the IRP. In the Sensitivity section of the IRP, UNSE considered the case where it achieved only 50% of its energy efficiency and distributed generation targets. The case stated that this reduction would cause UNSE to install additional combustion turbines in 2019 and 2024.[65] This

[65] IRP at 244.

means that energy efficiency and DG are offsetting the need for additional generation resources, and as such should take credit for those capital savings when considering their cost-effectiveness.

The combustion turbines cited in the IRP were 21 MW LM2500s. As the IRP did not contain cost data for this model, I used the closest one for which explicit data were provided, the LM6000. The Figures on pages 79 and 83 of the IRP suggest that this is a reasonable assumption.

Q: How did you calculate avoided generation capacity cost?

A: The calculation is shown below in Table 4. As is common practice (e.g., see RUCO witness Huber's December 9 testimony), I assumed that avoided generation capacity cost can be represented by the cost of a new combustion turbine (CT). This is because CTs tend to be the least-cost source of new utility-scale capacity, as well as the explicit type of resource identified as offset by DG and energy efficiency in the IRP.

I took the total construction cost of the LM6000 CT from the IRP, adjusted the value to 2017 dollars and applied a carrying charge. A carrying charge effectively translates an investment amount over the life of the asset. The value used here, 11.17%, is from the value of solar DG study commissioned by APS in 2013 and performed by SAIC (as cited in the Crossborder Report). [66] I then added the fixed operating and maintenance (O&M) cost and gas transportation reservation costs from the IRP. [67] This sum was then scaled up to account for reserve margin savings (i.e., a 10% reduction in peak load results

[66] Crossborder ReportCrossborder Report at 10.
[67] Unless it was explicitly stated otherwise, I assumed that all costs in the UNSE IRP were in 2014 dollars, and were adjusted to 2017 using deflators from the Department of Energy Information Administration in this analysis.

in an 11.5% reduction in capacity needs) and losses from the avoided CT to the meter.

I then applied a coincident factor from the 2014 IRP.[68] The coincident factor reflects the output of the solar system at time of system peak. For the Alternative case, I scaled the coincident factor up by the ratio of PV output during peak hours between a standard south-facing PV array and a west-facing array (using data from the NREL model, PVWatts). A west-facing array is instructional to consider: while it generates less overall electricity than a south-facing one, it generates more during the summer late afternoon and early evening hours, coinciding with UNSE system peaks. I then applied the capacity factor for solar PV to arrive at the levelized dollar per megawatt-hour value.

Table 4. Derivation of Avoided Generating Capacity Cost

IRP Case	Alternate	
$1,123	$1,123	per kW total construction cost
11.17%	11.78%	Carrying Charge
$125.39	$132.23	per KW-year
$16.68	$16.68	fixed O & M
$18.04	$18.04	gas transp $/kW-yr
$160.10	$166.95	per KW-year
15%	15%	Reserve Margin
$184.12	$191.99	per KW-year
10%	10%	losses
$202.53	$211.19	per KW-year
33%	52%	coincidence factor
$66.83	$109.82	per KW-year
19%	16%	Capacity Factor
$40.16	$77.62	per MWh

E. Avoided Transmission and Distribution

Q: How did you calculate avoided transmission cost?

A: The only quantitative data provided in the IRP for marginal transmission costs was for

[68] IRP at 70.

connecting a new generator to the UNSE grid.[69] These costs included a mile of transmission line plus the substation interconnection. Consistent with the avoided generation calculation, I used the interconnection cost assumptions associated with a LM6000. I then used a process similar calculating the avoided generation capacity; the only difference is that I used a slightly different carrying charge, per the Crossborder Report.[70] This calculation is shown in Table 5.

Table 5. Derivation of Avoided Transmission Cost (based on marginal generator interconnection)

IRP Case	Alternate	
$4.866	$4.866	million per installation
45	45	MW per installation
108.13	108.13	per kW
12%	12%	Carrying Charge
$12.74	$12.74	per KW-year
10%	10%	losses
$14.01	$14.01	per KW-year with losses
33%	52%	coincidence factor
$4.62	$7.29	per KW-year of solar
19%	16%	Capacity Factor solar
$2.78	$5.15	per MWh solar

Q: Shouldn't an avoided transmission cost calculation consider deferred or avoided investment in transmission assets?

A: Yes. However, there was insufficient data in the IRP to make such a calculation. Thus, the values I show below should be considered conservative.

Q: What did you assume for avoided distribution cost?

[69] IRP at 101.
[70] Crossborder Report at 11 (Table 6)

A: The IRP afforded no data that would allow me to estimate an avoided distribution cost. In the name of conservatism, I did not assume any avoided distribution costs for my IRP case. This is not because I do not believe that avoided distribution does not exist. Rather, that for this analysis, I could not quantify it based on the IRP. For the Alternative case, I used the value calculated in the Crossborder Report: $3/MWh.[71]

F. Avoided Greenhouse Gas

Q: How did you calculate a value for avoided greenhouse gas costs?

A: For the initial years 2017 through 2022, shown below in Table 6, I assumed the avoided cost of CO_2 to be zero. In 2023, I assumed a value of $17.26/metric ton, which I then escalated at 6% per year. This matches the carbon cost assumptions in the Emissions Prices section of the IRP.[72]

I then multiplied the emissions cost by the carbon content of natural gas (117 lb per MMbtu) and by the mean market heat rate (rounded) from the IRP.[73] As shown below, the levelized cost of carbon emissions offset by solar DG is $7.43/MWh.

[71] Crossborder Report at 12.
[72] IRP at 213.
[73] IRP at 219.

Table 6. Derivation of Avoided Greenhouse Gas Cost

year	$/ton	lbs/tonne	lbs/mmbtu	mmbtu/MWh	$/MWh	With 10% Losses
2017	$0.00	2200	117	8	$0.00	$0.00
2018	$0.00	2200	117	8	$0.00	$0.00
2019	$0.00	2200	117	8	$0.00	$0.00
2020	$0.00	2200	117	8	$0.00	$0.00
2021	$0.00	2200	117	8	$0.00	$0.00
2022	$0.00	2200	117	8	$0.00	$0.00
2023	**$17.26**	2200	117	9.5	$8.72	$9.59
2024	$18.30	2200	117	9.5	$9.24	$10.17
2025	$19.39	2200	117	9.5	$9.80	$10.78
2026	$20.56	2200	117	10	$10.93	$12.03
2027	$21.79	2200	117	10	$11.59	$12.75
2028	$23.10	2200	117	10	$12.28	$13.51
2029	$24.48	2200	117	10	$13.02	$14.32
2030	$25.95	2200	117	10	$13.80	$15.18
2031	$27.51	2200	117	10	$14.63	$16.09
2032	$29.16	2200	117	10	$15.51	$17.06
2033	$30.91	2200	117	10	$16.44	$18.08
2034	$32.76	2200	117	10	$17.42	$19.17
2035	$34.73	2200	117	10	$18.47	$20.32
2036	$36.81	2200	117	10	$19.58	$21.54
				Levelized:	**$6.76**	**$7.43**

G. Integration Costs

Q: How did you calculate a cost of integrating the solar DG into the utility system?

A: I followed the method laid out in the Renewable Resources Integration Costs section of the IRP.[74] There, Table 21 showed the integration cost for three renewable types, including solar PV, with each cost's sensitivity to renewable capacity and gas price. The base integration cost from the IRP for solar PV was $7.60/MWh, based on 25 MW of solar and Permian Basin gas prices of $6.00/mmbtu. However, this $6/mmbtu assumption is not consistent with my analysis. Given the gas futures price analysis described earlier,

[74] IRP at 170.

the levelized cost of Permian gas in my analysis is \$3.40/mmbtu. With the integration cost sensitivity shown in the IRP (\$1.40/MWh change in integration cost for every \$1 change in Permian gas prices) this results in an integration cost of \$4.14/MWh, or \$4.55/MWh with losses. This calculation is shown in Table 7.

Table 7. Derivation IRP Interconnection Cost

Per IRP	\$7.60	/MWh
Adjustments for lower gas prices		
Assumed Gas	\$6.00	/mmbtu
Used gas	\$3.53	/mmbtu
Difference	\$2.47	/mmbtu
Change in gas price	\$1.40	mmbtu/MWh
Change in integration cost	\$3.46	/MWh
integration cost	\$4.14	/MWh
losses	10%	
With losses	**\$4.55**	**/MWh**

H. Environmental Externality Savings

Q: How did you calculate the cost of avoided air emissions?

A: First, I took the emissions rates for sulfur oxides (SO_x), nitrogen oxides (NO_x), and fine particulate matter (PM10) for a combustion turbine (CT) and a natural gas combined cycle (CC) from the IRP.[75] Because the market heat rate tended to fall between that of a combustion turbine and combined cycle, I used a simple average of the two emissions rates. I then multiplied these emission rates by the emissions cost from the Crossborder Report and summed the costs to arrive at the final air emissions cost.[76] This process is illustrated in Table 8.

[75] IRP at 73, 74.
[76] Crossborder Report at 13.

Table 8. Derivation of Air Emission Externality Cost

	Emissions rate, lb/MWh			Cost			Total	With10%
	CT	CC	Ave.	$/tonne	lb/tonne	$/lb	$/MWh	Losses
SOx	0.006	0.004	0.005	$11,144	2,200	$5.07	$0.03	$0.03
NOx	0.323	1.094	0.7085	$6,926	2,200	$3.15	$2.23	$2.45
PM10	0.73	0.054	0.392	$1,642	2,200	$0.75	$0.29	$0.32
								$2.80

Q: Did you calculate the marginal cost of water consumption?

A: Yes. I used the same basic method for estimating the marginal cost of water as I used for estimating the emissions costs. I used the simple average of the water use for a CT and a CC from the IRP[77] and then multiplied these water consumption amounts by the marginal water cost from the Crossborder Report to arrive at a marginal avoided cost of water of $1.88/MWh.[78]

Q: Did you consider greenhouse gas emission costs above the market values you included earlier?

A: Yes. For an incremental externality cost for GHG, I made two adjustments. First, I accounted for methane leakage during transport from the wellhead to the marginal power plant. The US EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" places methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant at 1.1% of production.[79] But because methane is a much more potent greenhouse gas than carbon dioxide, I multiplied the natural gas leakage emissions by methane's

[77] IRP at 73, 74.
[78] Crossborder Report at 13.
[79] EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013," US Environ. Prot. Agency, pp. ES1–ES26, 2014.

global warming potential, 25.[80] Second, I used the EPS's societal cost of carbon rather than the market value per the UNSE IRP.[81]

Table 9 Greenhouse Gas Externaltiy Cost, $/MWh

Powerplant Emissions	$33.75
Natural Gas System Methane Losses	$9.28
Net Market Cost	($7.43)
	$35.60

I. Other, Not Easily Quantifiable Benefits

Q: You included eight elements in your value of solar analysis. Are there additional elements that might be included in such an analysis?

A: Yes. There are a number of other benefits that distributed solar can provide that are much more difficult to quantify. In this section of my testimony, I address a few of these and note values that other parties have placed on the benefits. I have chosen not to include them in my quantitative analysis as they require more analysis than time allowed for in this proceeding.

Q: Can solar DG provide reliability benefits and reduce a utility's reserve margin requirement?

A: Yes. For example a 2005 article by Duke, Williams and Payne in the *Energy Policy* journal notes that PV deployment makes it possible to reduce the reserve margins needed to ensure power system reliability. [82] Duke *et al* point out that electric grids with large

[80] *Ibid.*

[81] https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. 3% discount rate. Accessed 2/19/16.

[82] "Accelerating residential PV expansion: demand analysis for competitive electricity markets" Duke et al., *Energy Policy* 33, 2005 (Duke 2005) p. 1922

generation facilities require a higher reserve margin since an unanticipated loss of output from even a single generating facility could affect service continuity. In contrast, a power system with a large number of distributed PV systems alleviates reserve requirements because individual systems are far smaller than central-station plants, and the risk of unexpected technical failure is uncorrelated across different PV systems.

This is echoed a 2011 report prepared for the New York State Energy Research and Development Authority (NYSERDA), which noted that, in general, distributed generation can increase system reliability by increasing the number and variety of generating technologies; reducing the size of generators and the distance between generators and load; and by reducing loading on distribution and transmission lines.[83]

The reserve margin benefit issue is illustrated by an example cited in the NYSERDA study:

> During the last wave of nuclear plant construction, single units were built as large as 1100 MW in capacity. Seabrook I is an example. At the time Seabrook I came into service, its loss became the single largest risk to the reliability of the New England grid and substantially increased the risk of system outages. To remedy this situation, the New England Power Pool had to increase the required reserve margin for every utility in New England by several percentage points. A two percentage point increase in the region's required capability would amount to something on the order of 500 MW. The cost savings implicit in reducing the size of plants and dispersing them can be appreciated from that observation.[84]

Q: Beyond providing reliability benefits by lowering reserve margin requirements, can solar DG provide other grid support or ancillary services?

A: Yes. According to a 2013 meta-study by the Rocky Mountain Institute, grid support

[83] "Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies." Prepared for NYSERDA by Pace Energy and Climate Center and Synapse Energy Economics 2011 (NYSERDA 2011) p.17
[84] NYSERDA 2011, p. 17

services provided by solar DG can include reactive supply and voltage control, frequency regulation and response, making up for energy imbalances, providing operating reserves, and scheduling and forecasting benefits to ensure operational safety.[85] The study notes that differing standards and rules based on different systems could affect the valuation of solar DG grid support services,[86] however it is likely that with changes in technology, the net value proposition of solar DG as grid support will increase.[87]

This fundamental conclusion that solar DG can provide grid support is corroborated by reports and studies prepared for the National Renewable Energy Laboratory,[88] and NYSERDA.[89] These studies assign values as high as 1.5 cents/kWh to the ancillary services provided by distributed generation.[90] Further evidence of benefits with respect to power quality, conservation voltage regulation, equipment life extension, and reliability and resiliency benefits have been quantified in the recently published SolarCity paper "A Pathway to the Distributed Grid." (Attachment C) While I do not attempt to replicate SolarCity's analysis for UNSE due to a lack of available data, I note that the estimates of the value of solar in this analysis are conservative given the limited data available to estimate these difficult-to-quantify values.

Q: Can solar DG provide a hedge against volatile fuel prices?

A: Yes. A 2013 paper by the Interstate Renewable Energy Council notes that solar DG provides a fuel cost price hedge benefit by reducing reliance on fuel sources that are

[85] "A Review Of Solar PV Benefit & Cost Studies", Rocky Mountain Institute 2013 (RMI 2013) p. 15
[86] RMI 2013 p. 33
[87] RMI 2013 p. 34
[88] "Photovoltaics Value Analysis," Prepared for National Renewable Energy Laboratory by Navigant Consulting 2008 (NREL 2008) p. 13
[89] NYSERDA 2011 p. 18
[90] NREL 2008, p. 13

susceptible to shortages and market price volatility.[91] It further notes that solar DG provides a hedge against uncertainty regarding future regulation of GHG and other emissions, which also impact fuel prices. Solar DG customer exports help hedge against these price increases by reducing the volatility risk associated with base fuel prices, effectively blending price stability into the total utility portfolio.

Q: What is the value of this fuel price hedge?

A: A number of studies have placed values on this benefit. These include Duke 2005 (0.7¢/kWh in California for natural gas price risk);[92] NREL 2008 (up to 0.9¢/kwh);[93] NYSERDA 2011 (0.4-0.9¢/kWh, quoting Americans for Solar Power 2005);[94] and Xcel Energy 2013 (0.66¢/kWh).[95]

Q: Does this conclude your surrebuttal testimony?

A: Yes.

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[91] "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," Interstate Renewable Energy Council 2013 (IREC 2013) p. 30
[92] Duke 2005 p. 8
[93] NREL 2008 p. 5
[94] NYSERDA 2011 p. 25
[95] "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System" Prepared by Xcel Energy Services 2013 (Xcel 2013) Table 16, p. 43

ATTACHMENT A

Use Great Caution in Design of Residential Demand Charges

Jim Lazar

For decades, electricity prices for larger commercial and industrial customers have included demand charges, which recover a portion of the revenue requirement based on the customer's highest usage during the month. Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Great caution should be applied when considering the use of demand charges, particularly for smaller commercial and residential users. Severe cost shifting may occur. Time-varying energy charges result in more equitable cost allocation, reduce bill volatility, and improve customer understanding. The caution applied should address the following key issues in most demand-charge rate designs:

- *Diversity:* Different customers use capacity at different times of the day, and these customers should share the cost of this capacity.
- *Impact on Low-Use Customers:* Most demand-charge rate designs have the effect of increasing bills to low-use customers, including the vast majority of low-income customers.
- *Multifamily Dwellings:* The utility never serves individual customer demands in apartment buildings, only the combined demand of many customers at the transformer bank.
- *Time Variation:* If demand charges are not focused on the key peak hours of system usage, they send the wrong price signal to customers.

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In the recent Regulatory Assistance Project (RAP) publication *Smart Rate Design for a Smart Future,*[1] we looked at many attributes of rate design for residential and small commercial consumers. We identified three key principles for rate design:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Customers should pay for power supply and grid services based on how much these customers use and when they use it.
- Customers supplying power to the grid should receive full and fair compensation—no more and no less.

Applying these principles results in an illustrative rate design that constructively applies costing principles in a manner that consumers can understand and respond to. **Exhibit 1** shows the illustrative rate design, including a customer charge for customer-specific billing costs and a demand charge for customer-specific transformer capacity costs. The exhibit also includes a time-varying energy price to recover distribution

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Exhibit 1. Illustrative Rate Design

Illustrative Residential Rate Design

Rate Element	Based On the Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

Source: Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://raponline.org/document/download/id/7680.

system capacity costs and power supply costs designed to align prices with long-run marginal costs.

Customers can and will respond to rate design. We need to make sure that their actions actually serve to maximize their value and minimize long-run electric system costs. The illustrative rate is clearly directed toward these ends.

DEMAND CHARGES HAVE ALWAYS BEEN ONLY AN APPROXIMATION

Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month. Demand charges are sometimes coupled with a "ratchet" provision that charges the customer on the basis of the highest measured demand over the previous 12-month period or other multi-billing-period span of time.

Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month.

Exhibit 2 is a typical medium commercial rate design. It includes a demand component.

Utilities often justified demand charges on the basis of two arguments. First, they were

Exhibit 2. Illustrative Demand Charge Rate

Basic Tariff For Large Commercial Customer

Rate Element	Price
Customer Charge $/month	$20.00
Demand Charge $/kW/month	$10.00
Energy Charge $/kWh	$0.08

Key Terms for Demand Charges

CP: coincident peak demand: the customer's usage at the time of the system peak demand.

NCP: non-coincident peak demand: the customer's highest usage during the month, whenever it occurs.

Diversity: the difference between the sum of customer NCP and the system CP demands.

asserted as a "fairness" rate that assured that all customers paid some share of the utilities' system capacity costs. Second, especially when coupled with ratchets, they had the effect of stabilizing revenues.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak.

But demand charges are a shortcut, measuring each customer's individual highest usage during a month, regardless of whether the usage was coincident with the system peak. The customer's individual peak was used as a proxy for that customer's contribution to system capacity costs. Demand charges were implemented in this way even though customers' individual demands did not coincide with the peak system demand, or more accurately, with the coincident peak for the individual components of the system involved, each of which may have peaks different from the system peak. This was always a "second-best" approach. It is roughly accurate for large commercial customers, because their highest usage *usually* (but not always) coincided with the system peak.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak. The rough accuracy that exists for using non-coincident peak (NCP) demand charges for large commercial customers is woefully inaccurate for residential consumers. But coincident-peak (CP) demand charges have other shortcomings, leaving some customers with more than their share of costs and others with none at all, as shown in **Exhibit 3**.

With data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour of usage.

Today, with data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour

Exhibit 3. Garfield and Lovejoy Criteria and Alternative Rate Forms

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant cost.	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage.	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak.	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something.	Y	N	Y

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of usage. This more precise usage data makes demand charges a largely antiquated approach for all customer classes—and particularly inappropriate for residential consumers.

DIVERSE USER PATTERNS VARY GREATLY

Residential customers use system capacity at different times of the day and year. Some people are early-risers, and others stay up late at night. Some shower in the morning, and some in the evening. Some have electric heat, and others have air conditioning.

This variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs. Demand charges are not very useful for this purpose.

A half-century ago, Garfield and Lovejoy discussed how system capacity costs should be reflected in rates.[2] Their observations, summarized in Exhibit 3, are as relevant today as when they were published. We compare the performance of three rate-design approaches to these criteria.

Variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs.

Following this guidance, capacity costs need to be recovered in every hour, with a concentration of these charges in system peak hours. The illustrative rate design in Exhibit 1 does this effectively. The typical commercial rate design in Exhibit 2, loading system capacity costs to an NCP demand charge, does not, because it recognizes only one hour of customer-specific demand.

Churches and stadiums illustrate this problem with demand charges. Churches have peak demands on days of worship—most often Wednesday nights and Sunday mornings, and stadium lights are used only a few hours per month, in the evening hours in the fall and winter. None of this usage is during typical peak periods.

Applying demand charges to recover system capacity costs based on non-coincident peak demand to churches and stadiums has long been recognized as inappropriate. Such charges have the effect of imposing system capacity costs on customers whose usage patterns contribute little, if anything, to the capacity design criteria of an electric utility system at the same rate as customers using that capacity during peak periods. The same problem applies for residential consumers.

On a typical distribution system, multiple residential consumers share a line transformer, and hundreds or thousands share a distribution feeder. The individual non-coincident demands of individual customers are not a basis for the sizing of the distribution feeder; only the combined demands influence this cost. Even at the transformer level, some level of diversity is assumed in determining whether to install a 25-kilovolt-amp or 50-kilovolt-amp transformer to serve a localized group of perhaps a dozen customers.

Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month.

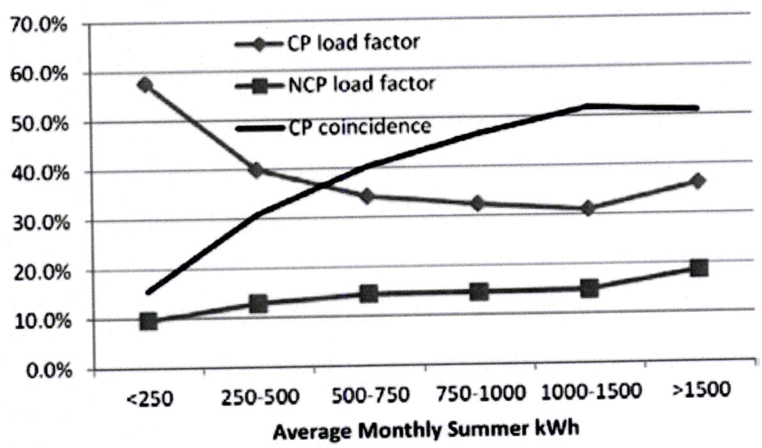
Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month. Some customers (think of a doughnut shop and nightclub) use capacity only in the morning or evening, and can share capacity, while others (think of a 24-hour mini-mart) use capacity continuously and preempt this capacity from use by others. Modern rate design needs to distinguish between different characteristics in the usage of capacity and ensure all customers make an appropriate contribution to system capacity costs.

Time-varying rates do this very well, while simple CP and NCP demand charges do not.

IMPACT ON LOW-USE CUSTOMERS

Individual residences have very low individual customer load factors but quite average collective usage patterns.

Exhibit 4. Load Factors



Source: Marcus, B. (2015, June). Presentation at Western Conference of Public Service Commissioners, Phoenix, AZ.

Exhibit 4 shows data from Southern California Edison Company. As is evident, while the individual customer load factors of small-use residential customers are only about 10 percent, their group coincident peak load factor is more like 60 percent, quite close to an overall system load factor. A demand charge based on NCP demand greatly overcharges these customers. Meanwhile, the high-use residential customers, who have more peak-oriented loads, would be undercharged with a simple NCP demand charge based on overall residential usage.

The evidence is that the effect is to shift costs to smaller-use customers.

Rate analysts have examined the impact of demand-charge rate designs on residential customers. The evidence is that the effect is to shift costs to smaller-use customers, with about 70 percent of small-use residential customers experiencing bill increases, and about 70 percent of large-use residential customers experiencing bill decreases, even before any shifting of load.[3]

APARTMENT DIVERSITY

About 30 percent of American households live in some sort of multifamily dwelling. Apartments generally have the lowest cost of service of any residential customer group, because the utility provides service to many customers at a single point of delivery through a transformer bank sized to their combined loads. Because the sum of individual customer NCP demand greatly exceeds the combined group demand the utility serves, and by a greater margin than for other customer subclasses, NCP demand charges shift costs inappropriately to these multifamily customers.

About 30 percent of American households live in some sort of multifamily dwelling.

Low-income consumers are more likely to reside in apartments, and nationally, low-income household usage is about 70 percent of average household usage.[4] Therefore, imposing NCP demand charges on residential consumers, without separate treatment of apartments, would have a serious adverse impact on these customers, many of whom are

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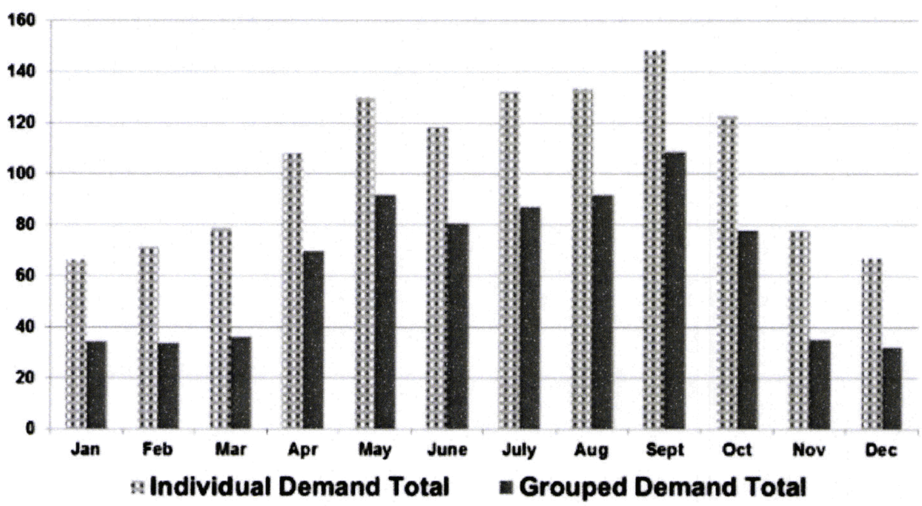
Exhibit 5. Individual and Group Peaks for a 26-Unit Apartment Building



Source: Author, from data supplied by Los Angeles–area municipal utility.

low-income households and often strain to pay their electric bills.

Exhibit 5 shows the sum of individual customer monthly non-coincident peaks for a 26-unit apartment complex in the Los Angeles area, and the monthly group peaks of these customers actually seen by the utility at the transformer bank serving the complex. The exhibit shows that billing customers on the basis of non-coincident peak demand would dramatically overstate the group responsibility for system capacity costs.

TIME-VARYING COST RECOVERY

As expressed by Garfield and Lovejoy, the optimal way to recover system capacity costs is through a time-varying rate design. This can be as simple as a higher charge for usage during on-peak hours than off-peak hours, or it can be a fully dynamic hourly time-varying energy rate. What is clear is that a single demand charge, applied to a single one-hour NCP or CP measure of demand, is unfair to those customers whose usage patterns allow the shared use of system capacity.

Some utilities have implemented time-varying demand charges. California investor-owned utilities impose NCP demand charges for distribution costs, and CP demand charges for generation and transmission capacity on larger commercial consumers. More recently, some utilities have imposed demand charges on smaller customers based on summer on-peak-hour demands only. All of these reflect gradual movement toward equitable recovery of system capacity costs, but full time-of-use (TOU) energy pricing is more effective, more cost-based, more equitable, and more understandable.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month. Usage during peak periods can be assigned the costs of peaking power supply resources and seldom-used distribution system capacity costs installed for peak hours. Usage during other hours can be assigned the cost of baseload resources and the basic distribution infrastructure needed to deliver that power.

  / DOI 10.1002/gas

The pricing can be as granular as the analyst chooses and the regulator approves—but a key element of rate design is simplicity. For that reason, most analysts shy away from rate design with more than three time periods and a few rate elements.

The illustrative rate design in Exhibit 1 shows a three-period TOU plus critical peak price for both power supply and distribution capacity cost recovery, a customer charge for billing costs, and a demand charge to recover the cost of the final line transformer. It may be as complex a rate design as most residential consumers will reliably understand.

TRANSITIONING TO A TOU RATE DESIGN

Many customer groups are apprehensive about time-varying utility rates, because some consumers will receive higher bills and may not be able easily to change their usage patterns. This same concern would apply to implementation of a demand-charge rate design, but because that produces a less desirable result, we do not consider it a meaningful option. There are the following tools that can be used for a transition:

- *Shadow billing:* Provide consumers with *both* the current rate design and the proposed TOU rate design calculated on the bill prior to rollout.
- *Load control:* Prior to implementing a TOU rate, assist customers to install controls on their major appliances to ensure against inadvertent usage during on-peak periods.
- *Customer-selected TOU periods:* The Salt River Project in Arizona has had excellent success allowing customers to choose a three-hour "on-peak" period out of a four-hour system peak period.[5]

COMMON ERRORS IN DEMAND-CHARGE DESIGN

Common errors include the following:

- *Upstream Distribution Costs:* Any capacity costs upstream of the point of customer connection can be accurately assigned to usage and recovered in time-varying prices.
- *Using NCP Demand:* NCP demand is not relevant to any system design or investment criteria above the final line transformer, and only there if the transformer serves just a single customer.
- *Accounting for Diversity:* Diversity is greatest among small-use customers and needs to be fully accounted for.
- *Apartments:* Apartments have the lowest cost of service of any residential customer group, the highest diversity, and suffer the most when a single rate design is applied to all residential customers.

GUIDANCE FOR COST-BASED DEMAND CHARGES

The following guidelines can be used;

- Limit any demand charges to customer-specific capacity.
- Fully recognize customer load diversity in rate design.
- Demand charges upstream of the customer connection, if any, should apply only to the customer's contribution to system coincident peak demand.
- Compute any demand charges on a multi-hour basis to avoid bill volatility.

Modern metering and data systems make it possible to increase greatly the accuracy, and therefore the fairness, of cost allocation among a diverse customer base. Legacy concepts, such as demand charges, especially those based on NCP demand, prevent the implementation of these improvements and should be eliminated. Time-varying cost assignment is preferred, so that these new technologies can deliver their full value to customers and utilities alike.

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ATTACHMENT B

SALT RIVER PROJECT

SPECIAL BOARD MEETING

CONTINUATION SPECIAL BOARD)
MEETING ON PROPOSED CHANGES TO)
STANDARD ELECTRIC PRICE PLANS)
AND TERMS AND CONDITIONS OF)
COMPETITION)
)

February 12, 2015
9:40 a.m.
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continue to look at that possibility because if we're going to be all about price signals producing appropriate results, then I think we need to be fair and consistent in how we look at that.

MR. LOWE: Understood. Thank you.

MR. BONSALL: If I could kind of amplify a little bit on some of those answers. You know, we already have demand charges in our industrial customers, our commercial class. As you know, you're on EZ-3, EZ-3 is getting closer to a demand kind -- it's a demand related version of an energy charge. If you took EZ-3 and you compressed it down to an instantaneous number, you basically got a demand charge. You got Time-Of-Use customers. Between EZ-3 and Time-Of-Use, we've got a quarter of a million residential customers, plus or minus currently, correct me if I'm wrong, on time differentiated pricing which is a reflection of demand cost. You've got seasonal differentiation as well in the wintertime, summertime, summer peak seasons.

So we've got a number of versions that are kind of along those lines economically and it's the customer's choice, frankly, which price plan they select. I mean, ultimately in this discussion, you will get to the point where you're weighing the benefits of customer choice or customer preference versus how (unintelligible) you want to be on sending an economic signal and Rob economically established it would be the purest economic thing to do to send a demand signal.

On the other hand, when people buy a commodity, they are not just buying a commodity. They're buying a lot of things that go around the commodity, including information, including convenience, including just their level of interest in the commodity purchase itself. It's not just explicitly through the commodity.

I guess the bottom line on that is I think it would be very difficult, were she still with us, to put my grandma ma on a demand charge. I mean, we're gonna have people that just don't want to do that or it's too complicated for them to understand and/or they don't care about it. I think we need to be sensitive to some of those issues as well.

MR. HOOPES: I hope you're not suggesting that I want your grandmother to pay more than she needs to, but --

MR. BONSALL: Actually, President Hoopes, I was assuming that. Knowing you, I thought, "He makes some sense."

MR. HOOPES: You can deal with those things with a more transparent subsidy of the core or price plan, poor people, people who don't have the capabilities of making a rational choice, but I would suggest to some degree that's throwing the baby out with the bath water. It's all about the numbers, how many would benefit from it and how it would be applied.

But I guess also to carry on with one of Wendy's comment is, is we're doing it for the solar people and I understand it's -- those are new customers. They can make a choice as to whether or not they want to play at all, but we make much of the price signal for them and I think -- I'm not suggesting it makes sense now or it will make sense three years from now, but I think it's not fair and is inappropriate to just categorically exclude the possibility that it might make sense over time to move to more of a tiered demand for more customers and distributed generation customers.

MR. BONSALL: I wasn't suggesting that we would not do that. I just think there's a no trade off involved there that we all consistently need to keep in mind. You know, one option that we could consider here is the possibility, frankly, of opening up E-27 on a pilot basis to other customers and see what they think.

MR. HOOPES: Yeah.

MR. BONSALL: Just try it out and see what they think.

MR. WHITE: Mark.

ATTACHMENT C

SolarCity

Grid Engineering

A Pathway to the Distributed Grid

Evaluating the economics of distributed energy resources and outlining a pathway to capturing their potential value

White Paper

Executive Summary

Designing the electric grid for the 21st century is one of today's most important and exciting societal challenges. Regulators, legislators, utilities, and private industry are evaluating ways to both modernize the aging grid and decarbonize our electricity supply, while also enabling customer choice, increasing resiliency and reliability, and improving public safety, all at an affordable cost.

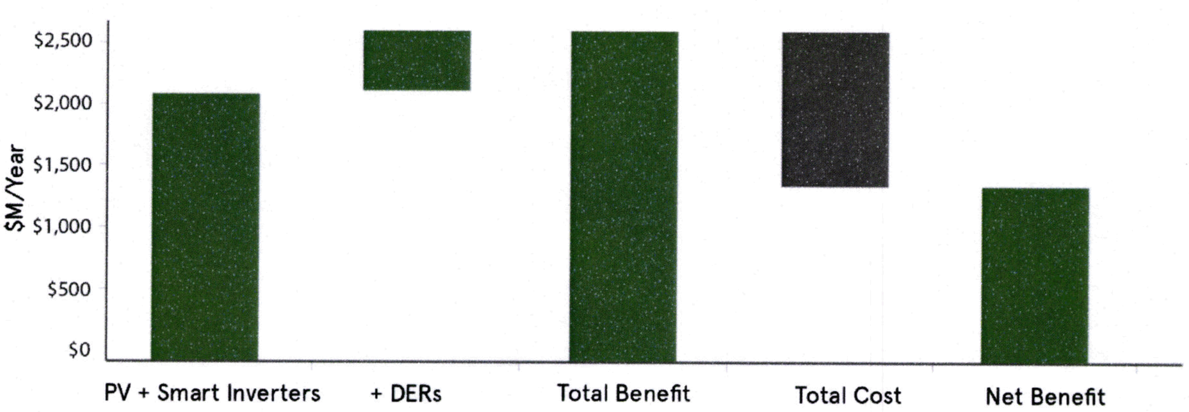
However, modernizing an aging grid will require significant investments over and above those seen in any recent period – potentially exceeding $1.5 trillion in the U.S. between 2010-2030.[1] Given the large sums of ratepayer funds at stake and the long-term impact of today's decisions, it is imperative that such investment is deployed wisely, cost-effectively, and in ways that leverage the best technology and take advantage of customers' desire to manage their own energy.

In this report, we explore the capability of distributed energy resources (DERs) to maximize ratepayer benefits while modernizing the grid. First, we quantify the net societal benefits from proactively leveraging DERs deployed in the next five years, which we calculate to be worth over $1.4 billion a year in California alone by 2020. Then, we apply this methodology to the most recently available Investor Owned Utility (IOU) General Rate Case (GRC) filing – Pacific Gas and Electric's 2017 GRC – in order to evaluate whether DERs can cost effectively replace real-world planned distribution capacity projects. Finally, we evaluate the impediments to capturing these benefits in practice. These structural impediments undermine the deployment of optimal solutions and pose economic risk to consumers, who ultimately bear the burden of an expensive grid. Accordingly, we suggest several ways to overcome these impediments by improving the prevailing utility regulatory and planning models.

Distributed Energy Resources Offer a Better Alternative

This report presents an economic analysis of building and operating a 21st century power grid – a grid that harnesses the full potential of distributed energy resources such as rooftop solar, smart inverters, energy storage, energy efficiency, and controllable loads. We find that an electric grid leveraging DERs offers an economically better alternative to the centralized design of today. DERs bring greater total economic benefits at lower cost, enable more affordability and consumer choice, and improve flexibility in grid planning and operations, all while facilitating the de-carbonization of our electricity supply.

Over $1.4 Billion per Year in Net Societal Benefits from DERs by 2020



February 2016

To evaluate the potential benefits, we build on existing industry methodologies to quantify the net societal benefits of DERs. Specifically, we borrow the *Net Societal Costs/Benefits* framework from the Electric Power Research Institute (EPRI),[2] incorporating commonly recognized benefit and cost categories, while also proposing methodologies for several hard-to-quantify benefit categories that are often excluded from traditional analyses. Next, we incorporate costs related to the deployment and utilization of DERs, including integration costs at the bulk system and distribution levels, DER equipment costs, and utility program management costs. Using this structure, we quantify Net Societal Benefits of more than $1.4 billion a year by 2020 for California alone from DER assets deployed in the 2016-2020 timeframe, as depicted in the previous figure.

In addition to evaluating net societal benefits at the system level, we consider the benefits of DER solutions for specific distribution projects in order to evaluate whether DERs can actually defer or replace planned utility investments in practice. Specifically, we apply the relevant set of cost and benefit categories to the actual distribution investment plans from California's most recently available GRC filing, which is PG&E's 2017 General Rate Case Phase I filing. This real-world case study assesses a commonly voiced critique of utilizing DERs in place of traditional utility infrastructure investments: that not all avoided cost categories are applicable for every distribution project, or that DERs only provide a subset of their potential benefits in any specific project. Therefore, we consider only a subset of utility-applicable avoided cost categories when assessing the set of distribution infrastructure projects in PG&E's 2017 GRC filing; we also utilize PG&E's own avoided cost values rather than our own assumptions. Even using PG&E's conservative assumptions on this subset of benefits, we quantify a net benefit for DER solutions used to replace the distribution capacity investments in PG&E's 2017 GRC.

Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

While our analysis shows net societal benefits from DERs, both at the societal and distribution project levels, under the prevailing utility regulatory model DER benefits cannot be fully captured. Instead, utilities have a fundamental financial incentive of "build more to profit more", which conflicts with the public interest of building and maintaining an affordable grid. Under today's regulatory paradigm, utilities see a negative financial impact from utilizing resources for distribution services that they do not own – which includes the vast majority of distributed energy resources – even if those assets would deliver higher benefits at lower cost to ratepayers. This financial incentive model is a vestige of how utilities have always been regulated, a model originally constructed to encourage the expansion of electricity access. However, in this age of customers managing their energy via DERs, this regulatory model is outdated. This report offers a pathway to removing this structural obstacle, calling for a regulatory model that neutralizes the conflict of incentives facing utilities. While separating the role of grid planning and sourcing from the role of grid asset owner – such as through the creation of an independent distribution system operator (IDSO) – would achieve this objective, some states may choose not to implement an IDSO model at this time. In these instances, this paper proposes the creation of a new utility sourcing model, which we call *Infrastructure-as-a-Service*, that allows utility shareholders to derive income, or a rate of return, from competitively sourced third-party services. This updated model would help reduce the financial disincentive that currently biases utility decision-making against DERs, encouraging utilities to deploy grid investments that maximize ratepayer benefits regardless of their ownership.

Grid Planning Must be Modernized in Order to Capture DER Benefits

A second structural impediment to realizing DER benefits is the current grid planning approach, which biases grid design toward traditional infrastructure rather than distributed alternatives, even if distributed solutions better meet grid needs. Combined with the "build more to profit more" financial incentive challenge, current grid planning can encourage 'gold-plating', or overinvestment, in grid infrastructure. Furthermore, outdated planning approaches rely on static assumptions about DER capabilities and focus primarily on mitigating potential integration challenges rather than proactively harnessing these flexible assets. This report offers a pathway to modernizing grid planning, calling for the utilization of an *Integrated Distribution Planning* approach that encourages incorporating DERs into every aspect of planning, rather than merely accommodating DER interconnection. Additionally, transparency into grid needs and planned investments is fundamental to realizing benefits. As such, this report recommends a data transparency approach that invites broad stakeholder engagement and increases industry competition in providing grid solutions.

Key Takeaways

1. Distributed energy resources offer *net economic benefits to society* worth more than $1.4 billion per year in California alone by 2020, including benefits related to voltage and power quality, conservation voltage reduction, grid reliability and resiliency, equipment life extension, and reduced energy prices.

2. To realize these benefits, the *utility regulatory incentive model* must change to take advantage of customer choices to manage their own energy. Utility incentives should promote best-fit, least-cost investment decisions regardless of service supplier – eliminating the current bias toward utility-owned investments.
3. Utility planning approaches must also be modernized to capture these benefits. Utilization of an *integrated distribution planning* framework will unlock the economic promise of distributed energy resources, while widely sharing utility grid data in standard data formats will invite broader stakeholder engagement and competition.

Recommendations and Next Steps

Our ultimate goal is to help provide concrete evidence and recommendations needed by regulators, legislatures, utilities, DER providers, and industry stakeholders to transition to a cleaner, more affordable and resilient grid. While the details of implementing these recommendations would vary from state to state, we see the following as promising steps forward for all industry stakeholders in modernizing our grid:

1. Future regulatory proceedings and policy venues related to capturing the benefits of DERs should *incorporate the expanded benefit and cost categories* identified in this paper.
2. Regulators should look for near-term opportunities to *modernize the utility incentive model*, either for all utility earnings or at a minimum for demonstration projects, to eliminate the bias toward utility-owned investments.
3. Regulators should require utilities to *modernize their planning processes* to integrate and leverage distributed energy resources, utilizing the integrated distribution planning process identified in this paper.
4. Regulators should require utilities to *categorize all planned distribution investments* in terms of the underlying grid need. Utilities should make data available electronically to industry, ideally in a machine-readable format.

Call for Input

We offer this paper as an effort to support the utilization of grid modernization to maximize ratepayer benefits. The cost/benefit analysis we develop here is an effort meant to expand the industry's ability to quantify the holistic contribution that DERs offer to the grid and its customers, extending the familiar cost/benefit framework beyond PV-only analyses and into full smart inverter and DER portfolios. Furthermore, we recognize that important regulatory proceedings – such as the CPUC Distribution Resource Plans (DRP) and CPUC Integrated Distributed Energy Resources (IDER) – will play an important role in giving stakeholders the tools to calculate the value of DERs, and offer this paper a as resource in those efforts.

No single report could adequately address all the issues – engineering, economic, regulatory – that naturally arise during such a transformative time in the industry. By compiling the major issues in one place, we attempt to advance the discussion and suggest that this paper includes a "table of contents" of critical topics for regulators and industry stakeholders to consider when evaluating the full potential of distributed energy resources.

There are many details of this paper that can be refined, including utilizing more complete data sets to inform the cost/benefit analysis. We welcome ongoing dialogues with utilities and other stakeholders to improve the assumptions or calculations herein, including sharing data and revising methodologies to arrive at more representative figures. In fact, most of the authors of this paper are former utility engineers, economists, technologists, and policy analysts, and would value the opportunity to collaborate. We welcome a constructive dialogue, and can be reached at gridx@solarcity.com.

Acknowledgements

We would like to thank the following industry stakeholders who were willing to provide their valuable feedback on the content of this paper. While we incorporated their input to every extent possible, we, the authors, are solely responsible for the information presented and the conclusions drawn in the report.

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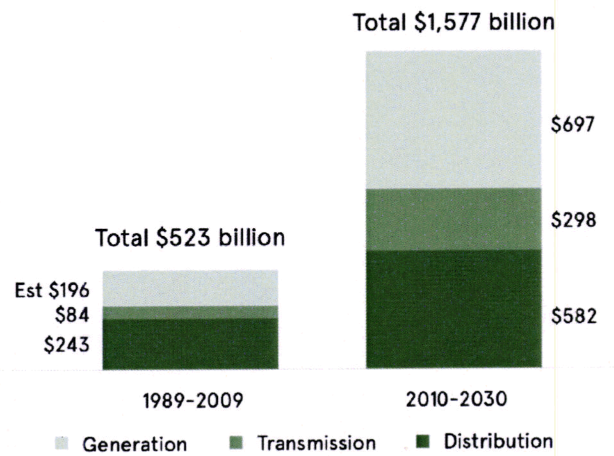
I. Introduction

Grid Investments are Increasing

Grid infrastructure planners are responsible for some of the most significant infrastructure investments in the United States. As of 2011, U.S. utilities had almost half a trillion dollars of undepreciated transmission, distribution and generation assets on their balance sheets, growing at a rate of 6 to 8% per year.[3] As depicted in the adjacent figure, the Edison Electric Institute forecasts that another $879 billion dollars in distribution and transmission investments alone will occur in the twenty year period of 2010 through 2030 – about $44 billion dollars per year – significantly larger than investments seen in the previous 20 year period.[4] Grid investments have a significant and increasing impact on the total electricity costs faced by U.S. consumers.

U.S. Grid Investments



In light of this huge level of grid investment occurring over the next few decades, an imperative exists to ensure that these investments are deployed to maximize ratepayer benefits. There has been relatively little focus to date on how to effectively focus and reduce these infrastructure costs, particularly in the areas of transmission and distribution planning, despite the fact that they often make up half of the average residential customer's bill. This level of investment calls for a reexamination of the technological solutions available to meet the grid's needs and an overhaul of the planning process that deploys these solutions. States like California and New York have begun this process, primarily spurred by a focus on how distribution planning and operations may evolve in a future with high penetration of distributed resources.[5] While these nascent discussions and rulemakings are positive first steps, the planning framework for grid modernization must change considerably to avoid costing ratepayers billions in unnecessary, underutilized investments.

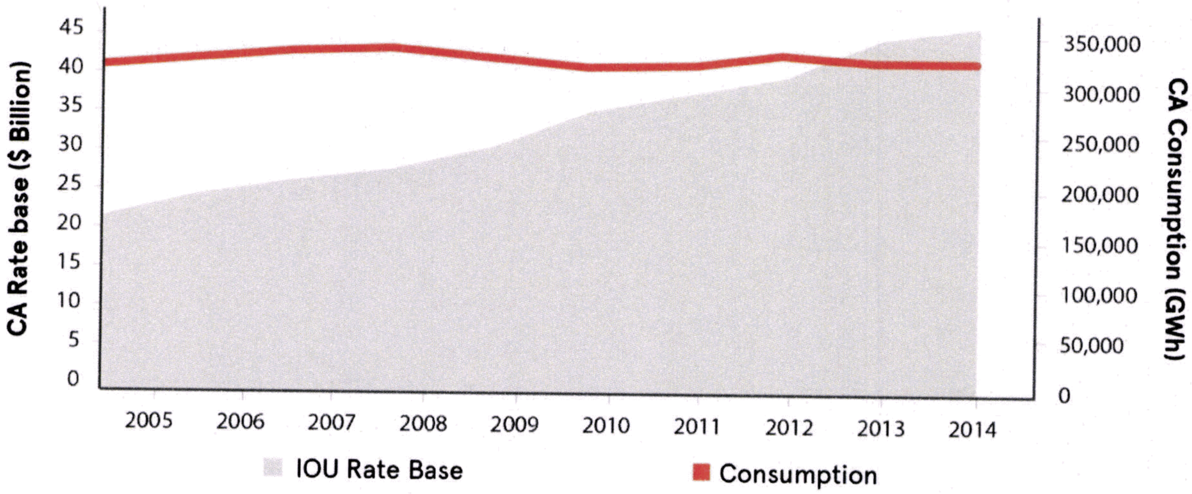
Current Utility Regulatory Model Incents a *Build More to Profit More* Approach

The current utility regulatory model, which was designed around a monopoly utility managing all aspects of grid design and operation, is outdated and unsuited for today's reality of consumers installing DERs that can benefit the grid. Therefore, industry fundamentals need to be reexamined, and the utility incentive model is a key place to start.

Electric utilities are generally regulated under a "cost plus" model, which compensates utilities with an authorized rate of return on prudent capital investments made to provide electricity services. While this model makes sense when faced with a regulated firm operating in a natural monopoly, it is well known to result in a number of economic inefficiencies, as perhaps best analyzed by Jean Tirole in his Nobel Prize winning work on market power and regulation.[6]

One fundamental problem resulting from the "cost plus" utility regulatory model is that utilities are generally discouraged from utilizing infrastructure resources that are not owned by the utility, even if competitive alternatives could deliver improved levels of service at a lower cost to ratepayers. Beyond regulatory oversight, this model contains no inherent downward economic pressure on the size of the utility rate base, or the cumulative amount of assets upon which the utility earns a rate of return. As such, utility rate bases have consistently and steadily grown over time. For example, the following chart depicts the size and recent growth of the electricity rate base for California investor-owned utilities, which continues to significantly grow even in the presence of flat electricity consumption. In short, the fundamental incentive utilities have to build more utility-owned infrastructure in order to profit more conflicts with the public interest as the grid becomes more customer-centric and distributed.

Trends in Rate Base for California Investor-Owned Utilities[7,8]



Traditional Grid Planning Focuses on Traditional Assets

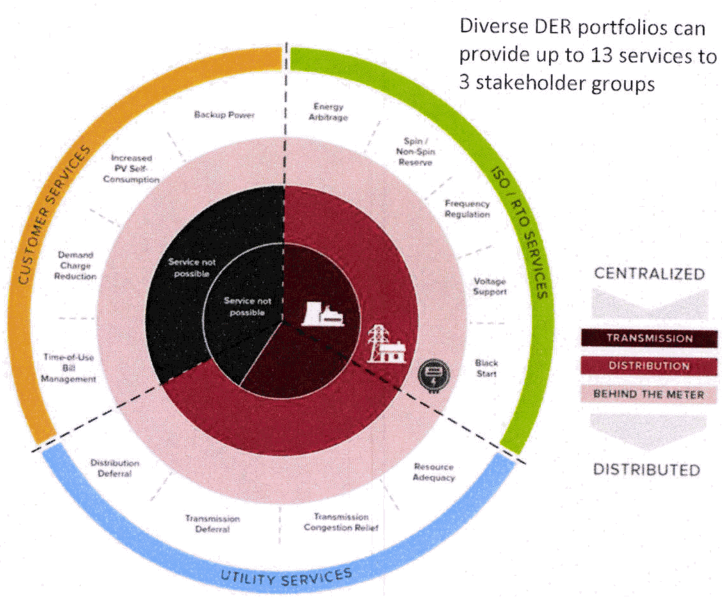
Grid planning for infrastructure investments has historically focused on installing expensive, large assets that provide service over a wide geographic region. This structure naturally evolved from the technology and market characteristics of the original electricity industry, including a natural monopoly, centralized generation, long infrastructure lead times, high capital costs with significant economies of scale, and a concentration of technical know-how within the utility.

Many of these barriers have been eliminated with the technological advancement in physical infrastructure options – such as DER portfolios that can meet grid needs – and increased sophistication of grid design and operational tools. However, grid planning remains focused on utilizing traditional infrastructure to the detriment of harnessing the increasing availability of DERs. Utilizing DER solutions will require a shift in grid planning approaches, as well as increased access to the underlying planning and operational data needed to enable DERs to operate most effectively in concert with the grid.

Distributed Energy Resources Offer Increased Grid Flexibility

Distributed energy resources include assets such as rooftop PV, smart inverters, controllable loads, permanent load shifting, combined heat and power generators, electric vehicles, and energy efficiency resources. These resources provide a host of benefits to the customer, utility, and transmission operator as identified by numerous research organizations including EPRI and the Rocky Mountain Institute (RMI). As depicted in the RMI figure to the right, diverse portfolios of DERs offer a wide range of grid services at the distribution, transmission, and customer levels.[9]

Distributed energy resources can offer deferral and avoidance of planned grid investments, improved grid resiliency, and increased customer choice. DERs, if deployed effectively and placed on equal footing in the planning process with traditional grid investments, can ultimately lead to increased net benefits for ratepayers.



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II. Distributed Energy Resources Offer a Better Alternative

Motivated by the challenge faced in designing a grid appropriate to the 21st century, this report first focuses on determining the quantifiable net economic benefits that DERs can offer to society. The approach taken builds on existing avoided cost methodologies – which have already been applied to DERs by industry leaders – while introducing updated methods to hard-to-quantify DER benefit categories that are excluded from traditional analyses. While the final net benefit calculation derived in this report is specific to California, the overall methodological advancements developed here are applicable across the U.S. Moreover, the ultimate conclusion from this analysis – that DERs offer a better alternative to many traditional infrastructure solutions in advancing the 21st century grid – should also hold true across the U.S., although the exact net benefits of DERs will vary across regions.

A. Methodology

The methodology utilized in this paper is built upon well-established frameworks for valuing policies, programs and resources – frameworks that are grounded in the quantification of the costs and benefits of distributed energy resources. Specifically, the methodology employed here:

1. Begins with the Electric Power Research Institute's 2015 Integrated Grid/Cost Benefit Framework in order to quantify total net societal costs and benefits in a framework that applies nationally. [10]
2. Quantifies the benefits for the state of California, where the modeling of individual cost and benefit categories is possible using the California Public Utilities Commission 2015 Net Energy Metering Successor Public Tool.[11] Within the context of California, this report's DER avoided cost methodology is expanded beyond EPRI's base methodology to incorporate commonly recognized (although not always quantified) categories of benefits and costs, while also proposing methodologies for several hard-to-quantify categories using the Public Tool.
3. Incorporates the full costs of DER integration, including DER integration cost data as identified by California utilities in their 2015 Distribution Resource Plans[12] to determine the net benefits of achieving 2020 penetration levels.
4. Repeats the methodology in a concrete case study by applying it to the planned distribution capacity projects from the most recent Phase I General Rate Case in California.

Enhancing Traditional Cost/Benefit Analysis and Describing Benefits as Avoided Cost

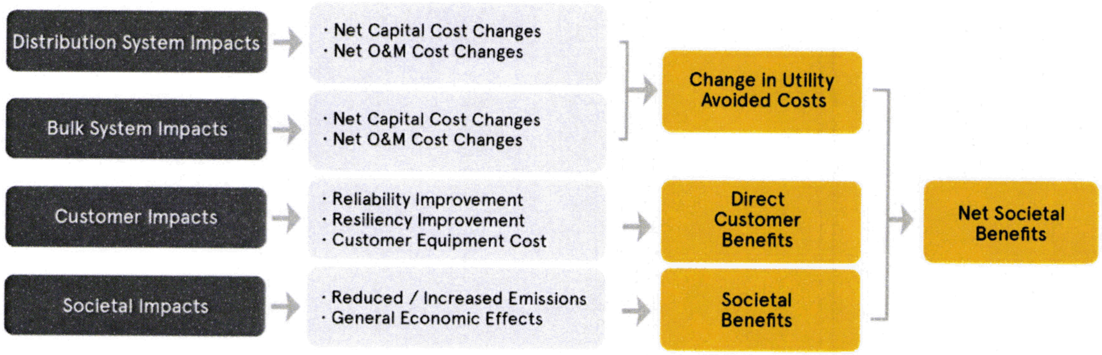
Cost/benefit analyses have been conducted for many decades to evaluate everything from utility-owned generation to utility-administered customer programs such as energy efficiency rebates and demand response program funding. This paper replicates established methodologies wherever possible, and offers new or enhanced methodologies where appropriate to consider new benefit categories that are novel to customer-driven adoption of DERs, and therefore often excluded from traditional analyses.

A key component of cost/benefit analysis commonly used for valuing the benefits of DER is the avoided cost concept, which considers the benefits of a policy pathway by quantifying the reduction in costs that would otherwise be incurred in a business-as-usual trajectory. While avoided cost calculations can be performed with varying scopes,[13] there is some degree of consensus on what the appropriate value categories are in a comprehensive avoided cost study. Groups like IREC,[14] RMI[15] and EPRI[16] have attempted to take these standard valuation frameworks even further, describing general methods for valuing some of the benefit categories that are often excluded from traditional analyses.

Each step taken by researchers to enhance previously used avoided cost methodologies advances the industry beyond outdated historical paradigms. DER-specific methodological updates include the consideration of new types of avoided costs that could be provided by distributed resources, or a revision of the assumption that resources adopted by customers are uncontrollable, passive deliverers of value to the grid and that proactive planning and policies cannot or will not be implemented to maximize the value of these grid-interactive resources.

This report continues the discussion using EPRI's 2015 Integrated Grid/Cost Benefit Framework as a springboard. EPRI's framework, depicted in the following image) was chosen as it is the most recently published comprehensive cost/benefit analysis framework for DERs. This report assumes a basic familiarity with EPRI's methodology – or avoided cost methodologies in general – on the part of the reader, although explanations of each cost or benefit category are included in the following section.

EPRI Cost/Benefit Framework[17]



The Value of DERs within California

While the overall methodology enhanced within this report is applicable nationwide, the focus of this report's economic valuation of DERs in the cost/benefit analysis is limited to the state of California. For California's NEM 2.0 proceeding, the energy consulting firm Energy+Environmental Economics (E3) created a sophisticated model that parties used to determine the impact of various rate design proposals. A major component of this model was the ability to assess DER avoided costs under different input assumptions. The more traditional avoided cost values in this paper are derived from the inputs used in the NEM 2.0 proposal filing of The Alliance of Solar Choice (TASC) for the E3 model, which is available publicly online.[18]

Additionally, benefit and cost categories for DERs – along with accompanying data and quantification methods – are being developed in the CPUC Distribution Resource Plans (DRP) proceeding. This update of the DER valuation framework in the DRP proceeding, however, is not present in the existing methodologies being used to quantify the benefits of rooftop solar in California as part of the NEM 2.0 proceeding due to the concurrent timing of the two proceedings. This report bridges these two connected proceedings in its economic analysis of the value of DERs within California.

While evaluating net societal benefits at the system level in California is a key step in understanding the total potential value of DERs, there remains much discussion within the industry regarding whether calculated net benefits can actually be realized from changes in transmission and distribution investment planning. To this end, this analysis applies the developed California DER valuation framework to a real-world case study utilizing the latest GRC filed in California, PG&E's 2017 General Rate Case Phase I filing. By utilizing this third dataset, in addition to the NEM 2.0 and DRP proceedings, this analysis delivers a comprehensive and up-to-date consideration of the potential value DERs can provide to the grid.

Analysis Scope, Assumed Scenario, and End State

This report evaluates the benefits of customer DER adoption, the associated costs, and the resulting net benefit/cost.

DESCRIPTION OF SCOPE

Net Societal Benefit = Societal Benefits – Societal Costs	
Societal Benefits	The benefits that would be generated if California achieved high-penetration of distributed energy resources.
Societal Costs	The investment cost that would be necessary to enable California to achieve high-penetration of distributed energy resources.
Net Societal Benefits	The value to society of achieving a high-penetration California defined as the benefits of the outcome less the costs of achieving the outcome.

The benefits and costs of DER are highly dependent on penetration levels. Therefore, this analysis utilizes a set of common assumptions for expected DER penetration, and specifies a market end state scenario upon which benefits and costs are quantified. The end-state assumed in this report utilizes scenarios in Southern California Edison's (SCE) July 1, 2015 Distribution Resource Plan, which includes DER adoption levels and integration cost estimates for the 2016-2020 period. These integration costs inform DER penetration assumptions, which are applied consistently across the benefits calculations to ensure that the costs of low penetration are not attributed to the benefits of high penetration, and vice-versa.

Incremental DER Adoption Scenario for 2016-2020

TECHNOLOGY	QUANTITY
Solar	4.5 GW
With Storage	900 MWh (10% Adoption)
With Load Control	150 MW (20% Adoption)

To simplify the discussion, solar deployment is focused on the years 2016-2020, adopting the penetration levels and costs associated with the TASC reference case as filed in the CPUC NEM 2.0 proposal filing, which corresponds approximately to SCE's Distribution Resource Plan Scenario 3. Of the approximately 900,000 new solar installations expected to be deployed during this period, SolarCity estimates 10% would adopt residential storage devices and 20% would adopt controllable loads (assumptions are based on customer engagement experience and customer surveys). These adoptions are central to the ability of customer DER deployments to defer and avoid traditional infrastructure investments as assessed in this paper.

The assumptions described above are used to complete the cost/benefit analysis of DERs for the whole of California. After evaluating net societal benefits at the system level, the methodology is then applied to a particular case study of actual distribution projects proposed under the latest GRC filed within California, PG&E's 2017 General Rate Case Phase I filing.

In the following sections, the deployment scenario is evaluated both qualitatively and quantitatively under a cost-benefit framework that is grounded in established methodologies, but enhanced to consider the impact of such a large change in the way the electric system is operated. The study consolidates a range of existing analyses, reports and methodologies on DERs into one place, supporting a holistic assessment of the energy policy pathways in front of policy-makers today.

B. Avoided Cost Categories

The avoided cost categories evaluated in this report are summarized in the following table. The first seven categories are included within traditional cost-benefit analyses, and as such are not substantially extended in this report (see Appendix for methodological overviews and TASC NEM Successor Tariff filing for comprehensive descriptions and rationale on assumptions[19]). The next five categories (in yellow highlight) represent new methodology enhancements to hard-to-quantify avoided cost categories (i.e. benefit categories) that are often excluded from traditional analyses. In this section, we detail the methodology and rationale for quantifying these five avoided cost categories.

AVOIDED COST	DESCRIPTION
Energy + Losses	The value of wholesale energy that would otherwise be generated in the absence of DERs, adjusted for losses that would occur. In CA, the cost of carbon allowances from the Cap and Trade program is embedded in the wholesale energy value
Generation Capacity	The value of avoiding the need for system generation capacity resources to meet peak load and planning reserve requirements
Transmission Capacity	The value of avoiding the need to expand transmission capacity to meet peak loads
Distribution Capacity	The value of avoiding the need to expand distribution capacity to meet peak loads
Ancillary Services	The value of a reduced need for operational reserves based on load reduction through DERs
Renewable Energy Compliance	The value of reducing procurement requirements for renewable energy credits, due to reduced delivery of retail energy on which RPS compliance levels are based
Societal Benefits	The value of benefits that accrue to society, and are not costs directly avoided by the utility
Voltage and Power Quality	The value of avoiding or reducing the cost required to maintain voltage and frequency within acceptable ranges for customer service
Conservation Voltage Reduction	The value of enabling conservation voltage reduction benefits by providing localized voltage support
Equipment Life Extension	The value of extending the useful life and improving the efficiency of distribution infrastructure by reducing load and thermal stress equipment
Reliability & Resiliency	The value of avoiding or reducing the impact outages have on customers
Market Price Suppression	The value of reducing the electric demand in the market, hence reducing market clearing prices for all consumers of electricity

Voltage, Reactive Power, and Power Quality Support

Solar PV and battery energy storage with 'smart' or advanced inverters are capable of providing reactive power and voltage support, both at the bulk power and local distribution levels. At the bulk power level, smart inverters can provide reactive power support for steady-state and transient events, services traditionally supplied by large capacitor banks, dynamic reactive power support, and synchronous condensers. For example, in Southern California the abrupt retirement of the San Onofre Nuclear Generation Station (SONGS) in 2013 created a local shortage of reactive power support, endangering stable grid operations for SCE in the Los Angeles Basin area. To meet this reactive power need, SCE sought approval to deploy traditional reactive power equipment at a cost of $200-$350 million, as outlined in the table below. DERs were not included in the procurement to meet this need. Had DERs with smart inverters been evaluated as part of the solution, significant reactive power capacity could have been obtained to avoid the deployment of expensive traditional equipment.

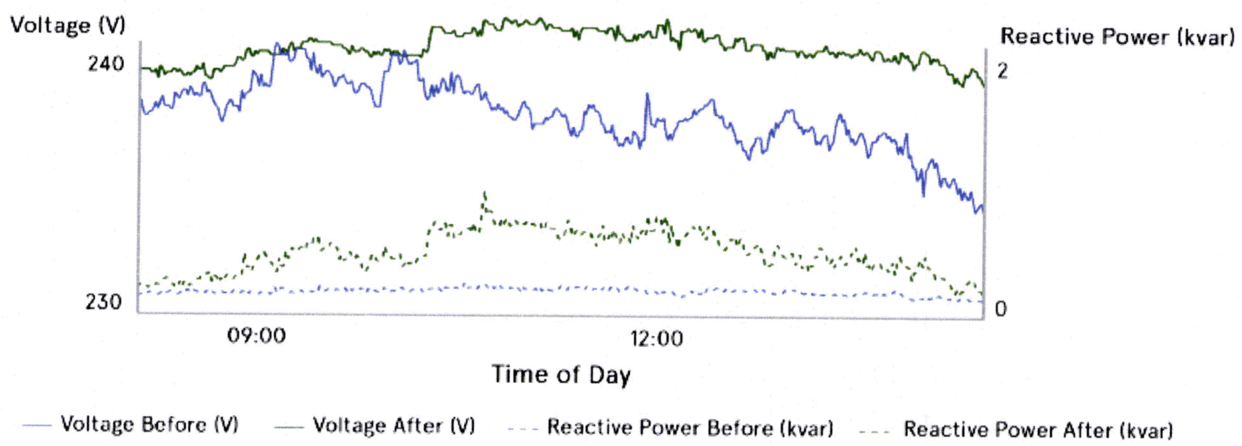
SONGS Reactive Power Replacement Projects

PROJECT	CAPACITY (MVAR)	IN-SERVICE	COST
Huntington Beach Synchronous Condensers	280	6/1/2013	$4.75M
Johanna and Santiago 220 kV Capacitor Banks	160	7/1/2013	$1.1-10M
			$10-50M
Viejo 220 kV Capacitor Banks	160	7/1/2013	$1.1-10M
			$10M
			$10-50M
Talega Area Dynamic Reactive Support	250	6/1/2015	$58-72M
South Orange County Dynamic Reactive Support	400	12/1/2017	$50-75M
Penasquitos 230 kV Synchronous Condenser	240	5/1/2017	$56-70M
Total	**1,400**		**$201-$352M**

Sources[20,21,22,23,24,25,26,27]

At the distribution level, smart inverters can provide voltage regulation and improve customer power quality, functions that are traditionally handled by distribution equipment such as capacitors, voltage regulators, and load tap changers. While the provision of reactive power may come at the expense of real power output (e.g. such as power otherwise produced by a PV system), inverter headroom either exists or can readily be incorporated into new installations to provide this service without impacting real power output. The capability of DER smart inverters to provide voltage and power quality support is currently being demonstrated in several field demonstration projects across the country. For instance, a demonstration project in partnership with an investor-owned utility is currently demonstrating the voltage support from a portfolio of roughly 150 smart inverters controlling 700kW worth of residential PV systems. The chart below depicts the dynamic reactive power delivered to support local voltage. In this instance, smart inverter support resulted in a 30% flatter voltage profile.[28]

Reactive power and voltage support from a smart inverter



Projects such as the SONGS reactive power procurement project provide recent examples where utility investment was made for reactive power capacity. These projects were used to quantify the economic benefit of DERs providing reactive power support. To do so, a corresponding $/kVAR-year value was applied to the inverter capacity assumed in the deployment scenarios to determine the value of the services offered by the DER portfolio. Note, also, that markets including NYISO, PJM, ISO-NE, MISO, and CAISO already compensate generators for capability to provide and provision of reactive power.[29]

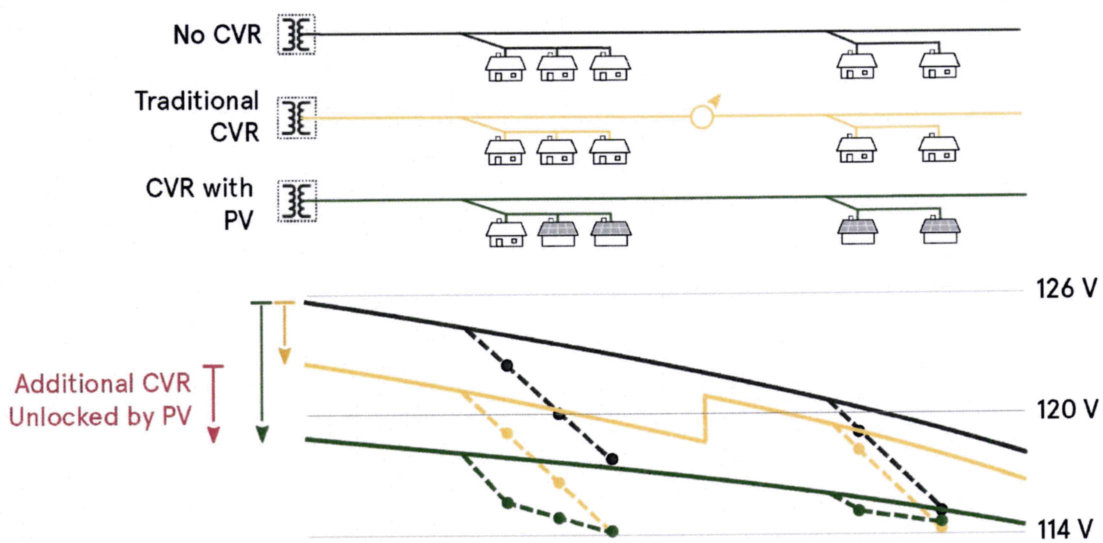
Conservation Voltage Reduction

Smart inverters can enable greater savings from utility conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that reduces customer service voltages in order to achieve a corresponding reduction in energy consumption. CVR programs are often implemented system-wide or on large portions of a utility's distribution grid in order to conserve energy, save customers on their energy bills, and reduce greenhouse gas emissions. CVR programs typically save up to 4% of energy consumption on any distribution circuit.[30] The utilization of smart inverters is estimated to yield another 1-3% of incremental energy consumption savings and greenhouse gas emissions reductions.

From an engineering perspective, CVR schemes aim to reduce customer voltages to the lowest allowable limit as allowed by American National Standards Institute (ANSI) standards. However, CVR programs typically only control utility-owned distribution voltage regulating equipment, changes to which affect all customers downstream of any specific device. As such, CVR benefits in practice are limited by the lowest customer voltage in any utility voltage regulation zone (often a portion of a distribution circuit), since dropping the voltage any further would violate ANSI standards for that customer.

Since smart inverters can increase or decrease the voltage at any individual location, DERs with smart inverters can be used to more granularly control customer voltages in CVR schemes. For example, if the lowest customer voltage in a utility voltage regulation zone were to be increased by, say, 1 Volt by controlling a local smart inverter, the entire voltage regulation zone could then be subsequently lowered another Volt, delivering substantially increased CVR benefits. Such an example is depicted in the image below, where the green line represents a circuit voltage profile where smart inverters support CVR. Granular control of customer voltages through smart inverters can dramatically increase CVR benefits.

DERs control voltage locally and enable CVR

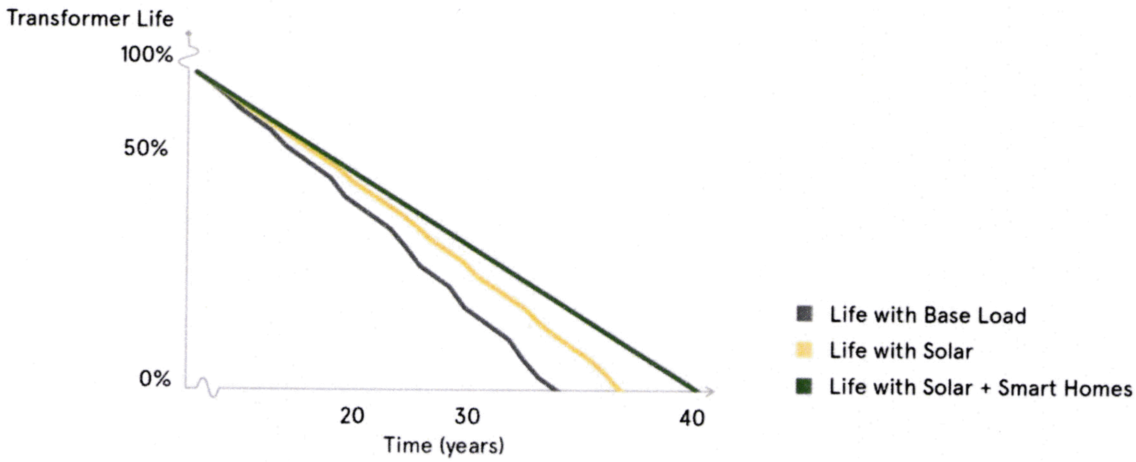


Equipment Life Extension

Either through local generation, load shifting, and/or energy efficiency, DERs reduce the net load at individual customer premises. A portfolio of optimized DERs dispersed across a distribution circuit in turn reduces the net load for all equipment along that distribution circuit. Distribution equipment, such as substation transformers, operating at reduced loading will benefit from increased equipment life and higher operational efficiency.

Distribution equipment may operate at very high loading during periods of peak demand, abnormal configuration, or emergency operation. When the nominal rating of equipment is exceeded, or overloaded, the equipment suffers from degradation and reduction in operational life. The more frequently that equipment is overloaded, the more that such degradation occurs. Furthermore, the efficiency of transformers and other grid equipment falls as they perform under increased load. The higher the overload, the larger the efficiency losses. Utilities have significant portions of their grid equipment that regularly operate in overloaded fashion. DERs' ability to reduce peak and average load on distribution equipment therefore leads to a reduction in the detrimental operation of the equipment and an increase in useful life, as shown in the following figure. The larger the peak load reduction, the larger the life extension and efficiency benefits.

Distributed Energy Resources Extend Transformer Life



To quantify these benefits, medium to large liquid-filled transformers were modeled with typical load and DER generation profiles. The magnitude of the reduced losses and resulting equipment degradation avoidance were calculated using IEEE C57.12.00-2000 standard per unit life calculation methodology.[31,32] DERs such as energy storage are able to achieve an even greater avoided cost than solar alone, as storage dispatch can more closely match the distribution peak. Quantified benefits contributing to net societal benefits calculation include the deferred equipment investment due to extended equipment life and reduced energy losses through increased efficiency.

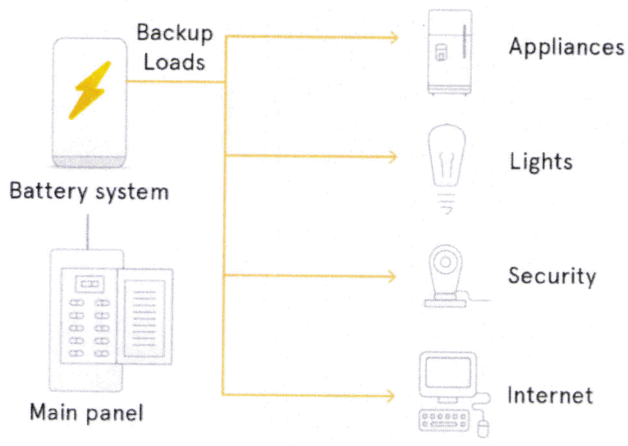
Note that non-optimized DERs can be cited as having negative impact on equipment life. While highly variable generation and load can negatively impact equipment life – such as driving increased operations of line regulators – optimized and coordinated smart inverters mitigate this potential volatility impact on equipment life.

Resiliency and Reliability

DERs such as energy storage can provide backup power to critical loads, improving customer reliability during routine outages and resiliency during major outages. The rapidly growing penetration of batteries combined with PV deployments will reduce the frequency and duration of customer outages and provide sustained power for critical devices, as depicted in the adjacent figure.

Improved reliability and resiliency has been the goal of significant utility investments, including feeder reconductoring and distribution automation programs such as fault location, isolation, and service restoration (FLISR). Battery deployments throughout the distribution system can eventually reduce utility reliability and resiliency investments. However, this analysis utilizes a conservative approach, only considering average customer savings from reduced outages and excludes avoided utility investments.

Distributed Energy Resources Improve Customer Resiliency and Reliability



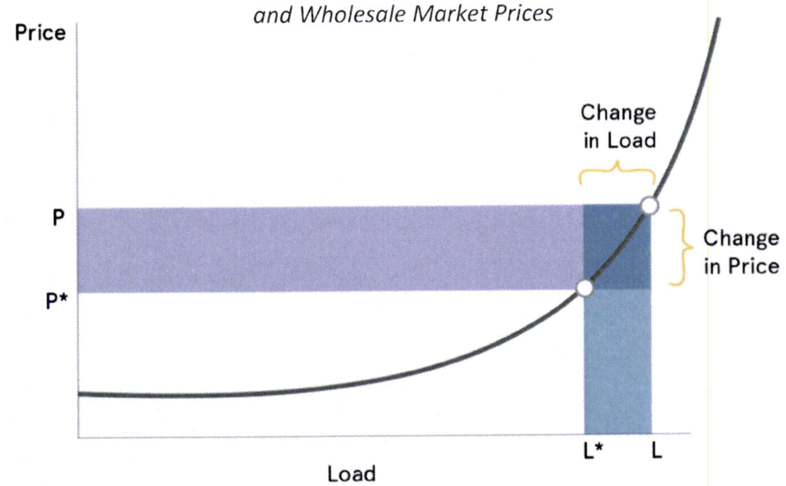
To quantify near-term reliability and resiliency benefits, the value of lost load as calculated by Lawrence Berkeley National Lab[33] was applied to the energy that could be supplied during outages. Outages were based on 2014 CPUC SAIFI statistics.

Market Price Suppression Effect

Wholesale electricity markets provide a competitive framework for electric supply to meet demand. In general, as electric demand increases market prices increase. DERs can provide value by reducing the electric demand in the market, leading to a reduction in the market clearing price for all consumers of electricity. This effect was recently validated in the U.S. Supreme Court's decision to uphold FERC Order 745, noting that operators accept demand response bids if and only if they bring down the wholesale rate by displacing higher-priced generation. Notably, the court emphasized that "when this occurs (most often in peak periods), the easing of pressure on the grid, and the avoidance of service problems, further contributes to lower charges."[34] As a behind-the-meter resource, rooftop solar impacts wholesale markets in a similar way to demand response, effectively reducing demand and thus clearing prices for all resources during solar production hours. While the CPUC Public Tool attempts to consider the avoided cost of wholesale energy prices, it does not consider the benefits of reducing wholesale market clearing prices from what they would have been in the absence of solar.

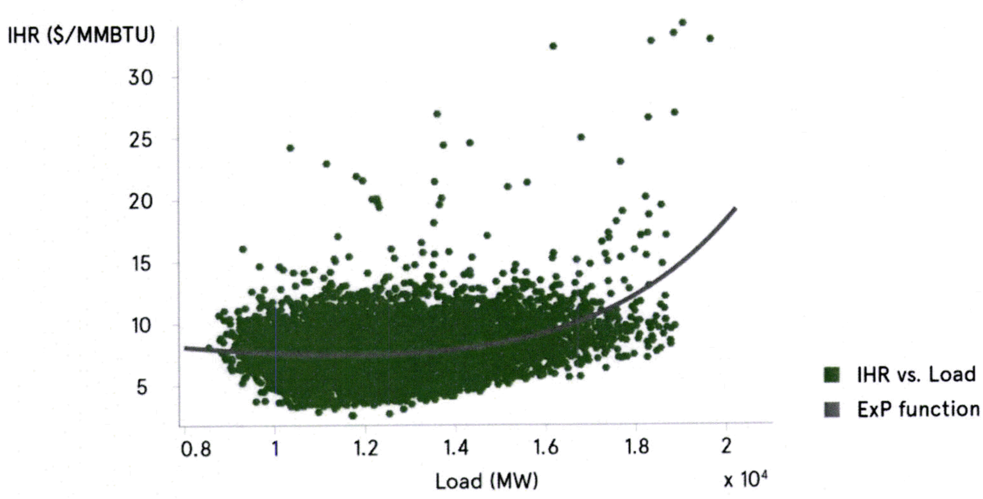
This effect is illustrated in the adjacent figure. In the presence of DERs, energy prices are at the lower "P*" price which otherwise would have been at the higher "P" price absent the DERs. Market price suppression could then be quantified as the difference between prices multiplied by load, or $(P - P^*) * L^*$.

Relationship between Electric Demand and Wholesale Market Prices



To quantify the magnitude of cost reductions due to market price suppression, this report estimates the relationship between load and market prices based on historical data. It is important to isolate other driving factors to only capture the effect of load change on prices. One of these driving factors is natural gas prices, which directly impacts electric prices because the marginal supply resource in California is often a natural gas-fired power plant. This can be isolated by normalizing market prices over gas prices, known as Implied Heat Rate (IHR), and estimating the relationship between IHR and load, which is shown in figure below for PG&E DLAP prices and load.

Relationship between electric demand and Implied Heat Rate for PG&E



Smart energy homes equipped with energy storage are able to achieve an even greater avoided cost than distributed solar alone. Storage devices that discharge in peak demand hours with high market clearing prices can take advantage of the stronger relationship between load and price at high loads.

Results

After establishing the 2016-2020 penetration scenario and defining the methodologies for each category of avoided cost, the CPUC Public Tool was utilized to estimate the benefits of achieving the 2020 penetration scenario. For avoided cost categories the CPUC Public Tool was not able to incorporate, calculations were completed externally using common penetration and operational assumptions for each technology type. In order to be consistent with the CPUC Public Tool outputs, levelized values are expressed in annual terms in 2015 dollars below.

Annual Benefits of 2016-2020 DER Deployments

AVOIDED COST CATEGORY	PV + SMART INVERTER ($M/YEAR)	+DERs ($M/YEAR)	TOTAL ($M/YEAR)
Penetration Levels	4.5 GW	90,000 Homes	
Energy + Losses	$637	$74	$710
Generation Capacity	$91	$99	$190
Transmission Capacity	$333	$42	$375
Distribution Capacity	$187	$54	$241
Ancillary Services	$6	$1	$7
Renewable Energy Compliance	$199	$23	$221
Societal Benefits	$371	$43	$414
Voltage and Power Quality	$91	$7	$99
Conservation Voltage Reduction	$34	$4	$38
Equipment Life Extension	$31	$4	$36
Reliability & Resiliency	$0	$8	$8
Market Price Suppression	$163	$19	$182
Total Benefits	**$2,143**	**$378**	**$2,521**

Previous assessments of high penetration DERs have replicated existing methodologies that have often been applied to passive assets like energy efficiency; however, these approaches fail to recognize the potential value of advanced DERs that will be deployed during the 2016-2020 timeframe. When a more comprehensive suite of benefits that could be generated by DERs today is considered, total benefits of the 2016-2020 DER portfolio in California exceeds $2.5 billion per year.

C. The Costs of Distributed Energy Resources

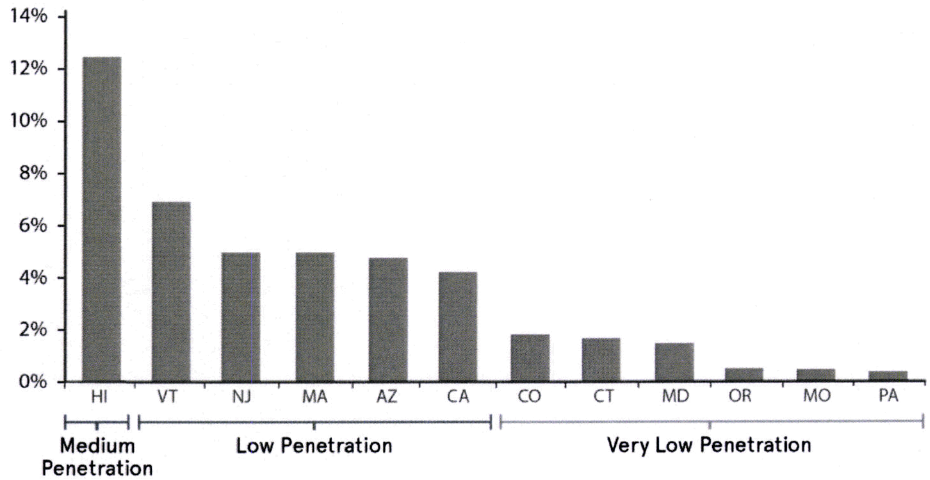
As presented above, distributed resources offer significant ratepayer benefits; however, these benefits are not available without incurring incremental costs to enable their deployment. In order to quantify the net societal benefit of DERs, these costs must be subtracted from the benefits. Costs for distributed energy resources include integration at the distribution and bulk system levels, utility program management, and customer equipment.

Distribution Integration Costs

DERs are a critical new asset class being deployed on the distribution grid which must be proactively planned for and integrated with existing assets. This integration process will sometimes require unavoidable additional investments. However, it is essential to separate incremental DER integration costs from *business as usual* utility investments. Recent utility funding requests for DER integration have included costs above those needed to successfully integrate DERs. This subsection will explore typical DER integration costs and evaluate the validity of each type.

While new DER integration rules of thumb and planning guidelines are emerging,[35] no established approach exists for identifying DER integration investments or estimating their cost. It is clear, however, that integration efforts and costs vary by DER penetration level. Generally, lower DER penetration requires fewer integration investments, while higher penetration may lead to increased investment. As depicted in the following chart, NEM PV penetration levels vary across the U.S.[36] Most states have *very low* (<5%) penetrations, while only Hawaii experiences *medium* (10-20%) penetration. California exhibits *low* (5-10%) penetration overall, although individual circuits may experience much higher penetration.

NEM Solar Capacity as a Percentage of Total System Peak



For this analysis, DER integration costs were developed from estimates submitted by California utilities to the CPUC as part of their Distribution Resource Planning (DRP) filings. This analysis incorporates the specific cost categories and figures from Southern California Edison's filing, since this filing alone included specific cost estimates. In assessing these costs, each proposed investment was reviewed to determine whether it was a required incremental cost resulting from the integration of DERs. If so, it should indeed be included in the cost/benefit calculation. If the investment (or a portion thereof) was determined to be a component of utility *busines as usual* operations, such investment was not included in the analysis.

In order to determine whether a proposed utility investment is required, the following *threshold question* was asked:

- *Would these costs be incurred even in the absence of DER adoption?*

If the costs would be incurred regardless of DER adoption, or if the utility had previously requested regulatory approval for the investment but justified the investment via a program unrelated to DER adoption, then the costs should not be classified as DER integration costs. For example, if a utility had previously requested approval to upgrade (i.e. cutover) 4kV circuits to a higher voltage in order to increase capacity and reliability before DERs were prevalent, yet now associates the upgrade costs to DERs, then the investment should not be attributed to DER integration. This threshold analysis eliminates from consideration or reduces some of the proposed utility integration costs.

Of the remaining costs, each was further assessed by asking the following set of *screening questions*:

- Do more cost effective mitigation measures exist for the proposed investment? Can advanced DER functionalities (e.g. volt/VAR support) mitigate or eliminate the need for the investment?
- Are costs relevant for the forecasted DER penetration levels, or only for much higher penetrations?
- Do stated costs reflect realistic cost figures, or do they reflect inflated estimates?

Several utility integration investments are proposed to mitigate an integration challenge where more cost effective solutions exist. For example, voltage-related concerns due to PV variability are often used to justify replacement of capacitor banks on distribution feeders. However, the use of embedded voltage and reactive power capabilities in smart inverters make the deployment of new capacitor banks redundant and overly expensive in most instances. Furthermore, while some proposed costs may be relevant for high penetrations of DERs – such as bi-directional relays to deal with reverse power flows – these investments may not be necessary at low penetration levels.

The following table presents the DER integration investment categories as identified in SCE's DRP filing according to its Scenario 3 forecast for DER growth in California. SCE's integration costs were scaled up in order to estimate total distribution integration costs for all California utilities; therefore, the table represents total California distribution integration costs over 2016-2020. For each investment, applicability to DER integration is assessed using the threshold and screening questions discussed above, resulting in a quantification of costs that are directly "Applicable to DERs". An overview of the assessment of each high-level integration category is provided in the table, with more detailed technical discussion of each investment type and assessment rationale offered in the Appendix. This cost quantification is necessarily high-level due to the lack of details available for each investment type. As such, more specific assessment is necessary in order to evaluate integration investment plans. This exercise identifies 25% of SCE's DER integration costs, or $1,450 million (or levelized to $189 million annually[37]), as truly applicable to DER integration, which is the number utilized in the cost/benefit analysis in this paper.

CATEGORY	INVESTMENTS	UTILITY COST CLAIM ($M)	APPLICABLE TO DERs (%)
Distribution Automation	Automated switches w/enhanced telemetry, remote fault indicators	$710	0%
Substation Automation	Substation automation, modern protection relays	$691	30%
Communication Systems	Field area network, fiber optic network	$888	0%
Grid Reinforcement	Conductor upgrades to a larger size, conversion of circuits to higher voltage	$1,070	50%
Technology Platforms and Applications	Grid analytics platform/applications, long-term planning tool set, distribution circuit modeling tool, interconnection application processing, DRP data sharing portal, grid/DER management system, system architecture and cyber security, distribution Volt/VAR optimization	$2,337	30%
Total Distribution Integration Costs		**$5,697**	**25% (1,450)**

Bulk System Integration Costs

Integration of variable resources with the bulk power grid is expected to result in an increase in variable operating costs associated with the way the generation fleet is used to accommodate the variability. To quantify this cost, $/MWh values quantifying this cost for a 33% renewable portfolio standard were scaled per calculations adopted by the California PUC.[38]

Utility Program Management Costs

To estimate the incremental utility program costs associated with DER adoption, the default inputs within the Public Tool were used, which include upfront installation and metering costs, as well as incremental billing costs. All told, these costs amounted to $26 million per year based on the level of adoption in the TASC base case scenario.

Customer Equipment Costs

The costs of DERs themselves must be considered, including the cost of equipment, labor, and financing. For solar, CPUC Energy Division staff's reference case solar price forecast is used to determine the cost of deployed equipment in the 2016-2020 timeframe, factoring in the December 2015 extension of the Federal Investment Tax Credit. For storage, the price forecast was based on Navigant Research's projections;[39] for controllable thermostats, current vendor prices were used.

Based on these forecasts, deployments forecasted for the 2016-2020 timeframe yielded a blended average adoption cost of the installed base of $3.86/W for the 2016-2020 timeframe, or $2.70/W after reflecting the 30% Federal Investment Tax Credit (ITC). In absolute terms, the total cost of adoption to Californians translates to $12.1 billion (nominal) for 4.5GW of rooftop solar. For co-located storage and load control, total investment to meet adoption forecasts totals $259 million.

Results

Societal net benefits calculations require a comprehensive consideration of costs that society bears as a result of attaining the specified 2020 penetration levels, including the costs of administering customer programs, grid integration costs needed to accommodate new assets, and the cost of the assets themselves, which are borne by customers. In the table below, each category is quantified, totalling $1.1 billion per year.

CATEGORY	PV + SMART INVERTER ($M/YEAR)	+DERs ($M/YEAR)	TOTAL ($M/YEAR)
Penetration Levels	*4.5 GW*	*90,000 Homes*	
Utility Program Management Costs	$24	$3	$26
Integration Costs (Distribution + Bulk)	$170	$20	$189
Customer Equipment Costs	$770	$119	$889
Total Costs	**$964**	**$141**	**$1,105**

D. Quantifying Net Benefits

In this section, we complete EPRI's Cost/Benefit analysis by comparing benefits and costs of DERs during the 2016-2020 deployment timeframe. For consistent comparisons, levelized costs and benefits are based on the year 2020, with all benefits and costs values translated to 2015 dollars.[40]

Establishing a common DER penetration scenario and converting all benefits and costs to net present value terms allows simple summation of each category to provide indicative societal net benefit, suggesting a significant societal value for widespread DER adoption. In total, the benefits of the analyzed scenario are $2.5 billion per year, compared to costs of $1.1 billion per year, resulting in a net societal benefit to Californians of $1.4 billion per year by 2020.

Results of EPRI Societal Net Benefit Test

	CATEGORY	PV+SMART INVERTER ($M/YEAR)	+DERS ($M/YEAR)	TOTAL ($M/YEAR)
Benefits	Energy + Losses	$637	$74	$710
	Generation Capacity	$91	$99	$190
	Distribution Capacity	$333	$42	$375
	Transmission Capacity	$187	$54	$241
	Ancillary Services	$6	$1	$7
	Renewable Energy Compliance	$199	$23	$221
	Voltage and Power Quality	$91	$7	$99
	Conservation Voltage Reduction	$34	$4	$38
	Equipment Life Extension	$31	$4	$36
	Reliability & Resiliency	$0	$8	$8
	Market Price Suppression	$163	$19	$182
	Societal Benefits	$371	$43	$414
	Total Benefits	**$2,143**	**$378**	**$2,521**
Costs	Program Costs	$24	$3	$26
	Integration Costs	$170	$20	$189
	Equipment Costs	$770	$119	$889
	Total Costs	**$964**	**$141**	**$1,105**
	Total Net Benefits			**$1,416**

E. Case Study: PG&E's Planned Distribution Projects in 2017 General Rate Case

In the previous section, categories of avoided costs were described and the corresponding values were quantified for the state of California. In this section, the same methodology is applied to PG&E's planned distribution projects from its most recent PG&E 2017 General Rate Case filing from September 2015.

Every three years, California utilities seek approval to recover expenses and investments, including a target profit level, that are deemed necessary for the prudent provision of utility services. For perspective, half of customer's utility payments were driven by the "wires" component of the electric grid in 2014[41] and California's investor owned utilities are expected to add $143 billion of new capital investment into their distribution rate bases through 2050.[42]

Despite the significant size of this avoided cost category, DERs have historically been considered passive assets having little potential on the "wires" side of the business. While not all distribution investment can be avoided by DERs, some of the currently-planned projects are being implemented to accommodate demand growth and replacement of aging assets; these projects could instead be deferred or avoided by DERs. While the CPUC Public Tool uses a generalized treatment of distribution capacity avoided costs to estimate the potential value of deferrals across utilities, more specific values are used in this section sourced from publicly available documents.

The table below summarizes the large capacity-related distribution projects detailed in PG&E's General Rate Case. PG&E seeks approval of $353 million for these distribution system investments.[43] When this $353 million PG&E capital investment is adjusted to factor in the ratepayer perspective – which includes the lifetime cost of the utility's target profit level and recovery of costs related to operations and maintenance, depreciation, interest and taxes from ratepayers – the net present societal cost to PG&E ratepayers of these distribution capacity projects is approximately $586 million.[44] This $586 million cost to ratepayers adds over 1GW of conventional distribution capacity but addresses only 256 MW of near-term capacity deficiencies on PG&E's distribution system when deployed.

Summary of PG&E Electric Distribution Capacity Request – 2017 GRC[45]

Net Present Ratepayer Cost of Capital Investment ($M)[46]	**$586**
Near-term GRC Forecast Deficiency Addressed (MW)	**256**

Based on this societal cost, we consider the net benefits of an alternative, DER-centric solution, which relies on solar with smart inverters, energy storage and controllable thermostats. Due to lack of sufficient detail from PG&E's General Rate Case regarding the operational profiles of the electric distribution capacity projects in question, a simplifying assumption of 75% is used for the DER portfolio's distribution load carrying capacity ratio, which is based on the CPUC's Public Tool default peak capacity allocation factors (PCAF) for PG&E's distribution planning areas. This load carrying capacity ratio reflects capabilities based on customer adoptions with a storage sizing ratio of 2 kWh of energy storage for every 1 kW of PV capacity, or approximately 10 kWh of energy storage for a customer with 5kW of solar installed, as well as a controllable thermostat.

In order to accurately compare the DER solution, the full lifetime cost of the DER solution is considered, which includes the costs of additional DERs that would be needed to accommodate load growth over the lifetime of the conventional solution – assumed to be 25 years. This DER solution deployment schedule, which continuously addresses incremental capacity needs on the grid, contrasts with the traditional, bulky solution deployment schedule, which requires a large upfront investment for capacity to address a small, incremental near-term need. While a DER solution delivers sufficient capacity in each year to provide comparable levels of grid services, deployments occur steadily over time rather than in one upfront investment.

This approach highlights one of the key potential benefits of utilizing a DER solution over a traditional, bulky grid asset: DERs can be flexibly deployed in small bundles over time, a benefit that is further explored in Section IV on the benefits of transitioning to more integrated distribution planning.

Using these assumptions, the previous state-wide methodology is applied to DERs avoiding PG&E's planned distribution capacity projects, but two conservative assumptions are made. First, the scope of benefits is limited to a subset of avoided cost categories that would be directly considered by utility planners today for these types of projects. Whereas conventional equipment used to meet distribution capacity projects are generally unidimensional resources providing a single source of value – distribution capacity – DERs provide multiple sources of value. Second, we base our calculations on PG&E's lower avoided cost values,[46] rather than our own, to demonstrate that there are net benefits even under a conservative scenario.

In addition to avoiding the ratepayer cost of $586 million for planned distribution capacity projects, the DERs deployed to avoid PG&E's distribution capacity projects also avoid $946 million in energy purchases and $79 million and $99 million in generation capacity and avoided renewable energy credit purchases, respectively, totaling $1,709 million in benefits. On the cost side, program costs, integration costs and equipment costs for the associated DERs total to $1,605 million, resulting in a net present value to PG&E ratepayers of $104 million. This net benefit result is particularly notable given the limited scope of benefits considered in this case study and the reliance on PG&E's lower avoided cost values.

Net Benefit of DER Solutions to PG&E Electric Distribution Capacity Request – 2017 GRC
(Calculations Based on PG&E Cost and Benefit Assumptions)

TYPE	CATEGORY	SOURCE	NPV (2015 $M)
Benefits	Energy + Losses	PG&E NEM Successor Filing [48]	$946
	Generation Capacity[49]	PG&E NEM Successor Filing	$79
	Distribution Capacity	PG&E 2017 General Rate Case	$586
	Transmission Capacity	Not Included	-
	Ancillary Services	Not Included	-
	Renewable Energy Compliance	PG&E NEM Successor Filing	$99
	Voltage and Power Quality	Not Included	-
	Conservation Voltage Reduction	Not Included	-
	Equipment Life Extension	Not Included	-
	Reliability & Resiliency	Not Included	-
	Market Price Suppression	Not Included	-
	Societal Benefits	Not Included	-
	Total Benefits		**$1,709**
Costs	Program Costs	PG&E Nem Successor Filing	$55
	Integration Costs	SCE DRP with SolarCity Revisions	$363
	Equipment Costs	PG&E NEM Successor Filing	$1,188
	Total Costs		**$1,605**
	Total Net Benefits		**$104**

In this section, the data available to third-parties around distribution capacity projects from the most recent California Phase I General Rate Case (PG&E's 2017 GRC filing) was used to explore the potential benefits of leveraging DERs to avoid conventional distribution capacity-related investments. Calculations were performed based on PG&E's own avoided cost assumptions from NEM Successor Tariff filings and General Rate Case filings. Results indicate that deploying DER solutions in lieu of PG&E's planned distribution capacity expansion projects in its 2017 GRC could yield net benefits, even looking only at the energy, capacity, and renewable energy compliance values of the DER solutions. While not preferred, simplified assumptions were used to fill missing sources of information and data (e.g. distribution peak capacity allocation factors and forecasted load growth) where necessary. That such simplifying assumptions are necessary highlights the need for additional data sharing on specific infrastructure projects in order to assess the potential of DERs to offset these investments.

III. Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

Section II demonstrated how California could realize an additional $1.4 billion per year by 2020 in net benefits from the deployment of new DERs during the 2016-2020 timeframe. This state-wide methodology was then applied to the planned distribution capacity projects for California's most recent GRC request, showing how the deployment of DERs in lieu of planned distribution capacity expansion projects in PG&E's next rate case could save customers over $100 million.

Despite this potential value from embracing a distribution-centric grid, utilities face institutional barriers to realizing these benefits. Reducing the size of a utility's ratebase – its wires-related investments – cuts directly into shareholder profits. Expecting utilities to proactively integrate DERs into grid planning, when doing so has the potential to adversely impact shareholder earnings, is a structurally flawed approach. It will be impossible to completely capture the potential benefits of DERs until the grid planner's financial conflict with the deployment of DERs is neutralized.

Incentive Barriers

Realigning the incentives of the grid planner to solely focus on delivering a safe, reliable and affordable grid, regardless of the ownership and service models that materialize in the market, is a necessary first step to realize the potential of DERs. There are two fundamental paths forward to address this conflict of interest.

The first path towards realizing this objective would be to separate the role of distribution planning, sourcing, and operations from the role of distribution asset owner, similar to the evolution of Independent System Operators (ISOs) and Regional Transmission Operators (RTO) at the bulk system level. FERC's decree to create independent operators in Order 2000 was driven by the observation that the lack of independent operation of the bulk power system enabled transmission owners to continue discriminatory operation of their systems to favor their own affiliates and further their own interests.[47]

However, while an independent distribution system operator (IDSO) is an appealing governance model, some state regulators may choose a second path for addressing the utility conflict of incentives: maintaining the utilities' traditional role in planning and operating the distribution grid, while neutralizing the misalignment by changing utility incentives. Given the near-term focus in many states on retaining the utility's current role in grid planning and operation, this paper chooses to focus on this path and proposes a model that ensures the utility incentive against non-utility owned assets is neutralized.

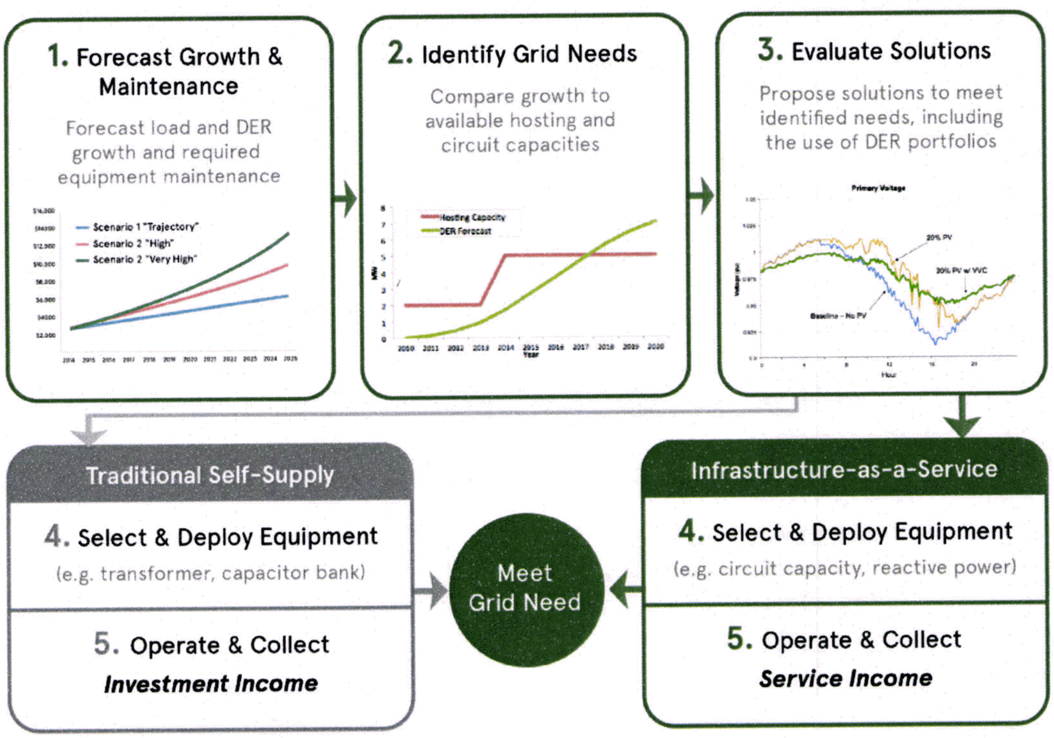
Proposed Solution

In order to ensure least cost/best fit distribution investments in states without an IDSO, this paper proposes the creation of a new utility incentive model, *Infrastructure-as-a-Service,* which would neutralize the utility incentive to deploy utility-owned infrastructure in lieu of more cost-effective third-party options. This model would enable utility shareholders to derive income from third-party grid services, mitigating the financial impact that may bias utility decision-making. Such a model would help ensure that utilities take full advantage of DER readily being adopted by customers.

Infrastructure-as-a-Service

Infrastructure-as-a-Service is a regulatory mechanism that would modify the incentives faced by utilities when sourcing solutions to meet grid needs. This new mechanism would allow utilities to earn income, or a rate of return, from the successful provision of grid services from non-utility owned DERs. Infrastructure-as-a-Service facilitates the least cost/best fit development of distribution grids by creating competitive pathways for DERs to defer or replace conventional grid investments, while maintaining equal or superior levels of safety, reliability, resiliency, power quality, and customer satisfaction. As the figure below shows, the three primary steps of a utility distribution planning process (forecast, identify needs and evaluate solutions) remain identical to the current process, followed by the infrastructure-as-a-Service mechanism's enhancements to sourcing in steps four (select and deploy) and five (operate and collect).[48]

Utility Planning and Sourcing Utilizing Infrastructure-as-a-Service Model



Under the proposed approach, after evaluating all feasible technical solutions for a particular grid need, including alternative grid solutions derived from DER portfolios, Infrastructure-as-a-Service would empower distribution planners to select and deploy third-party assets that address the specified need *if* more cost-effective for ratepayers than conventional solutions. Importantly, Infrastructure-as-a-Service would create an opportunity for utilities to operate and collect streams of service income, or a rate of return, based on the successful deployment of competitively sourced third-party solutions. This service income provides fair compensation for effective administration of third-party contracts that enable alternative resources to deliver grid services, and helps mitigate the structural bias towards utility-owned infrastructure that currently exists under distribution "cost plus" regulation. Note that other mechanisms attempting to achieve a similar utility indifference to DER solutions have been proposed, such as the modified clawback mechanism being discussed in New York.[49] While the clawback mechanism offers the potential to reduce the financial disincentive that utilities face in utilizing DERs, the potential utility upside may be small as compared to the lost opportunity and insufficient to neutralize the utility disincentive. This downside to the clawback mechanism may be overcome via the infrastructure-as-a-service mechanism.

Distribution Loading Order

Neutralizing the utility disincentive to utilizing DERs is critical but not sufficient to drive transformation in distribution planning. New incentives may be ignored in practice without corresponding changes to long-established and familiar utility processes that have sourced only self-supplied solutions to date. The adoption of a Distribution Loading Order[50] would borrow an existing concept from bulk system procurement policy in California, which prioritizes procurement of preferred resources, including energy efficiency, demand response, and renewable energy, ahead of fossil fuel-based sources. In the distribution context, a Distribution Loading Order prioritizes the utilization of flexible DER portfolios over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs. The table below depicts the types of resources that would be prioritized over traditional investments in such a policy.

Distribution Loading Order: Sourcing Solutions

PRIORITY	RESOURCE TYPE	RESOURCE EXAMPLES
1	Distributed Energy Resources	Energy efficiency, controllable loads/demand response, renewable generation, advanced inverters, energy storage, electric vehicles
2	Conventional Distribution Infrastructure	Transformers, reconducturing, capacitors, voltage regulators, sectionalizers

In concert with a mechanism like *Infrastructure-as-a-Service*, a Distribution Loading Order provides the procedural framework for evaluating distribution solutions in order to ensure grid planning is consistent with longer term policy objectives that support environmental, reliability, and customer choice goals. Importantly, a Distribution Loading Order would ensure that DER solutions are properly incorporated into grid planning. However, utilities would always maintain the authority to select and deploy a suitable portfolio of solutions, including conventional solutions when more appropriate, to ensure reliability. For these conventional investments, utilities would continue to earn an authorized rate of return.

Benefits of Infrastructure as a Service

Creating a pathway for DERs to offer grid services in lieu of utility infrastructure investment would be beneficial for utility ratepayers for a variety of reasons.

1. Saves ratepayers money: Allowing full and fair consideration of DER solutions equips grid planners with a broader suite of tools to meet grid needs, resulting in higher infrastructure utilization and lower customer electricity bills.
2. Promotes competition: Expanding the set of suppliers that are eligible to offer distribution solutions unleashes the power of markets to benefit ratepayers. Well-designed competitive markets can deliver superior solutions that are more affordable than those resulting from a self-supply "cost plus" planning model.
3. Increased flexibility and sources the best solution: Sourcing mechanisms that can deliver resources with new desirable characteristics (e.g. granular sizing, fast lead-times, flexible operational traits) into the distribution planners' toolbox creates no-regrets flexibility. And by rendering a utility neutral to the choice of ownership structure, the planner can focus on the singular objective of delivering the least-cost, best-fit solution.
4. Encourages innovation: Providing clear market opportunities for third-party solutions promotes product and service innovation, putting the collective innovation capabilities of all market participants and customers to work.

5. Engages customers: Utilizing DERs to provide grid services increases the capability and willingness of individual customers to actively manage their energy profiles. Ultimately, a neutral decision model like Infrastructure-as-a-Service will help foster the transition from passive ratepayers to proactive customers.

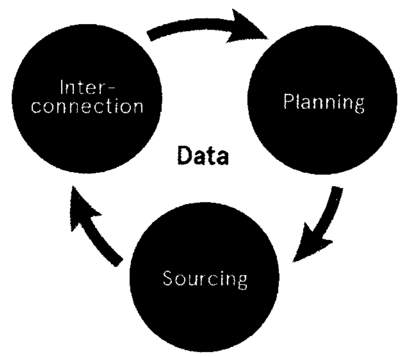
The CPUC recently enhanced the 2016 scope for its Distribution Resource Plan proceeding to formally consider the utility role, business models, and financial interest with respect to DER deployment.[51] Infrastructure-as-a-service is one mechanism to consider that would reduce the conflict of interest towards third-party services inherent in the utility incentive model today. Alternative efforts, such as creating greater functional independence between ownership and operations, as in an IDSO model, should also be explored. Irrespective of the mechanism, an effort to neutralize the utility decision model is needed to ensure that DERs are fully utilized and valued for grid services.

IV. Grid Planning Must be Modernized in Order to Capture DER Benefits

A second structural impediment to fully realizing DER benefits is the current grid planning approach, which biases grid design toward traditional infrastructure rather than distributed alternatives, even if distributed solutions better meet grid needs. Outdated planning approaches rely on static assumptions about DER capabilities and focus primarily on mitigating potential DER integration challenges, rather than proactively harnessing these flexible assets.

A. Adopt Integrated Distribution Planning

Grid planning can be modernized by utilizing an approach to meeting grid needs while at the same time expanding customer choice to utilize DERs to manage their own energy. We call this holistic process *Integrated Distribution Planning.*



Integrated Distribution Planning encourages the incorporation of DERs into every aspect of grid planning. The framework, as depicted in the adjacent figure, expedites DER *interconnections*, integrates DERs into grid *planning*, *sources* DER portfolios to meet grid needs, and ensures *data* transparency for key planning and grid information. Ultimately, the approach reduces overall system costs, increases grid reliability and resiliency, and fosters customer engagement.

If grid planning decisions are made before consideration of customers' decisions to adopt DERs, – which is frequently the case today – grid investments will underutilize the potential of DERs to provide grid services, ultimately resulting in lower overall system utilization and higher societal costs of the collective grid assets. In contrast, prudent planners who proactively plan for customer adoption of DERs may avoid making unnecessary and redundant grid investments, while also enabling the use of customer DERs to meet additional grid needs. Ultimately, planning processes must ensure that DERs are effectively counted on by grid planners and leveraged by grid operators. For more details on integrated distribution planning, see the "Integrated Distribution Planning" white paper overviewing the framework at www.solarcity.com/gridx.

B. Grid Planning Data Must be Transparent and Accessible

The first step in grid planning is to identify the underlying grid needs. As discussed throughout this paper, the use of alternative solutions such as DERs should be included in the portfolio of solutions that are considered to meet these grid needs. While utilities could ostensibly assess these alternative solutions within their existing process, opening up the planning process by sharing the underlying grid data would drive increased competition and innovation in both assessing and meeting grid needs. Any concerns from sharing such data – such as customer privacy, security, data quality, and qualified access – can be mitigated through data sharing practices already common in other industries. In fact, stakeholder engagement and access to planning data is already a central tenet in electric transmission planning across the country. The challenges of ushering a new industry norm of data transparency are far outweighed by the potential that broader data access can drive in increased stakeholder engagement and industry competition.

Data transparency efforts should first focus on communicating the exhaustive list of grid needs that utilities already identify in their planning process. While utilities may claim that such needs are already communicated within general rate cases, the information contained in those filings are incomplete. A standard set of comprehensive data should be shared about each grid need and planned investment so that stakeholders can proactively propose and develop innovative solutions to those needs. This proactive data access broadens the set of innovative solutions made available to utilities and guards against an insular approach to deploying grid investments. The table below is an initial set of minimally-required data to foster adequate stakeholder engagement in regards to specific, utility-identified grid needs.

Data to Foster Engagement in Grid Needs and Planned Investments

DATA NEED	DESCRIPTION
Grid Need Type	The type of grid need (e.g. capacity, reactive power, voltage, reliability, resiliency, spinning/non-spinning reserves, frequency response)
Location	The geographic (e.g. GPS, address) and the system location (e.g. planning area, substation, feeder, feeder node) of the grid need
Scale of Deficiency	The scale of the grid need (e.g. MW, kVAR, CAIDI/SAIDI deficiency)
Planned Investment	The traditional investment to be deployed in the absence of an alternative solution (e.g. 40 MVA transformer, 12kV reconductor, line recloser, line regulator)
Reserve Margin	Additional capacity embedded within the planned investment to provide buffer for contingency scenarios (e.g. 20% margin above expected deficiency embedded within equipment ratings to ensure available capacity during contingency scenarios)
Historical Data	Time series data used to inform identification of grid need (e.g. loading data, voltage profile, loading versus equipment ratings, etc.)
Forecast Data	Time series data used to inform identification of grid need and specification of planned investment (e.g. loading, voltage, and reliability data). Forecast to include prompt year deficiency (i.e. near-term deficiency driver), as well as long-term forecast (i.e. long-term deficiency driver)
Expected Forecast Error	Historical data that includes forecasts relative to actual demands for relevant grid need type in similar projects. Data to be used to evaluate uncertainty of needs and corresponding value of resources with greater optionality (e.g. lead times, sizing, etc.)

While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Access to underlying grid data allows third parties to improve grid design and operation by proactively identifying and developing solutions to meet grid needs, even before they are identified by utilities. The following data should be made available and kept current by utilities in order to encourage broad engagement in grid design.

Data to Foster Engagement in General Grid Design and Optimization

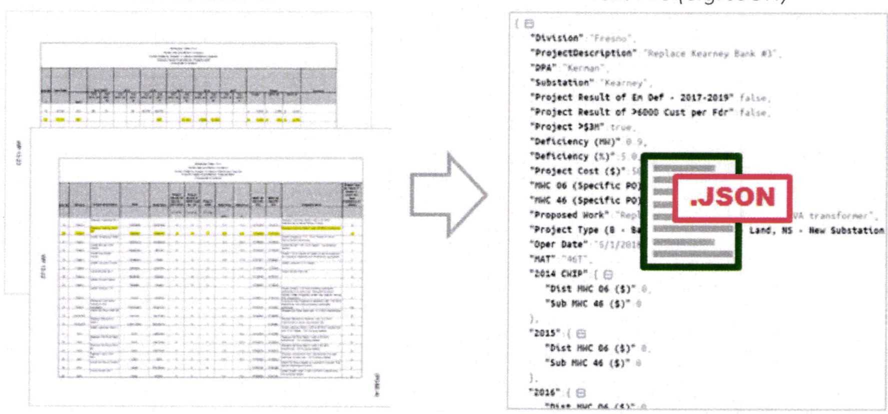
DATA NEED	DESCRIPTION
Circuit Model	The information required to model the behavior of the grid at the location of grid need.
Circuit Loading	Annual loading and voltage data for feeder and SCADA line equipment (15 min or hourly), as well as forecasted growth
Circuit DER	Installed DER capacity and forecasted growth by circuit
Circuit Voltage	SCADA voltage profile data (e.g. representative voltage profiles)
Circuit Reliability	Reliability statistics by circuit (e.g. CAIDI, SAIFI, SAIDI, CEMI)
Circuit Resiliency	Number and configuration of circuit supply feeds (used as a proxy for resiliency)
Equipment Ratings, Settings, and Expected Life	The current and planned equipment ratings, relevant settings (e.g. protection, voltage regulation, etc.), and expected remaining life.
Area Served by Equipment	The geographic area that is served by the equipment in order to identify assets which could be used to address the grid need. This may take the form of a GIS polygon.

Share Standardized, Machine-Readable Data Sets

Data that *is* made available on grid needs and planned investments is rarely provided in an accessible format. Often, information is provided in the form of photocopied images of spreadsheet tables within utility GRC filings, hardly a format the enables streamlined analysis. This data communication approach requires stakeholders to manually recreate entire data sets into electronic version in order to carry out any meaningful analysis, a time-intensive and needless exercise. Other potential stakeholders never attempt to engage due to the barrier of data access.

The use of standard, machine-readable data formats is prevalent in many industries and within the utility industry itself; organizations like the Energy Information Agency (EIA) foster such broad access to electronic, standardized data sets. Distribution grid needs and planned investments should follow suit. To illustrate a potential path forward, below is an example of traditional grid capacity needs and corresponding capacity investments as communicated via PG&E's 2017 GRC Phase 1 filing; the image of the text file on the right shows how those same grid needs and planned investments could be translated into a machine-readable format.

General Rate Case Worksheet PDF | *Standard Format Text File (e.g. JSON)*



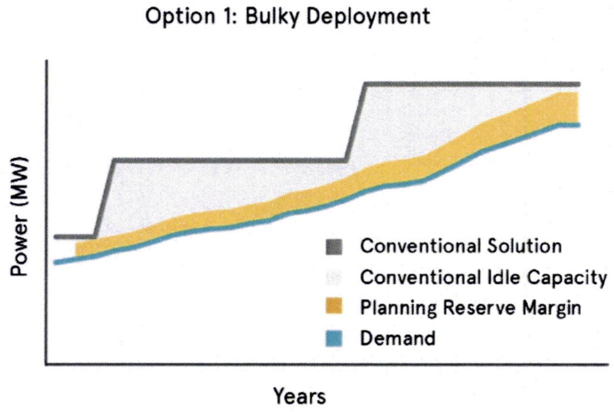
C. Benefits of Integrated Distribution Planning

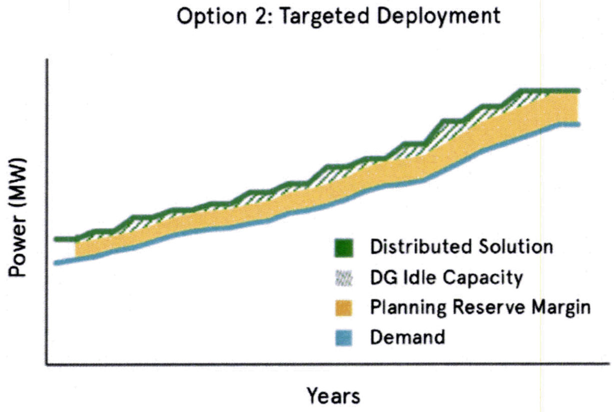
Opening the door to DER solutions in grid planning provides the obvious benefit of a new suite of technological options for grid planners. In some cases, DERs may simply be lower cost on a $/kW basis or more effective at meeting the identified grid need than the conventional solution, making them an obvious choice. DERs, however, also offer an advantage over convertional options due to their targeted and flexible nature, which fundamentally changes the paradigm of grid planning.

Status quo grid planning relies on deploying bulky, traditional infrastructure solutions to address forecasts of incremental, near-term grid needs. In many cases, conventional solutions are 15X larger than the near-term grid need that is driving the actual deployment of the infrastructure.[52] This fundamental reality of grid planning creates two major opportunities for DERs to deliver better value to ratepayers than conventional solutions: 1) utilizing small and targeted solutions, and 2) utilizing the flexibility of DER portfolios.

Value of Small & Targeted Solutions in Modern Distribution Planning

The first source of value is the result of more incremental and targeted investment, which captures the benefit of time value of money. Bulky utility solutions with long equipment lifetimes present a lumpiness challenge for planners. Needs for new resources are driven at the margin, but the available solutions are only cost-effecive when sized to match their long lifetimes, often resulting in low lifetime utilization rates. The significantly smaller building blocks that modern DERs offer planners effectively overcome this historical problem. The figures below compare the deployment timeline of a traditional bulky solution installed to meet demand growth long in the future, relative to a targeted DER solution deployed in small batches to meet continuous demand growth, and the corresponding expectation of idle capacity over time.[53]





Option 1 meets every year's capacity requirement by deploying large solutions infrequently, whereas Option 2 meets annual needs through smaller and more continuous deployments. While the infrastructure deployed with Option 1 will continue to meet the required planning reserve margins decades into the future, it requires a significant upfront investment. Option 2 targets the near-term required planning reserve margins on a continuous basis. Both options ensure that the planning reserve margin for reliability purposes is met, but Option 1 results in higher idle capacity rates over the lifetime of the infrastructure in aggregate when compared to Option 2.

Extending the basic financial idea of the time value of money, paying for capacity today is more expensive than paying for capacity tomorrow – even before considering any cost decreases resulting from technological advancements. DER solutions that can preserve reliability, while delaying capital investments for new capacity until future periods, are inherently valuable to ratepayers. This value driver means that solutions that may look more expensive on a per unit of nameplate capacity basis are actually more cost effective on a net present value basis.

Value of Increased Flexibility in Modern Distribution Planning

The second source of value to be realized from modernizing planning stems from a related but separate challenge that grid planners face: the risk of suboptimal decisions arising from forecast error. This risk is primarily driven by two dynamics:

1. Long lead times are necessary to deploy traditional infrastructure.
2. Long depreciation lifetimes are allowed by regulators for those assets.

As a result, grid planners commonly make investment decisions many years into the uncertain future, and then charge customers for the maintenance, depreciation, profit and taxes associated with those assets over 20 to 30 years or more. Investment under uncertainty imposes risks, which, if not managed properly, create unforeseen ratepayer costs. Among other sources of uncertainty, grid planning and expansion using traditional bulky infrastructure is subject to demand growth uncertainty and technology uncertainty. Both of these forecast errors can be large and expensive.

Over-forecasting demand can result in an overbuilt system for which ratepayers must bear the full burden, even if the infrastructure was not needed. Under-forecasting demand can require the installation of suboptimal, expensive patchwork solutions, or threaten reliability if solutions cannot be provided in time. Similarly, on the technology side, inaccurately forecasting the future costs and capabilities of technologies may result in premature obsolescence as technological advancement dramatically reduces equipment costs or increases equipment efficiency. While private firms typically bear these investment risks in other industries, utility ratepayers bear 100% of these forecast error risks in the electric industry unless the utility regulator acts to disallow cost recovery.

Due to these risks, DERs with shorter lead times can offer real-option value (ROV) by delaying deployment until forecast uncertainty is smaller, effectively buying time for planners and reducing the probability of a mistake. While the value of real options can be significant, it is difficult to quantify without the requisite data, including historical loading data, historical forecasts, and current long-term project forecasts. These data needs are further elaborated on in the subsequent section.

Policy Considerations

The additional sources of value, including time value of money and real option value, associated with a transition towards integrated distribution planning that fully leverages DER deployments were explored above, but are not explicitly quantified due to the limited data publically available. Ongoing proceedings in California, such as the Distribution Resource Plan (DRPs) and Integrated Distributed Energy Resources (IDER), create important vehicles to share information between parties in order to explore these important but less conventional sources of value that are not yet well quantified.

V. Conclusion

In this report, we explored the capability of distributed energy resources to maximize ratepayer benefits while modernizing the grid. The opportunity associated with proactively leveraging DERs deployed over the next five years is significant, creating $1.4 billion a year by 2020 in net societal benefits across the state of California. Applying the state-wide methodology to a subset of real distribution capacity projects identified in California's most recent utility General Rate Case yielded similar results, suggesting DERs can cost effectively replace real-world planned distribution capacity projects today.

The impediments to capturing these benefits in practice remain significant. Utility incentives must be realigned to ensure that the full potential of DERs can be realized. Shifting the utility's core financial incentive from its current focus of "build more to profit more" towards a future state where the utility is financially indifferent between sourcing utility-owned and customer-driven solutions would neutralize bias in the utility decision making process. However, modernizing grid planning is also necessary. Grid planning must be updated to incorporate DERs into every aspect of grid planning, and the process itself must become radically more transparent with greater access to and standardization of data.

The benefits of achieving these changes would be real – and large. While initially complex to consider, the greater flexibility DERs can provide to grid planners and operators leads to greater reliability and resiliency. Similarly, the more targeted and incremental deployments of DERs can enable more efficient and affordable grids. Most importantly, utilities that can successfully modify planning processes would be able to fully take advantage of the assets their customers chose to adopt.

While no single report will adequately address all the issues – engineering, economic, regulatory – that naturally come with a transformative time in the industry, we hope that compiling these issues in one place, even with a high-level focus, advances the discussion and provides an overview of the critical topics for regulators and industry stakeholders to consider when evaluating the full potential of distributed energy resources.

About Grid Engineering Solutions

Our Grid Engineering Solutions team is leading efforts to make the 21st century's distributed grid a reality. At SolarCity, grid engineering is more than understanding how the current power system works and how to interconnect distributed energy resources. It encompasses a cross-functional approach to evaluating engineering, technology, economic, and policy considerations side-by-side. We apply our expertise in power systems engineering, energy economics, and advanced grid technology to unlock innovative solutions that enable the grid of the future.

The majority of the Grid Engineering Solutions team members, including the authors of this paper, are former utility engineers, economists, technologists, and policy analysts. We treat the design and operation of the electric grid as a major opportunity to partner across the energy industry, with the aim of driving innovation to benefit consumers and our environment. Collaboration across utilities, grid operators, regulators, national laboratories, philanthropists, environmentalists, distributed energy resource providers, energy service providers, and customers is paramount to meeting the challenge of modernizing our grid. We welcome any dialogue that helps foster the next generation of grid design and operations. For more information, please visit us at www.solarcity.com/gridx or contact us at gridx@solarcity.com.

Appendix 1: Overview of Traditional Avoided Cost Categories and Methodologies

The traditional avoided cost categories evaluated in this report are detailed in the following table. Descriptions of the avoided cost, overview of the CPUC Public Tool's treatment of these avoided costs, and TASC's adjusted methodologies are provided. The adjusted TASC methodologies are used to quantify the traditional avoided cost values used in this paper. See TASC NEM Successor Tariff filing for more details on quantification approach.[54]

AVOIDED COST	DESCRIPTION	CPUC PUBLIC TOOL METHODOLOGY	TASC INPUT
Energy + Losses	The value of wholesale energy that would otherwise be generated in the absence of DERs, adjusted for losses that would occur. In CA, the cost of carbon allowances from the Cap and Trade program is embedded in the wholesale energy value.	The Public Tool creates a forecast of future energy prices using a simplified dispatch model and applies those prices to the DER generation in each hour. The model also allows a locational multiplier to be applied to capture the additional value of DER generation that occurs in specific locations.	TASC used the default assumptions for calculating energy value, but utilized the locational multiplier with a value of 4.8%, which was the premium derived from the empirical correlation between DER locations and CAISO locational marginal prices (LMPs).
Generation Capacity	The value of avoiding the need for system generation capacity resources to meet peak load and planning reserve requirements.	The Public Tool calculates the long-run cost of capacity by determining the Cost of New Entry (CONE) for a combustion turbine, and nets that cost against the energy and ancillary services revenues that a plant would be expected to earn.	TASC used the default assumptions for net CONE, and assumed that the long-run marginal cost that net CONE represents is the value of capacity starting in 2017, also known as the Resource Balance Year (RBY).
Transmission Capacity	The value of avoiding the need to expand transmission capacity to meet peak loads.	The Public Tool allows the user to input a $/kW-year value for avoided transmission capacity. The model takes this input and assesses the avoided cost by taking into account the level of coincidence of DER generation with the coincident peak that drives transmission expansion.	TASC assumed the avoided cost was the marginal cost of transmission capacity, which was estimated to be $87/kW-year based on regression analysis of historical transmission costs and their correlation with load growth.
Distribution Capacity	The value of avoiding the need to expand distribution capacity to meet peak loads.	The avoided cost attributable to DERs takes into account the level of coincidence of DER generation with the drivers of these marginal costs, which are allocated to specific time periods by Peak Capacity Allocation Factors (PCAFs).	TASC assumed the avoided cost was the marginal cost of distribution capacity, which was sourced from each IOU's most recent CPUC general rate case.
Ancillary Services	The value of a reduced need for operational reserves based on load reduction through DERs.	The Public Tool defines the cost for ancillary services as a 1% of wholesale energy costs, and allocates the value based on hourly load.	TASC did not modify any assumptions with respect to how avoided ancillary services are calculated.
Renewable Energy Compliance	The value of reducing procurement requirements for renewable energy credits, due to reduced delivery of retail energy on which RPS compliance levels are based.	The Public Tool bases this value on the above market costs of RPS generation. Under a 33% RPS, each kWh of DER generation reduces the need for RPS generation by 0.33 kwh.	TASC assumed a 33% RPS by 2020 and did not modify any assumptions with respect to how avoided RPS costs are calculated.
Societal Benefits	The value of benefits that accrue to society, and are not costs directly avoided by the utility.	The Public Tool model provided the flexibility to insert assumptions for societal benefits based on $/tonne of emissions or $/kWh benefits.	TASC included the Environmental Protection Agency's value for the social cost of carbon, as well as estimates for NOx, PM10, land use, and water use benefits.

Appendix 2: Utility-Proposed Distribution Integration Investments in CA DRP

The following table presents the DER integration investment categories as identified in SCE's DRP filing. SCE's costs were scaled up to estimate total integration costs for all California utilities over 2016-2020. SCE cost estimates were stated at the category level, and were uniformly spread across the underlying investments. For each investment, applicability to DER integration is assessed using the threshold and screening questions identified in this paper. This quantification is necessarily high-level due to the lack of details provided, and additional details are necessary in order to fully evaluate investment plans.

INVESTMENT CATEGORY	INVESTMENTS	UTILITY COST CLAIM ($M)	APPLICABLE TO DERS (%)	RATIONALE
Distribution Automation	Automated switches w/enhanced telemetry	$355	0%	Business as usual: Automation programs are reliability driven and not necessary for DER integration.
	Remote fault indicators	$355	0%	Business as usual: fault indicators are reliability driven and not necessary for DER integration.
Substation Automation	Substation automation	$346	0%	Business as usual: Automation programs are reliability driven and not necessary for DER integration.
	Modern protection relays	$346	60%	Investment in protective relay upgrades can be valid at high penetration of DERs, although setting changes can frequently eliminate need for relay replacements.
Communication Systems	Field area network	$444	0%	Business as usual: supports preexisting utility efforts to extend SCADA visibility throughout distribution system.
	Fiber optic network	$444	0%	
Technology Platforms and Applications	Grid analytics platform	$119	33%	Investments in identification and communication of grid needs are valid for high DER penetrations. However, only some of these costs are applicable to DERs as these tools broadly support grid modernization and will be used to process data from smart meters and utilityi grid devices.
	Grid analytics applications	$119	33%	
	Long-term planning tool set	$119	50%	Long-term planning and distribution circuilt modeling tools are used to forecast all grid needs and scenarios, including reliability, loads, and DERs; therefore, only a portion of these costs are driven by DER integration.
	Distribution circuit modeling tool	$119	50%	
	Interconnection application processing	$119	100%	Investments that support DER interconnection are directly related to DER integration.
	DRP data sharing portal	$119	100%	
	Grid and DER management system	$119	50%	Grid and DER management systems are used to manage all grid assets, including utility equipment and DERs; only a portion of these costs are driven by DER integration.
	System architecture and cyber security	$119	25%	As the grid becomes more reliant on more granular visibility and control, system architecture and cybersecurity investments are needed irrespective of DERs. Therefore, only a portion of these costs are driven by DER integration.
	Distribution Volt/VAR optimization	$119	25%	Business as usual: Volt/VAR Optimization programs preexisted DER deployments; while DERs increase Volt/VAR benefits, only a portion of these costs are driven by DERs.
Grid Reinforcement	Conductor upgrades to a larger size	$1,168	50%	Capacity and conductor upgrades driven primarily by safety, reliability and resiliency needs. However, capacity investments for high DER penetrations resulting in thermal limit violations are valid.
	Conversion of circuits to higher voltage	$1,168	10%	Business as usual: Supports preexisting utility efforts to convert circuits to higher voltage. Incremental costs associated with accelerated replacement could be driven by DER integration in some cases.
	Total	**$5,697**	**25% ($1,450)**	

Endnotes

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