

RETHINKING STANDBY & FIXED COST CHARGES: REGULATORY & RATE DESIGN PATHWAYS TO DEEPER SOLAR PV COST REDUCTIONS

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ABSTRACT

Current net energy metering (NEM) rate options offered by many of the largest investor-owned and public power utilities in the U.S. allow residential customers to realize substantial average monthly savings, and are a critical driver of sustained customer-sited solar PV development. However, standby and fixed cost charges rates (solar PV-specific rate designs intended to recover a more significant share of fixed costs solely from solar PV customer-generators) present fundamental risks to beneficial rooftop PV non-hardware “soft” cost reductions that can sustain rooftop solar PV development at limited to no cost to taxpayers and non-solar utility customers. Standby and LFCR rates, which limit customer NEM savings, present short-term cost recovery benefits for utilities, but are often unduly discriminatory, frequently misrepresent the potential benefits associated with PV, and do not account for all of the drivers of diminished across-the-board utility fixed cost revenue recovery. Nevertheless, recent examples from investor- and publicly-owned utilities and their regulators across the country demonstrate that it is possible to implement “softer” and more equitable ratemaking pathways that provide stable utility cost recovery, which are less likely to result in a missed opportunity to reduce solar PV costs and spur greater, more cost-effective PV development.



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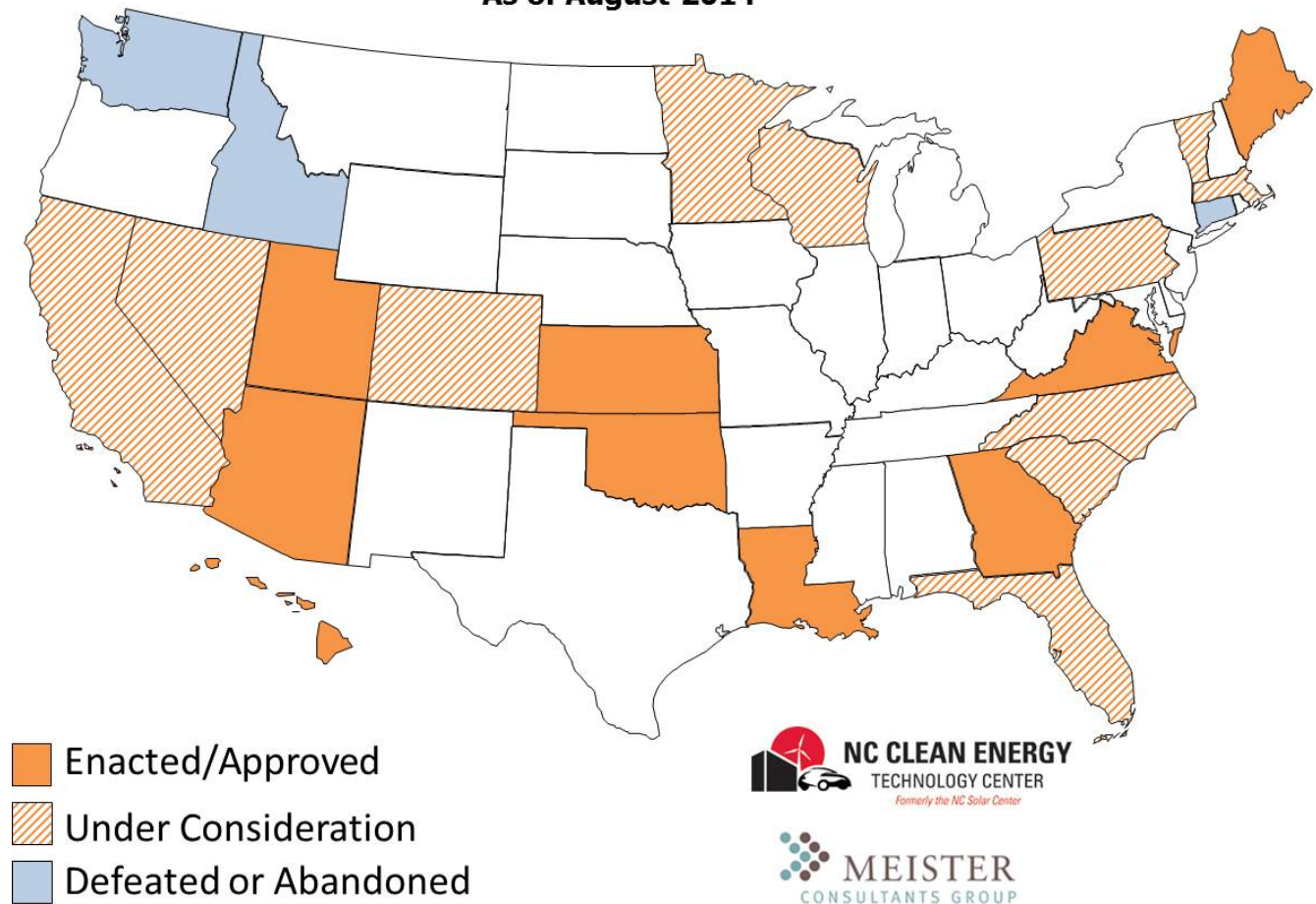
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SECTION 1 INTRODUCTION

Figure 1¹

Recent Action on Solar PV-Specific Standby & Fixed Cost Charges

As of August 2014



As the rapid deployment of rooftop solar photovoltaics (PV) progresses, and the hardware costs of (and incentives for) PV decline, maintaining a steady adoption rate for rooftop solar PV will require

¹ Sources for this map, and for the current status of various standby and fixed cost charge debates can be found in the Appendix to this report.

market-based policies that aid in the reduction of non-hardware “soft” costs of solar PV. In fact, due to hardware cost declines, soft costs now account for the majority of the total cost of residential and commercial systems. Average soft costs for a residential installation in the United States are, on average, several times higher than in Germany, the world’s leading rooftop solar PV market.^{i ii} Thus, the goal of the Department of Energy’s SunShot Initiative, the parent initiative of the SunShot Solar Outreach Partnership (SolarOPs), is to reduce the “all-in” cost of rooftop solar PV to a level at which the technology is broadly competitive with retail (and even wholesale) prices of electricity around the United States without added incentives.

However, as the rooftop solar PV market has expanded, some utilities have acted with alarm regarding the growth of the rooftop solar PV market and other distributed electricity generation technologies and utility future sales, revenue and profits. This concern has led to discussions and/or formal proposals for fixed cost charges and standby rates in over 20 states across the country. While the issue of lost utility fixed-cost revenue is an important issue in an age of expanded distributed solar PV, these rate designs can have a disproportionately negative and unduly burdensome impact on customer-sited projects relative to their value.

Nevertheless, little attention has thus far been paid to the risks posed by these solar PV-specific rate designs (and the increasingly toxic policy development process) upon the concerted efforts of the Department of Energy to reduce soft costs, particularly those related to financing and customer acquisition. Thus, the purpose of this report is to explore the impacts of these rate designs on soft costs, and a set of more beneficial and equitable rate designs that take the broad-based erosion of fixed costs into account.

The report will 1) explore the way in which utility costs are classified and allocated, 2) the areas in which stakeholders have expressed disagreement about the costs avoided by solar PV, 3) the ways in which utilities have designed solar PV-specific rates and charges, 4) why some proposed solutions are, in general, unduly burdensome and pose grave risks to PV development and soft cost reduction, and 5) a more holistic and equitable utility cost recovery strategy that does not pose such significant and potentially damaging risks to further solar PV cost reductions.

SECTION 2 SOLAR SOFT COST REDUCTION: A PATHWAY TO UNIVERSALLY COMPETITIVE ROOFTOP SOLAR PV

In the United States, the price for solar PV hardware such as solar modules (panels) and inverters has declined significantly since 2008. During 2013, panel prices increased slightly, but were offset by a

continued decrease in inverter prices.ⁱⁱⁱ Given these trends, U.S. solar market has experienced rapid growth in recent years. Growth has been driven by declining hardware costs, coupled with streamlined installation and labor practices, and innovative marketing and finance methods, such as third-party ownership models, group-purchase programs, and crowd-sourced financing.

STATE OF SUNSHOT INITIATIVE AND SOFT COST REDUCTION EFFORTS

Nevertheless, soft costs have persisted, posing challenges to enhancing the cost-effectiveness of solar PV. To help tame any growth in soft costs and meet the SunShot goals, the National Renewable Energy Laboratory (NREL) has identified four major soft cost categories that can most easily be influenced by government policy or by private market efforts. To this end, NREL has developed a soft cost reduction roadmap to achieve reductions in major categories of costs by 2020 to increase the cost-competitiveness of solar systems. The four major soft costs categories addressed by this strategy are 1) customer acquisition, 2) permitting, inspection and interconnection, 3) installation labor, and 4) financing.

Residential Soft Cost Reduction Status The authors of the NREL roadmap identified residential-scale PV soft costs as being disproportionately higher (64% of total system costs) than the same costs for commercial-scale PV installations (between 52%-56%). However, many of these costs, including PII, customer acquisition and financing costs, were characterized by NREL as more easily reachable given current trends in soft cost reduction.^{iv} Figure 2 below illustrates the SunShot soft cost reduction goals for residential-scale PV systems.

Figure 2²

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Customer Acquisition (\$/W)	\$0.67	—	—	\$0.53	\$0.49	\$0.45	\$0.41	\$0.36	\$0.28	\$0.19	\$0.12
PII (\$/W)	\$0.20	—	—	\$0.18	\$0.16	\$0.15	\$0.13	\$0.11	\$0.10	\$0.06	\$0.04
Installation Labor (\$/W)	\$0.59	—	—	\$0.51	\$0.46	\$0.42	\$0.36	\$0.30	\$0.24	\$0.19	\$0.12
Other Soft Costs (\$/W)	\$1.86	—	—	\$1.30	\$1.14	\$0.97	\$0.82	\$0.68	\$0.56	\$0.48	\$0.37
Financing (WACC %-real)	—	—	9.9%	9.4%	8.8%	8.2%	7.7%	7.7%	4.8%	3.4%	3.0%
Total Soft Costs (\$/W)	\$3.32	—	—	\$2.52	\$2.25	\$1.99	\$1.72	\$1.45	\$1.18	\$0.92	\$0.65
Total System Costs (\$/W)	\$6.60	—	—	\$4.99	\$4.49	\$3.99	\$3.49	\$3.00	\$2.50	\$2.00	\$1.50

² According to NREL, green cells in Figs. 1 and 2 represent reachable goals based on current trends. Yellow, orange and red cells depict goals that are reachable, but only in conjunction with further government or private market action or technological innovation.

Commercial Soft Cost Reduction Status As noted above, commercial-scale PV installations have proportionately lower “manageable” soft costs than residential PV installations, and they also identified customer acquisition and financing cost reductions as more easily reachable.^v However, NREL associated greater uncertainty for commercial-scale soft cost reduction in the years immediately following 2014, whereas average residential-scale systems were likely to enjoy easily reachable cost reduction targets through 2015. Figure 3 below illustrates the SunShot soft cost reduction goals for commercial-scale PV systems.

Figure 3

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Customer Acquisition (\$/W)	\$0.19	—	—	\$0.15	\$0.13	\$0.10	\$0.08	\$0.08	\$0.08	\$0.05	\$0.03
Installation Labor (\$/W)	\$0.42	—	—	\$0.33	\$0.30	\$0.25	\$0.20	\$0.16	\$0.12	\$0.09	\$0.07
Other Soft Costs + PII (\$/W)	\$2.03	—	—	\$1.53	\$1.36	\$1.22	\$1.08	\$0.90	\$0.72	\$0.53	\$0.34
Financing (WACC %-real)	—	—	8.6%	9.5%	9.2%	8.2%	7.9%	5.1%	4.4%	3.9%	3.4%
Total Soft Costs (\$/W)	\$2.64	—	—	\$1.98	\$1.76	\$1.54	\$1.32	\$1.10	\$0.88	\$0.66	\$0.44
Total System Costs (\$/W)	\$5.96	—	—	\$4.03	\$3.64	\$3.24	\$2.84	\$2.44	\$2.05	\$1.65	\$1.25

RATE DESIGN-RELATED RISKS FOR SUNSHOT SOLAR COST REDUCTION EFFORTS

While it is fairly easy to imagine how a rate design intended to recover more fixed costs solely from solar PV customers can create business and customer uncertainty (as well as large erosions of monthly bill savings), a relatively unexplored aspect of the NEM debate is the potentially damaging impact that solar PV-specific rate design changes could have upon reaching the SunShot solar cost reduction goals described above. More specifically, while the magnitude of the threat to solar cost reductions is not immediately clear, applying solar PV-specific rate designs that limit the payback and attractiveness of solar PV could make it impossible for rooftop PV to reach these deployment and price goals by increasing the non-hardware “soft” costs of financing and customer acquisition. This could lead to a perverse outcome in which solar PV is systematically hindered from more rapidly reaching a point at which it would need no ratepayer or taxpayer funds to be cost-effective. In general, it appears that the application of standby rates and fixed cost charges is likely to have the greatest impact on customer acquisition and financing costs - the two soft costs for which the least difficult reductions were likely to take place.

Customer Acquisition NEM policies have become the main instrument for conveying utility bill savings associated with PV to customers, and are well understood by market players. In addition, funding for rebate programs in the United States has been declining or in some regions has ceased, increasing the importance of NEM, particularly for residential markets. The addition of significant new charges for NEM customers could portend a tangible and potentially dangerous market disruption. Such developments would likely increase the costs associated with generating new leads and acquiring new customers.

The application of these rate designs could also decrease the competitiveness of PV under NEM, and solar developers and installers will have to include these estimates in their sales pitches to potential customers. Furthermore, these rate designs could limit the ability of solar PV systems to help customers hedge against utility price increases.^{vi} This situation could be further exacerbated if these rate designs are not transparent, easily explained and readily calculable. While developers interested in large-scale solar systems may have the resources and expertise to calculate the impacts of policy changes, this is often not true for residential customers. Finally, the application of standby and fixed cost charges to larger-scale commercial PV systems could discourage the development of community shared solar, a key cost reduction opportunity for reducing customer acquisition costs, given that it allows customers with unsuitable sites the ability to realize savings from PV.^{vii} "Virtual" net metering, which is necessary for the development of community shared solar, allows energy credits from one PV system to be shared across multiple customers, offsetting additional demand. However, applying a standby or fixed cost charges upon customers benefitting from these systems could make solar a more difficult sell, and make solar less accessible to potential distributed generators.

Financing As mentioned in previous sections, NEM policies are well-established and enable project developers to develop stable, predictable cash flow models based on estimated system outputs. Standby and fixed cost charges tied to system output could also increase reliance on more volatile sources of revenue for solar projects (e.g. solar renewable energy credits (SRECs), upfront rebate programs, and state/federal tax credits), delaying the point at which PV development will be fully independent of incentives. Most stakeholders agree that the best incentives will be relatively consistent over time and can be gradually reduced as cost-competitiveness improves. With the application of standby and fixed cost charges to NEM customers, these incentives will play an even more important role in securing financing for solar PV projects, potentially creating a more hardened investor perception that solar PV is a risky, incentive-driven investment that is subject to the outcome of hundreds of different potential polarizing disputes over standby and fixed cost charges at all major utilities in all 50 states. The re-evaluation of these risks due to charges which may not be justified increases the risk that the weighted average cost of capital (WACC) for a residential solar project will

miss current SunShot Initiative targets by a wide margin. Overall, if current trends continue, these developments will likely have a disproportionate impact on soft cost reductions for residential PV systems, since the current discussions of utility compensation for lost fixed costs have targeted residential NEM customers. Thus, a fundamental re-evaluation of the role of standby and lost fixed cost rate design is needed in order to ensure that critical solar PV cost reductions that benefit both taxpayers and utility customers can continue.

SECTION 3 UTILITY COST RECOVERY AND NET ENERGY METERING

COMPONENTS OF A UTILITY'S COSTS OF SERVICE

Ratemaking for regulated utilities (including municipal and investor-owned utilities) typically uses cost-of-service approach. A cost-of-service approach values what are known as a utility's "embedded costs" of providing service, and passes those costs on through customer rates.³

When using the embedded cost approach, a utility accounts for the total cost of serving 100% of its customers' needs during a specific period of time, often referred to as a "test year," which is a specific, year-long past or future snapshot of the utility's finances. The utility then allocates the costs incurred during that year based on the degree to which different kinds of customers cause them to be incurred (referred to as a "cost causation" approach). Rates are then designed (using both objective and subjective methods) to collect these costs from customers.^{viii}

In order to provide electric service, utilities incur both long-term investment costs, which do not vary much at all in the short-term, , as well as variable costs, which change in the short-run to reflect the quantity of electricity produced and delivered. Utility costs are determined to be fixed or variable based on the results of a cost of service study. The cost of service study helps the utility and its regulators to:

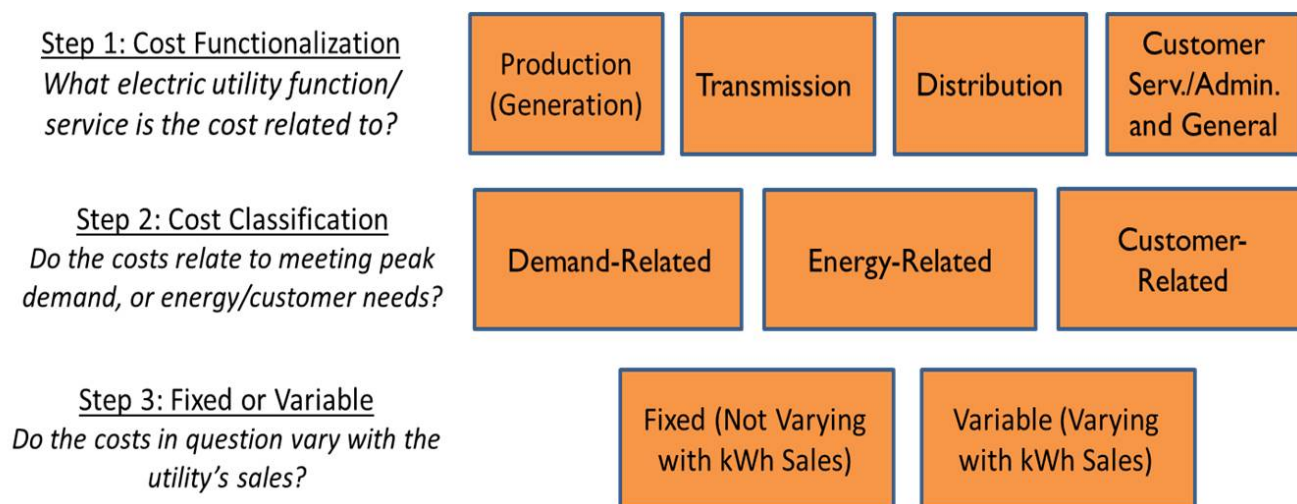
- Assign costs by specific functions (e.g. electricity production, transmission, distribution, other), referred to as "**cost functionalization**";
- Classify those costs as intended to meet peak demand, expected energy (or kilowatt-hour) demand or basic customer needs, referred to as "**cost classification**"; and
- Determine which costs of service are fixed and which are variable, and allocate them to the different classes of customers (referred to as "**cost allocation**"); and,

³ For more on the embedded cost model, see the National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual*, January 1992, p. 14. The manual is available for purchase only.

- Design rates that allow utilities to offer “just and reasonable” rates to their customers that have a strong chance to help the utilities provide returns to their investors (referred to as “**rate design**”).

Generally, utilities consider demand-related and customer-related costs to be fixed, and energy-related costs to be inherently variable.

Figure 4



THE IMPACT OF NEM ON UTILITY COST RECOVERY

One of the most important factors encouraging the expansion of rooftop solar has been the creation and expansion of state and local requirements that electric utilities offer NEM options to the customers they serve. NEM is the utility billing practice that requires local utilities to account for (that is, to “net”) the difference between the flow of power from the utility to its customer and from the customer to its utility, during each monthly billing period.⁴ Customers receiving service under NEM rules typically receive a utility-bill credit for excess energy they feed back to their local utility at the retail rate at which they would purchase power from their utility. While NEM can facilitate significant customer savings, the fixed costs of serving residential customers are incorporated into the *variable* “energy” rate paid by customers for each kilowatt-hour of electricity they buy from the utility. The Edison Electric Institute, a trade association of investor-owned utilities, estimates that, on average 55%

of the costs⁵ its member utilities incur are fixed.^{ix} San Antonio's municipal utility CPS states that their fixed costs are as high as 70%.^x

Despite the high degree of fixed costs embedded in volumetric rates, most electric utilities tend to be careful to avoid charging significant fixed monthly rates to most residential and small commercial customers. One reason for this long-standing practice is to avoid creating a significant disincentive for energy conservation. As American Electric Power notes, recovering most or all of the fixed costs of utility service through a monthly fee that greatly exceeds typical basic customer charges is not a common (or altogether desirable) practice amongst electric utilities, given that there are "a host of alternative regulatory strategies that are far more flexible" and thereby more accommodating of customer-sited energy conservation investments.⁶ Thus, the cumulative effect of the status quo for many types of lower-usage customers is to moderately discourage fixed cost recovery in favor of conservation-friendly rate designs focused on volumetric usage. However, many utilities have realized that relying too heavily on revenue recovery via volumetric usage is likely to be an ineffective strategy in a business environment favoring more efficiency and distributed generation.^{xi}

In 2013, this realization has apparently caused the public position of nearly all regulated utilities to shift, as they simultaneously and unanimously raised concerns that the burden of the apparent fixed costs unrecovered from NEM customers borne by non-participants could be significant. A report from that time by the Edison Foundation argues:

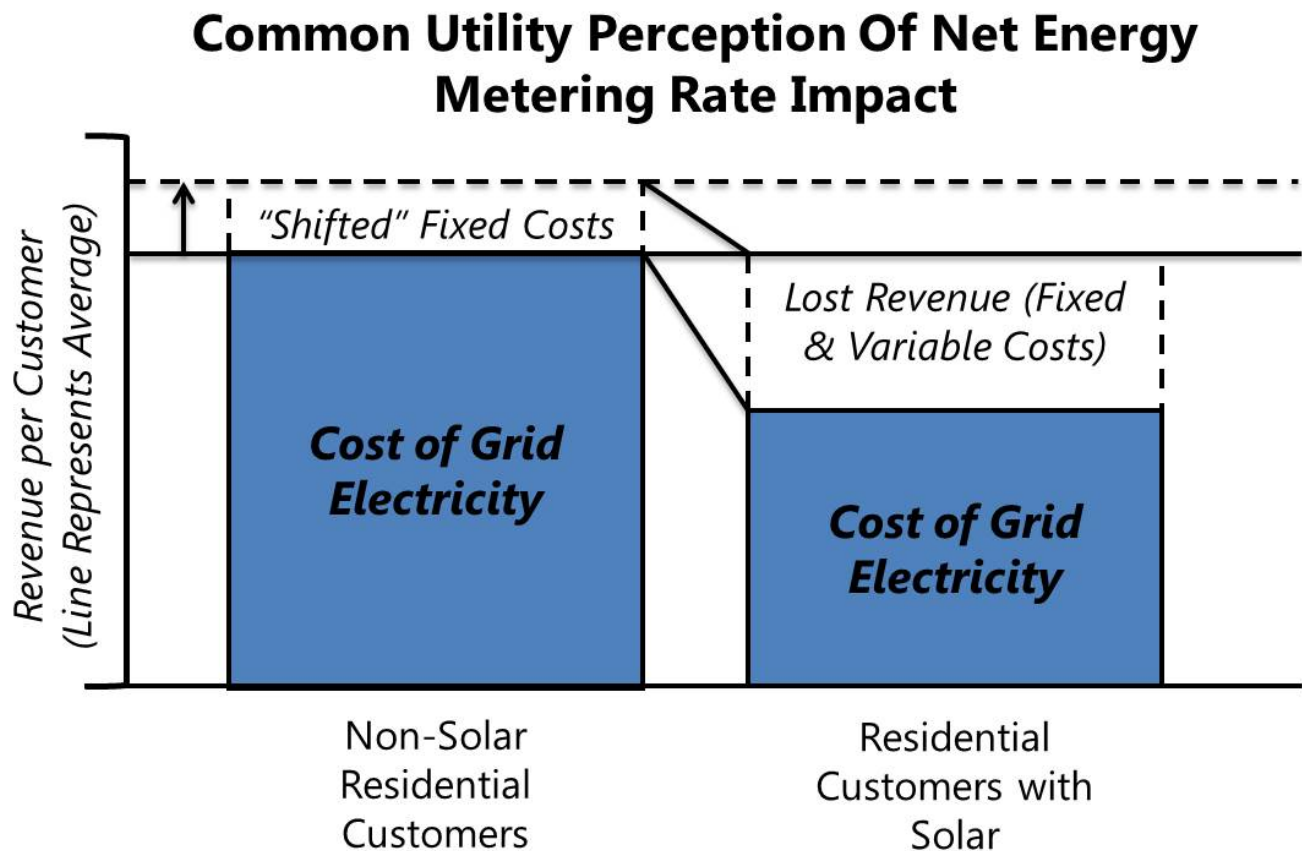
...These 'grid' costs are quite significant – about 55 percent of the monthly electric bill for a residential customer." Although this may not have been a major problem when the DG market was in its infancy, it is now sending the wrong price signals to both customers and to the DG industry as the DG market rapidly grows and develops. **A DG customer could shift up to 55 percent of the retail rate onto non-DG customers (and, unlike efficiency charges, which are transparent, the DG cost shifting is essentially invisible to customers).**^{xii}

In other words, these utilities believe that customers that invest in solar PV or energy conservation measures are by definition shifting fixed costs that cannot be avoided to other customers who do not choose to invest in them, and thus raising rates.^{xiii} For these reasons, utilities tend to argue that NEM customers should have to shoulder a much more significant degree of fixed costs in the form of standby and fixed cost charges. Figure 5 below illustrates this commonly-held perception of the impact of solar PV on non-solar customers.

⁵ Note that, as described above, each utility's fixed costs can be determined only by completing a comprehensive cost of service study.

⁶ This practice is referred to in the ratemaking community as "straight fixed-variable" rate design. Given their unique cost characteristics, it is employed in some states to regulate the rates of natural gas distribution companies.

Figure 5 (Example Not Drawn to Scale)



ARE FIXED COSTS REALLY “FIXED FOREVER”?

In arguing that cost shifts are inevitable, utilities and their advocates tend to make two assumptions. First, they argue (or frequently imply) that neither PV (nor, by extension, any other energy conservation technology) is able to aid a utility and its ratepayers in avoiding current or future fixed costs.⁷ Inherent in this assumption, though, is a more troubling one – that a utility’s fixed costs are permanently fixed, and functionally should never vary for the purpose of setting customer rates. As the Arizona Residential Utility Customer’s Office notes in its NEM proposal for Arizona Public Service,

“If the fixed costs associated with each individual customer were to be assigned to household related behaviors and technologies such as conserving energy, investing in energy efficiency upgrades or solar PV systems, these actions would never pencil out. **Fixed costs are not fixed forever; every cost is variable given the proper time horizon (emphasis added).**”^{xiv}

⁷ A good example of this phenomenon is Arizona Public Service’s petition to change its net metering policies, which will be explored in greater detail later in this analysis.

Thus, while it is important to understand the key role of fixed cost investments in the provision of utility service, it is also important to remember that solar PV deployed today can avoid a significant degree of *both* fixed and variable utility costs, now and in the future, even as penetrations increase. Indeed, as NEM policies have garnered more attention, many stakeholders have begun to quantify the net avoided cost “value of solar” to fairly price incentives and compensation for distributed generators. Due to differences in electricity mix, power prices and other variables, though, the value of solar often varies dramatically between utilities, and does not provide a uniform degree of value to all utilities and their non-solar owning customers. The categories of both system and societal costs that many stakeholders have asserted that solar PV can avoid in various degrees include:

- ◎ **Energy Production Costs.** Distributed solar PV offsets the need for power from non-renewable resources. For many grid regions in the United States, a working assumption is that solar energy offsets natural gas plant loads, while in others solar energy can even offset oil- and coal-fired peaking plant loads. Indeed, solar PV can often avoid the highest-cost peaking electricity in the middle of the day, which means it has a higher avoided cost value than many other renewable resources.
- ◎ **Environmental Compliance Costs:** The cumulative effect of reduced central generation energy production effect is a reduction in greenhouse gas and criteria air pollutant emissions, as well as diminished consumption of surface water supplies needed to cool such plants. These benefits can either be quantified in terms of reduced health and societal impacts or in terms of the savings from reduced need for remediation and mitigation.
- ◎ **Transmission Costs:** When energy is transmitted from a central power plant to a utility customer, losses occur across the lines due to electrical resistance. Since solar energy is produced on-site, a much higher percentage of energy is delivered to the customer. This process has the effect of increasing the efficiency of the grid system, since more of the energy being produced is delivered to end-users with minimal line losses.
- ◎ **Distribution Costs:** High penetrations of solar can also reduce the need for additional investments in distribution infrastructure if the aggregate impact of distributed generation decongests lines or offsets the need for extending infrastructure to additional plants.
- ◎ **Generation Capacity Costs:** Much like energy efficiency programs, solar resources have the impact of reducing the quantity of grid electricity demanded. These reductions can defer the

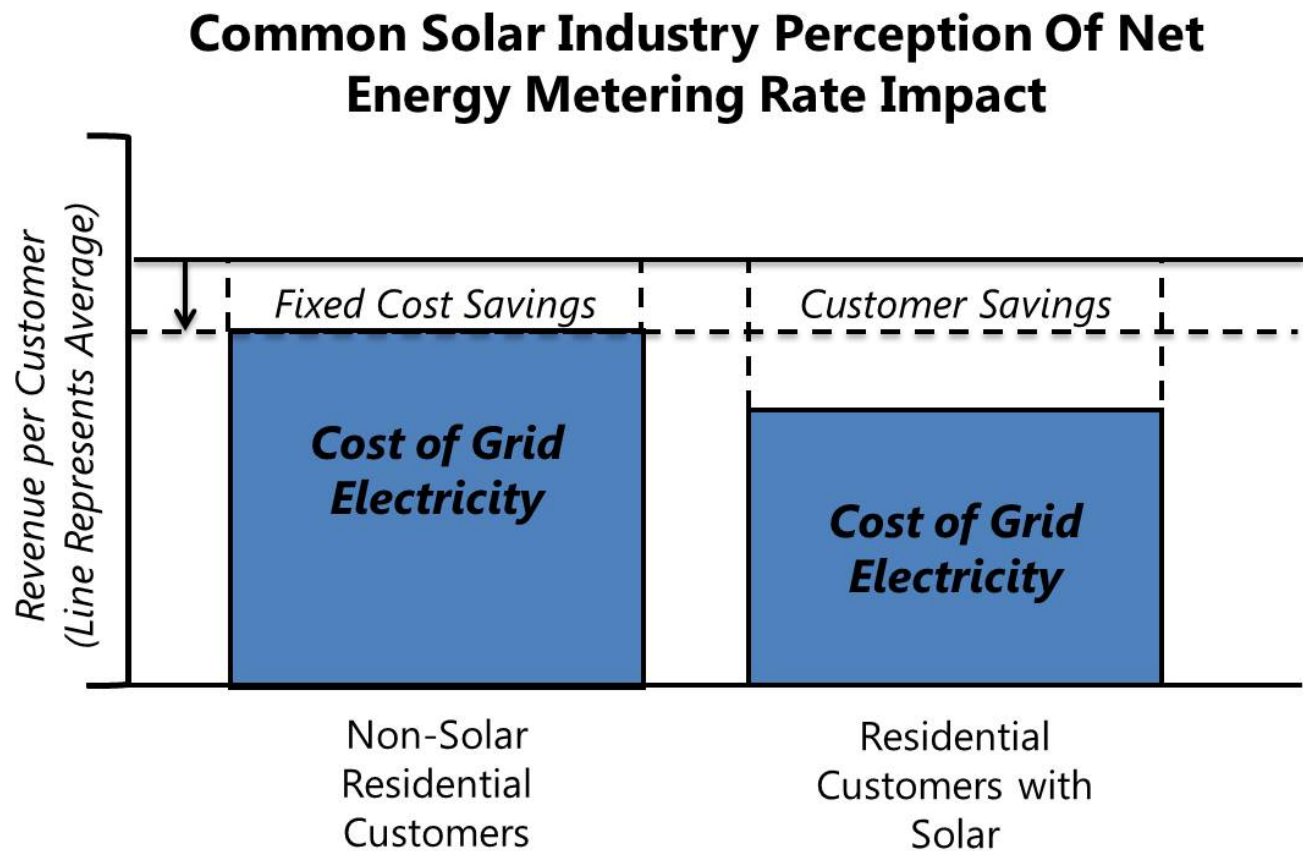
need for additional generation investments. However, some of the valuation analyses noted that at high penetration levels, variable resources could impact reserve requirements.

- ◎ **Fixed and Variable Operations and Maintenance (O&M) Costs:** Power plants experience operation and maintenance costs as generators are called into service. Solar energy can reduce the need for generation assets to be dispatched and thus reduce these variable costs.
- ◎ **Fuel Hedging Costs:** Each kWh of solar production offsets the need to purchase fossil or nuclear fuels. It also mitigates the risk and exposure of utilities and customers to changes in fuel prices, and the costs incurred by utilities to hedge their fuel purchases. For example, the impact of increased natural gas prices would be mitigated if the electricity mix relied less on natural gas power plants.
- ◎ **Renewable Portfolio Standard (RPS) Compliance:** States and utilities with renewable portfolio standards (RPS) mandate that a certain percentage of energy be delivered from renewable or alternative sources. Depending on the specific rules applicable in each state, customer-sited solar systems often reduce the portion of the obligation which must be met by utilities developing renewable or alternative resources or purchasing RECs or SRECs.

However, solar PV industry and related advocates often take the argument about avoided costs even further. After pointing out the obvious inconsistencies in the common utility argument about fixed costs, many often go further assert that utility “cost shift” claims are *always* misleading, thus fundamentally (and publicly) asserting that the benefits of solar PV always exceed its costs.⁸ As a result, in this formulation, solar PV thus always lowers rates on net for all customers and providing added societal benefits for all, suggesting that net energy metering even at the retail rate is insufficient compensation. Figure 6 below illustrates the solar PV industry and advocates’ view of the impact of NEM and solar PV on other non-solar customers.

⁸ See the various cost/benefit analyses undertaken by Crossborder Energy that find net PV benefit.

Figure 6 (Example Not Drawn to Scale)



UNDERSTANDING NON-PARTICIPANT NEM “COST SHIFTS”: WHAT’S REALLY GOING ON?

Unsurprisingly, fundamentally divergent perspectives on the impact of solar PV result in very different views of the degree to which utility costs might be shifted to non-participants (or vice versa). A good example of the panoply of viewpoints is in the recent Arizona Public Service case, in which the utility sought to sharply limit the utility bill savings that would accrue to customers with installed solar PV systems.

However, disagreement related to what charges or credits on NEM customers should be assessed can have wildly divergent potential impacts on participants, while making a nearly imperceptible monthly cost difference to non-participants. For example, the APS proposal would have eliminated up to \$99 in average monthly NEM customer savings to avoid \$1.48/month in alleged cost shifts borne by non-

participants. The solar industry's proposal would have resulted in a \$2.79 monthly cost shift per APS residential customer to NEM customers, and increased participant monthly savings of \$157/month.^{xv} Indeed, as the solar industry's proposal suggests, it is possible (and in many cases probable) to expect that the avoided utility cost value of behind-the-meter solar PV would outweigh the cost of utility's services to these customers, especially if all avoided system and societal cost benefits are included in the analysis. A similar disparity in impacts based on stakeholder perceptions can also be observed in California. Two studies, one by The Vote Solar Initiative and the other was commissioned by the California Public Utilities Commission, came to opposite conclusions. The first indicated that NEM provides a small subsidy to non-participating ratepayers,^{xvi} while the second paper concluded the opposite.^{xvii}

REFRAMING THE UTILITY COST RECOVERY PROBLEM: ACCOUNTING FOR ALL LOST REVENUE DRIVERS AND RATE DISTORTIONS

At root, development of sound regulatory policy is a multi-step process of negotiation, in which the goal is to develop effective settlements to complex economic and social problems. The first and most fundamental step for developing effective public policy that functions correctly is to develop an appropriate "problem statement".^{xviii} While cost-benefit analysis is often critically important to understanding the value of a technology or government policy, focusing the problem statement of utility lost fixed cost revenue too specifically upon solar PV fails to account for a multiplicity of other customer-driven technologies or customer actions to save energy threaten long-term utility fixed cost recovery.

Remembering Dr. Bonbright and the Fundamentals of Rate Design

Even in an age in which emerging technology is permanently altering the focus of utilities and their customers, it is important for all affected stakeholders to remember regulated utilities can still utilize long-held principles of utility ratemaking and rate design to create fair rates for customer-generators and facilitate a distributed energy future with thoughtful, deliberate, and incremental alterations to utility business models. These principles should be based on incremental, but significant shifts in the application of principles.

More than 50 years ago, Dr. James Bonbright articulated an approach to designing public utility rates which has stood the test of time, and is still recognized by utilities and regulators as the consensus set of principles upon which rate design for all electric utilities is based. Paraphrased, Dr. Bonbright's eight key principles include:

1. Ease of interpretation by regulators and stakeholders;
2. Ease of revenue collection and subsequent attraction of investor capital;
3. Stability of revenue collection over time;
4. Stability of rates, with minimal changes “seriously adverse to existing customers”;
5. Efficiency and avoiding waste in terms of total utility service provided and the encouragement of “justified” use of alternatives to utility service;
6. Fairness in allocating total costs;
7. Avoiding pricing discrimination not based on measurable cost characteristics;
8. Practicality, simplicity and public acceptance.^{xix}

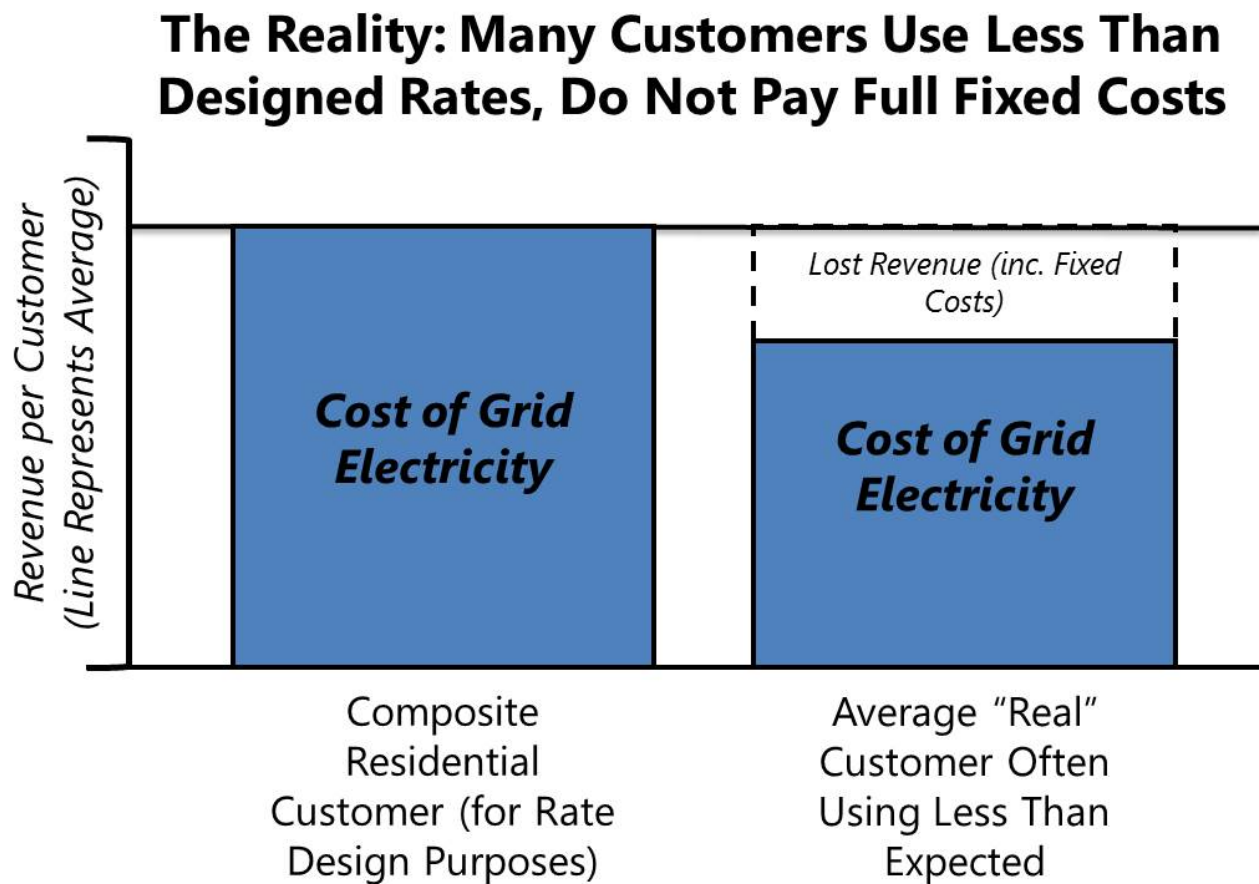
A relatively basic comparison of existing, PV-specific fixed cost recovery rate designs applicable to distributed energy resources with these principles strongly suggests that the approaches have critical and obvious aspects that are inconsistent with Dr. Bonbright’s principles of avoiding price discrimination and promoting energy efficiency and conservation.

Examining the Drivers of Utility Cost Under-Recovery: Broad-Scale Efficiency and Conservation

To be sure, the focus on solar PV and NEM in relation to the future viability of the utility business model is understandable, given that solar PV is a new, emerging, and paradigm-shifting technology that is declining rapidly in cost. What’s more, the pairing of highly modular PV installations with cost-effective energy storage, as described by the Rocky Mountain Institute, could lead to increasing degrees of “grid defection” and stranded utility assets.^{xx}

Nevertheless, focusing on NEM and customer-sited PV as the driver of future declines in utility revenue expectations fundamentally mischaracterizes the real drivers of why utilities are not collecting enough revenue (and under-earning their fixed costs). The persistent cost pressures associated with flat and/or declining utility sales growth (due to an increasing degree to customer-initiated investments in efficiency or distributed generation) over the past several years appear likely to be systemic in nature, and attributable to many and varied causes. If they persist, they are quite likely to disrupt and undermine the basic structure of the regulated utility business model.

Figure 7 (Example Not Drawn to Scale)



Evidence supporting this new "average" non-solar customer is emerging from several sources. For example, the "base case" of the U.S. Energy Information Administration's 2014 Annual Energy Outlook forecasts residential electricity usage per household to decline 4% overall from 2012 to 2040. This means that EIA expects that demand per customer will decline even if *no further federal appliance or other efficiency standards for energy efficiency were to be developed during that time period*. Thus, 4% is likely to be an unrealistically optimistic scenario, given that the development of progressively more stringent standards is required by federal law. Perhaps most remarkably, this decline in usage is expected to occur as the amount of revenue electricity utilities need per sale to residential customers in order to cover their costs doubles from an average of 11 cents/kWh to over 22 cents/kWh.^{xxi}

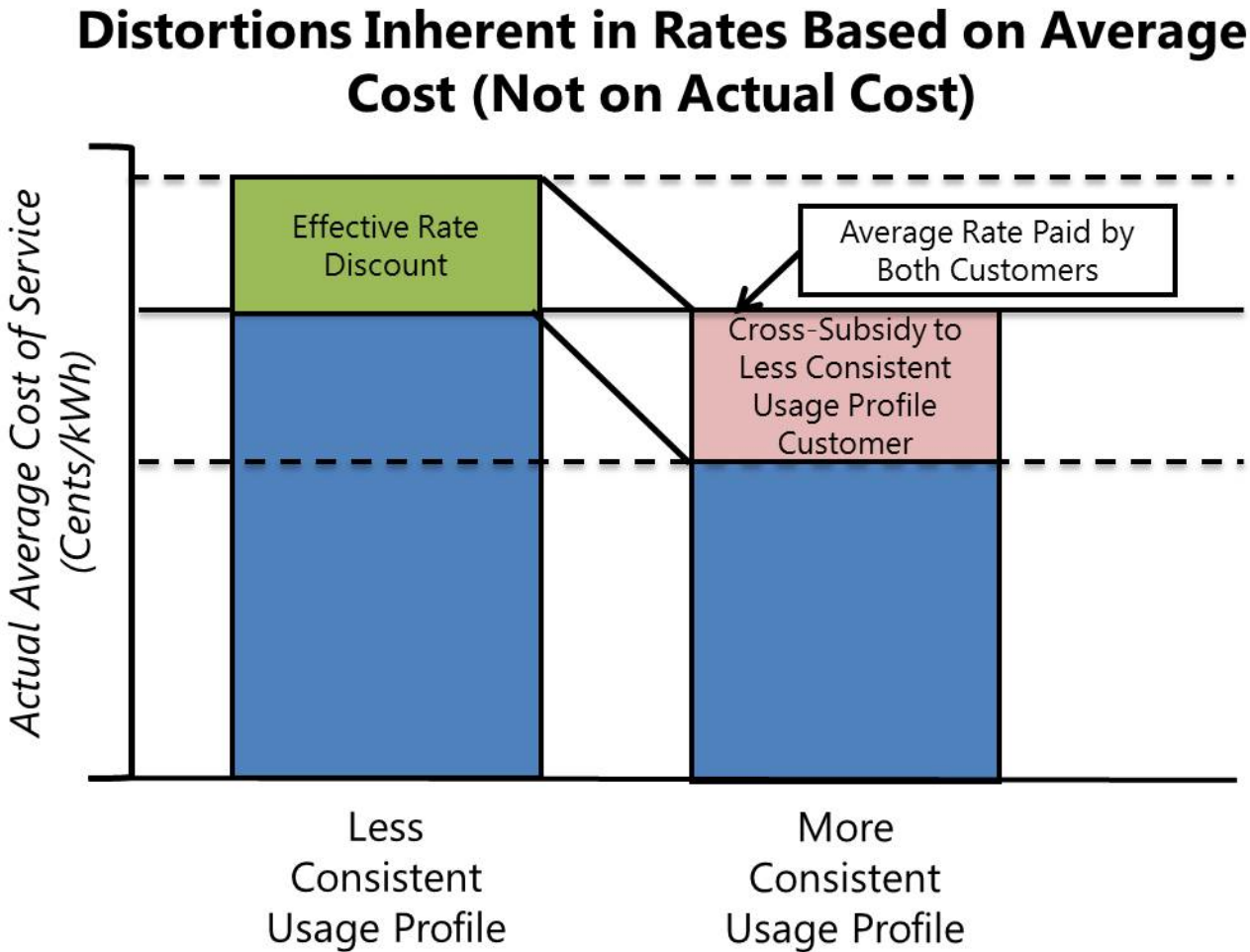
Furthermore, even utility- and customer-sourced data has begun to emerge that serves as a stark confirmation of the potency of the risk for utilities inherent in declining usage (and, thus, revenue) per customer in an increasing cost environment. For example, the Sacramento Municipal Utility District (SMUD) recently found that 75% of its customers did not pay their full share of fixed cost of service,

even though fewer than 2% of them had installed rooftop solar PV.^{xxii} In another surprising statistic, survey research in North Carolina conducted in 2013 indicates that 85% of *all adults* (far more than the participants in utility efficiency programs) have “taken steps to make (their) home more energy efficient.”^{xxiii}

Other Distortions in Non-Participating NEM Customer Rates

In addition, most (if not nearly all) customers do not pay the full cost of the electricity they use, especially during peak or critical-peak hours. Instead, they pay the average cost of energy throughout the year, which creates significant distortions and cost shifts between customer classes that do not reflect cost causation.

Figure 8 (Example Not Drawn to Scale)



In addition, tiered rates that are too “steep” can also accentuate cost-shifting amongst non-solar owning customers as well. For example, California’s utilities are regulated in such a way as to create a large and intentional incentive (and thus higher savings) for customers with high usage at the top of the rate structure to offset their energy *using NEM*.^{xxiv} For example, the California Public Utilities Commission Energy Division calculated that residential users across all IOUs paid approximately 154% of their cost of service without distributed generation and NEM, and 88% with distributed generation and NEM.^{xxv} According to Faruqi again, this non-cost based rate distortion results in another multi-hundred million dollar cross-subsidy in California from customers who use more energy to customers who use dramatically less, which may not reflect true utility cost savings.^{xxvi}

Clearly, the magnitude of this trend towards behind-the-meter load reductions (originating from PV and traditional conservation efforts, driven by higher rates) cannot be understated. In addition, it is clear that other rate designs that do not reflect the true cost of service (for which the above are only two basic examples) complicate the simplified picture painted by utilities and related advocates, in which solar PV is depicted as a (or even the) main driver of lost fixed costs. Even if NEM were to represent a “cost-shift” from solar PV customers to non-solar customers in certain jurisdictions, selectively enforcing upon solar PV a policy of “no cost shifts” is not only unduly discriminatory, given the existence of other uncontested cost shifts, it also represents a significant missed opportunity to address in a comprehensive way why utilities are not recovering sufficient or appropriate revenues.

SECTION 4 FIXED COST RECOVERY

CHARGES AND STANDBY RATES: AN OVERVIEW

Despite 1) not correcting for any other significant rate distortions or other factors affecting cost recovery and 2) the clear risk that such rates violate Bonbright’s principles of avoiding undue price discrimination and disincentivizing conservation and waste of utility service, several utilities have begun proposing to recover more of their fixed costs through new rate designs specific to solar PV-owning customers.

In addition, many fixed or flat charges are indirectly levied on the entire output of a customer’s PV system, including the portion that does not supply or in any way “touch” a utility’s distribution system or affect utility operations in any way different from other intermittent energy-consuming appliances would in the case of a customer with no PV.^{xxvii} This section describes three examples of this type of rate design: 1) “non-bypassable” fixed cost charges, 2) modifications to payments for net excess

generation and 3) standby rates that are generally applied to commercial customers or the largest residential PV systems.

NON-BYPASSABLE FIXED COST CHARGES

Fixed charges are often proposed or assessed on a per customer bill (\$/customer/month) or per kilowatt (\$/kW/month) of NEM customer installed capacity. With charges varying by kW, utilities designing and proposing these charges utilize a sliding scale to account for the size of the system, given that the size of the system is directly related to the amount of bill savings customers can realize and revenue the utility loses. On the other hand, depending on which component of unrecovered fixed costs the utility is attempting to recover (e.g. distribution/transmission, customer costs, etc.), the amount of unrecovered revenue does not always vary by customer, and thus the utility ought not to recover it via a flat monthly per customer charge.

Near-Term Potential Advantages of “Non-Bypassable” Fixed Charge Approach for Electric Utilities

- *Guarantee of Cost Recovery Regardless of Energy Use.* Fixed charges instituted solely for NEM customers that cannot be bypassed by using less energy from the utility allow utilities to collect what is, from their perspective, a revenue deficiency associated with NEM without concern for how much energy NEM customers purchase from them.
- *Ease of Application and Derivation.* Fixed, non-bypassable charges have tended to be the more common approach, given that they are clearer and more easily calculated and explainable for regulators and customers. However, this approach’s ease of explanation does not mitigate the controversy often caused by the application of such charges.

Near-Term Potential Disadvantages and Concerns with “Non-Bypassable” Fixed Cost Charge Approach

- *Piecemeal, Incomplete Application.* The most significant disadvantage of this approach for utilities is that customer-sited solar PV simultaneously imposes costs and causes them to lose revenue, but also demonstrably avoids future utility costs.^{xxviii} As a result, efforts to place charges on customers rely on taking very small snapshots of certain types of fixed costs (such as distribution or customer-related costs of metering, servicing and billing) that many utilities are unsure will be avoided in the future. Thus, many utilities tend to not take a broad, holistic look at how, in general, they are under-recovering their fixed costs, similar to the one we suggest later in this report.

Spotlight: Rocky Mountain Power in Utah (PacifiCorp)

A very clear example of a utility attempting to collect a fixed charge strictly from their solar PV customers (and the overall limitation of this approach for many utilities) is a \$4.75/customer/month charge that Rocky Mountain Power in Utah has proposed as part of their most recent rate case.

According to Rocky Mountain Power's regulatory witness, the purpose of their proposed fixed monthly per-customer charge is to "reflect only the distribution and retail service costs...(as a) a good first step in addressing this issue." However, the utility's witness also admitted that they were unable to definitively conclude which costs solar PV actually did not avoid or impose on their system. In addition, the charge is calculated on the basis of the total usage of RMP's services by NEM customers, forcing customers to pay for lost fixed costs on energy that never affects or interacting with the utility's distribution system. As of this writing (August 2014), the issue has not yet been ruled upon by the Utah Public Service Commission.

[Source: Testimony of Joelle Steward, Rocky Mountain Power.](#)

⦿ *Potential for Misapplication to Behind-the-Meter Energy Use.* In addition, fixed charges run the risk of charging their customers for lost revenue from the use of energy that is generated and used 100% behind the customer's meter. According to some practitioners, this approach may violate the Public Utility Regulatory Policies Act (PURPA)'s provisions permitting customers to take a portion of their services from qualifying distributed generation facilities (QFs).^{xxix} Furthermore, charging customers for an activity that is not easily distinguishable from relatively commonplace behind-the-meter energy usage variation (or usage of intermittently-used energy conservation measures) may be inequitable, and sends an inappropriate and inconsistent price signal to customers regarding their own efforts to conserve energy and reduce utility system costs.

⦿ *Risk of Systematic Mis-Valuation of Utility Costs and PV Benefits.* If non-bypassable charges do not account for clear, known, and measurable avoided costs displaced by solar PV, then depending on the location and cost characteristics of individual utilities it is possible or even likely that solar PV customer-generators will be under-compensated for

the value of the services they provide all utility customers. In addition, if a an insufficient number of avoided cost benefits are included, utilities and non-participating customers may continue to enjoy the benefits of costs avoided by the proliferation of solar PV without paying for them.

MODIFICATIONS TO PAYMENTS FOR NET EXCESS GENERATION

Some large municipal utilities (e.g., Colorado Springs Utilities and Omaha Public Power District) and investor-owned utilities (e.g., Georgia Power) have consistently only offered to purchase energy sold

back to them at rates that reflect their current and future avoided cost rates for wholesale capacity and energy, which are often well below their retail rates.

Near-Term Potential Advantages of the Energy Payment Modification Approach

- ⦿ *Standardization of Payments for Different Types of PV.* One advantage of setting the payment rate for energy sold back to them at the same rate at which they would purchase utility-scale PV capacity and energy means that they would pay a uniform rate for all solar PV-derived energy, regardless of the size or type of PV system. This approach creates some degree of standardization, and can appeal to regulators looking for easy-to-administer approaches.
- ⦿ *Avoids Charging Customers for Behind-the-Meter Lost Fixed Costs.* If the payment for PV is set at a rate that is different from the retail rate, utilities can apply that rate simply to the amount of generation that interacts with their distribution system (e.g., the amount that could potentially cause the utility to incur costs) and would avoid penalizing customers for the portion of the electricity that is generated and used entirely behind the customer's meter, thereby reducing system load.

Near-Term Potential Disadvantages and Concerns with the Energy Payment Modification Approach

- ⦿ *Risk of Systematic Mis-Valuation of PV-Related Avoided Cost Benefits and Overvaluation of Utility Costs* There are more known and measurable avoided cost benefits associated with solar PV than many utilities are willing to measure.^{xxx} Modifying customer payments to include only capacity and energy, may systematically undervalue benefits.
- ⦿ *Risk of Not Capturing Distinct Benefits of Behind-the-Meter PV Relative to Utility-Scale.* In addition, while some utilities note the benefits of using utility-scale resources to virtually serve customers with unsuitable sites for PV, the benefits for behind-the-meter and utility-scale PV selling into a wholesale market are quite different. These values should be valued differently since behind-the-meter generation has different service characteristics.

STANDBY AND SUPPLEMENTARY SERVICE TARIFFS ("STANDBY RATES")

While the conversation surrounding lost fixed cost recovery can often center on residential NEM customers, many electric utilities consider all of the service provided to (typically) commercial

customers that do not receive 100% of their service from utilities to be on a “standby” or backup basis, and thus levy “standby charges” to cover this cost. The putative justification for these charges is similar to that of solar PV integration costs - according to many electric utilities that apply these charges, the purpose of standby service is to fill in the gaps when a customer’s generation is not operating. The costs incurred for serving these systems, utilities claim, are related to regulating the power grid and ensuring a reliable and balanced electricity supply at all times for all customers.^{xxxii} Many utilities have instituted standby tariffs and rates specifying the terms, conditions and cost of this service, which often were initially intended (and priced) for large industrial customers with natural gas-fueled combined heat and power (CHP) systems supplying most of their energy needs.^{xxxiii}

Common standby rate components often include:

- Demand charges, which are most often “ratcheted” (set based on the highest demand over a certain period of time), and can also sometimes be referred to as “contract demand” or “generation reservation” charges;
- Energy charges, which include the cost of the “backup” energy necessary to supply a customer when the generation does not perform under normal operating conditions; and
- Fixed monthly customer charges.^{xxxiii}

Why Would Standby Rates Apply to Solar PV Systems?

Larger PV systems, as inherently intermittent generation resources, have operating characteristics very different from combined heat and power (CHP) systems, which standby rates were originally designed for (and which, unlike PV, are intended to operate on a nearly constant or dispatchable basis). Many utilities justify these charges on non-CHP systems, such as PV systems, on the basis that PV, even when operating in a typical fashion, impose costs on the utility system due to variable output.^{xxxiv}

Several large and notable municipal and investor-owned utilities have instituted standby charges on their NEM customers. Among several others, investor-owned utilities instituting standby charges specifically on solar PV customers include Dominion Virginia Power,⁹ Duke Energy and Florida Power and Light (FPL). Two notable municipal examples include the Omaha Public Power District and the Los Angeles Department of Water and Power (LADWP), the latter of which has a special rate schedule for its large commercial customers with on-site generation. Generally speaking, standby charges, when applied to solar PV, are applied to commercial customers. For example, LADWP’s standby rate schedule only applies to commercial customers receiving service at primary distribution voltage or

⁹ Dominion Virginia Power has instituted a standby charge for large residential customer PV systems over 10 kW.

higher.¹⁰ However, some utilities, including Florida Power and Light and Dominion Virginia Power, apply standby charges to residential systems as well.^{xxxv}

Distinguishing Standby Rates from Fixed Cost Charges: Is it Even Possible?

Based on the reliability justifications often provided by utilities for instituting standby rates, many people assume that under a cost causation approach, standby rates are intended to compensate utilities strictly for the cost of reliably integrating solar PV into their system. However, due to several key similarities between standby rates for PV systems and regular rate tariffs, standby rates are, in many cases, priced in functionally the same way as fixed cost recovery charges.

As a result, most of the same potential advantages of fixed cost recovery efforts (via fixed charges or reductions in payments) for utilities considering such charges (as detailed above) also apply to standby charges, including (but not limited to):

- ⦿ A guarantee of a degree of fixed cost recovery regardless of energy use; and
- ⦿ Ease of calculation and application to monthly customer bills on a \$/kW/month or \$/customer/month basis.

A corresponding and basic set of disadvantages associated with other fixed cost recovery efforts also apply, including (but not limited to):

- ⦿ The piecemeal and incomplete nature of the valuation of the utility's costs involved;
- ⦿ The risk of recovering costs based on the self-supply of solar PV generation that occurs entirely behind the meter; and
- ⦿ The risk of undervaluing (or not valuing) the services provided by the PV system itself.

For example, while Dominion Virginia Power justified its standby rate with the following:

"...the Company is required to be available to provide **supplemental and backup service** at all times including when the on-site generation fails or is being serviced, or is otherwise non-functioning, such as when the sun sets (*emphasis added*)..."

The standby rate Dominion filed with (and had approved by) the Virginia State Corporation Commission is based solely on the value of the *fixed cost portion* of Dominion's transmission and distribution system, which is assessed on customers at a rate of \$2.79/kW for distribution and

¹⁰ Explanatory note: small commercial and residential customers are served at secondary distribution voltage, given that they do not need as high of a volume of electricity at any given time as larger commercial and industrial customers, the latter of which is often served by their utility at transmission or subtransmission-level voltage.

\$1.41/kW for transmission, curtailing a sample customer's savings by up to \$48/month. *No costs of integrating PV into the distribution grid* were included in the calculation supplied by Dominion to the Virginia State Corporation Commission.^{xxxvi} This decision was made despite expert testimony from the local solar industry association suggesting that, on a levelized basis over 20 years, the net value of the system's PV output exceeded the retail rate paid by Dominion residential customers by up to 1.2 ¢/kWh.^{xxxvii}

THE IMPACT OF PV-SPECIFIC CHARGES: ARIZONA PUBLIC SERVICE AND HOLYOKE GAS AND ELECTRIC

By engaging in a bill analysis of an affected large commercial customer, it is possible to demonstrate the potential impact of standby and fixed cost charges on both a large commercial customer and a residential customer. As test cases, we utilized data from an hourly energy model for a supermarket in Holyoke, MA (Holyoke Gas & Electric)¹¹ and a high-usage residential customer in Phoenix, AZ (Arizona Public Service)¹² and compared it to data¹³ from PVWatts using the National Renewable Energy Laboratory's System Advisor Model (SAM). The results suggest that standby and fixed cost charges and charges can have a dramatic, disproportionate effect on customer generators that, on its face, does not appear to reflect the true avoided system cost benefits of installing rooftop PV systems.

¹¹ Holyoke Gas and Electric was selected because it had a standby service tariff that was a flat \$/kW charge, for ease of modeling. The Holyoke case assumed a 293 kW system (the maximum possible size of system that fits on a typical supermarket rooftop [as determined by NREL](#)), which is insufficient to meet peak load, thus obviating nearly all but incidental net excess generation. Financing was assumed to be 100% of the upfront cost at 7.5% over the life of the system (the standard commercial loan offer in SAM) in order to mimic a bank loan. Simulated hourly load data for Worcester, MA (the closest city with typical meteorological year (TMY3) data necessary for the simulation) was utilized using a data set [created by NREL](#). The financing is only relevant, however, for the system levelized cost calculation – not for the utility bill savings, which does not require financing terms to determine. The supermarket was modeled using Holyoke Gas and Electric's standard commercial tariff (non-agricultural), and a \$3.30/nameplate kW charge was added to reflect the cost of the standby service tariff each month for 25 years (a \$986/month cost). The savings/kWh cases were modeled by dividing the savings by system output for each of the 25 years of the system life.

¹² The APS case assumed a 7 kW system on the rooftop of a high usage customer. Simulated hourly peak load data ([created by NREL](#)) that uses typical meteorological year (TMY3) data for Phoenix Sky Harbor Airport was utilized. Financing was assumed to be 100% of the upfront cost at 5% interest (the standard loan value in SAM) over the 25-year life of the system in order to mimic a bank loan – however, this only figured into the levelized cost of the system, not the savings, which is compared on the pages to come. The differences in the LFCR cases is that the "No LFCR" case utilizes APS' standard residential tariff, whereas the "LFCR (APS Proposal)" required new NEM customers to migrate to APS' ECT-2 tariff, a time-of-use rate with a demand charge. The "LFCR (Approved)" case simply subtracts the \$4.90/month (\$0.70/system kW) charge agreed upon by the Arizona Corporation Commission from the "No LFCR" case. The savings/kWh was calculated by dividing system output by the total customer savings under the two rate and bill scenarios.

¹³ The data was modeled using the National Renewable Energy Laboratory's System Advisor Model (SAM). For ease of calculation, both cases assume 100% financed customer ownership of the system.

Over the course of a single year, the standby rate applied to Holyoke Gas and Electric large supermarket customers reduces their savings associated with PV (nearly all of which is generated and used on-site, behind the customer’s meter) by 22%, which amounts to nearly \$12,000 in reduced savings per year, averaging over \$986/month. What’s more, Figure 10 below shows that the standby rate applied by Holyoke Gas and Electric reduces the rate at which the customer saves money with a PV system below the project’s levelized cost, which means that the customer is, economically, taking a loss on the project for seven additional years beyond the situation in which no standby rate was applied. This is particularly compelling information, given that the “No Standby” case effectively represents the supermarket’s retail rate over time.

Figure 9

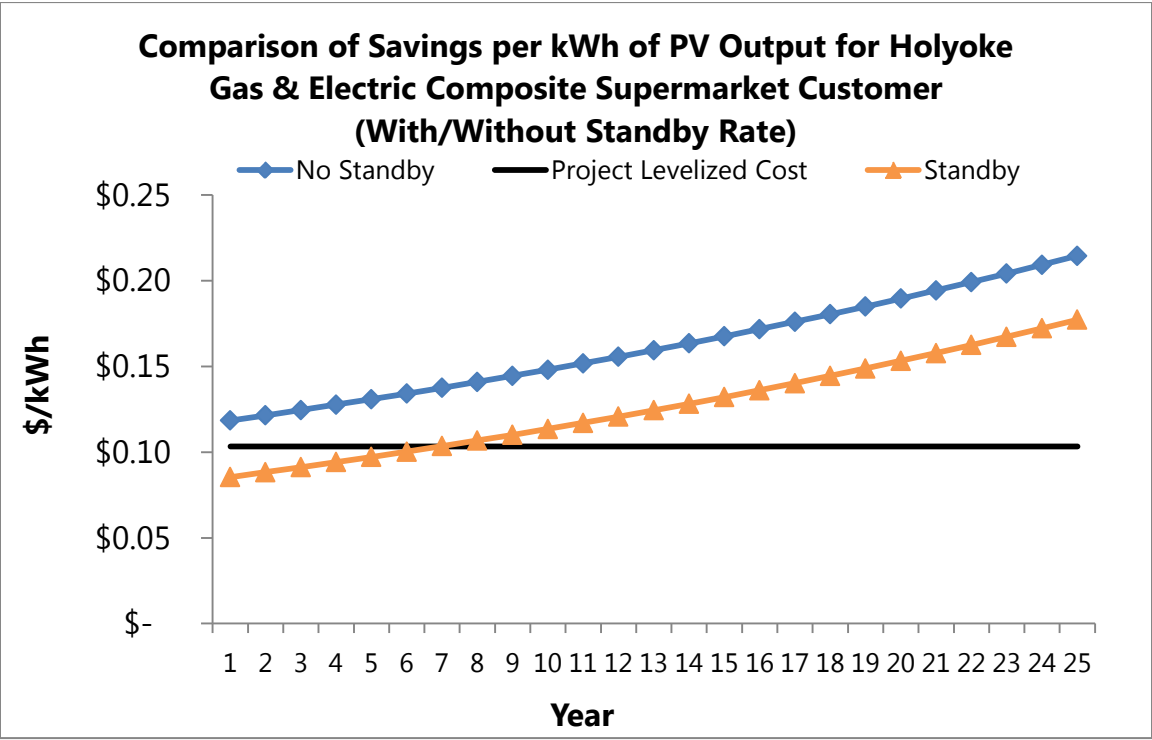


Table 1

Case	25 Year Electric Savings	Average Annual Savings
No Standby Rate	\$ 1,358,526	\$ 54,341
With Standby Rate	\$ 1,062,723	\$ 42,509
Standby Charge Cost	\$ 295,803	\$ 11,832
% Savings Reduction	22%	22%

The Arizona Public Service example demonstrates both the impact of a fixed cost charge, but also the potential impact of the most economically attractive rate schedule for solar customers that was proposed by APS and rejected by their Corporation Commission. As Table 2 below shows, while the regulator approved a charge that cut customer savings by 5% (about \$5/month), APS had proposed a cut that would have reduced savings by 48% (about \$88/month). Figure 11 also shows that the APS proposal would have severely limited customers’ ability to enjoy savings at a rate that equaled the levelized cost of their project, adding 12 years relative to the “No LFCR” case.

Figure 10

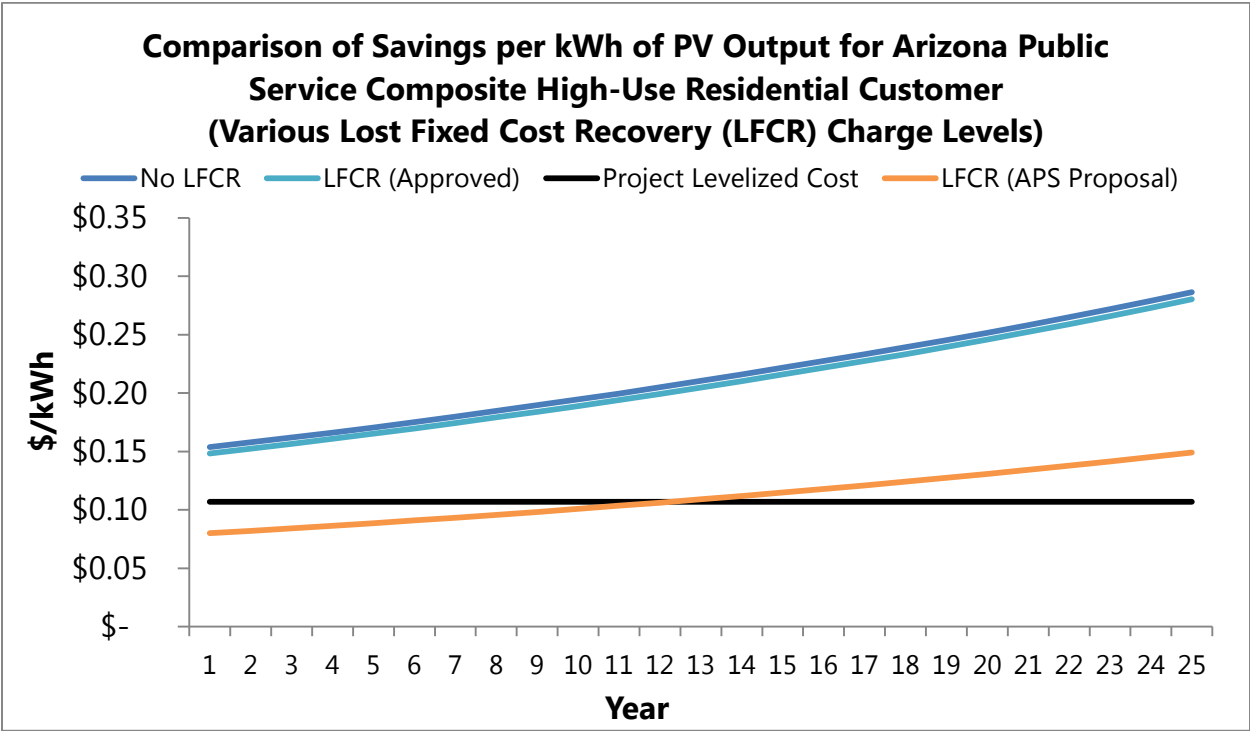


Table 2

Case	25 Year Electric Savings	Average Annual Savings
No LFCR	\$ 55,018	\$ 2,201
LFCR (AZCC Approved)	\$ 53,548	\$ 2,143
LFCR (APS Proposal)	\$ 28,563	\$ 1,143
% Savings Reduction (AZCC Approved)	48%	48%
% Savings Reduction (AZCC Approved)	5%	5%

Taken together, these examples suggest that a very cautious, balanced approach to standby and fixed cost rate design should always be employed, so as to balance sufficient utility revenue recovery with avoidance of damaging savings losses relative to their initial expectations for solar PV customers.

SECTION 5 A "SOFTER PATH": FAIR AND EQUITABLE RATE DESIGN FOR A DISTRIBUTED AGE

In a landmark *Foreign Affairs* article from 1976, Amory Lovins, an early champion of renewable energy and energy efficiency and a founder of the Rocky Mountain Institute, spoke of a "soft energy path" that would place "softer" clean energy technologies at the center, rather than the periphery, of our energy system.^{xxxviii} At this point in time, in which a great deal of controversy has emerged over how to balance the impacts and benefits of solar PV is beginning to threaten further soft cost reductions, the NEM debate seems overdue for a "softer path" for solar PV ratemaking and utility cost recovery that focuses more intently on balancing the broader interests of utilities and solar PV.

At present, current conventional wisdom pre-supposes that determining the future of NEM is as simple as doing the best possible solar-specific cost-benefit analysis, and applying the results as a net charge or credit. However, as noted above, this approach can lead to blind alleys that focus, to its clear detriment, too intently upon solar PV. Such approaches also fail to look beyond solar to other impactful drivers of lost fixed cost recovery, such as energy efficiency and demand-side management.

In view of the long-term risks to solar PV soft cost reduction posed by superficial and outdated rate designs, utilities and their regulators interested in thriving during this time of increasing distributed energy and efficiency may want to consider a broader, more holistic strategy for 1) recovering their fixed costs. These emerging strategic approaches are merely observations of what other similarly-situated utilities have completed or are considering and may not be a match for every utility.

IMPLEMENTING A HOLISTIC THREE-PRONGED COST RECOVERY SYSTEM

Many larger municipal and investor-owned utilities have begun to realize that fixed cost recovery strategies applied to all customers that, in practice, address all the major drivers of declining revenue or slower revenue growth (including energy efficiency) are necessary for their future financial

adaptability. However, in most cases, these companies have selected specific approaches, without considering the others as an integrated cost recovery “system” that will not unduly punish solar, and will sustain them financially for years to come.

The three strategies described herein, which include revenue decoupling, the application of a related “minimum monthly contribution”, and phased-in time of use pricing, represent an integrated cost recovery system. If this three-component approach is pursued in a systematic manner, utilities can recover their costs in a way that accounts for all of the drivers of its lost revenue in a time of stagnant sales. This will likely obviate the need for imposing solar PV-specific charges based on “value of solar” approaches.

Component 1: Revenue Decoupling The first, most essential step towards a comprehensive, integrated, and gradualist fixed cost recovery strategy is the adoption of full revenue decoupling. When implementing revenue decoupling, utilities establish a particular target of revenue and collect that revenue regardless of sales. From an economic perspective, this approach leads utilities to be more indifferent to encouraging volumetric sales, the typical utility approach to spreading costs and increasing profitability.^{xxxix}

Perhaps most importantly, and unlike solar PV-specific rates and charges implemented without it, decoupling honors the ratemaking principles of fairness in pricing and cost allocation. By implementing it, a utility recognizes that innovative, behind-the-meter energy saving approaches like solar PV (or just traditional energy conservation approaches) are becoming evenly spread across utility customers and classes, and are facilitating considerable utility avoided cost benefits that all customers benefit from. By extension, utilities implementing both full revenue decoupling strategies *and* solar PV-specific charges *are at distinct risk of engaging in an inappropriate double recovery of fixed costs from their customers adopting solar PV*. Figures 12 and 13 below illustrate the way in which decoupling mechanisms can ensure that utilities recover lost fixed cost revenue from all of their customers, given that the “average” customer often does not pay their full share of utility fixed costs.

Functionally, decoupling mechanisms assess all utility customers an added charge fixed or volumetric charge if the utility does not recover its full, expected revenue requirement during the year, or a refund with interest if it exceeds that revenue requirement. The cumulative effect of these charges, particularly if they are not tied to customer energy usage, is to ensure that the utility’s full expected revenue requirement is met, regardless of how much electricity it sells.

Figure 11 (Example Not Drawn to Scale)

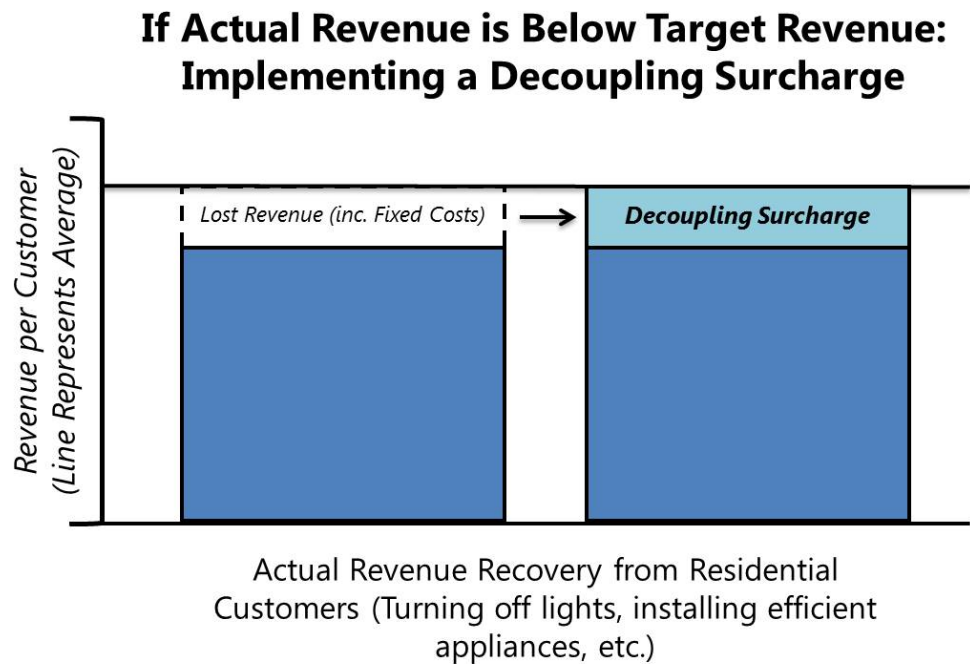
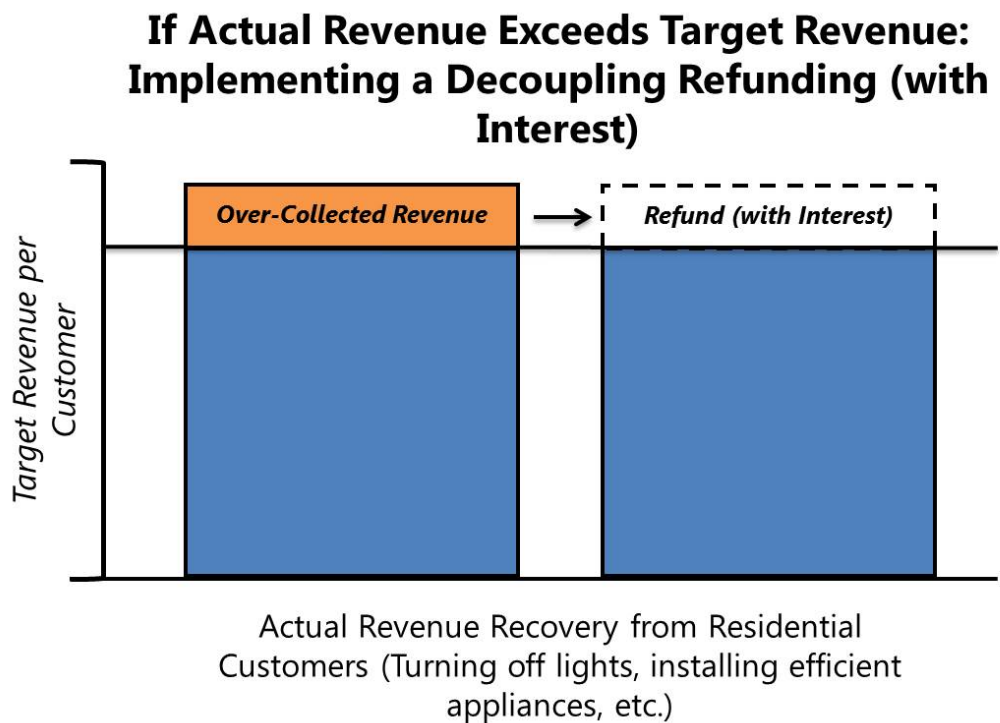


Figure 12 (Example Not Drawn to Scale)



Indeed, decoupling will likely have a more tangible appeal when utilities begin to experience even broader-based revenue erosion per customer, particularly as customer-sited PV adoption accelerates. However, by the time certain utilities may wish to decouple, it may in fact be too late – it could appear to be an attempt to place the burden of increasing stranded costs upon its customers, and a request could subsequently be denied.

More specifically, while a utility may design its rates to include a higher target rate of return due to its investor risk profile and hope to earn it by encouraging sales, this can be a risky financial proposition for utilities that are unable to fully and consistently capture that target rate of return as a result of lost sales. As Figures 14 and 15 below show, even though U.S. investor-owned utilities have initiated more applications to state public service commissions to increase their rates, the same group of utilities still consistently struggles to earn the profits built into their rates that they aim to return for their stockholders.

Figure 13 (from ScottMadden, excerpted from SNL Financial)

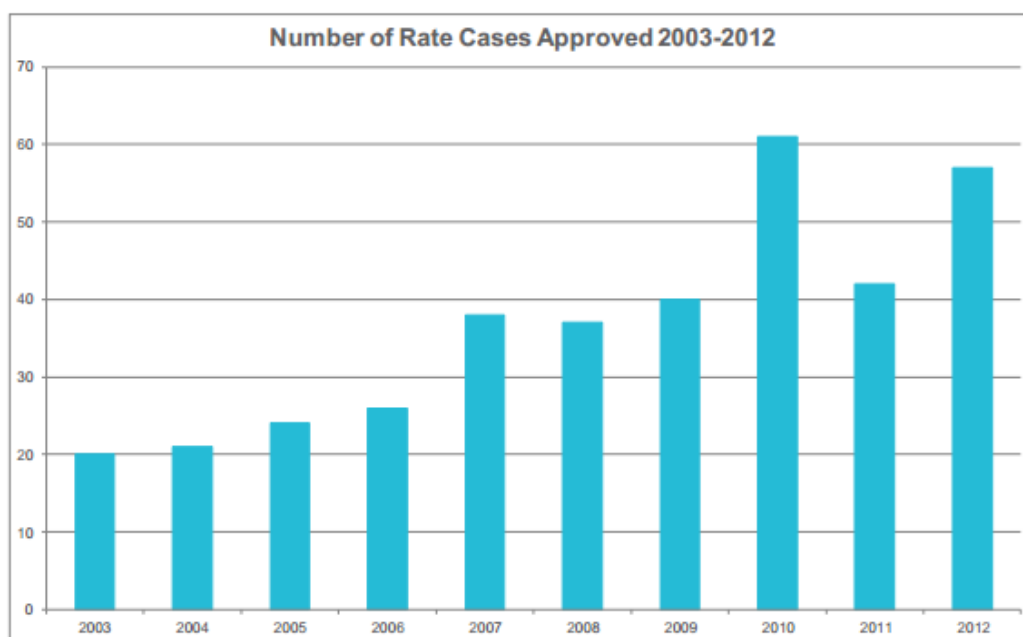
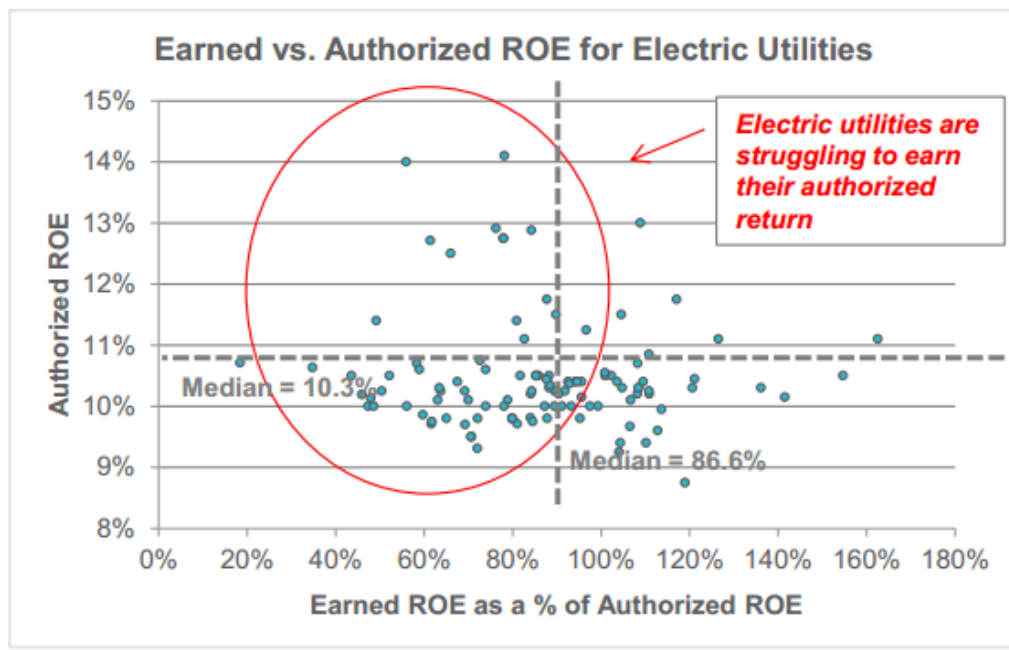


Figure 14 (from ScottMadden – excerpted from SNL Financial)



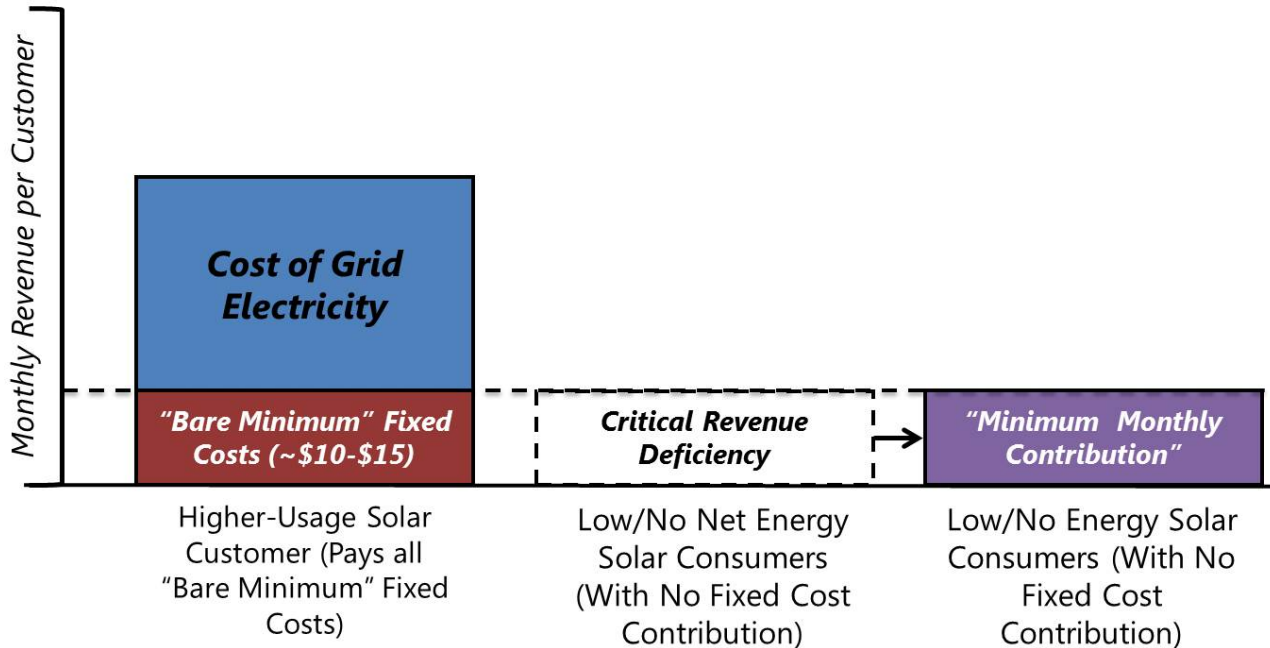
Thus, a reduced return on equity from decoupling (and overall rate of return) is unlikely to financially harm a group of utilities that, as a group, *already tend to systematically under-earn* relative to their investors' expectations.

Component 2: Establishing “Bare Minimum” Fixed Cost Contributions to Capture Decoupling Adjustment from Lowest-Usage Customers However, adopting a decoupling approach makes it absolutely crucial for a utility to adjust what are known as minimum fixed cost contribution for all customers that use zero net energy. Unlike basic customer charges, these charges usually are higher, and are only assessed if a customer uses zero net energy in any given month.

These charges could be assessed on a monthly or annual basis, based on the costs that would need to be incurred even if customers use no net energy from the grid, such as the cost of their metering and distribution infrastructure, and any other of the most basic costs of servicing their account. This approach makes particular sense in the case of a growing number of low-usage customers who install solar and then use little to no net energy in a given month.

Figure 15 (Example is Not Drawn to Scale)

Why “Bare Minimum” Fixed Cost Contributions Are Key to Effective Decoupling Implementation for Low/No Usage Solar Customers



In many ways, the minimum fixed cost contribution, an approach adopted in California’s landmark Assembly Bill 327, makes a great deal of sense as a way to ensure that the decoupling surcharge has sufficient traction when dealing with lower net usage customers. Indeed, raising minimum bills for customers to the point at which they pay a sufficient share of any of the costs associated with renewable energy incentives and other decoupling-related fixed costs can be a prudent, incremental step to ensuring a correct degree of revenue recovery. This is especially true, given that many revenue decoupling bill adjustments are assessed on a per kWh basis. Thus, when those customers use zero net energy from the grid, a minimum fixed cost contribution may be necessary to capture the critical share of the most basic fixed costs left unrecovered.

Figure 16 above illustrates how, in a situation in which a decoupling surcharge is necessary to maintain a revenue target, a minimum fixed cost contribution can ensure that the surcharge per customer is fully collected, even by customers who use zero net energy. If a surcharge is unnecessary, however, the minimum fixed cost contribution is still collected from all customers, given that it is critical revenue that all utilities must collect from all customers.

“Minimum Bill” Spotlight: California Assembly Bill 327

A compromise bill to expand California’s net metering cap supported by both the solar industry and its utilities demonstrates that flexible “minimum bills” that apply to all customers can effectively substitute for solar PV-specific standby rates or fixed monthly charges when a utility has instituted a decoupling mechanism, as California’s major investor-owned utilities have.

While AB 327 allows California’s investor-owned utilities to assess a “fixed charge” to recover basic fixed costs, the charge must be assessed to all solar and non-solar customers, is capped at \$10 (or \$5 for low income program participants) and must be phased in over time. Functionally, this means that this effective “minimum bill” would immediately effect would only be low- or no-usage “prosumers” with solar PV.

This bill thus recognizes the principle of incrementally spreading the cost of solar PV’s ability to create utility avoided cost benefits to all customers that are able to benefit them, while also not singling out solar PV customers for potentially discriminatory charges that represent a (typically impermissible) double recovery.

Source: California Legislative Information. Assembly Bill 327 (Perea). Available at:
https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

Component 3: Phasing in Time-Differentiated Rates Applied to All Customers

Time-differentiated rate schedules are more common for larger commercial and industrial customers, given that nearly all but these customers are not required to pay for the actual (or rough approximation) of the cost of their electricity at the time it was generated. Under Bonbright’s principles, this approach is a fairer, more cost-based and accurate approach to ratemaking for all customers. This is because all customers that use less energy behind-the-meter should pay for the actual cost of the electricity actually consumed, (and avoid the cost of that which they do not) given that time-differentiated rates are designed to more accurately reflect their value to the utility and its customers.^{xi} To mitigate some of the impacts of shifting to time-differentiated rate schedules, utilities can also gradually phase them in for all customers over a period of years.

A time-differentiated approach applied to all customer, particularly one that is phased in over time to gain greater customer acceptance, is far more equitable and in the interest of customers, as it tends to reflect marginal costs for all customers¹⁴, thus reducing cross-subsidies from low usage customers to higher usage customers. It is an approach that can limit potentially unfair and

discriminatory charges for solar PV customers that may not be justified based on its unique costs and benefits to a particular utility and its customers. Indeed, the California Public Utility Commission’s Energy Division staff have recommended that the cost recovery impacts of time-differentiated rates be accounted for in valuing the costs and benefits of NEM in the upcoming proceeding on the subject in California.^{xli}

It is also important to note that differences in local incentive policies may impact the effect of time-differentiated rates on solar PV customers. Thus, the interaction between time-differentiated rates and

specific local incentives should be carefully calibrated, because the price suppression effects of solar PV can change the peak to when solar PV is not generating.^{xlii}

TRANSITIONING TO A SOFTER RATEMAKING PATH: ADDRESSING COMMON QUESTIONS

Q: Wouldn't a more transparent "value of solar" approach make more sense than decoupling with a minimum bill and TOU rates?

A: While this is a common argument made by utilities and other proponents of applying "value of solar" approaches to NEM customers^{xliii}, it elides the reality that retail utility rates are rife with cost shifts that functionally serve as inter-class and intra-class cross-subsidies. As noted above, several common ratemaking cross-subsidies that do not reflect real differences in costs include (but are not limited to):

- Setting the same rates for rural and urban utility customers of all types;
- Setting economic development or other "job retention" discounts for industrial customers;
- Providing "lifeline" rates or other discounts to low-income customers.^{xliv}
- Allowing residential customers to not pay monthly demand charges (as discussed above); and
- Allowing most customers to pay average "energy" rates that do not reflect the cost of energy generated on peak.^{xlv}

Time-Differentiated Pricing Spotlight: Sacramento Municipal Utility District (SMUD) and the California Public Utilities Commission

Not only does the Sacramento Municipal Utility District (SMUD) have the third-highest number of residential NEM customers, totaling around 6,000 at the end of 2013, it is also considered a national leader in community solar PV, deploying energy efficiency measures, and investing in renewable power generation.

In its most recent rate review, SMUD found that three-quarters all of its customers did not pay SMUD their full cost of service. In response, its board decided to implement aspects of a comprehensive fixed cost recovery strategy by, among several other steps, developing a gradual phase-in plan for requiring all customers to take their service from SMUD on a time-differentiated basis by 2018, shifting away from tiered rates. In addition, as a result of California Assembly Bill 327, the California Public Utilities Commission has recommended a phase-in on the same basis.

According to SMUD, their purpose in doing this was to send appropriate price signals about the cost of energy and urge customers to "take advantage of new energy management technologies and new electric services, such as solar and electric vehicles.

Source: EIA Form 826 and SMUD *General Manager's Report on Rates and Service*, Vols. 1 and 2. Available at: <https://www.smud.org/en/residential/customer-service/rate-information/rates-2014-2017.htm>. Other information taken from the California Public Utilities Commission Energy Division's Staff Proposal on Residential Rate Reform. Available at: <http://www.cpuc.ca.gov/NR/rdonlyres/66CCE840-F464-42F5-8B6A->

While it is not even clear that NEM consistently might cause cost-shifting or net rate increases for non-participating customers, all of the practices listed above have been proven to raise the rates of certain customers in order to intentionally lower the rates (and bills) of other customers. Given that most utilities consistently agree to build many of these commonplace cost shifts into their rates, it makes more sense to implement a revenue decoupling mechanism, along with minimum bills to ensure that the mechanism will collect sufficient revenue from very low usage customers, along with time-differentiated rates. Together, these policies will provide utilities with a realistic opportunity to earn sufficient fixed cost revenue and remain attractive to investors.

Thus, regulators should resist the temptation to apply PV-specific fees and charges to NEM unless it is in the context of correcting all of the more significant rate distortions and cost shifts built into customer rates. Doing so without addressing these other cost-shifts constitutes the very undue price discrimination that Bonbright's principles of rate warn against.

Q: Will keeping NEM at the retail rate designing work at higher penetrations of solar PV if there's a cost shift?

A: It is possible that creating a special rate class for solar PV customers could make a significant degree of sense much further in the future (e.g. when customer-sited solar PV supplies a sizable plurality (~20%-30%) of a utility's potential peak load, or if a regulated utility or affiliate were to go directly into the business of selling PV systems directly to their customers). Indeed, high-quality value of solar studies that model not only the utility system, but also each component part, are still important for utilities and others to engage in, if only to gain a better understanding the avoided cost dynamics of PV on their system.

Nevertheless, this degree of PV penetration is not likely to be manifested soon in many, if not most, jurisdictions. Furthermore, improperly focusing solar PV ratemaking discussions around the value of solar PV to the exclusion of all the other drivers of lost utility revenue (and the net value of other distortions built into rates, such as a lack of time-differentiated pricing) still carries with it the same potential for undue rate discrimination as with current standby and fixed cost charges.

In addition, this approach still questionably assumes that NEM creates a net cost shift over time in all jurisdictions, which it has not been definitively demonstrated to cause in all situations, even without adjusting for other rate distortions.

Q: If standby rates are unduly discriminatory, how are utilities supposed to be compensated for backup power to PV customers?

A: Cost-based, time-differentiated rates for all customers that more accurately reflect the time-dependent price of electricity render standby rates based on the cost of supplemental and backup power are functionally unnecessary. This is especially in the case of larger electricity users that are on time-differentiated tariffs with demand charges, because these customers already pay a far more significant share of their fixed costs through demand charges. In addition, time-differentiated pricing,

unlike standby rates, is a particularly transparent approach that is well-suited for all solar PV customer-generators, since PV systems allow these customers to avoid a large degree of their peak usage, but still pay the costs of their electricity usage on-peak if their unit cannot generate at certain times.

In this way, time-differentiated rates serve as a vastly superior alternative to standby rates as pricing signal for supplementary and backup power, as well as for net excess generation. However, they would pay for this more expensive power on an equal basis with all customers choosing to use a large amount of electricity on-peak.

Q: Won't minimum bills to cover fixed costs limit customer incentives to invest in solar PV?

A: This concern, while valid for certain kinds of fixed cost charges that should reduce "energy" rates per kilowatt-hour^{xlvi}, is misplaced when a minimum bill is only functionally applied to customers that use zero net energy. It is true that instituting a minimum bill without a decoupling mechanism in place is, indeed, certain to reduce the customer's "energy" rate (or at least the rate at which it increases). However, if a utility institutes a decoupling mechanism, the "minimum bill" only functionally serves to ensure that the decoupling mechanism collects enough revenue for the most basic distribution and customer costs from prosumers. This serves the interests of customer-generators and utilities alike, as utilities will make enough basic revenue to ensure their most basic costs are covered, without massively burdening customer generators with added fixed costs for transmission or generation.

Q: Isn't it true that these approaches raise rates, and are unjust to low-income and other vulnerable customers?

A: While an added decoupling surcharge per kilowatt-hour may superficially appear to be a rate increase, this view rests upon an incomplete understanding of the inherent cycle of decoupling mechanisms. Utilities are allowed to design a rate of return into their rates, and that rate of return tends to correspond to the risk associated with their core regulated business. When a utility implements revenue decoupling, it is far more likely to earn a particular return for their investors regardless of how much they sell, and thus is a less risky investment. This has the effect of improving its credit ratings, allowing regulators to lower the rate of return built into the utility's cost structure.^{xlvii} In fact, if utilities earn more than their target, a decoupling mechanism can return the over-collected revenue to customers, sometimes with interest.^{xlviii}

In the case of time-differentiated rates, customers receive an appropriate price signal about the cost of peak-time energy usage, which will cause them to shift usage to lower cost times, enhancing system avoided cost benefits. The net effect of approving all of these approaches will be that utility regulators will have sharply reduced the Averch-Johnson effect, the term for a monopoly utility's tendency and incentive to over-invest in its physical assets.^{xlix}

OTHER “SOFTER” RATE DESIGN PATHS TO SOLAR COST REDUCTION

There are numerous possible approaches to encourage the growth of distributed solar without undermining utility business structures.

Tariff Model Feed-in-tariff (CLEAN contract) models have emerged as a policy alternative to net metering internationally and across the United States. Customer-sited generators received fixed payments tied to system performance. Rates are set using transparent methods and can be adjusted on an annual basis or as appropriate. Through a tariff-based model, utilities would be able to fully recover their fixed costs since customers would still receive a standard bill tied to their consumption. This would render a standby charge unnecessary, since distributed generators would pay for their proportional cost of service. Value of solar calculations can also be utilized to set an appropriate rate for fixed, production-based incentives for on or off-site solar systems. This policy pathway has the potential to lessen administrative complexities for utilities, since it eliminates the need to calculate, carry-over and administer net-metering credits on monthly bills. The billing and crediting process would be distinct with cash production-based payments issued separately.

This model is currently being employed in several states including Rhode Island, Vermont, and Oregon, and numerous municipal utilities. Madison Gas and Electric in Wisconsin allows small solar customers to choose between a tariff system and net metering. As of 2009, all customers had opted for the tariff-based program.ⁱ Recently, Minnesota passed legislation allowing utilities to offer a value of solar based tariff for customers. Solar system owners opting into the program will receive payment for production based on an established value of solar rate. Transparent guidelines were released for any of the state's utilities which chose to use this incentive mechanism. When value of solar tariffs are utilized, utilities should not apply standby or fixed cost charges on customer bills.ⁱⁱ

Virtual Net Metering As noted above, capacity- and production-based standby charges could increase customer acquisition costs for larger-scale solar projects and/or higher-usage customers. Larger customer-sited projects are important from an energy efficiency and carbon reduction perspective, and also as a way of increasing access to renewable energy.

In states with virtual net-metering, solar production can offset energy consumption across multiple customer accounts. It is through this mechanism, that community solar projects are most feasible. Virtual net metering can also be deployed to share net-metering credits with neighbors or for larger customer-sited systems. Allowing virtual net-metering reduces utility costs by limiting interconnection points, and reducing meter installation and labor costs. If utilities developed a transparent, systematic method for assessing fixed costs, it would enable cost-recovery within a policy context which does not discourage larger residential projects.

Utilizing Emerging Technology to Target High-value Solar Installations Customer-sited solar systems have the ability to relieve strain on the transmission and distribution system. Emerging software platforms can enable planners and regulators to simulate and observe system constraints and strategically incentivize high-value customer-sited PV systems. Other customer-sited systems in less constrained zones of the utility territory may be subject to fixed costs in this policy model based on their value to the grid and the ratebase. The Electricity Distribution Grid Evaluator (EDGE) model is an analytical tool developed by the Rocky Mountain Institute as part of the Sunshot Initiative to calculate the value of energy resources based on specific utility inputs. The EDGE model is being reality-tested in partnership with a number of utilities.^{lii} As additional technology options emerge and are piloted, utilities will be able to leverage data inputs to incentivize high-value customer-sited generation.

SECTION 6 SOLAR PV COST REDUCTION BENEFITS OF A “SOFTER PATH” FOR RATE DESIGN

As noted in Section 2, solar PV-specific standby and fixed cost charges rate designs pose fundamental risks to SunShot soft cost reduction goals, particularly for financing and customer acquisition. However, these downside risks can be mitigated by the pathways we suggest in several key ways.

Financing Soft Cost Reduction Benefits The approaches we suggest can help mitigate financing soft cost risk in several ways .

- ⦿ *Equitable Fixed Cost Recovery Mechanisms* Stable, predictable, and equitable charges or credits for PV customers (if such are found to even be necessary after a decoupling adjustment) can help to reassure solar PV investors charges will be mitigated, or in fact reduced to zero.
- ⦿ *Fixed Cost Charge or Credit Phase-In Approaches* Phase in of “if necessary” charges or credits (which can only be *reduced* by the decoupling adjustment) provide investors with greater certainty about the extent of future costs that may impede their investment, thus lowering inherent investment risk.
- ⦿ *Alternative Tariff Structures (VOSTs and FiTs)* Tariffs requiring 100% of output to be sold to the utility can also provide investors with greater confidence.
- ⦿ *Virtual Net Metering* Community shared solar developments conferring customer bill saving via virtual net metering often utilize larger PV systems, which have lower costs per kW installed, which can help reduce overall installation costs and tap into a larger pool of capital backed, in essence, by the repayment of customer bills.

- Targeting High-Value Installations Focusing development on less congested distribution circuits can maximize grid benefit, which would create more avoided cost value for solar PV, could enabling it to be paid more for the benefits it provides if installed in the right locations, increasing its attractiveness to investors and customers.

Customer Acquisition Soft Cost Impacts Furthermore, each of the proposed approaches also helps maintain the pace of reductions in customer acquisition costs.

- Equitable Fixed Cost Recovery Mechanisms* Stable, predictable, and equitable charges or credits for PV customers (again, if even found to even be necessary after a decoupling adjustment) can help to reassure solar PV customers that PV is a sound investment.
- Fixed Cost Charge or Credit Phase-In Approaches* Phase in of "if necessary" charges or credits (as reduced by a decoupling mechanism) mitigate the risk that new potential PV customers will have their savings significantly curtailed all at once, thus mitigating the concerns of potential customers.
- Virtual Net Metering* Community shared solar developments tend to target customers that cannot install PV on-site, which allows them to benefit from savings, and the developer/program administrator to reduce costs involved in convincing a customer to invest in an on-site system.

In all, these rate design pathways are intended to mitigate or eliminate the risk of halting needed reductions in non-hardware "soft" costs inherent in currently contemplated rate designs. Thus, these pathways represent a more rapid route to sustainable cost recovery and a future in which rooftop PV needs limited to no taxpayer or customer-funded incentives to be competitive, even in an often less-than-competitive market.

SECTION 7 LOOKING AHEAD TO A PROSUMERIST WORLD

Customer-sited solar PV projects will continue to be integrated into the grid nationwide for the foreseeable future, and with an eye, to be sure, towards compensating utilities for continued use of existing infrastructure. However, in order to thrive in a future energy market with customers who feel strongly about establishing a greater degree of control over their own energy costs and supplies, it is of the highest importance for utilities and regulators to engage in a broader and more honest conversation regarding their business models than they have thus far.

Indeed, some utilities and their regulators may hope that rapid expansions of advanced customer-sited energy technologies are only temporary, and will thus allow the regulatory system to avoid reform. However, recent expansions of solar PV have created enough momentum to render the

question of *if* such technologies will become commonplace as irrelevant, making how to thrive in such an environment a question and conversation that cannot be prudently postponed.

SECTION 8 APPENDIX: CURRENT STATUS OF STANDBY & FIXED COST CHARGE DEBATES

Note: This table summarizes the current discussions around net metering and its implications and impacts. It is meant to illustrate the variance across states without being comprehensive.

State	<i>Net Energy Metering and Tariff Proceedings</i>
<i>Arizona</i>	As of January 2014, new net-metered rooftop solar systems are charged \$.70/kW, or approximately \$4.90 per month for most residential solar customers to account for fixed cost recovery. The policy will be in effect until the next Arizona Public Service rate case in 2015.
<i>California</i>	In 2013, California extended the state's net metering policy to offer net metering until programs reach net metering program limits or u July 1, 2017. After the net metering program limits are exceeded, distributed generators must receive a standard tariff determined by the Public Utility Commission. ¹⁵ A discussion concerning new rates and policies began in April.
<i>Colorado</i>	The Colorado Public Utilities Commission created a separate docket for the discussion of net metering, due to Xcel's energy claim that the current net metering rate was far above the value solar added to the grid. Xcel calculated the value of solar at \$.046/kWh, and pays \$.105/kWh for net metering credits. ¹⁶
<i>Connecticut</i>	In July 2014, due to a legislative error, Connecticut disqualified customers who received solar rebates from participating in net metering in House Bill 5115. After alarm from customers and the solar industry, the decision was quickly reversed. ¹⁷
<i>Florida</i>	Florida established net metering for all of its utilities in 2009. Florida Power and Light currently has in place a standby charge for both residential and commercial DG customers
<i>Georgia</i>	In 2013, Georgia Power proposed an average fee of \$22/month for distributed solar

¹⁵ J Durkay, J. "Net Metering: Policy Overview and State Legislative Updates," *National Conference of State Legislatures*, 2014, Available at: <http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx>.

¹⁶ Trabish, H. , "Rooftop Solar and Net Metering Win a Big Decision in Colorado: Greentech Media," January 30, 2014, Available at: <http://www.greentechmedia.com/articles/read/rooftop-solar-and-net-metering-win-a-big-decision-in-colorado>.

¹⁷ Dowling, B. "Error In Bill Put Solar Industry On Its Heels." *Hartford Courant*, July 7, 2014. Available at: http://articles.courant.com/2014-07-07/business/hc-solar-industry-major-legislative-error-20140707_1_net-metering-solar-panels-bill.

	users to recover fixed costs. The Georgia Public Service Commission denied the request. ¹⁸
Hawaii	In 2014, Hawaii's House Bill 1943 called for grid modernization and a revision of the current net metering policy to reflect the value provided by solar to utilities and the grid services provided to DG customers. This legislation was passed due to increasing penetrations of solar on the Hawaiian grid. ¹⁹
Idaho	In 2013, Idaho Power sought to raise the service charge for residential and commercial net-metering customers from \$5.00/month to \$20.92 and \$22.49/month, respectively to help recover fixed costs and distribution expenses. The request was denied by the Idaho Public Utilities Commission, and said the utility's concerns should be discussed in future rate cases. ²⁰
Kansas	In 2014, House Bill 2101 revised the net metering rules for systems installed after July 1 st . The regulations set capacity limits for net metering for residential and small commercial systems. The legislation also allowed the utility to propose time-differentiated rates, minimum bills and other rate structures for DG customers. Utilities were restricted from accessing standby rates or tariffs on systems installed prior to July 1 st . The existing net metering system is set to expire in 2030. ²¹
Louisiana	In 2013, the Louisiana Public Service Commission rejected a proposal to decrease net metering payments, and change the state's policies. ²²
Maine	The Maine Solar Energy Act set state targets for solar energy development and required the Public Utilities Commission to quantify and develop a methodology for calculating the value of solar and release a report by January 15, 2015. ²³
Massachusetts	Massachusetts House Bill 4185, or the Solar Compromise Bill, proposed eliminating the cap on net metering. However, the bill engendered significant controversy related to the elimination of the SREC program, and thus died in committee July 31 st .

¹⁸ Howland, E., "Georgia Power Drops Proposed Solar Fee." *Utility Dive*. November 18, 2013. Available at: <http://www.utilitydive.com/news/georgia-power-drops-proposed-solar-fee/196169/>.

¹⁹ State of Hawaii. *A Bill for an Act Related to the Modernization of the Hawaii Electric System*. 2014. Available at: http://www.capitol.hawaii.gov/session2014/bills/HB1943_CD1_.pdf.

²⁰ Idaho Public Utilities Commission. "Most of Idaho Power's Net Metering Proposals Denied." July 3, 2013. Available at: http://www.puc.idaho.gov/press/130703_IPCnetmeterfinal.pdf.

²¹ State of Kansas. *AN ACT Concerning Utilities; Relating to Renewable Energy Resources; Amending K.S.A. 2013*, n.d.

²² Passera, L. "Louisiana Rules to Preserve Net Metering | Interstate Renewable Energy Council," *Interstate Renewable Energy Council*. July 11, 2013. Available at: <http://www.irecusa.org/2013/07/louisiana-rules-to-preserve-net-metering/>.

²³ Vitelli, E. *An Act To Support Solar Energy Development in Maine*. 2014. Available at: http://www.mainelegislature.org/legis/bills/bills_126th/billtexts/SP064401.asp.

	A different bill, which temporarily lifted the NEM cap, passed the Massachusetts House the same day. ²⁴
Minnesota	In 2013, the Minnesota legislature asked the Minnesota Department of Commerce to develop a value of solar tariff methodology as an alternative to net-metering. The Public Utilities Commission accepted the tariff in April 2014 (See Section 2.3)
Nevada	Nevada Assembly Bill 428 called for a study of the impacts on net metering on ratepayers. A 2014 analysis for the Public Utilities Commission discusses that net energy metering is likely to have a minor impact on all rate classes, be it positive or negative. The Public Utilities Commission plans to use this analysis to investigate if DG systems should be a separate rate class. ²⁵
North Carolina	Duke Energy is interested in reducing the net metering buyback price in order to cover the cost of service for DG. The proposal has not yet gone before the North Carolina Utilities Commission. ²⁶
Oklahoma	Senate Bill 1456 authorizes utilities to charge DG systems interconnected after November 1 st , 2014 to reflect their full cost of service and prevent impacts on non-participating ratepayers. The law also allows utilities to create a new rate class for DG, and all new tariffs to be considered in a transparent manner by the Oklahoma Corporation Commission by December 2015. ²⁷
Pennsylvania	The Pennsylvania Public Utilities Commission is currently proposing regulatory changes which would tighten the definition of customer generator to ensure that net metered systems are primarily serving on-site loads. The changes also require systems over 500 kW to receive approval from the PUC to net meter. ²⁸
South Carolina	House Bill 1189 introduced South Carolina's Distributed Energy Resource program, which established net metering, set program caps and capacity limits. The South Carolina Public Utilities Commission is tasked with establishing rates which account

²⁴ Murphy, M. Massachusetts House Lifts Cap on Solar Projects. Masslive.com. 1 August 2014. Available at: http://www.masslive.com/politics/index.ssf/2014/07/massachusetts_legislators_life.html

²⁵ Energy and Environmental Economics. "Nevada Net Energy Metering Impacts Evaluations." Prepared for the Nevada Public Utilities Commission. July 2014. Available at: http://puc.nv.gov/uploadedFiles/pucnv.gov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

²⁶ Dalesio, E., "Duke Energy Wants to Pay Less for NC Rooftop Solar." *BusinessWeek*. January 24, 2014. Available at: <http://www.businessweek.com/ap/2014-01-24/duke-energy-wants-to-pay-less-for-nc-rooftop-solar>.

²⁷ State of Oklahoma Senate. *Section 156, Title 17 Statue Amendment*. 2014. Available at: http://webserver1.lsb.state.ok.us/cf_pdf/2013-14%20ENR/SB/SB1456%20ENR.PDF.

²⁸ Passera, L. "Pennsylvania PUC Proposes Net Metering Changes," Interstate Renewable Energy Council. March 2014., Available at: <http://www.irecusa.org/2014/03/pennsylvania-puc-proposes-net-metering-changes/>.

	for the benefits of DG. The bill also authorizes utilities to recover their costs from participating customers. ²⁹
Utah	In May 2014, the Utah State Senate revised the Utah net metering law, and called upon utilities and cooperatives to convene a public process to discuss the benefits and costs of net energy metering, and determine a fair process for any needed rate adjustments. ³⁰
Vermont	The Washington Electric Cooperative filed an application with the Vermont Public Services Board to modify its net metering program to include a monthly grid-service charge based on the production of a net-metering system. The proposed fee would be calculated by multiplying a customer's gross kWh by .0463 less the remaining consumption charge. The application notes that the fees would be revised every 10 years. The Washington Electric Cooperative is also proposing a fixed customer charge. ³¹
Virginia	Dominion Power in Virginia's monthly standby fee for large residential customers was approved by the Virginia Corporation Commission. The charge is for \$2.79/kW for distribution related costs and \$1.41/kW for transmission. (See Section 4.3)
Washington	Three pieces of legislation which would have limited third-party leases and levied additional fees on customers in net metering programs were rejected by the state legislature. ³²
Wisconsin	Madison Gas and Electric, We Energies and the Wisconsin Public Service Corp. are all proposing rate changes for net energy metering customers with increases in fixed monthly charges ranging from \$16-\$25. We Energies and Alliant Energy Corp are also proposing to lower the buyback price for energy from net-metered systems. ³³

²⁹ South Carolina State Senate. *South Carolina Distributed Energy Resource Program*. 2014. Available at: http://www.scstatehouse.gov/sess120_2013-2014/prever/1189_20140521.htm.

³⁰ Bramble, C. *Public Utility Modifications*. 2014. Available at: <http://le.utah.gov/~2014/bills/static/SB0208.html>.

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³³ Newman, J. 'We Energies Also Faces Opposition for Its Proposed Rates.' *Wisconsin State Journal*. Available at: http://host.madison.com/business/we-energies-also-faces-opposition-for-its-proposed-rates/article_d6ae2cd9-f5ba-5fed-aa60-b640e32b6de3.html.

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