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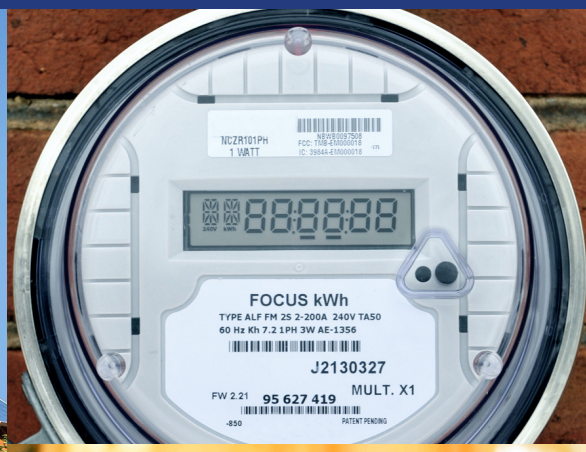

Ratemaking, Solar Value and Solar Net Energy Metering—A Primer

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It was the authors' aim to provide an unbiased and balanced primer on ratemaking and issues related to distributed solar generation and net-energy metering. This document is not intended to suggest consensus or the specific views of individual authors or contributors.

The contributors do not endorse any positions espoused herein but have contributed to ensure that this report reflects a wide variety of perspectives.

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Preface To The Report

An August 2012 *Utility Solar Business Models Bulletin* from the Solar Electric Power Association (SEPA) and the Electric Power Research Institute (EPRI) summarized the mechanisms under net-energy metering (NEM) that may create utility revenue losses and ratepayer cost transfers—e.g., the shifting of some utility costs to non-solar customers.[1] It focused on regulatory cost-recovery tools and NEM-related innovations seen in the utility-solar market to date, but it was limited in providing broader regulatory or solar-industry context. The report welcomed further input and contributed to broad-based discussions, which are ongoing, and which SEPA continues to facilitate.

An early result of those discussions was the recognition that participants approach NEM policy (and, more broadly, all policies on customer energy consumption offset by distributed generation) from different backgrounds and perspectives. Economic and equitable solar integration requires basic understanding of at least two disciplines—state utility regulation (particularly rate-setting) and principles that are considered during the valuation of incremental resource additions, specifically distributed solar resources (and the interplay between those two areas). This paper is an introduction to both of those disciplines, with an emphasis on key concepts and terms. It is designed to ensure that stakeholders engaged in these conversations are more fully informed in those areas in order to have a common understanding of the lexicon used.

This paper is laid out in three sections:

- Section 1 is an introduction, briefly defining NEM and describing the status of NEM policies across the US.
- Section 2 deals with state regulatory processes. It focuses on ratemaking and rate design, the locus for many of the current NEM-related efforts across the United States.
- Section 3 reviews "solar value" concepts and terms. It focuses on the generic definition of terms most commonly identified in the literature exploring values of resources in the distributed setting. These literature resources include plans ordered by state agencies and regulators and analyses submitted by utilities and stakeholders for regulatory review. Section 3 describes solar-related value terms as neither costs nor benefits, but as net impacts, which must be assessed for each utility in each regulatory jurisdiction.

The goal of each section is to provide an unbiased foundation for broad and productive participation in NEM-related discussions and policy processes. This includes regulators, utility staff, and the full range of solar stakeholders. The authors understand that all parties work under assumptions that need periodic review and that an increasingly diverse group of stakeholders is entering this complex discussion.

The context for this report is a rapidly changing and increasingly dynamic utility environment. In particular, as the penetration of distributed solar generation increases, the debate on NEM policies and impacts is intensifying. Utilities in some regions have observed distributed solar adoption at rates not previously forecast and are now seeing significant amounts of grid-tied solar on their systems. Stakeholders across the energy space are beginning to understand the system impacts of distributed solar and ratepayer equity concerns and are exploring policy alternatives for the immediate and longer term. Solar stakeholders also recognize the need to work with utilities in order to support solar market growth and to maximize the value of this renewable resource. The broad regulatory tenets that guided the US utility industry in the last century are still generally in place in this current age of technical and market complexity. However, as readers will find, the path

forward for distributed solar is not simply mapped; it must be created by a broad collaboration of educated and creative problem solvers.

A bibliography, included in the Appendix, lists expert texts and references written from distinct perspectives. We hope that this paper will support better critical understanding of those references and more productive communications going forward.

Introduction

1.0 | NET-ENERGY METERING HISTORY

Net-energy metering (NEM) is a billing mechanism for electric utility customers with grid-connected distributed generation (DG). NEM facilitates use of the electric utility system, allowing customers to virtually "bank" generation not used immediately, in exchange for kilowatt-hour (kWh) and/or financial credits. Those customers subsequently may draw on their credits at other times to offset consumption and/or charges when the DG system is not meeting their full energy needs, up to the total amount they have banked within the applicable period (often 12 months). Specific utility NEM policies dictate how any credits remaining at the end of the period are "rolled over" to future periods, compensated or retired. Furthermore, somewhat independent of the NEM billing arrangement, DG customers displace energy usage directly, which has important ramifications within rate discussions, utility cost recovery, and customer perceptions of bill savings.

"NEM has always been popular with solar stakeholders and well received by utility customers, but at least somewhat controversial among utilities and cautiously considered by regulators."

It is important to distinguish between the energy produced by customer DG that offsets on-site load in real time and the energy managed through a NEM transaction. Each of these transactions has distinct impacts on utility costs and their recovery. For purposes of the discussion in this paper, we refer to both under the inclusive term, NEM. In those instances that distinctions between the two transactions is necessary this paper will make those distinctions. Importantly, in looking forward, solutions affording sustainable DG integration into utility rates and operations may require treating these two transactions differently.

The Energy Policy Act (EPACT) of 2005 required state utility regulators to consider NEM, basically as defined above.[2] Some states already had NEM policies when EPACT became law; the first state NEM program was enacted in Minnesota in 1983. But EPACT encouraged widespread adoption. Today, all but seven states (Alabama, Idaho, Mississippi, South Carolina, South Dakota, Tennessee, and Texas) have statewide NEM policies, which may or may not apply to all utilities in the state. Of the states without policies several have voluntary utility NEM programs.

NEM has always been popular with solar stakeholders and well received by utility customers, but at least somewhat controversial among utilities and cautiously considered by regulators; DG—and especially customer-side DG—introduces challenges to distribution system engineering and design standards, questions about ratepayer equity, and to the regulatory compact that has directed utility investment and operations for over a century.[3] Note however that NEM is not the only tariff mechanism advocated by distributed PV stakeholders as a means of providing financial value for DG. For example, select jurisdictions and utilities have introduced feed-in tariffs (FITs) or other ways of structuring transactions between the utility and grid-connected distributed generators.

NEM is by far the most common DG billing mechanism in the US today. Between 2011 and 2012, the number of newly installed solar NEM systems increased from 61,400 to 89,620—a 46% annual growth rate—bringing the cumulative total to 302,380 NEM systems. By year end 2012, US solar generation under net metering totaled more than 3,500 MW-ac. It is striking to consider

that in 2005, when EPACT passed, total grid-connected solar capacity nationwide was only about 200 MW-ac.

Among stakeholders and policymakers who aim to build the distributed solar market, NEM is widely seen as a success story. While introduced with some controversy, the 2010 California Public Utilities Commission (CPUC) *Introduction to NEM Cost-Effectiveness Evaluation* noted that NEM gives customers "tremendous 'peace of mind,' knowing that exports either will offset their consumption at other times or produce a bill credit that can be applied in the next billing cycle."[4]

That same report commended NEM for encouraging larger systems: "NEM allows an intermittent DG resource, such as wind or solar, to be sized larger than 'minimum load,' so that annual generation can be matched to annual electrical demand at the site, optimizing the economic value of the DG investment."[5] Of course, this statement reinforces that even absent NEM, customers benefit from their investment in DG by offsetting all energy consumption up to the moment that production exceeds concurrent consumption. Offsetting of consumption with solar production and NEM are often cited for the benefits and relative simplicity from the perspective of the DG customer. But the actual nature of a NEM transaction is not so simple; in fact, a NEM customer is generating electricity and may be creating other system benefits while the utility is providing a variety of support services to the NEM customer. At the same time, the reconciliation of charges and credits under NEM often form a source of confusion for even the most savvy program participants.

The growth in DG customers has raised concerns among some utilities, regulators, and policymakers about whether NEM is suited for long-term use in rapidly growing PV markets. The essentials of NEM were developed before there was much research on the strategic value of PV or on the impacts of NEM tariffs on participants, non-participants, utilities, or the collective body of stakeholders. At the beginning, NEM was adopted to promote the growth of DG, but caps on program size (typically a set percentage of utility peak demand) or caps on eligible system size have been used in order to monitor, evaluate, and evolve NEM policies over time.

When regulators first approved policies to give retail credit for generation returned to the grid, they did so to provide a simplified vehicle for DG adoption, but did not consider it as a reflection of specific solar value. And when most utilities could barely imagine that one percent of their customers would deploy DG, concerns about rate design, customer equity or revenue losses were best put off for the future. Now that the number of net-metered customers in some states has approached meaningful numbers (and for other states, will do so in the foreseeable future), utilities, regulators, policymakers, and solar stakeholders understand that—for better or worse—NEM policies have become consequential.

1.1 | THE STATE OF THE STATES ON NET METERING

In many states, rising solar market penetration has triggered NEM policy and tariff reviews. In some cases, regulatory processes have even caught the media spotlight. A debate in California last year over how to interpret the state's increased net metering cap was covered in *The New York Times*.[6] Similarly, when the New York Public Service Commission directed Central Hudson Power Corporation to triple its net metering limits (and subsequently raised the aggregate cap to 3% for all state IOUs), there was interest beyond the utility's territory.[7]

Increased legislative and regulatory attention to DG and NEM policies has also prompted new (or updated) analyses to be conducted in a number of states. One example is the December 2012 Navigant Consulting billing gap study prepared for Arizona

Public Service (APS) that found subsidies to solar distributed energy customers when considering energy benefits.[8] Another example is an update of a California PUC study of NEM-ratepayer impacts and cost-of-service, which is expected to be completed by Energy and Environmental Economics, Inc. (E3) no later than September 2013. Finally, The Vote Solar Initiative, a national solar advocacy group, released a study in January 2013 based generally on the E3 methodology but with modifications, finding a subsidy in the other direction, with NEM customers providing a net benefit to non-NEM customers.

For NEM policy updates from across the nation, the Database of State Incentives for Renewables and Energy Efficiency (DSIRE) provides access to searchable policy updates. Further, Interstate Renewable Energy Council (IREC) and the Vote Solar Initiative produce an annual report focused on state NEM policies, called *Freeing the Grid*.[9] While state-by-state "scores" are an obvious advocacy tool for particular policies, this document's reasoned approach for information gathering is useful to track NEM policy changes in every state, based on the following characteristics:

- Individual system capacity allowed
- Total state NEM capacity cap
- Value used (wholesale or retail) and billing period for rollover of unused kWh credits
- Metering provisions
- Renewable energy credit provisions
- Constraints on eligible customers or technologies
- Safe-harbor provisions, which disallow some charges or requirements that might be considered specific to distributed solar customers
- Variations, such as aggregated net metering or virtual metering for community solar projects

The Regulatory Assistance Project (RAP), which also monitors state NEM developments, noted a half-dozen important NEM trends at the end of 2012.[10] These included challenges to increasing state NEM aggregate capacity, allowances for greater per-system capacity, more states compensating net excess generation, improved guidelines regarding solar REC ownership, accommodations for third-party and community solar projects, and testing of more NEM alternatives, such as FITs and solar tariffs, by some utilities.

Increased focus on the impact from DG resources on the electric distribution system and bill credits for DG energy offsets and NEM is driving efforts to consider an evolution of DG and NEM policies.

Recently, some utilities have proposed network-use charges for solar customers. These are also known as access fees, solar riders, or standby charges, depending on their structure. They are designed to recover a portion of the utility fixed costs that have typically been embedded in volumetric, per-kWh rates. In principal, this approach allows those fixed costs to be collected from all customers and specifically from DG customers whose kWh purchases are offset by their solar generation. Fixed costs might include certain transmission and distribution services charged on a customer's retail bill. Other costs that must be considered include those for various social programs (i.e., DG incentive or energy efficiency programs) that are included in customer rates.

Regulatory and public acceptance of network use and other related charges has been very mixed. In 2009, Xcel Energy in Colorado proposed a network-use charge that was withdrawn by the utility after significant stakeholder pushback. In 2011, Public Service of New Mexico (PNM) proposed a similar solar charge, which the utility also withdrew. About the same time, Dominion Power, in Virginia, supported legislative changes to allow, and subsequently proposed a standby charge for net-metered customers, which was approved by the state commission. However, it applies only to residential systems of 10 kW or larger—a very small segment among residential consumers in that territory.

A few other states, including North Carolina, have approved similar charges for larger net-metered systems. The California PUC's procedural decision not to consider a proposed San Diego Gas and Electric (SDG&E) network-use charge last year underscores the continued lack of consensus surrounding these proposals.

A key underlying challenge is how to assess the net value of distributed solar resources to the system for all ratepayers, including specifying benefits as well as identifying grid-support services provided to the NEM customer. The analysis can be performed from a rate-impact (non-participant cost) perspective, from the broader, total resource cost perspective, or from other regulatory perspectives. The questions include what services are provided to and which costs need to be recovered from the DG customer as well as what benefits are provided by a DG customer and the appropriate level of compensation. Even more fundamental questions also arise such as how to adapt utility cost-recovery models for an increasingly diverse, distributed resource landscape. As a result, proposed solutions range from quick fixes, to targeted innovations, to deep work that may reinvent the utility industry, its regulation and the resulting business models.

Works in progress (or recently concluded) include NEM benefit/cost studies and cost-of-service studies in Arizona, California, Colorado, Michigan, Ohio, New York, Texas, Vermont, and other states. The fast-growing distributed solar market in Arizona has prompted commission deliberations and an expedited study of NEM rate impacts and solar value for Arizona Public Service (APS), including updates to a frequently cited 2009 study.[11] As a result of the APS process, the Arizona Corporation Commission has decided to open a formal docket to address net metering issues statewide. High-profile solar industry-sponsored studies include the Vote Solar/Crossborder Energy report, an IREC report for the Solar America Board for Codes and Standards (funded by the U.S. Department of Energy), and a fall 2012 report by Clean Power Research for the Mid-Atlantic Solar Industries Association.

Legislation was passed in CA directing the Public Utilities Commission to study the costs and benefits of NEM and calculate the ratepayer impacts and cost of service of solar customers. Added to this list is a recent proposal for a NEM alternative, called "SmartFIT," introduced in *Solar Today* magazine by Richard Perez, Tom Thompson, and Tom Hoff, and others.[12] Forward-looking proposals to reform utility energy services pricing have come from SDG&E[13] and others. A comparative summary of select published reports is included in the Appendix. Much NEM research has been aimed at specific legislative or policy questions (e.g., NEM capacity limits, solar carve-outs in Renewable Portfolio Standards (RPS), etc.) or in utility rate-case proceedings that include NEM provisions. A few "meta studies" are also anticipated in the coming year, in hopes of gaining more clarity on NEM issues and paths forward.

Regulatory Processes For NEM Policy Review

2.0 | REGULATORY OVERVIEW

State lawmakers often set the tone for state policies crediting DG customers for their systems' production and potential export—for example, by passing NEM-related legislation. However, legislators typically instruct state regulatory commissions (and in some cases, the policy boards for public power utilities and electric cooperatives) to develop specific NEM or NEM-alternative rules and guidelines. In turn, the regulatory process engages a range of stakeholders to draft related rules and regulations, which must then be approved by the commission. In some cases, litigation must be resolved before final adoption. Utilities are subsequently charged to implement policies and rates for crediting DG system production (NEM or alternatives) subject to continuing regulatory review.

Thus, there are several opportunities for utilities and stakeholder groups to participate upstream in DG-related state policy development and downstream, in specific related regulatory proceedings, including NEM-specific proceedings.

This section is aimed at helping all parties understand the underlying regulatory principles, solar-value considerations, and steps in DG- and NEM-related regulatory proceedings. First, it addresses the fundamental challenge of balancing sometimes conflicting regulatory goals. Then, the section focuses on major steps in the ratemaking process, the locus of most DG- and NEM-related policy discussion today. Multiple ratemaking steps are summarized in the following section. The purpose is to highlight how these steps impact utility revenue, determine and allocate costs to different customer classes, and serve as a basis for rate design to meet certain policy objectives. This section distinguishes between recoverable costs—meaning costs that may be reflected in utility rates—and non-recoverable costs, including costs that are external to the utility and therefore borne by the broader population. Specific benefits and cost impacts related to solar DG, which are relevant to ratemaking, are briefly discussed in Section 3 of this report.

The concepts and terms in this paper are intended to be generic for regulated, investor-owned utilities with distribution responsibilities. Public power utilities and member-owned electric cooperatives can be regulated by a state commission but usually have their own regulatory bodies and distinct processes. Nonetheless, much of this discussion applies in some fashion to public and cooperative utilities.

2.1 | RATEMAKING OBJECTIVES

State utility regulation is a long-established practice, with a mission that is specific in some areas and broad in others. Fundamentally it comes down to setting the rates that utility customers pay for the services they receive in order to assure fairness to customers and the continued viability and improvement of in-state electricity services. In achieving this, regulation must be responsive to changes in technologies, markets, and societal needs. This set of obligations is on display when regulators seek to address rates for solar customers and related policies for crediting their production and export, including NEM policies.

The regulatory challenge of balancing numerous and sometimes conflicting objectives was famously described by James C. Bonbright in *Principles of Public Utility Rates*, some fifty years ago.[14] Bonbright outlined three sets of objectives for rate-setting, which were so well supported by case law and so widely accepted that they are still cited in regulatory cases today. These are summarized below.

The regulator's job involves striking a balance among all these objectives, recognizing current market conditions and evolution. For example, regulators are pressed to consider the benefits of innovation, such as solar development, while keeping an eye on risks and how costs are a pportioned. As another example, a state's preference for utilizing "least cost" resources might be tempered, as regulators consider simultaneous commitments to long-term rate stability, efficiency, economic development, environmental goals and other risks and benefits.

"Regulators must become accustomed to dealing with complexity, ambiguity, and competing priorities in making sound decisions about DG policies and NEM, as with a range of other regulatory concerns."

In addressing rates that impact solar DG customers, regulators generally place a priority upon the need for adequate and equitable (fairly apportioned, non-discriminatory) revenue collection from both non-solar and solar customers. But they remain mindful of other objectives. If a shortfall or inequity resulting from a proposed DG rate is deemed to be modest in magnitude or duration, regulators might decide that progress toward other policy objectives tips the balance in favor of the rate. Practical concerns can trump analytical precision, too. Regulation is not a science, but it is a well-established practice. Regulators must become accustomed to dealing with complexity, ambiguity, and competing priorities in making sound decisions about DG policies and NEM, as with a range of other regulatory concerns.

The following discussion presents considerable detail on the ratemaking process, including how ratemaking proceedings unfold and their most central concerns. This is done simply because DG and NEM policy-making is increasingly taking place in and around ratemaking processes where there is interplay between NEM rules and the rates that return value to the DG customer. Further, at the root of these proceedings is the interplay between rate-related benefits offered to a solar DG customer and the value that same DG customer has returned to the electrical system. Regulators generally agree that

BONBRIGHT'S THREE SETS OF OBJECTIVES FOR RATE-SETTING

REVENUE REQUIREMENT	REVENUE COLLECTION	PRACTICAL CONCERNS
1. Rates should yield the total revenue requirement 2. Rates should provide predictable and stable utility revenues 3. Rates themselves should be stable and predictable	4. Rates should be set so as to promote economically efficient consumption 5. Rates should reflect the present and future private and social costs and benefits of providing services (i.e., internalities and externalities)[15] 6. Rates should be apportioned fairly among customer classes and among customers in each class 7. Undue discrimination should be avoided 8. Rates should promote innovation in supply and demand (dynamic efficiency)	9. Rates should be simple, certain, conveniently payable, understandable, acceptable to the public, and easily administered 10. Rates should be, to the extent possible, free from controversies as to proper interpretation.

the specific impacts (benefits and costs) of DG solar should be reflected in utility rates in a way that is consistent with the treatment of all costs of service. However, there are sometimes statutory limits in the ability of regulatory agencies to implement measures that would ensure such an outcome.

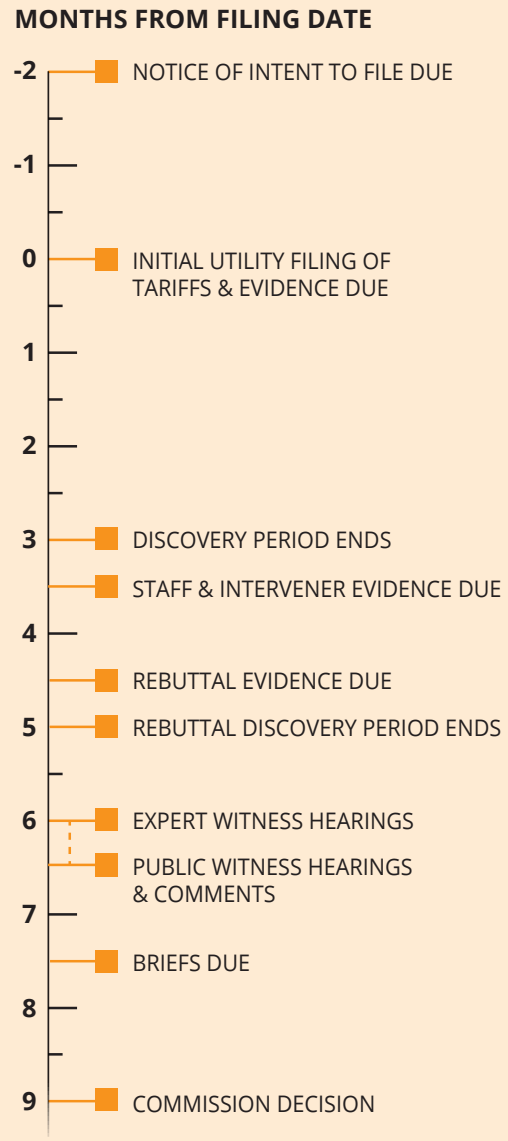
Throughout this paper the term "value" is used to reflect both potential benefits and costs. The term is not used to imply a resulting net-value but rather assumes that both costs and benefits must be fully considered, which in many instances is the subject of utility specific analysis presented to its oversight body for consideration.

2.2 | STEPS IN THE RATEMAKING PROCEEDING

Stakeholder groups, public agencies and institutions, individual citizens, and utilities have many opportunities to contribute to DG-related policy development, but the culmination of these has generally been a rulemaking proceeding. Given the types of issues arising currently, utility rate proceedings are likely to be the venue for addressing DG crediting and NEM policies. Utility, regulatory, and consumer-advocate agency staff participate in these proceedings by law, as statutory parties. Other participants, called "interveners," typically must petition the regulatory commission to participate. Most interveners represent affected groups or government entities, and in nearly all cases, they must be represented by legal counsel. In a general rate proceeding, an intervener might address the entire case or just specific issues, such as low-income concerns or renewable energy interests. In some states, interveners may qualify for financial assistance, but often, they must cover their own (sometimes considerable) costs.

Table 2.1 summarizes a typical schedule for a general rate case. The timeline shown is a rough estimate—it could be shorter or much longer, depending on the state and the issues at stake. DG- and NEM-related issues have not historically been the headliner issues in a general rate case. They might take shape as a proposed NEM-participation cap, amendment to an existing NEM tariff, network-use charge or standby rate, revision of the customer charge, or some other relatively small proposal in the overall case. Parties interested in these issues should expect to follow

TABLE 2.1. TYPICAL SCHEDULE FOR A MAJOR RATE CASE



Source: RAP 2011

every step of the ratemaking process in order to keep a focused view on specific matters of interest.

Ratemaking hearings are conducted like court proceedings. Expert testimony is filed, rebutted, and sometimes surrebutted in advance. At hearings, expert witnesses are questioned and incisively cross-examined. There may be questions from the bench. Usually public comments are accepted. These would be secondary to expert testimony, but they could be influential. One veteran intervener noted, "A large turnout with a clear, concise, relevant message can inform a commission's decision, where the evidence and law give … some discretion to craft an equitable resolution."[16] Commissioners may be present at all hearings, but more often they review filed briefs, proposed orders from staff, and exceptions (final comments) before conferring, often in public, to issue a final order.

As noted above, regulators have the responsibility and the power to weigh conflicting objectives in deciding a case within the confines of their legal authority (which in some states may be limited by particular sections of code). Sometimes parties anticipate the need for negotiation—usually on a particular issue—and propose a stipulation or settlement. The commission may accept or reject their proposal. Whatever the decision, parties have a final chance to pursue their arguments, as commission decisions may be appealed to the courts. However, it should be noted that appellate courts often defer to the expertise of the regulatory body, unless the decision can be shown to be arbitrary and capricious.

2.3 | THE REVENUE REQUIREMENT

In the conventional ratemaking process, the utility's primary concern is establishing its revenue requirement.[17] This is the total amount of revenue the utility would need to cover its expenses, plus costs in its rate base (primarily capital investment), on which it is eligible to make an approved rate of return.

The use of an approved rate-of-return is characteristic of regulated utilities, and has been upheld repeatedly by the US Supreme Court. The authorized rate-of-return is based on the return on investment for businesses that face comparable risks, and it is aligned with the cost of capital needed for utility investments.[18] However, there is no guarantee that the utility will earn its rate-of-return. The utility may experience higher costs or lower revenues than predicted. For example, an economic recession may trigger energy conservation and a loss of industrial loads—thus, lower revenues. The converse is true, too. A utility can realize savings on expenses beyond those anticipated in its last rate case. For example, staff vacancies could lower total personnel costs, or a dip in transportation fuel prices could add up to savings for field service operations. Interested stakeholders regularly monitor case-by-case situations and may increase public pressure when earnings seem unbalanced.

BASIC REVENUE REQUIREMENT FORMULA

$$\begin{aligned} &\text{Annual Operating Expenses} \\ &+ \text{Depreciation Expense} \\ &+ \text{Taxes} \\ &+ (\text{Net Depreciated Rate Base Investment} \times \text{Rate of Return}) \\ &= \text{Total Cost} \\ &= \text{Revenue Requirement} \end{aligned}$$

In select jurisdictions, regulatory mechanisms generally referred to as "decoupling" insulate utility earnings from changes in sales revenues, even in-between rate adjustment proceedings. This results in the utility being indifferent to, and potentially promotional of, customer-side demand reductions. However, the reduced sales revenues, net of costs avoided, are then absorbed by all other customers.

At the outset, the selection of the test year is key.

A test year is the full accounting of a utility for a 12-month period, which is used as the basis for modeling the revenue requirement in a rate-case proceeding. Regulators may choose a forward-looking test year, requiring modeling of future conditions, or they may focus on the realistic (and generally less complicated) process of developing a historic test year analysis that also includes pro forma adjustments to reflect future conditions.[17] Different commissions take different approaches, and some make adjustments, such as weather normalization—the process of adjusting the test-year costs and revenues to those of an "average" weather condition year. Basing the revenue requirement on one proximate test year means that rate setting is incremental by nature. Complex multi-year utility system upgrades, demand-side programs with significant long-term cost impacts, and similarly long-term customer solar programs are reflected, but only as they would look in the single test year. The adjusted test year establishes a relationship between costs and billing parameters intended to be reflective of actual experience once the new rates go into effect.

2.4 | EXPENSES AND COSTS IN RATE BASE

Two major cost categories comprise the revenue requirement—expenses and costs in rate base. Expenses include operating and maintenance costs (i.e., labor, program, and administrative costs) and associated materials cost, as well as rents, fuel, and purchased power, including resources acquired under Power Purchase Agreements (PPAs). Depreciation expense, amortization (i.e., an increment of costs for unusual expenses that are spread over several years), taxes, and uncollected billing revenues are also counted as expenses.

Costs in rate base are mostly capital investments. Power plants in service, distribution system investments, and transmission investment (all if applicable), and the cost of facilities apply, minus accumulated depreciation. Some materials and supplies, such as stockpiled fuel, count as rate-base costs, not expenses. Utilities are also allowed some working cash in rate base. Accumulated deferred taxes are subtracted, as are other customer contributed capital, and there may be other adjustments.

The determination of costs in rate base is important because the total of net rate base costs are multiplied by the approved capital structure and return-on-equity to determine allowed revenues for shareholder earnings. Arguably, this means that, all other things being equal, utilities have an incentive to increase rate base costs, and this sometimes leads to assertions that utilities over-engineer and over-build their infrastructure.

Prudency reviews are designed to evaluate and ultimately resolve such criticisms of over-investment in rate base. Parties review the utility's expenses and investments to determine if they are prudent, and thus allowable costs for recovery. Ultimately, the regulatory commission decides. Many questions might be asked in a prudency review, concerning issues such as necessary and reasonable costs to provide adequate service and the benefit to ratepayers as a whole.

REVENUE REQUIREMENT CATEGORIES

EXPENSES	COSTS
Operating	Power Plants
Maintenance (Labor, Program, Administrative)	Distributed System Investments
Associated Materials (Rent, Fuel, Power)	Transmission Investments
Taxes	Facilities
Uncollected Billing Revenues	Materials & Supplies (Stock-piled Fuels)

WHAT IS AVOIDED COST?

Avoided cost is the cost at the margin to meet an additional energy need. It is an incremental (unit) cost, typically $/kWh or $/MWh. Yet in practice, the term avoided cost has taken on different meanings, based on the perspective taken. Three relevant perspectives include the wholesale utility's, the distribution utility's, and the solar customer's.

From the wholesale utility's perspective, the standard for assessing avoided cost was set by the Public Utilities Regulatory Policy Act of 1978 (PURPA). That act required the Federal Energy Regulatory Commission (FERC) to adopt regulations for utilities to buy electricity from qualifying non-utility generating facilities, known as QFs.[20] In this context, avoided cost is the cost at the margin to meet an additional unit of utility (energy and capacity) need, and it is the basis for the rate that a wholesale utility would pay for QF generation. Each state uses a different, specific calculation to set avoided-cost rates—for example, reflecting market characteristics and whether it is a long-run or short-run avoided cost.

From the distribution utility's perspective, additional marginal costs—besides energy and capacity—are typically included in the avoided-cost calculation. For example, in California, the avoided cost calculation for a distributed generation FIT program looked at seven components: energy, generation capacity, ancillary services, certain environmental costs, transmission capacity, distribution capacity, and electrical system losses. Again, each state would use a different, specific calculation for this value. The calculation of distribution utility avoided cost is used in ratemaking, including DG and NEM proceedings, and also in integrated resource planning, assessing policy alternatives (e.g., RPS compliance costs), and other utility investment analyses. Section 3 of this report discusses net solar-value impacts in a context of avoided costs.

The solar customer is likely to think of avoided cost as bill savings that result from installing a grid-connected PV system. The solar customer perceives the total bill savings as his or her aggregate avoided cost. Clearly, this is a very different perspective from the utility perspectives described above.

2.5 | DISTRIBUTED SOLAR AND THE REVENUE REQUIREMENT

It is reasonable to ask how distributed solar resources affect the utility revenue requirement. The answer depends on state regulatory practices and on the specific utility—especially whether the utility has enough distributed solar on the grid to create an identifiable fingerprint. Generally, costs that might be considered include financial incentives and associated administrative costs (if offered), interconnection and integration costs, billing and related administrative costs, and distribution demand capacity or standby costs. Generally, distributed solar costs are not specifically discernible in revenue-requirement analyses for utilities with relatively little distributed solar. Further, distributed-solar impacts that could lower utility expenses, such as power supply costs, and/or defer rate-base investments are not identified as such in revenue requirement analyses today. Questions that arise from this situation include the following:

- Are specific adjustors in place for identified distributed generation programs, and does the utility have reason to isolate certain costs and services in ratemaking?
- How are impacts accounted for, and what is the timeframe for being able to measure impacts that can change over the life of a solar investment? How does this get captured when the analysis is limited to a single test year? Does this contribute to or drive avoided-cost impacts?

These and other questions highlight important cost-saving and cost-driving impacts that need further examination. For example, customer-sited solar could contribute to a lower need for purchased power. That might lead to accounting for reduced line losses and other secondary impacts. A utility with increasing solar DG might even be able retire an old, less efficient generator. However, the cause and effect might be difficult to determine: the retirement could be associated with a variety of changing conditions—perhaps including the growing solar market or perhaps not. Alternatively, increased investment to ensure reliable operations in a local area due to increased penetration of customer-sited solar could be a cost driver. Further, at certain high penetrations of DG utilities might experience broader distribution or transmission system costs. In the end, revenue requirement analyses are focused on test-year end results, not necessarily the direct cause and effect reasons for the results.

"In the end, revenue requirement analyses are focused on test-year end results, not necessarily the direct cause and effect reasons for the results. "

Some utilities are experiencing enough solar DG installations to recognize impacts on the system as a whole, and they are beginning to incorporate these impacts into the rate-setting process. Utilities in California, Arizona, Hawaii, and in parts of the Northeast (e.g., participants in the Mid-Atlantic Distributed Resources Initiative) are at the forefront of such innovation. Projects like the Rocky Mountain Institute (RMI) EDGE model, funded under the US DOE SunShot Initiative and SEPA's work in partnership with EPRI are also aimed at understanding solar DG in operational, infrastructure-investment, and business-model innovation contexts. Taken together, their work and similar efforts could contribute to better revenue-requirement analyses and better alignment among revenue requirements, cost-of-service studies, and solar tariffs.

2.6 | COST OF SERVICE

A cost-of-service study applies the revenue requirement to all of the utility's customers, which are divided into classes based on shared energy-use characteristics. Major customer classes typically include residential, commercial, industrial and agricultural. Once the relative cost of serving each class is determined, the utility can set the rates needed to yield the total revenue requirement.

Historically, utilities used basic inputs to calculate cost-of-service, such as the total number of customers in the class, peak usage of the class, average density of customers per square mile, service voltages required, average annual and seasonal energy use, and data from low-resolution load studies. Today, utilities have much more data, leading to more accurate analysis and more classes (or sub-classes), with corresponding tariffs. These may include customers with premium power-quality demands, high-demand or demand-response customers, public-facility customers, etc. Residential customers with grid-connected PV systems might be considered a sub-class within the residential class; commercial customers that have grid-connected PV might be considered a sub-class of their larger encompassing class. However, as discussed below, whether to identify sub-classes and the depth of analysis for cost-of-service varies among utilities and regulatory authorities today.

The total cost of service for each class includes common costs, joint costs, and direct-assigned costs. Common costs are borne by all rate classes, but are not directly caused by any of them. An example would be costs for the utility's company headquarters. Joint costs are directly caused by more

than one customer class. These costs of service might be divided functionally (e.g., production, transmission, distribution), and then subdivided further and apportioned.[21] Apportioning joint costs properly among applicable rate classes is a major part of a cost-of-service study.

Finally, direct-assigned costs are those that are caused directly by a customer class and are assigned directly and exclusively to a particular rate class. For example, an industrial customer might require a dedicated substation or system protection equipment. Assigning such costs is sometimes controversial, but the practice reflects a regulatory commitment to cost-based rates.

About 30 states use an "embedded cost" method when performing cost-of-service studies, meaning that they focus on actual, historic costs reflected on the accounting books of the utility. The other states use a "marginal cost" approach, meaning that they focus on the incremental cost for expanding plant or energy supplies, based on current or prospective costs. The former approach may be criticized as static and backward-looking; the latter approach may be criticized as incomplete—shorting fixed costs and producing different results depending on the time horizon used. Yet both methods have proven acceptable in practice.

Cost-of-service analysts are cautious about assigning the cost of an investment to one sub-class if the benefits flow to the entire class or to all ratepayers. However, utility planning and policy studies that compare costs and benefits of different investment paths should not be confused with cost-of-service studies. The planning approach may be informative, but a cost-of-service study focuses tightly on the costs of established or (using a marginal-cost approach) fully anticipated system needs.

"The relatively narrow focus of most methodologies for assessing the cost of service for solar customers is in keeping with the traditional incrementalism of utility ratemaking. Yet the limitations of these methodologies suggest a looming challenge."

For most utilities today, solar DG customers would comprise a very small sub-class of a few hundred or few thousand customers, distinguished primarily because they provide relatively low revenue and utilize utility infrastructure in ways previously not considered. As noted above, utilities have historically accounted for few, if any, differences in cost of service between solar DG customers and others in a similar rate class without solar DG. Thus, a rate equity question might arise, in the effort to treat customers within each major class alike, because analysts could question the shortfall in the revenue recovered from solar customers, compared to other customers in the class. The utility might say that this shortfall—magnified by NEM—is evidence of a policy-driven subsidy. But, without more analysis, it would be difficult to support or challenge that assertion.

When the cost of service for solar DG customers and NEM-related issues are specifically addressed in a rate case or a related proceeding, the utility might prepare a more in-depth analysis. For example, a utility might check past estimates of solar integration costs against the actual costs of working on relatively high-penetration solar circuits. A range of system-wide and solar-specific research, including field monitoring and modeling, can help utilities better understand the interplay and associated costs and potential benefits of DG solar interconnected to utility infrastructure.

The state of the art for understanding the net cost of solar on a complex and ever-changing grid is still evolving. A 2012 study from Lawrence Berkeley National Laboratory (LBNL), *Changes in the Economic Value of Variable Generation at High Penetration Levels*, surveyed related research available today. It observed a growing body of literature, but noted that much of the existing work from utilities, research institutions, and stakeholders tended to either:

1. Focus on longer term value (of variable resources), but lack high temporal resolution and/or consideration of the operational constraints of conventional resources…, or
2. Have high temporal resolution and pay significant attention to operational constraints, but assume a static mix of conventional generation…, thereby focusing on short-run impacts and ignoring long-run dynamics.[22]

In other words, there is a gap in the way that studies of economic value of renewables are conducted: those studies that account for the long run economic value do not account for detailed operational impacts, while those studies that account for detailed operational impacts don't account for long run economic value. The LBNL study and similar works point to the need for a broader and longer view in utility planning and investment, and subsequently in apportioning the net cost of specific resources through rates.

The relatively narrow focus of most methodologies for assessing the cost of service for solar customers is in keeping with the traditional incrementalism of utility ratemaking. Yet the limitations of these methodologies suggest a looming challenge. Regulators may call for better data and better analytical tools to modernize cost of service research, or they may call for a radically new approach. In keeping with their overarching goals, they would most likely aim for ratemaking outcomes that are more comprehensive, but also cost-effective, relatively stable, and relatively simple.

2.7 | ALLOCATION OF COST OF SERVICE

In general, residential and small-business classes have higher total costs per kWh of electric use because they require more distribution investment than larger customers (i.e., service is provided at lower voltages) and they have relatively lower load factors; thus, requiring more capacity per unit of usage. The residential and small business classes may also have proportionally greater energy use during peak periods of the day and year. Large commercial and industrial customers are assigned lower total costs on a per kWh basis, because they have more stable loads, often take power at higher voltage levels, and have higher load density in relation to distribution infrastructure. Their capacity requirements often are directly covered by separate demand charges and those demand charges are often significant relative to the total retail rate. Beyond these generalizations, specific cost burdens are allocated to specific sub-classes based on cost causation, either as separate charges or as a distinct tariff.

"...specific cost burdens are allocated to specific sub-classes based on cost causation, either as separate charges or as a distinct tariff."

Regulators also allow other considerations to affect rate outcomes. They may seek to minimize rate increases on residential customers or phase in increases slowly. Regulators may be asked to encourage economic development—occasionally focusing on specific industries. They may shift cost burdens somewhat in order to support energy efficiency or renewable energy goals. Still, unless directed by statute, they cannot stray too far, or their decisions might be overturned in court.

The regulatory guide, *Energy Utility Ratesetting*, cites an established strategy called "setting a band" of acceptable cost allocation, so that each class covers a proportional share of the utility's revenue requirement, plus or minus a modest percentage (say, 10%).[23] The purpose of this strategy is to make room for uncertainties and non-cost considerations. While this is only a rule of thumb, it underscores how utility regulators use judgment, as well as analytic findings in setting rates.

WHERE DO ENVIRONMENTAL AND SOCIETAL COSTS COME IN?

The regulatory mission, as discussed in Section 2.1 above, included considering "the present and future private and social costs and benefits of providing services (i.e., internalities and externalities)." In practice, the treatment of these costs and benefits differs from state to state and depends on the type of proceeding. In ratemaking, regulators often limit their consideration of societal impacts (including environmental impacts) to those that are internal and directly related to the utility's test-year revenue requirement and cost-of-service. Regulators may take a broader view when considering utility resource planning or when addressing environmental mandates. Nevertheless, while the electric system remains the focus for regulators, they are generally aware of both internal and external environmental impacts, and, depending on whether authorized by law, they might consider both in balancing their regulatory considerations.

Notably, accounting for environmental impacts must include costs as well as benefits; in order to yield a true net-cost impact. For example, a growing solar market may result in greater load variability, leading utilities to build peaker plants that run less often, rather than high efficiency combined cycle plants that run more often. The net impact often depends on the legacy generation being replaced by the combination of new gas plants and renewable resources. Or the utility may have an approved lower-cost alternative for diversifying its portfolio with solar, compared to buying RECs from solar customers.

In addition, a few internal *societal* costs are considered in conventional cost of service. These include certain insurance costs related to storm damage and other aspects of reliability. The cost of programs that serve approved needs (e.g., low-income assistance) also may be counted.

Other costs that may be avoided by a utility policy or program are external, meaning that society incurs them beyond the transaction between utility and ratepayer. Select examples such as pollution allowance costs in certain areas may point to greater consideration of societal externality costs in the future, but the impacts of these costs remain hard to attribute and monetize at this time.

Historically, some regulators have considered externality costs in ratemaking decisions, to the extent that their considerations represent a well-balanced and defensible regulatory view. Public power utilities, which are locally regulated, have sometimes been among the first to count such values as energy security costs, water conservation benefits, economic development benefits, etc. Currently, however, most regulators take a conservative view of utility-related costs that are not self-evident.

2.8 | RATE DESIGN

The process of designing just and reasonable rates requires balancing considerations for the sometimes-conflicting regulatory objectives listed in Section 2.1, above. Historically, the primary tools for cost recovery in rates have been the fixed customer charge ($/month), the volumetric energy charge ($/kWh), the demand charge ($/kW) and reliability-related (e.g., power factor) charges. Other rate components have proven effective in specific situations or on a state-by-state basis. As this report discusses below, ratemaking trends are more frequently relying on dynamic rate-setting tools, such as riders or adjustor mechanisms. These address the fact that in an efficient, modern utility, conventional revenue recovery may no longer keep pace with utility system costs, investment needs and the changing dynamics of customers which have a growing range of energy related choices ranging from DG to demand response.

In deregulated states, local utilities are focused on distribution—the delivery of energy from

the wholesale market to the retail customer. Depending on the degree of deregulation, these utilities may pass through wholesale power costs and add distribution and billing services, or they may simply provide distribution and billing services for competitive retail electricity suppliers. The discussion below assumes the more conventional, regulated utility structure, but it includes comments on the particular concerns of the "wires only" distribution company.[24] It begins by generically defining the primary ratemaking tools for cost recovery, including common rate structures and rate (tariff) designs. Secondarily, it describes other relevant rates and charges, including common net metering rates, standby charges, and riders. Finally, this section discusses basic steps in rate design and rate impact analysis. A subsequent section will focus on rate impacts and ratemaking innovations and trends specifically relevant to the discussion solar DG.

The primary rate-setting tools include:

1. Customer Charge ($/month)

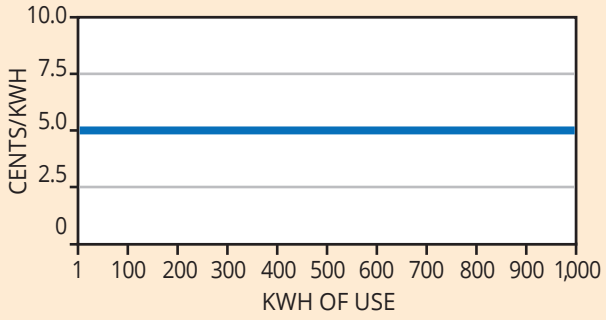
The customer charge is that portion of the monthly customer bill that is "flat" and does not vary by the customer's energy consumption or level of demand in a month. It is sometimes known as the basic charge or service fee. Theoretically, it should cover all "customer-related costs" faced by the utility—costs that vary directly with the number of customers served by the utility. In concept these costs can include metering, billing and related expenses, investments for meters and some lines, plus related depreciation and O&M and possibly some portion of other facilities costs, although there is debate on including some equipment that is beyond the service drop and meter/pole-mounted transformer in the customer charge. To address the distinct metering and infrastructure needs of some customer classes, there may be several categories of customer charges.

2. Volumetric Energy Charges ($/kWh)

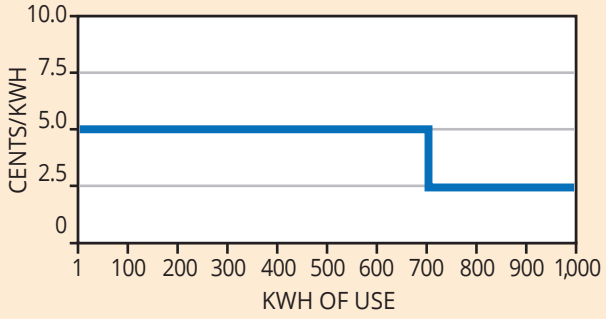
The volumetric energy charge is a rate per energy unit ($/kWh) that is designed to collect the energy-related costs incurred by a utility. If the tariff for a rate class does not contain a separate demand charge (see below), then the volumetric energy charge also collects capacity-related and other fixed costs of the utility. Typically, residential and small commercial rate structures do not contain a separate demand charge, while rate structures for large commercial and industrial customer usually measure and bill separately for demand units ($/kW). The energy charge may be designed in different ways to send various price signals to communicate desired customer behavior

BASIC VOLUMETRIC RATE STRUCTURES

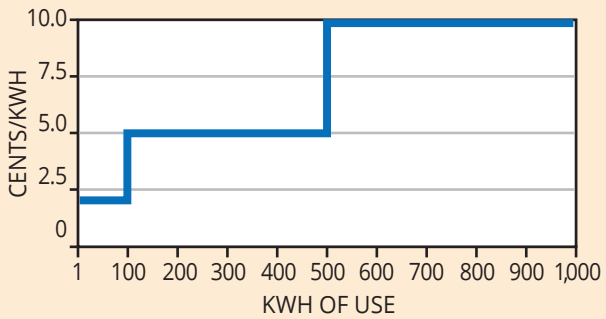
FLAT RATES



DECLINING BLOCK RATES



INVERTED BLOCK RATES



or to improve rate equity. There are a variety of specific rate structures for the energy charge, as summarized below.

Basic volumetric rate structures include:

Flat Rates. In this structure, there is only one cost per kWh rate for all levels of usage. This is the simplest rate structure.

Declining Block Rates. These rates are set so that prices decline as usage increases, encouraging energy consumption. For example, the first block of energy (say 500 kWh) might be priced at $0.09/kWh, and the next 500-kWh block would be priced at $0.06/kWh. This rate structure has primarily become a historic example, since the Public Utility Regulatory Policies Act (PURPA) prohibited it except where marginal energy costs clearly fall with increasing output.

Inverted Block Rates. These rates increase with increasing energy usage. They typically allow smaller households or businesses a minimum amount of low-cost electricity. As people try to avoid highest-cost blocks (also known as tiers), this rate design has been championed because it arguably encourages energy conservation.

As the interaction of net-metering credits with these pricing structures is considered, it becomes clear that the type of volumetric rate chosen can alter the rate-related benefits received by the DG customers, depending on the calculation used and value of each kWh that is offset (e.g., inverted block rates could encourage solar DG as credits to customers offset the highest-cost energy billed). It will impact the revenue loss experienced by the utility and remaining customers. See additional discussion below of the relationship between rate design and NEM-rate impacts.

Variations to rate structures:

The following rates may be offered (or mandated) under any of these basic structures. They are usually presented as choices for customers who meet particular criteria. Residential customers usually pay only the customer charge and volumetric rate ($/kWh), though they may participate in less common rate programs, described below. Commercial and industrial customers often pay these rates plus a demand charge and possibly other charges, as described below. Note that customer bills include numerous other charges and taxes that are not discussed here, depending on the wholesale and retail utility structures in effect and upon their location.

"...the type of volumetric rate chosen can alter the rate-related benefits received by the DG customers, depending on the calculation used and value of each kWh that is offset..."

Seasonal Rates. These rates differ by season. Most US utilities have higher costs in summer, and summer rates reflect that. Seasonal-rate adjustments are very common.

Time-of-Use Rates. These rates differ based on the time of day, usually divided into higher-cost on-peak hours and lower-cost off-peak hours. Properly set and communicated, they encourage conservation during the hours that utilities see high operating costs. Some time-of-use rates include a demand charge. Today, utilities may offer several time-of-use rates, to appeal to customers with different habits and needs as well as reflect system value with more time-sensitive accuracy. Real-time pricing is an ultimate form of time-of-use rate. Based on market-driven utility costs, real-time pricing has proven difficult to implement. Yet it remains a possible goal for strategic application.

Interruptible or Demand Response Rates. These rates provide an incentive for customers that can respond to a time-specific call for energy curtailment. Utilities may offer different contractual agreements to define how often and for how long a conservation event can occur. The incentive may be delivered as a discount on the prevailing $/kWh rate, assuming a number of interruptions, but often it is a separate incentive, paid seasonally or per interruption. The rate may include a demand charge component. These rates

have more frequently been introduced for large commercial and industrial customers, but are increasingly considered for residential and small commercial.

3. Demand Charge ($/kW) and Power Factor

A demand charge collects the demand-related costs of the utility caused by the pattern of a customer's energy usage. These costs include portions of the capacity cost of power plants, and portions of transmission, distribution and other infrastructure costs. With variations, the demand charge is usually calculated as a rate applied to the maximum power demand (kW) required by the customer in a month. It may be based on the customer's highest 15- or 30-minute kW demand per month, or on the level of customer demand that is coincident with utility system peak demand. In some instances demand charges will be time-of-use differentiated with different capacity costs recovered through different demand charges.

Most utilities apply demand charges only to large energy users (commercial, industrial, and agricultural), though some utilities offer residential demand charges to encourage peak-load reduction. If the rate structure of a customer class does not have a separate demand charge, then demand costs usually are collected through the volumetric charge. When a customer is assessed a demand charge, the volumetric charge obviously is lower because it no longer collects demand-related costs.

When a customer has a solar DG unit, there is an interplay between energy charges and demand charges, affecting different customers in different ways. Customers with DG avoid a utility retail-rate charge when concurrent load is served by solar DG. However, the situation is more complicated when the customer faces a separate demand charge. To the extent the DG resource reduces a customer's peak demand that charge will be reduced. However, under NEM, while the customer will receive an energy rate credit on their bill, they will likely not receive a demand charge credit against their bill when they are exporting power.

Variations on the demand charge include:

Off-Peak Demand Charge. Some utilities have a lower-cost demand charge during off-peak hours or during the off-peak season.

Ratcheted Demand Charge. Some utilities use the highest seasonal or annual demand to set monthly demand billing for the entire season or year, a demand 'ratchet.' This approach is not as common as it was years ago, but it is still used in some cases. It creates a strong incentive to manage demand up to the point when the ratchet is set; thereafter, the customer's motivation for load management may be diminished.

Power Factor Adjustment. As noted above, this is not a demand charge, but rather a charge related to the ratio of reactive power to real power. It is due to the combination of electrical equipment (motors, light fixtures with ballasts, etc.) operating at the customer site. Power factor adjustment may show up as "PFA," or it may be quantified as "kVAR hours" (reactive power).

4. Other rates and charges, relevant to DG and NEM discussions

Utilities may use many other rates to accomplish customer price signals and revenue recovery. Whether geared to a particular sub-class (e.g., rates for schools, irrigators, water plants) or to a particular issue (e.g., fuel adjustment charges, public benefit charges, or charges to cover special utility project costs), most of these have only minor relevance to DG- and NEM-related issues. A full study of rates may be useful, but only a couple examples are provided here.

Standby Rates. Standby rates usually apply to large customers who have their own generation, but need a backup source. These rates recover the cost to back up customers with self-generation should their generation facility unexpectedly fail or need scheduled maintenance. Some utilities have special standby rates, which have been applied to larger PV customers. In some states NEM statutes prohibit the application of standby charges on solar customers.

Tariff Riders (or Adjustors). A rider is a temporary credit or charge approved by the regulator to cover special investments and costs between full ratemaking processes. Riders are sometimes used when the actual costs incurred by a utility to provide electricity service to their customers differ from the approved rates. They may be calculated as a cost per kWh or as a percentage of eligible charges. The actual impact of charges being collected from DG customers depends on whether those customers are charged for adjustment mechanisms (e.g., fuel clause, decoupling, etc.) or if they are applied and offset by crediting for DG production.

2.9 | DG AND NEM IMPACT CONSIDERATIONS

Utilities design rates to recover revenues in proportion to the cost of serving each customer class, and also to meet more nuanced regulatory objectives. The extent to which NEM tariffs can meet the criteria for cost-based rates is currently under review in many states as solar penetration grows and the market matures, recognizing that cost-basis was not the main consideration when net metering policies were first introduced. Justification for NEM was often based on analogies to energy efficiency programs and conservation.

It is important to understand how DG relates to cost-based rate design and impact analysis. As discussed in Section 2.6 above, many utilities today treat DG customers as relatively undifferentiated from the larger, encompassing (e.g., residential, commercial, etc.) class. To date, utility rate studies have focused on the most evident impacts of solar DG—the displacement of purchased energy and the utility's costs related to crediting energy that is returned to the grid. Increasingly all stakeholders seek to investigate in greater detail the full array of costs and benefits associated with DG solar resources. Without this detailed consideration rate-equity questions would almost certainly arise.

Assessing rate design is a complex process, involving software that models rate impacts upon a single rate class or upon all rate classes, in keeping with regulatory guidelines. When specific programs are evaluated, analysis includes application of various cost-test perspectives (see sidebar), such as the Participant Cost Test, Ratepayer Impact Measure (RIM), Total Resource Cost Test (TRC), and the Societal Cost Test (SCT) or some other measure of broader impacts. Whether or not regulators refer to these tests by name, these kinds of assessments are needed to answer key ratemaking questions, such as:

- How much revenue is collected from customers in each encompassing rate class (residential, large commercial, etc.) that are on a particular rate?
- How does that compare to the amount of costs caused by the encompassing class?
- What is the average impact on the particular rate customer, and what is the impact on the average ratepayer in the class?
- Is this rate compatible with the utility's overall tariff strategy, for meeting the utility's revenue requirement?

The rate design process includes testing changes in pricing and terms (for example, slight changes to the on-peak and off-peak windows on a time-of-use rate, or in the case of NEM, changing the way that a periodic true-up is done). In a general rate case, a utility might propose changes to numerous existing rates, as well as proposing new rates.

On the face of it, revenue collected from solar customers is disproportionately less than the revenue collected from others in their rate class. Despite their general similarity to other customers in terms of overall capacity (kW) needs and service requirements, solar customers typically use PV to offset significant kWh purchases. Assuming a rate design dominated by energy-based kWh,

CONSIDERATION OF DG-RELATED IMPACTS

The concept of regulatory perspective has already been introduced. Particular values may look like costs from one perspective and benefits from another; some values may be irrelevant from one perspective and crucial from another. Whether explicitly or implicitly, utility regulators or other policy makers determine the perspective they will take when assessing the value of distributed solar for a given proceeding. Their perspective may differ, depending on whether it is an integrated resource planning proceeding, RPS implementation order, NEM-related tariff, and so on. Sometimes regulators review multiple perspectives to determine whether a rate or plan is equitable to all parties. Utilities and other stakeholders presenting solar value analyses must be mindful of the required perspective, so their use of specific benefits and costs is appropriate to the proceeding.

Most regulatory commissions base their definitions of perspectives on the definitions in the California PUC (CPUC) Standard Practices Manual[25], a guide first developed in the 1980s to assess demand-side programs, updated regularly since that time. The five primary perspectives defined below are often used for assessing DG policies. In these definitions, "program" could refer to the utility's implementation of a NEM tariff.

Participant Cost Test. This is the measure of quantifiable costs and benefits to the customer participating in a program. For example, this test counts an incentive paid by the utility as a benefit.

Ratepayer Impact Measure (RIM) Test. Also known as the Non-Participant Cost Test, this test measures changes in utility revenues and operating costs caused by a program. It then indicates the direction and magnitude of the expected change in average customer bills or rate levels.

Total Resource Cost (TRC) Test. This test measures the net costs of the program based on the total costs, including both the participant's and the utility's costs. The TRC ratio equals the benefits of the program, counting the value of energy and demand (capacity) saved, plus other values if applicable, divided by all applicable net costs. The ratio is usually calculated over the accepted life of the investment.

Program Administrator (PA) Cost Test. Also known as the Utility Cost Test, if the utility is the administrator. This test measures the net cost of a program, including incentives paid, and excluding any net costs incurred by the participant. The benefits are similar to the TRC test, but with costs more narrowly defined.

Societal Cost Test (SCT). This is a modified version of the TRC, using a broad perspective rather than a utility service area perspective. The primary difference between the SCT and TRC is that, to calculate life-cycle costs and benefits, the SCT accounts for some environmental (and possibly, societal) externalities; it may exclude tax-credit benefits, and it uses a lower discount rate than the TRC.

When assessing DG for integrated resource planning, many states recommend the Total Resource Cost (TRC) perspective. In reviewing NEM tariff policies, the Ratepayer Impact Measure (RIM) (also known as the "non-participants cost test") often has been used. In 2009, the CPUC issued Decision 09-08-026, Adopting Cost-Benefit Methodology for Distributed Generation. In that order, it determined that California regulators would use three tests in DG policymaking: the Participant Cost Test, TRC Test (considering the Societal Cost Test as a useful variant), and Program Administrator Test. They allowed the RIM test specifically in rate-setting (e.g., NEM review). That was the impact test used for previous CPUC-sponsored NEM studies. Subsequently, the CPUC issued a cost-benefit report on the California Solar Initiative, which specifically considered the impacts of all of the output of an onsite solar project (offset load and exports). The current CPUC study of DG/NEM impacts (anticipated from E3 by September 2013) will similarly consider the rate impact of all of the output.

the customer can avoid payment of fixed costs embedded in the kWh charge.

From a utility perspective, this situation would be made worse when solar DG customers have had little impact on their demand on the system. That customer may also need metering and program administration services beyond the general rate class. Further, the utility provides enabling services for DG customers that include mitigating impacts from solar variability, as solar market penetration increases, and effectively provides a standby service. *Assuming no further detailed analysis*, the utility likely sees a clear prospect for new costs and expenses, accompanied by revenues from solar customers that are lower than considered when the rate structure was designed. From the NEM customers' perspective, their systems offset at least a portion of their demand and therefore they seek compensation for the capacity contribution.

Solar stakeholders and some utilities point out that conventional cost-of-service studies are painted with a broad brush, providing limited insight for a detailed solar DG impact analysis. Solar DG has the potential to bring specific utility economic benefits, as well as costs (besides those described above), which could be considered in the rate-impact analysis. This report offers a brief introduction to the range of possible solar economic impacts—both costs and benefits—in Section 3.[26]

One simple response to the need to recover more fixed costs might be to set the utility's customer and/or demand charges higher, to cover these costs. Fixed charges for fixed cost recovery could recover the utility's full cost of service and reduce cost shifts between customers; however, such a modification could also have impacts for low-usage customers or unintended revisions to price signals. This driver for reduced energy consumption warrants a broader review on rate design.

A standby charge (or network use charge, as defined above) applied to the DG customer for utility-provided services is another potential alternative. It would place specific system costs of serving solar customers directly on those customers. In practice, this approach has been controversial. State DG and NEM laws and regulatory provisions sometimes include "safe harbor" language, which protects solar customers from being assessed a separate charge not applicable to non-solar customers.

The question of fairness often leads to a review of the net-value of solar DG customers to the electric system. In some cases, regulators have focused more on the potential for a utility's revenue loss by limiting total solar DG capacity. This can avoid the narrow issue of utility revenue collection and postpones the immediate challenges of a detailed solar value analysis and remedial measures. It is a stopgap approach and does not address the prospect of ratepayer equity issues. It creates a regulatory barrier to solar DG growth.

Alternatively, regulators may adopt policies that are structured differently than NEM. A widely visible approach has been the Feed-In Tariff (FIT). Under a FIT, renewable energy (e.g., distributed solar) generators deliver their energy directly to the grid under a long-term contract agreement. The price may be cost-based for each form of renewable generation. In the case of solar DG, it could reflect solar-value considerations with possible changes over time. Furthermore, distributed solar customers would likely continue paying the applicable retail rate.

"Dual-rate" options have grown in visibility as interest has increased in seeking out alternatives that can both compensate solar DG customers for solar generation fed onto the grid and bill these customers separately for their consumption, thus creating two distinct transactions. One recent introduction to the discussion is called a Value-of-Solar Tariff or SmartFIT. It uses solar-value analysis to help set the tariff but also approximations for some values, in an effort to address fast-changing market adjustments, technological innovations, and other dynamics.[27]

RATE STRUCTURES, PRICING, AND MODELING ASSUMPTIONS THAT AFFECT DG AND NEM IMPACTS

Section 3, below, summarizes differences in the assumptions and calculations for different utility solar-value analyses. Yet another underlying reason for different DG-rate impacts has to do with the utility rate structure itself and with specific rate-related modeling assumptions.

A 2010 study, *The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California*,[28] from Lawrence Berkeley National Laboratory, used data from Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) to provide specific and broadly applicable insights. At the time, both utilities offered residential customers an inclining block rate with five usage tiers or a time-of-use rate that also included usage tiers. The study looked at NEM bill savings, rate impacts, and how rate- and technology-related factors might change total revenue results.

Relevant findings included:

- The increasing block rate structure at these utilities created a higher compensation level for NEM customers. That is because energy offset by a PV system would be in the most expensive, high-use tiers. Customers received the richest incentive for sizing their systems to offset only high-priced top-tier usage.
- For customers on time-of-use rates, the NEM incentive became increasingly more attractive with larger system sizes relative to compensation if those customers were under a flat rate.
- When NEM was applied to these rate structures, the total customer value of credits for distributed generation was high. For most customers, a system sized to the full load of the house would produce more NEM credits than customers could use before they would expire when under time-varying rates.
- The results from testing an alternative approach to crediting excess generation produced lower bill savings and lower non-participant rate impacts. The team also tested a FIT approach, which produced lower bill savings and lower non-participant impacts.
- Technical aspects of PV system design also affected overall bill savings and rate impacts. Specifications (system orientation, etc.), which would increase value, were not incentivized under existing NEM structures.
- Some findings of this study could improve understanding of commercial NEM programs as well. For example, commercial customers often pay time-of-use or interruptible rates, and they pay demand charges. Improved solar rate design might take these aspects of commercial billing into account.

Since this study was completed, NEM policy reviews have become more sensitive to rate-structure issues and technical assumptions. For example, a 2013 report by Southern California Edison (SCE) studied DG deployment planned for its territory under the range of California policies and found that directing DG projects to key areas on SCE's grid could moderate total deployment costs necessary to achieve its allocation of the state's distributed generation initiatives by up to $2.4 billion. Stakeholders have speculated that utilities could replace standard DG NEM rates with targeted solar rates, providing incentives for PV siting and system design that minimize total deployment costs.

2.10 | DG AND NEM RATES IN THE CONTEXT OF REGULATORY RATEMAKING TRENDS

The challenge of updating utility rate design for increasing participation by distributed solar customers is similar in important ways to other challenges facing utility regulators. The DG challenge is of course couched within the broader and increasingly important range of opportunities customers have to bypass conventional rate design models. Today's customers are increasingly embracing aggressive reductions in consumption (net-zero buildings), managing demand, considering energy storage, and of course deploying DG.

The early history of the utility industry, marked by near-steady and predictable growth in customers, loads, and revenues has been replaced by riskier times. According to an EEI history of utility cost-of-service regulation,

> *Today, investor-owned utilities point to a "paradigm shift," caused by the need for large, new capital additions, at a time of declining sales growth and reduced credit-worthiness. They urge the development of new regulatory frameworks, which provide for cost-recovery outside of the traditional regulatory rate case.*[29]

In addition to greater uncertainties in the US economy overall and in fuel and commodity markets in particular, utilities have been accommodating policies that call for greater energy efficiency, more renewables, and other program investments that do not trigger revenue creation for utilities—often the opposite. The so-called through-put incentive refers to the effect of having fixed costs embedded in the volumetric rate ($/kWh), so that utilities profit more when sales increase. Conversely, utilities profit less when sales decrease, all else being equal, because fixed costs are often subject to rate of return.

In a growing number of jurisdictions, various forms of revenue decoupling override concerns about the impact on earnings associated with changes in sales. In jurisdictions with decoupled rates, utility earnings are tied to investments, not sales. In these situations, revenue loss relative to cost avoidance remains a concern for utilities, while allocation of costs among ratepayer remains a concern for a broad range of stakeholders.

"Whether the best way for utilities to adapt is a dramatic departure from traditional rate design, or whether simpler modifications to traditional rate design will do, the rapid growth of distributed solar is helping to drive a resolution to the question."

Thus, the remedies introduced in the discussion of DG-related rate design, above, are characteristic of a trend toward revenue recovery solutions outside of traditional ratemaking. Some commissions are stressing so-called performance-based ratemaking, or incentive and penalty mechanisms, which direct utilities to achieve particular policy and service goals, and then reward them as they achieve certain milestones—or penalize them if they fail.

New ways of seeing the utility—as an "energy services company" or "smart integrator" are emerging, too. A few examples of utilities making a dramatic departure from traditional rate design, in order to address the paradox of falling volumetric revenues and increasing service costs is included in the accompanying sidebar. Whether the best way for utilities to adapt is a dramatic departure from traditional rate design, or whether simpler modifications to traditional rate design will do, the rapid growth of distributed solar is helping to drive a resolution to the question.

As we have seen in this section on ratemaking, design methodology and options chosen can fundamentally alter the solar DG customer/utility transaction. Historically, this has meant that within traditional ratemaking, DG programs

COULD NEW UTILITY BUSINESS MODELS TRANSFORM SOLAR DG PRICING?

In California, pressure to reform utility pricing structures increased with legislation calling for building standards that will promote "zero net energy buildings," e.g., new construction that will use energy efficiency, solar DG, and other strategies that would further depress utility revenues under current rate structures. In response to this and similar mandates, California utilities have begun to explore new business models, which some industry analysts say could transform the industry nationwide.[30]

San Diego Gas & Electric (SDG&E) has proposed a strategy that changes the application of conventional cost-of-service functions (production, transmission, distribution, etc.) to energy service functions in three distinct energy product markets:

- **Commodity Services:** Generating electricity and matching to customers' real-time needs
- **Reliability Services:** Business functions roughly corresponding to distribution services, with emphasis on quality and certainty
- **After-Meter Services:** Business functions to manage electricity use through programs and tools, such as energy management systems, energy efficiency programs, smart thermostats and appliances, PEV charging, security, and media services

The market structure necessary to support this vision would be based on cost-based unbundled utility price signals under which customers are charged for the services received and are compensated for the services provided to the grid. Incentives deemed appropriate to further policy goals could be introduced as a distinct line item.

According to SDG&E, this approach allows cost-based pricing of numerous, bi-directional transactions, so customers can mix and match individual, customized services and can sell generation and services back to the grid. This approach assumes that there is not one generic solar DG customer. Rather, it assumes a myriad of customers who engage in customized sets of transactions, based on whether they use solar for electric-vehicle charging, whether they use smart inverters or storage, and possibly other aspects, such as the location and orientation of PV systems and resource availability for other utility needs. SDG&E is currently involved in a stakeholder collaboration to develop proposals.

Some utilities foresee creating customer "apps" that would support greater understanding and customer control—even from mobile devices. According to their proponents, these new rate structures would not necessarily be more complex than incentive- and performance-based rate structures currently in place.

and NEM policies have been used to support solar DG deployment without specific detailed analysis on the exchange of services and values between DG customer and utility. In the next section, this paper reviews solar-value analysis, which is rapidly becoming an established and refined process embraced by both utilities and solar stakeholders. Its aim is to more completely determine the value, costs, and benefits, of distributed solar in distinct deployment scenarios and within specific utility systems, and thus, to support better ratemaking outcomes.

Solar Value Analyses: Generic Concepts And Terms

While utilities have a long history of valuing resources over a longer time horizon, they are currently faced with the need to assess distinct impacts that accompany increased levels of distributed generation. Solar-value analyses, therefore, become important tools to better align rates with the net impacts of solar DG. Utilities and other solar stakeholders are mutually aware that decisions about how to formulate and apply solar-value analyses will affect the evolution of solar pricing policies for years to come.

3.1 | TERMS FOR ANALYSIS IN NEM POLICY REVIEWS

In recent years, NEM-policy reviews have been conducted on behalf of state regulatory commissions, utilities, stakeholder groups, and others. While these studies vary in their methodology, scope, and assumptions, some categorical agreement has emerged regarding the terms for the analysis. This section describes the broad set of value categories commonly used in assessing solar DG costs and benefits, with ratemaking implications. Note that for this discussion, the term "impact" is often used instead of value, in order to underscore that these are *net* values, which may be positive or negative, within each category or in aggregate.

The categories discussed here represent a broad, but not necessarily comprehensive, list of the components of solar value, and not all studies evaluate each component. This is due largely to the fact that each state determines acceptable terms and methods, usually based on their use in general rate case proceedings and mandated energy plans. Another important limitation is the quality of available data. Utilities often have relatively little available data on some components of avoided cost, and approximations may or may not be useful. The table at right provides a summary of the common value categories found in the literature for determining the solar-DG impacts.

Throughout this paper the term *value* includes both prospective costs and benefits and does not bias or imply that either costs or benefits exist exclusively in any one or all areas of analysis.

The solar value components described in this section represent the performance of a fleet of distributed solar PV systems distributed throughout a utility's service area. This approach

TABLE 3.1 COMMON VALUE CATEGORIES FOR DETERMINING NEM SOLAR IMPACTS

Utility Energy Purchase/Generation Impacts
Utility Capacity Purchase/Generation Impacts
T&D Line Loss Impacts
Net Impacts on T&D Investments and O&M
Environmental Impacts
Fuel Price Hedge Impacts
RPS Compliance Impacts
Gross Lost Revenues
NEM Excess Generation Payments
Program Administration Budget Impacts
Power Quality and Other Ancillary Services as Another Line

reflects cumulative and dynamic impacts that would be missed in an analysis based on a single "average" system analyzed in isolation. For example, the aggregate amount of fleet hourly and annual solar generation would reflect the value from avoided energy and generation capacity at the margin (i.e., $/kWh and $/kW) *and* the magnitude of that value (i.e., number of kWh and kW avoided at the marginal price). This could be consequential, if the fleet were large enough not only to avoid the marginal source (and price) of generation, but also the impact to generation dispatch for the utility. Evaluating the energy and generation-capacity savings from the fleet also would capture any value provided by the geographic dispersion of systems throughout the additional flexible generation capacity to integrate solar generation and/or utility service area. By the same token, any need for additional flexible generation capacity to integrate solar generation and/or upgrades to distribution infrastructure to account for system impacts would be assessed in relation to the fleet rather than to a single system.

Ideally, a solar cost-of-service study would look at impacts on each utility circuit, with different solar penetrations, and only then assess fleet-wide impacts. In the discussion below, that approach is applied sparingly, to address specific circumstances. It would also consider whether solar installations utilize inverters with embedded capabilities to resolve power quality issues or whether the inverter might introduce power quality challenges to the grid. However, for most utilities, that level of analysis is not practical today.[31] If the analysis were intended for a rate review, another limitation would be the focus on the test year, rather than taking into account the dynamic impacts upon the utility of growing solar market penetration and other planned system changes. Some regulators may request additional analysis that takes a longer view, if only to provide context.

A summary of the value categories of solar in DG applications, and sub-sets of these categories where applicable, are as follows:

- **Utility Energy Purchases/Generation Impacts.** Solar DG reduces the on-site energy requirements of the utility customers who employ these systems. As the number of solar DG systems increase, sufficient energy may be generated by these systems to offset utility purchases of energy or utility generation. This value is generally calculated by multiplying the hourly output of the PV system by the utility's marginal cost of energy for the corresponding hour of PV generation and would be performed for each hour of the year that the PV system is generating, and then summed to derive annual energy-cost impacts. Embedded in this value are the net economic impacts associated with avoided fuel purchases and the net impacts on generation plant O&M costs.
- **Utility Generation Capacity Impacts.** In addition to purchasing and/or generating energy, utilities may also have to purchase or monetize generation capacity. Valuing the impacts of DG on utility generation capacity costs is a very utility-specific analysis and depends heavily on two factors: when the utility shows a need for incremental generation, and what capacity value they assign to solar PV.

  For example, utilities with excess capacity in the near-term would assign little to no value to incremental generation such as DG systems, because they are not avoiding or deferring generation additions until those years when load growth or retirements are forecast to establish a need for incremental generation capacity. For utilities that do show a need in the near term, DG systems could be attributed with deferring that incremental capacity; however, the actual amount deferred is contingent upon how well solar PV aligns in that utility's territory with its load curve.

  Multiple methods exist for determining this correlation, which provides a proxy for the percentage of a new generation asset that could be avoided/deferred with increased DG penetration (i.e., its capacity value or credit).[32]

Further, as utilities integrate a broad range of solar resources into their portfolios the capacity value provided by solar may change. Several utility IRPs have demonstrated that solar resources, including DG, ultimately at high penetrations have diminishing contributions towards system peak load. However, as forecasting load becomes more accurate, it may be possible to better determine capacity-like benefits provided by solar DG coincident with utility peaks.

- **Transmission and Distribution Line Loss Impacts.** Distributed solar projects generate energy at the point of use, reducing consumption of energy from the utility grid. In reducing grid energy requirements, the localized distribution feeders and transmission lines serving the utility experience reduced line losses. Transmission and distribution (T&D) line-loss impacts are typically calculated separately from each other, as the values differ for each system and even more by individual distribution-system feeder (inasmuch as data is available). T&D line loss impacts are typically calculated hourly, based on the marginal cost during the hours of PV production. In some deregulated wholesale power markets, marginal transmission costs are embedded in the locational marginal prices. In such cases, analysts would be careful to avoid double counting transmission line-loss impacts.

  In considering distribution-level impacts, analysts might consider that DG systems export power to the distribution grid when solar generation exceeds load. Ultimately power-flow studies are required to determine the value of DG on line losses as those impacts differ from dense to sparse territories and from low solar penetration to high solar penetration.

- **Net Impacts on Transmission and Distribution Investments and O&M.** Solar DG systems often impact the capacity levels on T&D systems, either by decreasing the capacity requirements during periods when distributed solar is being consumed on-site, or by increasing the capacity on the lines when excess power is exported to the grid. Capacity impacts are largely a function of the penetration of solar DG within individual feeder lines and within the overall service area as well as the operational characteristics and timing alignment between the solar and the specific circuits hosting the resource.

  As solar DG penetration increases, there may be feeder circuits where the utility could defer or eliminate capital investments in the system because the solar output coincides with peak demand on that circuit. Some utilities highlight tension with this potential value, relaying that reliance on DG resources to ensure the utility meets it regulatory requirements for reliability and safety is a practice that is shouldered with uncertainties and yet evolving with regulators. Other utilities and utility-published studies report that this situation is theoretically realizable, but currently rare in practice. The situation is most likely to occur where there is relatively high solar penetration on circuits that experience a peak that can be offset by solar, combined with low- or flat-load growth. A different impact might occur as reduced line loads decrease system wear, potentially resulting in deferral of replacement. In general, deferrals—to the extent achievable—have value due to the "time value of money," where money spent today has a higher cost than money spent in out years.

  One method for assessing T&D deferral value is equal to the expected long-term T&D system capacity upgrade cost, divided by load growth, times the financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load.[33]

  There may also be utility capital costs associated with adding distributed solar to the grid. As market penetration of DG systems increases, utilities must prepare the grid to accept this variable generation, and to perform well with two-way power flows. Costs of such grid preparation include technical and

operational investments and expenses. In some cases, analysts must be careful not to double-count grid upgrade costs that are accounted for as utility "smart grid" engineering upgrades, or as part of regularly scheduled system infrastructure upgrades. DG systems also may have infrastructure O&M impacts, including possible savings or costs. While the ratemaking process is focused on the test year, regulators also might want to note whether impacts will be sustained, or whether they have to do with system upgrades that can serve the utility for a given number of years at increasing solar market penetration.

- **Environmental Impacts.** Solar, and distributed solar within that broader category, is associated with a number of environmental impacts. Some of these occur as solar displaces conventional generation and related pollutants. A few occur as utilities increase their use of (typically natural gas) generators that can respond quickly to variable solar generation. In addition, there may be impacts on O&M costs for associated pollution control equipment. Because solar market penetration is just becoming consequential for a few utilities, the calculation of these impacts is subject to different assumptions and methodologies. A full, net accounting may be complex.[34] Analysts must be careful to avoid double-counting benefits that are embedded with costs in other categories.
- **Fuel Price "Insurance".** Electricity generation from solar resources has an embedded fuel price hedge-like value, since its cost of generation is known with reasonable certainty over the expected system life. This hedge-like value remains in place for the full life of the solar resource and as such can be referred to as fuel-price insurance, a known price for a defined outcome. Many utilities hedge against future fuel price uncertainty through the purchase of commodity futures, though state regulators may prescribe a particular approach and most often these hedging practices are short-lived (e.g., three to five years in duration). The generation output of a fleet of distributed solar systems provides insurance against future fuel price uncertainty equal to the annual generation of the fleet, but adjusted for any increase in fossil fuel use needed to ensure that these conventional plants can ramp up or down as needed to accommodate the intermittent nature of solar production.
- **RPS Compliance Impacts.** RPS targets are typically measured by accumulating renewable energy certificates (RECs), where one REC equals the renewable energy attributes of one MWh of renewable energy generation. Many utilities require transfer of the REC or solar REC (SREC) ownership from solar customers to the utility in exchange for some type of payment (e.g., a credit or rebate). To determine the SREC value of solar DG generation for a specific utility, the analyst would calculate the difference between the alternative cost of compliance (e.g., the prevailing SREC market price or the price of an alternative compliance payment) and the current unit cost of SRECs acquired from solar DG customers. If the alternative cost of RPS compliance is higher than the cost of acquiring SRECs from solar-DG customers, then the value of the solar DG SRECs is positive. If the compliance cost is lower, the solar DG SREC value is negative. In some jurisdictions (e.g, California), rooftop solar output does not directly count in furtherance of a utility's RPS. There may be an indirect, fractional benefit, because the amount of load for which the utility must procure renewable supplies is lower.
- **System Reliability Impacts.** A fleet of distributed solar systems may impact utility system reliability either positively or negatively. Examples of potential system reliability benefits range from the value of preventing blackouts and brownouts, to that of providing back-up power to critical customers, to the value of providing ancillary services and reactive power support to the grid.

Studies have recognized that these reliability impacts could be designed into DG system deployment, but since these implementations remain largely theoretical, they treat them in a qualitative manner. A CPUC order describing solar value calculation methodologies has described these as reliability benefits yet to be characterized and currently sets their value at zero.[35] There are also impacts of intermittent generation on system reliability such as islanding, voltage drops, etc. These impacts are reported by utilities as specific to individual electric system characteristics; some such costs are borne by the customer deploying the DG resource while other costs are socialized.

- **Gross Lost Revenues.** As discussed previously, solar-DG customers reduce their energy bills through use of the on-site generation, at times exporting energy to the grid and receiving credits for those kWh. This reduces utility energy sales, and it reduces gross utility revenues. For utility rate classes with flat retail energy rates, the calculation is merely the annual generation of the DG fleet multiplied by the retail energy rate. For utility rate classes with demand charges, seasonal differentials, time-of-use, and/or inclining block rates, the calculation becomes more complex. In these instances, an hourly analysis may be required.
- **NEM Excess Generation Payments.** Typically, DG customers who generate excess energy above their on-site energy requirements through NEM rates receive a billing credit for this unused generation, which is carried over into other hours or subsequent months. In some states, a periodic "true up" event occurs, wherein any excess generation by the customer for the period is quantified, and the customer is compensated. The rate and level at which customers are compensated varies, ranging from full retail rate compensation, to the average annual utility avoided cost of energy, with many variations in between. Perspectives have differed between solar stakeholders and utilities on the level of compensation that is most appropriate. Most states cap excess generation compensation to a percentage (typically 10-20%) above the annual energy requirements of the customer's facility. In this case, any excess generation above the cap would not be compensated. Regardless of how the customer is compensated, payments for excess billing credits are often considered a cost to the utility, depending on how the cost and value of this energy compares to the alternative the utility would have undertaken.
- **Program Administration Budget Impacts.** This is the total utility cost for running the solar-DG program. It may include costs of utility personnel to manage and market a distributed solar program, to process incentive applications, to conduct engineering reviews for interconnections, to inspect customer systems, and other program related costs. It may also include costs for NEM billing. Program administration costs are typically defined by the utility's program budget and are subject to the same type of regulatory review as other program costs.

The above inputs used in determining solar value are based on the most common categories of PV DG monetary impacts found in published literature. However, even in the literature, the application of these inputs varies widely. Table A1, in the Appendix was developed by the Vermont Public Service Department[36] and illustrates these differences. Analysts may have many reasons for using certain value categories and not others, but their reasons often relate to the perspective used in the analysis (e.g., TRC, RIM, etc.). They also may rely on categories and inputs that are prescribed by state commissions or suggested by state energy agencies.

The bottom line is that when these inputs are used in a given cost-effectiveness test, they estimate the value of a solar fleet within the jurisdiction analyzed. Results are not necessarily comparable or transferable. As with any benefit-cost analysis, a value greater than 1.0 indicates a positive value and value less than 1.0 indicates a negative value.

For example, in conducting a RIM test with the above inputs (or sub-set of inputs), if the resulting value were greater than 1.0, then the distributed solar fleet would be considered to have positive impact on rates; while a benefit-cost ratio of less than 1.0 would indicate that the fleet is having a negative impact on utility rates overall. Either way, rate equity questions may be raised. Indeed, the cost effectiveness test may result in a value greater than 1.0 for some classes of service and less than 1.0 for others.

While benefit-cost tests from various perspectives are commonly used in DG-related proceedings they do not provide the value of solar in terms of net unit costs or benefits (i.e., $/kW or $/kWh). These net unit costs are useful for comparative analysis, both in DG-related proceedings and in broader policy discussions. The same input values detailed in the above summary could be used to calculate the net unit value of a DG fleet. The analysis could be done for a single test year, or for multiple years, to capture the lifecycle benefits of a fleet of customer-DG systems.

This calculation provides additional granularity to the traditional benefit-cost tests. It might be used in adjusting solar DG/NEM rates and terms, to better meet policy objectives. For example, if it were determined that the net $/kWh value of solar is positive or negligible, then a status quo program would typically be acceptable. Conversely, if a program were determined to have a significant net negative or net positive impact, then changes to the program, in terms of incentives, DG/NEM participant retail rates, or some other adjustments, might be used.

3.2 | PRACTICAL USE OF SOLAR VALUE CALCULATIONS IN UTILITY DG AND NEM RATE DESIGN

A number of factors can have significant impacts on the results of a solar-value analysis. The first is the number of inputs that are used in the analysis. An analysis that includes only four input categories would likely provide different results than an analysis that includes eight input categories.

The second factor is the determination of assumptions used in calculating a specific input value or the determination of assumptions that bound the entire analysis. A clear example of how varying the assumptions would impact results is found in the literature on expected PV system life. Research studies commonly cited assume expected PV system life in the range of 20 to 30 years, while one study (cited by the Vermont commission staff in Table A1) assumed a system life of 30 years, and also proposed a "bonus system life" of an additional 10 years.[37] Varying system life from 20 to 30 years would, by itself, significantly impact the results, due to the discrepancy of 10 years worth of PV generation and associated costs and benefits. Other assumptions about the technology and orientation of systems, degradation in system efficiency, the pace of deployment, rates applied, and economic parameters, such the discount rate, greatly affect outcomes.

Despite the potential for differences, there is a trend running through recent published studies. Disregarding extreme outliers in the results and assuming the same number and type of inputs, the majority of studies in the literature value solar DG within a reasonably tight range when reflected over a levelized 20-year resource life. However, with the experience of European installations over the past decade, and even US installations over the past few years, there is a growing acceptance that with proper maintenance, solar DG systems can reasonably be expected to last 20 years or more. Utilities and stakeholders continue a critical review of whether the prevailing analyses will prove out, as growing solar market penetration affects the benefit/cost equation.

The above discussion on distributed solar rate impacts is based on the most common categories of benefits and costs found in the literature. However, some studies also include other input values. Some of these could be applied to a broader societal perspective, depending on acceptance by a particular regulatory commission. However, there is an active debate regarding the elements of value (costs and benefits) that should be included or reflected in utility rates. Thus, the following items should be considered as useful for consideration, but not necessarily reflective of a view that utility customers do or should pay rates that reflect these items. Stakeholders are generally aligned that to the extent that these impact areas are determined to have positive value and worthy of financial support there are various means of support, such as tax incentives (which exist today) and other economic stimuli.

"...there is an active debate regarding the elements of value (costs and benefits) that should be included or reflected in utility rates..."

Some of these additional impacts are defined below:

- **Market Price Impact.** This value comes into effect as a fleet of distributed solar systems impacts energy and capacity requirements region-wide. As increasing solar affects the amount of energy and capacity the utility purchases, the supply curve shifts, and the market-clearing price (or marginal cost of energy) will fall (or rise). Over time, as distributed solar market penetration increases, market price impacts could be significant.[38] For example, a high penetration of solar DG could lower the demand impacts on a utility system, which would move the supply curve to the right and result in a reduced marginal cost of energy and/or capacity for the hours that solar DG is operational. Yet, analysts must be wary about this anticipated impact. It is possible that higher solar market penetration might move the system peak hours to later in the day, without significant impact on daily peak demand costs. In that case, as more PV systems are added, the marginal impact on peak pricing from these systems would decrease.
- **Economic Development Value.** Some studies address the impacts of local economic development that stem from distributed solar installations. These studies assert that more jobs are generated from distributed solar installations than from conventional power generation. Other studies indicate that while solar provides short-term construction jobs, the long-term job impact for solar O&M is minimal. (One response might be to suggest that it will take many job-years for solar installers to reach full market penetration.) Regardless of the exact scenario, any job creation from solar projects could provide a net benefit to all taxpayers, due to increased tax revenues resulting from these jobs. In addition, benefits would accrue from the multiplier effects of local workers spending money within the local economy. This type of analysis, to the extent demonstrated, is nevertheless seldom accepted in the utility ratemaking process.
- **Other Environmental Impacts.** As noted previously, the environmental impact of NEM is not completely assessed by only looking at the utility's cost reductions. Reduced pollution, water usage/temperature rises (due to less combustion turbine cooling), and certain health impacts have been enumerated in studies. For utilities, these costs are not typically covered in rates; thus, some analysts have noted that it may be necessary to enact laws that charge for these costs, rather than justifying NEM, in part, on these externalities.

Some studies have suggested additional impacts, such as the market transformation impacts of PV systems (e.g., contributing to the creation of a robust and competitive market for renewable energy products). To date, these additional input categories have only been recognized as qualitative benefits, and they have not been documented in analyses before regulatory commissions.

3.3 | VARIATIONS IMPOSED BY DIFFERENT MARKETS AND UTILITY STRUCTURES

A number of specific considerations influence the impacts of solar projects in DG applications, including whether the utility obtains power within deregulated wholesale markets, whether the utility itself is regulated, and whether the distribution utility operates within a retail deregulated market. Each of these market structures will dictate different terms for the utility cost-of-service study and DG/NEM rate impact analysis or solar-DG deployment plan.

In the case of utilities that purchase wholesale power in deregulated markets, the methodology for determining the avoided cost of energy and capacity is generally the same as in regulated markets. However, the source of the generation and pricing mechanisms are likely to be different. For example, regulated utilities may obtain wholesale power from their own generation resources, supplemented by power purchase contracts with well-defined costs for energy and capacity. In contrast, utilities purchasing wholesale supplies in deregulated markets may experience more uncertainty at the margin on an hour-to-hour basis, depending upon regional load conditions and planned or forced outages of power units serving the particular supply node. There may also be fixed "take-or-pay" in power purchase agreements that will impact a utility's costs and therefore its rates to customers. In general, avoided costs of energy and capacity are calculated in a similar manner in regulated and deregulated markets, but the necessary calculations are more complex in deregulated markets.

Another consideration is the nature of the distribution utility—whether it is a regulated investor-owned utility, a public power utility, or an electric cooperative. Investor-owned utilities are almost always directed by regulatory guidelines. Their solar-impact and rate analyses would have little latitude, in terms of what input variables to include or how to assess them, until they receive approval from their state regulatory commissions. Public power utilities that are locally regulated often have fewer barriers (in addition to a non-profit business structure) which may provide a quicker path to innovations. They may decide locally which input variables to include and how to shape their solar-value analyses. This is one reason why public power utilities (e.g., Austin Energy) have included certain impacts in their tariff designs that are not typically considered in regulatory rate case proceedings. Notably, early consideration of solar-value analysis, virtual net metering for community solar projects, and alternative, FIT-based rates was also initiated in public power utilities (including at Sacramento, United Power, and Gainesville, respectively).

In some areas of the country, the impact of deregulated retail markets must be considered.[39] Retail competition presents a number of issues and concerns related to solar DG applications. Generally, in deregulated retail markets, an energy services provider sells power to individual customers. However, as billing involves the local distribution utility, and because the solar DG system may outlive the customer's relationship with a particular energy services provider, regulators have found it beneficial to promote consistency in DG programs statewide.

Conclusion

4.0 | CONCLUSION

Economic and equitable solar integration requires basic understanding of at least two disciplines—state utility regulation (particularly rate-setting) and distributed solar-value research. This paper has provided an introduction to both of those disciplines. By focusing on key concepts and terms, the report aims to create an unbiased foundation for broad and productive participation in DG-related regulatory and policy processes. This includes regulators, utility staff, and the range of solar stakeholders. The authors observe that all parties work under assumptions that need periodic review.

The context for this report is a rapidly changing and increasingly dynamic utility environment. In particular, as the penetration of distributed solar generation increases, the debate on DG and NEM policies and impacts is intensifying. Utilities that previously could not envision significant amounts of grid-tied solar on their systems are now becoming aware of distributed-solar impacts and are exploring policy options for the immediate and longer term. Solar stakeholders also recognize the need to work with utilities, in order to support solar market growth and to maximize the value of this renewable resource.

In noting the differences among state regulatory approaches for ratemaking, and then specifically for DG- and NEM-related proceedings, it should be apparent that details matter, and that there is no "one-size-fits-all" analysis for all situations. There is some misalignment between traditional cost-of-service ratemaking and the introduction of customer-based strategies (e.g., distributed generation, as well as other demand-side strategies), which are beginning to redefine the utility industry today. One outstanding example is that until very recently (and not yet to a full extent) conventional cost-of-service studies have not provided very fine resolution, which would be needed to better understand the specific costs and benefits of having small (but fast-growing) amounts of distributed solar on the system. For example, many utilities still have relatively little data on how costs of service vary in different parts of their territories or under different operating conditions. However, technology improvements are beginning to change that for some utilities.

Traditional regulation tends to fix the utility's sights on the relatively short term and on incremental changes. As researchers at the US DOE Lawrence Berkeley Laboratory (cited in Section 2) point out, current rate-setting analysis tends to view solar in relative isolation from the dynamic mix of utility resources and technologies, or else to view solar in a relatively full operational context, but paying little attention to how that context can (and will) change over time. Whether utilities adapt through a dramatic departure from traditional rate design, or whether simpler modifications to traditional rate design will suffice, the rapid growth of distributed solar is helping to drive a resolution to the question.

At this time, many utilities that are puzzling over DG and NEM policies are looking to customer equity issues and revenue-recovery solutions outside of traditional ratemaking. Some commissions are stressing so-called performance-based ratemaking or dynamic ratemaking that allows for program- or DG-specific charges, such as network-service charges or riders, on their bills. This does not imply that "the solution" to the NEM policy debate has been found. Rather, a range of approaches is under consideration, and such charges exemplify—at minimum—regulators' willingness to step out of the box of time-tried regulatory thinking.

It is also important to note that NEM had its roots in renewable energy deployment and incentive policies, but that solar DG is now more often subject to increasingly detailed cost-of-service and rate-impact analyses. As discussed in Section 3, these analyses need to be conducted on a locale-specific basis to reflect the unique characteristics of the regulatory environment, regional wholesale power markets, regional solar resources, state and local incentives, and rate structures to name a few. The term "impact" is often used in this report instead of value, when discussing the analysis of solar costs and benefits to the utility, in order to underscore that these are net values, which may be positive or negative, within each category or in aggregate. The list of specific possible impacts is growing. As discussed in Section 3, there has been some consensus across utility and stakeholder groups in identifying key impact categories, if not in identifying the best assumptions for the analysis.

Considering the regulatory mission, there is a risk that utilities and stakeholders could focus too keenly upon modeling distributed solar impacts, generating more detailed and more costly analytic methodologies, at the expense of productive dialogue. As the saying goes, "the map is not the territory." Ultimately, the regulatory task is to enlist a variety of data, analytic tools, stakeholder inputs, and careful, experience-based judgment in the right proportions to arrive at the best possible solar policies and rates.

Appendix

TABLE A.1 | SELECT EXAMPLES OF NEM VALUE STUDIES FROM STATES, UTILITIES, AND SOLAR STAKEHOLDERS (VERMONT 2013)

STUDY	TEST PERSPECTIVE			COSTS ANALYZED		BENEFITS ANALYZED								NOTES
	UTILITY	NON-PARTICIPATING RATEPAYERS	STATE/SOCIETY	NET METERING BILL CREDITS	PROGRAM ADMIN. COSTS	AVOIDED ENERGY PURCHASES	AVOIDED CAPACITY PURCHASES	AVOIDED T&D LINE LOSSES	AVOIDED T&D INVESTMENTS/O&M	ENVIRONMENTAL BENEFITS	NAT. GAS PRICE HEDGE	AVOIDED RPS PURCHASES	RELIABILITY BENEFITS (ANCILLARY SERVICES)	
EXPORTED ENERGY ONLY GENERATION														
Solar ABCs 2012 (Generalized Methodology)	■	■		■	■	■	■	■	■	■	■	■	■	Generalized methodology based on E3, Austin, and APS studies
E3 (For CA CPUC, 2010)	■	■		■	■	■	■	■	■	■		■	■	Benchmark study for cross-subsidization evaluations
Crossborder (Update To E3 Study, 2012)	■	■		■	■	■	■	■	■	■		■	■	Update to E3 based on interim restructuring of PG&E rate structures; results net cost 1/7 of that found in 2010.
Crossborder 2 (2nd Update, October 2012)	■	■		■	■	■	■	■	■	■		■	■	Second update using same methodology as first but instead looking at all three IOU territories; still a small net cost in PG&E but more than offset by net benefits in SCE and SDG&E.
GROSS OUTPUT GENERATION														
Austin Energy (Clean Power Research, 2006, Updated In 2012)	■	■		N/A	N/A	■	■	■	■	■	■			Values-only study looking at distributed (not just net metered) PV; looked at reactive power control and disaster recovery values but not included in final results.
APS (R.W. Beck, 2008)	■	■		N/A	N/A	■	■	■	■				■	Values-only study looking at distributed (not just net metered) PV and also residential solar hot water & commercial daylighting systems.
Perez (For NYC Area, 2011)	■	■	■	N/A	N/A	■	■	■	■	■	■		■	For distributed PV. Other costs analyzed: stream of revenues for devleoper to break even and costs to manage non-controllable solar for reliability. Other benefits analyzed: long-term societal value, economic growth value.
NYSERDA/NYDPS (2012)	■	■		N/A	N/A	■	■	■	■	■		■		Costs/benefits of achieving 2,500 MW PV by 2020 and 5,00 MW by 2025; other costs analyzed: lifetime average energy costs of all scales of PV, plus admin costs of state solar incentive program; other benefits analyzed: prices suppresion, maroeconomic/jobs impacts.
Clean Power Research (Perez For NJ & PA, 2012)	■	■	■	N/A	N/A	■	■	■	■	■	■		■	For distributed PV. Other costs analyzed: costs to manage non-controllable solar for reliability. Other benefits analyzed: long-term societal value, economic growth value.
This VT Study	■	■		■	■	■	■	■	■	■	■	■		

NOTE: The Department is aware of at least three additional, potentially relevant studies that will be published sometime in 2013.

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1. EPRI/SEPA, Utility Solar Business Model Bulletin #5, *Utility Options for Addressing Solar Net Metering Revenue Loss and Ratepayer Equity*, August 2012.
2. PURPA § 111(d)(11) denotes, "…the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable period."
3. Broadly defined, distributed generation (DG) is electrical generation that feeds into the distribution grid rather than the bulk transmission grid, whether it is sited on the utility side of the meter or on the customer side. In this paper, DG (specifically, solar DG) refers to PV resources on the customer side of the meter, unless stated otherwise, as this is a common regulatory interpretation.
4. Constantine, Sachu (project manager) and Energy and Environmental Economics, Inc. (E3), *Introduction to the Net Metering Cost-Effectiveness Evaluation*, for the California Public Utilities Commission, March 2010.
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11. The report, which is often cited, is R.W. Beck, Inc. Distributed Renewable Energy Operating Impacts and Valuation Study (for Arizona Public Service), 2009. The 2013 update produced by SAIC Energy, Environment and Infrastructure, LLC (SAIC)--the acquiring entity of R.W. Beck, Inc.-- is cited as 2013 Updated Solar PV Value Report (for Arizona Public Service), May 2013.
12. Perez, R., Thompson, T., et. al., *Why a SmartFIT is Smart Policy*, Solar Today, January-February, 2013, pp. 18-21.
13. See background information under "San Diego Solar Cost of Service Study" at http://www.sandiego.edu/epic/projects/?year=2012#6.
14. Bonbright, J. C., *Principles of Public Utility Rates*, Columbia University Press, 1961 Discussed in sources for this paper, including Alt (2006), US DOE (2007), and Lazar (2010).
15. Additional discussion on the inclusion of social costs and benefits is included on page 173 of Bonbright's text: "Neither the external or general benefits arguments for deviations from ordinary cost pricing, nor a counterpart, the external costs argument, can be ruled out on principle in public utility ratemaking. However, the extent to which such deviations are justified in actual practice is quite

another question. The reasons for caution and skepticism in use are indeed forcible. First, there is the extreme difficulty of prophesying and measuring indirect social benefits and social costs. Secondly, and in the absence of objective tests, there is the certainly that exaggerated claims of community benefits and costs will be put forward by various interest groups. And thirdly, there is the question whether the indirect benefits from the production of any given public utility service will be greater than those that would result from the alternative production of other commodities and services offered for sale at market prices that do not take social benefits into account.

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17. Some states have modified conventional regulation in various ways. Notably, performance-based regulation creates earnings incentives for utilities to achieve certain efficiency targets or policy goals, which supersede aspects of the revenue requirements. Still, the conventional approach discussed here is the basis for utility regulation nationwide. See McDermott, Dr. K., *Cost of Service Regulation in the Investor-Owned Utility Industry: A History of Adaptation, Edison Electric Institute*, June 2012.

18. The cost of capital is central to utility finance and to the determination of rate of return, but its detailed calculation is beyond the scope of this paper.

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20. See FERC's regulations on avoided costs and Qualifying Facilities in 18 C.F.R., Part 292.

21. The National Association of Regulatory Utility Commissioners has issued the *Electric Utility Cost Allocation Manual* (1992) and other resources to guide this effort. See http://www.naruc.org

22. Mills, A. and Wiser, R., *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California*, Lawrence Berkeley National Laboratory, LBNL 5445E, June 2012, p. 20. While this study focused on California, the authors apply some conclusions to broader markets, facing similarly rising penetrations of both distributed and centralized renewable energy resources.

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24. Barnes, J. and Vernado, L., *The Intersection of Net Metering and Retail Choice: An Overview of Policy, Practice, and Issues*, Interstate Renewable Energy Council, December 2010, offers a useful solar-stakeholder perspective on net metering issues in fully deregulated markets.

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26. Rate-setting approaches that incorporate the value of avoided costs are generally accepted by regulators nationwide, but avoided-cost analyses are often controversial. In a current review of the regulatory challenge, Peter Fox-Penner noted, "Measuring the costs of large and complex systems a utility would have built in the absence of DG and DR scattered all around its system presents challenges most regulatory practitioners love to hate." See Fox-Penner, P., *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities*, Press, 2010, p. 53.

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33. As noted above, various sources shed light on the requirements for evolving solar impact analysis methodologies. For example, Schwartz, L., et. al. for Western Governors' Association, *Meeting Renewable Energy Targets in the West: An Integration Challenge*, March 2012, takes a regional view of changing generation and associated costs, including use of a regional Energy Imbalance Market, which would improve regional generation fleet efficiency and lower cost impacts on individual utilities. Similar strategies are being considered in the Mid-Atlantic PJM market. Federal and/or state regulators must provide guidance on whether such innovations should be applied, on how they might be paid for, and on acceptable scenarios for analyzing solar impacts in the meantime.

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